

PORTFOLIO MANAGEMENT:

Looking After the Interests of Ordinary Customers in an
Electric Market That Isn't Working Very Well

Cheryl Harrington
David Moskovitz
Wayne Shirley
Frederick Weston
Richard Sedano
Richard Cowart

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The Regulatory Assistance Project

177 Water Street, Gardiner, Maine 04345 Tel: 207-582-1135 Fax: 207-582-1176
50 State Street, Suite 3, Montpelier, Vermont 05602 Tel: 802-223-8199 Fax: 802-223-8172
www.raponline.org

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Executive Summary

After ten years of restructuring activity, virtually every residential and commercial customer, more than two thirds of total load, remains a captive customer of one variety or another. Worse, the future has been truncated into short term markets where even four years can be an expensive eternity. This paper discusses the need for a return to long-term portfolio management with a stronger regulatory responsibility for long term public benefits.

Ideally, fully competitive markets with all customers making choices that reflect their own values would allow an optimal selection of resources. That's what markets are supposed to do. This vision for competitive electricity markets rests upon three essential conditions:

- 1) clear information and an opportunity to choose from a broad array of resources;
- 2) the actual exercise of choice; and
- 3) customer and supplier choices not skewed by significant market barriers and failures.

None of these three conditions is present in current retail electricity markets in the United States. Customers have little information, almost no choice, and standard offer service plans deter new market entrants by undercutting market prices.

Portfolio management is needed as an antidote to market power. Market power is most easily exercised in short-term markets where bidding strategies and capacity withholding can be profitable to suppliers. Portfolio management can reduce the risk of market power by relying more on long- and medium- term contracts and other proven risk management tools and less on spot markets. The long-term market is much less susceptible to these practices. The long-term market also benefits from the price-reducing effects of new entrants, new technologies, and other efficiency gains. Thus, in addition to reducing consumers' exposure to unwanted price volatility, another key role of portfolio management is to reduce consumers' exposure to market power-ridden, short-term markets. *The use of portfolio management may be the greatest leverage state regulators have to influence the actual operations of wholesale markets.*

Thinking about how to apply portfolio management to improve the service offered to retail customers requires understanding the differences among states in how retail service is now provided. Efforts to restructure the electricity industry have created wide variations among states as to how retail service is provided to low use customers. About half of the states have continued to regulate retail service for small-use customers on a cost-of-service basis while the other half have made various attempts to introduce competitive markets for small-use retail electricity service. The need for portfolio management exists in all states but the scope of portfolio management, the allocation of responsibility among different entities, and the regulatory approach are likely to differ significantly.

Creating a balanced and robust portfolio requires a process that includes:

- Collecting reliable data on electricity end-use demand patterns;
- Collecting reliable data on and evaluating technical alternatives for demand-side alternatives, capable of improving their the energy-efficiency or load profiles associated with particular end-uses;
- Calculating the costs and electric-load impacts of the demand-side alternatives;
- Comparing their costs with the economic costs and environmental impacts of conventional and alternative electricity supply options;
- Defining and projecting future energy-service (end-use) demand scenarios;
- Testing the sensitivities of potential plans to anticipated risks such as changes in fuel costs, load or weather patterns, and testing the plan in a variety of scenarios;
- Designing an integrated supply and demand-side plan that is robust (meaning performs well under most or all scenarios), has an acceptable level of risk, satisfies the least-cost criteria in terms of economic costs and environmental impacts;
- Reforming regulatory incentives, such as by decoupling revenues from sales, so as to make the “least cost” portfolio the most profitable course of action;
- Implementing a rate design consistent with the price patterns and demand assumptions used in building the portfolio; and, most important of all,
- Implementing the least-cost strategy.

Energy efficiency and renewables are some of the best the tools available to reduce consumer costs, prices, and risks. But by itself, adoption of portfolio management does nothing to assure that these resources will be of interest to the portfolio manager. Experience shows that even under the best conditions portfolio managers under-invest in these resources. This is the main reason most states that have elected to try retail competition have adopted System Benefit Charges and Renewable Portfolio Standards to assure that at least minimum amounts of these resources are delivered. It will remain a critical responsibility of regulators and lawmakers to keep energy efficiency and renewables a part of portfolio management.

Table of Contents

I. INTRODUCTION 1

II. THE PROBLEM..... 2

 A. The Failure of Portfolio Management..... 2

 B. Loss of Integration, Diversity, and Price Stability..... 3

 C. The Risks of Price Volatility..... 6

 D. Market Power is Accentuated in Short-term Power Markets, and Unchecked Market Power Worsens the Inherent Volatility of Electricity Markets..... 7

 E. Comparing the Prudence of Long and Short Term Purchasing Strategies..... 8

III. IT IS TIME TO RETURN TO PORTFOLIO MANAGEMENT..... 11

 A. Revisiting Integration..... 12

 B. Key Portfolio Management Considerations..... 13

 C. How Much Risk for Small Customers? 14

 D. Portfolio Management and Energy Efficiency and Renewable Energy 15

 E. Scope of Portfolio Management For Three Types Of States..... 17

 F. Administrative Options..... 23

 G. Putting It All Together: Options for Portfolio Management 28

IV. WHAT ARE THE RISKS OF PORTFOLIO MANAGEMENT TO CONSUMERS AND REGULATORS? 29

 A. Portfolio Management Prices and Short-term Market Prices 29

 B. Entry and Exit Policies..... 30

V. RAP’S SUGGESTED APPROACH TO PORTFOLIO MANAGEMENT. 30

 A. Overview..... 30

 B. Planning 30

C. Discussion of Suggested Approach	31
X. CONCLUSION	41

I. INTRODUCTION

After ten years of restructuring activity (dated from the enactment of the federal Energy Policy Act of 1992), virtually every residential and low use commercial customer remains a captive customer of one variety or another. In some states customers are captives of short-term energy markets. In other states they are captives of negotiated rate freezes that are about to end, exposing them to risks that were not fully appreciated a few years ago. In the remaining states where the pretext of retail competition does not exist, customers are captive to vertically-integrated utilities that focus more on their own uncertain future than on the long-term interests of their customers. This paper discusses how portfolio management can be applied in each of these situations, improving the cost and quality of electric service without impinging on the effort to build competitive retail markets in those states committed to that goal.

Electric restructuring has been a massive undertaking. After a decade of effort, we can begin to identify outcomes, some intended, some unintended, and some just plain undesirable. On the positive side, wholesale markets are slowly taking shape. It appears that competitive wholesale markets, though obviously harder to design and implement than first thought, are feasible but it will be some time before they are fully functioning and fully competitive.¹

On the other hand, retail markets are functioning only for a small number of the largest customers. For the vast majority of residential and commercial customers, about 60% of total load, retail markets have not yet come into existence. The sole viable version of retail competition to emerge for low use customers appears to be the aggregate bidding of the retail franchise, such as municipal aggregation in Ohio and bidding-out of default service² in Maine and New Jersey. These are essentially the bidding out of the entire retail franchise. The retail market may never work for most low use customers on anything but a conditional “franchise” basis. The non-traditional customers may in fact be a “natural monopoly”.

The most serious problem caused by the slow development of competitive wholesale markets and the non-existence of retail markets is that all but the largest customers have been stripped of the multiple benefits of portfolio management.³ What is portfolio management? It is the long run

¹ While wholesale competition is “feasible,” we do not mean to suggest that there is anything inevitable about it. It has been difficult to establish the essential elements of workably competitive wholesale markets, and maintaining effective wholesale competition will be equally challenging over time. The pattern of consolidation among energy providers both in the US and abroad is but one response of market participants seeking to dampen the effects of robust competition; other techniques for amassing market power are evolving as well.

² We use the words “default service” or “default” to mean the service retail customers receive if they do not select a provider. States use various terms to describe this service, (e.g., standard offer, or provider of last resort). All are included here under the general term “default”. A good overview of the problems default service has run up against in several states can be found at: Alexander, Barbara, *Default Service For Retail Competition: Can Residential and Low Income Customers be Protected when the Experiment Goes Away?*, 2002

³ R. Cavanagh, 2001, Revisiting “the Genius of the Marketplace”: Cures for the Western Electricity and Natural Gas Crisis, *The Electricity Journal*, 14 (5) June.

management of a diverse set of demand and supply side resources selected to minimize risks and long run costs, taking environmental costs into account. The essential characteristic of portfolio management is resource *diversity*. Not mindless diversity, but diversity carefully selected and managed to reduce risk, particularly the risk of price volatility, a salient feature of the wholesale markets. The lack of portfolio management exists to some extent in all states, but it is particularly acute in states that have moved to retail competition where customers are increasingly being forced into short-term energy markets.

State Regulators Affect Wholesale Markets When They Set Retail Rate

Setting retail rates is the most powerful point of leverage state regulators have over how wholesale markets function and what products the markets offer. With upwards of 95% of all load served on default rates, and likely to remain that way in the foreseeable future, the “demand” characteristics of the default rates becomes the primary force in defining the range of products offered at wholesale. If customers are to be served with a relatively stably priced, diverse portfolio of resources, it will be because state regulators require it. What we have learned in the recent few years is that if state regulators sit back, the market on its own, offers short-term products of only a few years duration, ignores most renewable resources, and does not produce the price stability and predictability desired by most customers.

II. THE PROBLEM

A. The Failure of Portfolio Management

Where customer choice exists, it was created in the hope that competitive retailers would provide a wide range of products and services. One expected product was long-term price stability for customers wishing to avoid the price volatility of hourly, daily, monthly, or even yearly markets. Why have such products failed to materialize? There are probably many explanations. The primary one is poorly designed default service pricing which left default service priced below any feasible retail cost. As a result, there are very few retail competitors serving small customers and most suppliers who first entered the market have since left. With very few competitors, it is unlikely that the hoped for innovative services and long-term stable-priced products will develop.⁴

It is not that the market lacks long-term portfolio management: large wholesalers, retailers, and traders may be very sophisticated portfolio managers. The problem is that the price stability

⁴ Indeed, one of the few clear lessons from retail competition, is that the marketing and transaction costs for serving small customers are in the range of 1 cent per kWh. This added cost may well exceed the potential efficiency gains from increased competition. In part, the high cost of providing competitive retail service has convinced most states, in essence, to give up on real competition for low use customers.

benefits of their long-term portfolio management efforts are not accessible to low use retail consumers. This problem may be inherent in the nature of energy markets, or it may simply earmark a flawed competitive market where no pressure exists to cause these benefits to be passed on to customers. A central issue for regulators is how to structure default service to encourage good portfolio management AND ensure the resulting benefits are delivered to customers.

Here are some of the specific problems arising out of the failure of portfolio management:

- 1) Wholesale providers are offering short-term products and managing for their own risk, not consumer's least cost;
- 2) Retail sellers do not offer a broad array of all possible resources (demand side and renewable resources have largely been left out of the market due to lopsided market rules) leaving customers no real opportunity to put together a stable, diverse personal portfolio;
- 3) Retail customers are forced into short-term markets which makes the markets even more volatile (or, exacerbates volatility);
- 4) Year-to-year price volatility, especially upward jumps in price of short-term markets is likely to be unacceptable to the vast majority of customers;
- 5) Short-term markets are especially susceptible to market power problems which in turn cause short-term market prices that are even higher and more volatile;
- 6) The reliance on short-term markets has led to a greater use of lower capital cost, higher operating cost facilities, which invariably have been fossil-fuel units, those most associated with environmental harm;
- 7) A sole focus on gas-fired combustion turbine, which can lead to a diversity problem in some places (like CA); and,
- 8) The lack of long term financial arrangements may prevent the construction of new plants by all but the incumbent vertically integrated utilities, narrowing participation in the wholesale markets.

B. Loss of Integration, Diversity, and Price Stability

Under accepted regulatory theory in the pre-restructured world, each vertically integrated utility had the responsibility to acquire all generation, transmission, and distribution resources needed to serve its jurisdictional customers. Utilities were expected to provide service using the most efficient portfolio of resources, over time. That meant making acceptable trade-off choices among all available resources, including: short- and long-term demand- and supply-side resources; transmission and distribution; as well as alternatives such as distributed resources.

System planning analysis required careful comparisons among the costs and functions of disparate resources (such as between a peak power generator and a transmission system upgrade or between an energy efficiency program and a generator), and the testing of possible resource portfolios against one another using various planning scenarios which took account of uncertainties (such as unexpected weather patterns or fuel price changes). The analysis considered total life cycle costs, patterns of costs over time, environmental impacts, and rate designs. The method of analysis for comparing such diverse resources was termed integrated resource planning (IRP).⁵

Diversity and price stability was delivered because utility planning, construction, and contracting decisions were incremental in nature. Each year, or so, a relatively small amount of resources were added to a much larger base of supply. The effect on consumer prices due to periodically tight market conditions or high fuel costs was moderated by both the size and mix of embedded resources.

⁵ Integrated Resource Planning (IRP) and electric restructuring are historically connected. The implementation of IRP processes in the late 1980's and early 1990's, together with the requirement to purchase QF power from independent generators, revealed the competitive potential of the wholesale electric market. In the states which required their utilities to put identified resource needs out to bid, often as part of the IRP process, the utilities were deluged with responsive bids from independent producers and other sellers in high multiples of the amounts sought in bid solicitations. For example, it was a common occurrence for a utility to receive 4000MW of power projects bid in response to a RFP looking for 200MW of power – often at prices below the utility's embedded cost of power. These results demonstrated to customers and regulators alike that the wholesale electric power procurement market could be competitive: It was no longer necessary to consider wholesale power procurement as a required component of a vertically integrated, regulated monopoly utility industry structure. IRP did the country the favor of identifying the generation market as potentially competitive and led directly to the path of industry restructuring. Thus, at the time the CA PUC issued its initial policy blueprint for establishing a fully competitive electric sector for that state (the Yellow Book) in 1994, marking the opening of an intensive period of state electric industry restructuring activity, about 36 states were requiring their utilities to use IRP to secure the resources to serve their retail electricity customers. (NARUC Compilation of Utility Regulatory Policy 1994-1995). Perhaps even more importantly, experience with utility IRP demonstrated the existence of a large, low-cost resource base on the customer side of utility meters, as well as the viability of demand-side management techniques to acquire them. It is critical that these lessons not be lost as the nation strives to design techniques for portfolio management either in vertically integrated franchises, or in states that have incorporated some measure of competition.

The 1992 Energy Policy Act (EPACT) clearly reflects these parallel (and not entirely harmonious) paths of planned and competitive approaches to electric system efficiency. That Act required each state to consider implementing IRP (most states already had IRP policies in effect but federal law often lags state realities). It established the authority of FERC to order use of the interstate transmission network to wheel power between unrelated buyers and sellers and created a new class of exempt wholesale generators, who were granted open access to the transmission system. Essentially the vision in EPACT was that of state-directed IRP with utilities shopping among all available resources when expanding system capacity and the federal opening of the transmission system to all sellers of generation services to greatly enlarge the pool of available resource options. The wildcard, of course, was retail competition (retail wheeling was the catchphrase in 1992).

Although the development of competitive wholesale power markets was long overdue, the advent of restructuring activity at both the state and federal levels caused integrated resource analysis and portfolio management to take an unfortunate turn for the worse. When competitive generation markets demonstrated that the book value of many utilities was far in excess of their market value, utilities became understandably nervous that they would not be able to recover their embedded costs and stopped acquiring resources for the long term. Further, as retail choice entered the scheme, generation functions were unbundled or divested from regulated transmission and distribution functions. In several states customers were given increased opportunities for choice, but the only choices offered were, with very few exceptions, relatively short-term market-prices. Customers lost the benefits of integrating diversified investment in generation, transmission, distribution, energy efficiency, and load management. Finally, in almost all states, utility-sponsored energy efficiency programs were cut back dramatically.⁶

Instead of a single entity making resource acquisition decisions, decisions in several states are now made piecemeal with no structural or market support for identifying the value to be gained or lost as between, say, additional transmission investment as compared to a generation purchase as compared to a demand side management program. There is no entity that is positioned to benefit from efforts to identify, compare, and determine the most efficient quantities of each resource.

Ideally, fully competitive markets with all customers fully participating, making choices that reflect their own values would allow the optimal selection of resources – that's what markets are supposed to do. This vision for competitive electricity markets rests upon three essential conditions Customers must have:

- 1) clear information and an opportunity to choose from a broad array of resources;
- 2) the actual exercise of choice; and
- 3) customer and supplier choices not skewed by significant market barriers and failures.

None of these three conditions is present in current retail electricity markets in the United States. Customers have little information, almost no choice, and standard offer service plans deter new market entrants by undercutting market prices.

⁶ Despite a generally solid record of success of utility-sponsored DSM programs between the mid-1980s and 1993, the programs suffered sharp reductions in the face of restructuring. Prior to restructuring, U.S. electric utilities reported plans to increase DSM expenditures from \$2.74 billion in 1993 to \$3.5 billion in 1999. (Nadel, Kushler, *The Electricity Journal*, October 2000) Instead, what actually happened was that 1999 DSM expenditures were cut by almost half, to \$1.4 billion (EIA, *Electric Power Summary Statistics, 2000*), and expenditures focused on energy efficiency, aside from load management, declined by about two-thirds. Some states, such as New Jersey, increased efficiency expenditures during the 1990's, while others, particularly in the Northwest, saw steep declines. The cutbacks may be abating somewhat as both California and New York have taken serious steps to revive utility investment in energy efficiency (Nadel, Kubo, Geller, *State Scorecard on Utility Energy Efficiency Programs*, ACEEE 2000).

Losing the single entity that was in a position to evaluate alternatives and make tradeoffs would not be so bad, if replaced with market-based mechanisms that revealed the value of different options to market participants and customers. But, this has not happened. Generation markets fail to accommodate a demand response; transmission investments continue to be made on a planned, socialized cost basis; no market participant is making trade-offs between supply- and demand-side options; and, distribution companies in many states are trying to balance responsibilities between requirements for what may be very short-term generation needs versus longer-term distribution system operations. Value is being lost. In point of fact, for most Americans, restructuring has taken away the actual benefits of integration but not yet replaced them with the potential benefits of competition.

C. The Risks of Price Volatility

Electricity markets in California, Illinois, the Northeast and mid-Atlantic regions, Australia, and Canada have all shown how volatile electricity prices can be. Although volatility is highest from hour-to-hour, even the day-to-day, month-to-month, and year-to-year volatility is more than most customers are probably prepared to accept.

Even in well-functioning electricity markets year-to-year price swings will likely be in the range of 2 to 3 cents per kWh. The annual average price can easily increase by more than 3 cents per kWh if natural gas prices are high and reserve margins are narrow, compared to when natural gas prices are low and ample generating capacity exists.

Academic economists would likely offer two responses. The first is that competitive generation and retail competition are needed to send more efficient price signals. Because electricity costs at the margin are highly volatile, prices should be volatile too. This gives buyers the right price signals to use electricity when costs are low and to avoid electricity use when prices are high. In theory, over time, such responses will enhance the efficiency of energy use. And second, with effective competition and retail choice, customers who dislike volatility can choose suppliers and products with fixed prices or moderate price swings, much like consumer choices between fixed and variable rate mortgages. We believe this perspective misses three critical limitations of existing electricity markets:

1. Almost no competitive markets have competitive service providers for any customers other than the large industrial users. Current default service policies in most markets mean there are almost no competitive retail suppliers and few of the existing competitive retail suppliers offer long-term options to consumers. Moreover, the creation of default service as a hoped-for “transitional” service has had the effect of undermining the providers’ ability to commit to long-term resources to fulfill standard offer supply commitments. Thus, default service plans – ironically, created to provide stability and continuity for low use customers – have essentially guaranteed that we will never know what a real market would have provided.
2. Existing wholesale electricity markets are characterized by the lack of demand response and the presence of market power, both of which make prices higher and more

volatile. Markets can be structured to promote more or less volatility, and current electricity markets are greatly biased to the high volatility end of the spectrum.⁷

3. Default service customers don't see hourly, daily, or weekly price signals due to the lack of necessary metering and rate design offerings. With retail access, even fewer customers will likely see real-time prices because, given the choice, most small customers choose flat rather than real-time prices (like in telecom, long distance service). Also, with retail access, suppliers that serve small consumers usually do not see the price signals either, because they are billed for electricity purchases based on average load profiles rather than the real-time use of their customers. This means suppliers have no reason to respond to volatile prices either (that is, there is no immediate and direct financial benefit to them for doing so). Further, where resource changes take place on a time horizon longer than that of the short-term market, there is a fundamental mismatch between prices and the addition of needed new capacity. That is, short-term price spikes are not likely to result in the near-term provision of new generation supply.

All of these factors combine to make today's electricity markets more volatile than they need to be, and policy makers in many jurisdictions have implemented retail access and standard offer policies that result in almost all low use customers being in excessively volatile, short term (one year or less) markets.

In theory, long-term price stability simply requires a customer to sign a long-term contract for power. In reality, however, most retailers do not offer long-term contracts and low use customers do not sign them. There are many possible explanations for why there are no long-term electricity products. It is probably for the same set of complex reasons that there are no long-term contracts for other commodities ranging from gasoline to pork bellies. Knowing the reasons why these products are lacking is less important than simply observing that they are lacking and then taking steps to manage the risks that their absence imposes on consumers.

D. Market Power is Accentuated in Short-term Power Markets, and Unchecked Market Power Worsens the Inherent Volatility of Electricity Markets

The evidence is rapidly mounting that market power is a more serious problem than originally thought. Studies by the California ISO's Market Monitoring Committee following the enormous price run up of late 2000 and early 2001 found that market power in the California market accounted for about \$7 billion in excess charges⁸. If this estimate is even close, market power already cost California consumers far more than any estimate of the efficiency gains to be

⁷ Argentina provides an example of a vigorously competitive generation market that has been designed to minimize market power and price volatility. The key design feature is that generators' bids are made for a three-month period, rather than hourly or daily. Experience there has shown that this practice virtually eliminated the gaming of bids and stabilized prices.

⁸ Hildebrant, Eric, July 9, 2001, *Analysis of Payment in Excess of Competitive Market Levels in California's Wholesale Energy Market, May 2000-2001*.

squeezed out of competitive markets. The cost of market power problems in California threatened to quickly exceed the total stranded cost that California utilities accumulated over the 20 years prior to restructuring.

At least as frightening as the degree of unchecked market power (where all generators regardless of intent benefit by “piling on”) is the slow pace at which the regulatory, legislative, and judicial process seems to be able to solve the market problems, once they are identified. Whether we will ever be able to reduce market power to acceptable levels is a debatable and important question. But, in the meantime, portfolio management provides a way to reduce consumer exposure to it.

Portfolio management can reduce the risk of market power by relying more on long- and medium- term contracts and other proven risk management tools and less on spot markets. Market power is most easily exercised in short-term markets where bidding strategies and capacity withholding can be profitable to suppliers. The long-term market is much less susceptible to these practices. The long-term market also benefits from the price-reducing effects of new entrants, new technologies, and other efficiency gains. Thus, in addition to reducing consumers’ exposure to unwanted price volatility, another key role of portfolio management is to reduce consumers’ exposure to market power-ridden, short-term markets.

The critical question for every regulator and policymaker right now is whether it is prudent to put the vast majority of small customers into the short-term market for all of their electricity needs. Most certainly, in a fully regulated monopoly market structure, if a utility put 100% of its load into the short-term market, it would have been found to have acted imprudently and been penalized accordingly. But, whether the answer is, “No, we don’t want to be 100% in the short term market because prices will be unacceptably volatile.” Or, “Yes, because price volatility adds economic efficiency to the grid and will be tolerated by consumers.” We at least need a temporary portfolio manager until effective means of reducing market power have been put into place. In either case, portfolio management is an essential function of the electric system under current conditions. It may be a necessary function for a very long time. The challenge, of course, is deciding specifically what should be incorporated into the portfolio management function and who should do it.

E. Comparing the Prudence of Long and Short Term Purchasing Strategies

One method to highlight the prudence of a provider’s purchasing strategy is to consider the extremes of its options. At one end of the spectrum is a portfolio that is 100% in the spot or short-term market (“Spot Market Case”). At the other end, is a portfolio that is 100% long-term with fixed prices (“Long-Term Case”). By “fixed” price, we mean pre-determined price, even if that number changes over time under a contract schedule. What are the strengths and weaknesses of these two strategies?

The term “prudence” is derived from the legal concept known as the “prudent man theory.” That is, what would a prudent decision-maker do, based on the information they ought to know at the time when they are making a decision? In this context, prudence is closely aligned with accepted risk management or portfolio theory. The prudent manager will apply accepted risk management principles when assembling a resource portfolio. Accepted risk management theory is premised

on the notion of diversification. It, therefore, seems to preclude both the Spot Market Case and the Long-Term Case, unless special circumstances would be identified for electric markets that would exempt them from the tenets of the theory. Without proof of such special circumstances, the theory holds that the least risky portfolio is one that provides the greatest diversification.

1. Spot Market Case

The principal strength of the Spot Market Case is its flexibility. As operating cost characteristics shift over time, a purchaser can modify their supply portfolio to capture the most efficient basket of resources. In a “pure” spot market case, the purchaser essentially allows the spot market to accomplish this directly and they merely “take” the spot market price as it is presented. The purchaser achieves the “optimum” or cheapest portfolio of supply, *given the choices available at that point in time*.

The weakness of this case, in addition to the obvious exposure to price volatility, is the absence of any entitlement to resources with any certain price or operating characteristics. The entire supply portfolio turns over every hour. In this case, the purchaser is not just a price-taker, but a supply-taker as well, with no firm resource commitments available to them.

Regulated utilities have generally been penalized for over reliance on short-term markets. For example, this approach to supply portfolio management was rejected for a natural gas utility by the New Mexico Public Utilities Commission (Case No. 2752, May 1, 1997). That decision was heavily influenced by the rate shock associated with a doubling of gas prices over a two month period and the associated flow-through of those costs to customers – especially its impact on low-income and small commercial customers. Although the utility argued that a 100% spot market portfolio was the least cost option over the long -run, the Commission rejected that position because of its associated risk of price volatility. While the Commission declined to find the utility’s past purchasing practice imprudent, partly in response to the Company’s assertions that (1) the issue had never been raised and (2) there was no clear mechanism for recovery of hedging expenses, it made clear that a pure spot market portfolio was not an acceptable or prudent strategy going forward. California’s recent experience only serves to reinforce that conclusion, although the particulars of California’s restructuring framework caused utilities, rather than customers, to bear the risk (with the exception of San Diego Gas & Electric).

Even if one could achieve lower long-run costs through reliance on the spot market (an as-yet unproven assertion), the potential adverse impact on customers of large price swings over short time horizons can be devastating. This is especially true for low-income and small commercial customers or their proxies, the load serving entities. When these very real social costs experienced by these and other customers are included in the analysis, reason dictates a move away from intensive reliance on spot market supplies. In short, such a strategy is inconsistent with sound risk management and should, therefore, be considered imprudent.

2. Long Term Case

While one might expect symmetry at the other extreme, it is not necessarily so. The principal advantage of having a long-term fixed price portfolio is, obviously, price stability and an

assurance of a supply with known, and presumably desirable, pre-commitment price or operating characteristics. A not too obvious correlation to this is that, under ordinary circumstances, the purchaser is unlikely to enter into long-term contracts with extremely high, fixed prices; although, as discussed below, California, with its extraordinary circumstances, achieved the opposite result

The principal weakness of a long-term fixed price portfolio is the risk associated with being “wrong” as compared to cheaper alternatives that come and go in the interim (the extreme of which is the spot market). This weakness is partly a function of the extent to which long-term fixed price supplies are acquired all at once or are staggered (“laddered”) over time. Once again California offers a lesson in the extreme. In response to the disastrous impact of being essentially 100% in the spot market, long-term fixed price contracts were signed for virtually all of California’s power needs going forward. Whenever long-term contracts are negotiated, the prices will inevitably be influenced by then-existing spot market prices and near-term expectations about those prices. Unfortunately, California’s contracts were negotiated at a point in time when supplies were tight or uncertain and spot prices were high (or were presumed to continue to be high over the near-term horizon). And, power companies appeared to be exercising market power and manipulating the market.

However, subsequent to the negotiation of those contracts, a variety of changed circumstances have lowered both spot market prices and expectations about them in the near term. As a result, purchaser’s remorse has set in and an effort is now underway to renegotiate the contracts because they appear to be high cost, *as compared to today’s spot market expectations*.

Does this mean that the Long-Term Case is as imprudent as the Spot Market Case? Perhaps, although the adverse impacts of the Long-Term Case may not be as severe as those of the Spot Market Case. Much of the purchaser’s remorse phenomenon can be mitigated where long-term purchase contracts are laddered over time, like dollar cost averaging in a mutual fund, causing only a limited portion of the supply price to be impacted by then-existing spot market price expectations. Nonetheless, the extreme Long-Term Case, which also generally runs afoul of accepted risk management theory, is probably not a prudent strategy either.

In short, the “prudent” portfolio manager will seek a balance between the two extremes, allowing for sufficient opportunity to capture short-term benefits, while maintaining a stable base of diverse supply. In evaluating a supply portfolio, it is important to credit long-term components with some value for avoided price shocks, even if their cost *in retrospect* appears higher than the spot market. Indeed, retrospective comparisons of the choices made by a portfolio manager run afoul of the principles embedded in the prudence standard and therefore should be avoided by the regulator. The comparison should be to the alternatives at the time when the choices were made.

The Failure to Pass Portfolio Benefits to Customers

The gasoline and heating oil markets are other examples of the failure to pass portfolio benefits to customers. In the gasoline market, Exxon, Texaco, and Shell are all portfolio managers. Each has assembled a portfolio of oil wells they own, supply contracts of various types and durations, financial hedges of all sorts, and, in varying degrees, spot market purchases. Meanwhile, retail gasoline consumers are all essentially in the spot market. Consumers may have some timing flexibility if they fill their tanks weekly. Farmers with on-farm fuel tanks may be in a slightly longer duration market. In the case of fuel oil or propane for home heating, many suppliers offer price stability for a year. But there are no longer-term products offered to or bought by consumers. In these markets, all consumers are essentially in the short-term market.

If the world price of gasoline and heating oil goes up by 20%, the retail price of gasoline and heating will go up by 20%, or something close to it, within a day or two. The average **cost** to Exxon, Texaco, and Shell does not go up 20%, because spot purchases are only one part of their portfolios. When the price of gasoline goes up by 20%, oil companies make a lot of money. The firm that had the best-managed portfolio makes the most money. Electricity markets are now like oil markets. But, even if a retail supplier is an excellent portfolio manager, neither the price stability nor the low average cost achieved through their diversity of supplies will necessarily flow through to their customers.

III. IT IS TIME TO RETURN TO PORTFOLIO MANAGEMENT

The concept and practice of portfolio management is not new to this industry. Portfolio management means assembling a mix of long-, medium-, and short-term resources, resource types, and financial instruments with the aim of most efficiently balancing long run cost and risk. The goals of portfolio management are the same goals as in decades of utility regulation and are currently being sought by introducing the greater use of competitive markets in this sector. The goals are to obtain: the least costly mix of resources; high system reliability; stable, affordable prices; minimized negative impact on the environment; markets untainted by market power; and, of increasing concern, system security. This is of course what major suppliers in the electricity market do today on an ongoing basis to protect their aggregate positions in the volatile electricity market. What has been lost is that these “portfolio” benefits are no longer passed on to customers.

Using portfolio management to achieve these economic, social and environmental benefits does not require abandoning or slowing the shift to more competitive **wholesale** markets, but policy makers do need to be more aware of the looming gap between consumers’ reasonable expectations and the gritty realities of emerging electricity markets, both retail and wholesale. Without retail competition, the utility, default service provider, or other licensed monopoly retail electricity provider is the portfolio manager. The manager can dampen the wholesale market price volatility by limiting the amount of resources drawn from the short term market at any one

time. A robust portfolio would consist of a diverse mix of power plants, contracts, spot energy purchases, and other risk-reducing measures such as investments in energy efficiency and renewable resources, as well as demand management and load response programs. This sort of robust portfolio does not need to be sacrificed to emerging markets. The trick is to recapture the positive elements of IRP that have been lost, without adversely affecting market development.

A. Revisiting Integration

Not all of today's regulators will be familiar with the strategic integrated portfolio concept known as Integrated Resource Planning, or IRP. IRP for the electric utility industry evolved in the 1980s. It broadened the scope of system expansion planning from traditional supply-side resources (that is, wires and power plants) to a more complete economic analysis that integrated all available resources and technologies. This included resources available on the demand-side, such as investments in programs to acquire energy efficiency and load management resources. In practice, IRP promotes the development of electricity supplies and energy-efficiency improvements, including managing the growth of demand (DSM options), to provide energy services at minimum total cost, including environmental and social costs. Ideally, IRP investigates the broadest reasonable range of options to meet demand for electric service, including technologies for energy efficiency and load control on the demand-side, as well as decentralized and non-utility generating sources. By selecting technologies and programs to minimize the total cost of electric service, and incorporating analysis of environmental and social costs, IRP makes it possible to plan electric supply and demand-side options that will meet electricity demands most efficiently without wasting economic or environmental resources.

Creating a balanced and robust portfolio requires a process that includes:

- Collecting reliable data on electricity end-use demand patterns;
- Collecting reliable data on and evaluating technical alternatives for demand-side alternatives, capable of improving their the energy-efficiency or load profiles associated with particular end-uses;
- Calculating the costs and electric-load impacts of the demand-side alternatives;
- Comparing their costs with the economic costs and environmental impacts of conventional and alternative electricity supply options;
- Defining and projecting future energy-service (end-use) demand scenarios;
- Testing the sensitivities of potential plans to anticipated risks such as changes in fuel costs, load or weather patterns, and testing the plan in a variety of scenarios;
- Designing an integrated supply and demand-side plan that is robust (meaning performs well under most or all scenarios), has an acceptable level of risk, satisfies the least-cost criteria in terms of economic costs and environmental impacts;

- Reforming regulatory incentives, such as by decoupling revenues from sales, so as to make the “least cost” portfolio the most profitable course of action⁹;
- Implementing a rate design consistent with the price patterns and demand assumptions used in building the portfolio; and, most important of all,
- Implementing the least-cost strategy.

The IRP planning horizon generally spans 10 to 20 years, or as long as can be reasonably forecast, with a specific action plan developed for the upcoming two to three years. Total electricity demand is disaggregated by sector, end-use, and technology, with as much resolution as possible given available data. Technologies for improving energy end-use efficiency or influencing load shapes are identified. The technical and economic performance of these alternatives are estimated, compared, and ranked according to cost-effectiveness. Based on these results, DSM programs and other energy-efficiency strategies are analyzed in terms of their total costs and rates of market penetration over time.¹⁰

Production-cost analysis of the performance of existing and new electric supply alternatives is used to rank these alternatives according to marginal cost values. The results are compared to the marginal costs of demand-side options, including environmental costs to the extent possible. The two sets of options (supply- and demand-side) are then compared and combined to produce the integrated least-cost electricity plan. The integrated electricity plan is subjected to further financial evaluation and sensitivity analysis before the final plan is completed. The incorporation of these issues may re-order the ranking of the integrated plan somewhat, or exclude certain resources from the plan. This step fine-tunes the IRP results to account for specific issues and options inherent in the local or national setting.

B. Key Portfolio Management Considerations

Deciding what resources are needed requires taking into account a long list of variables.

- *Demand* - What is the likely level of demand for service over the relevant time period? What kind of end uses will drive that demand? How variable is the forecast? What factors are responsible for the variability? What ranges are those factors likely to take?
- *Resources* - What are the available resource choices? What are the trade-off choices that can be made among resources? What is the range and variability of fuel prices,

⁹ S. Carter, 2002, Breaking the Consumption Habit: Ratemaking for Efficient Resource Decision, *The Electricity Journal*, 14(10) December.

¹⁰ Hirst, *A good Integrated Resource Plan: Guidelines for Electric Utilities and Regulators*, Oak Ridge National Laboratory, 1992. Also, Harrington, et al. *Integrated Resource Planning for State Utility Regulators*, RAP 1994

market prices, construction costs, investment and financing costs likely to be incurred to provide the required service?

- *Reliability* - Will the resources operate when they are needed and what are the costs of replacement power or damages if they don't?
- *Environmental* - Will the resources incur environmental damage that isn't internalized to the price? Who will pay these costs and when?
- *Market power* - Are prices subject to manipulation by market participants?
- *Security* - Are there external threats to the selected resources? What are those threats? Can they be ameliorated? If any of the threats materializes, what additional costs might be incurred as a result? What additional costs might be incurred to protect against those threats?

Under traditional regulation, customers bore virtually all the risks and benefits of power supply decisions. Utilities bore the risk of making imprudent decisions. Utilities and regulators managed risks through the IRP process, certificate of need reviews, and *post hoc* prudence reviews. One of the goals of moving to a fully competitive retail market was to change this risk allocation. It was hoped that in a competitive market, customers would have a wider range of choices and would bear only the risks they chose. However, as we have seen to date, essentially no competitive market for services to low use customers has developed.¹¹

C. How Much Risk for Small Customers?

A critical issue for portfolio management is deciding what level of risk small (non-industrial) customers should be asked to assume. This decision requires judgment informed by the tradeoff between risk and price. Identifying and assessing the risks of different portfolios is the heart of IRP. IRP helps portfolio managers decide what mix of energy resources and financial arrangements best strikes a balance between price level, price risk, price volatility, total energy costs, environmental and other non-price effects, and financial risk. Key questions and issues include:

1. How much exposure should there be to any one fuel, or conversely, what is the desirable level of fuel diversity? This question is particularly pertinent in light of the massive increase on reliance on natural gas and the diminishment of energy efficiency resource procurement in the last five years or more.

¹¹ Large industrial customers, unlike the commercial and residential classes, usually have choices regarding whether they want to increase or decrease production in response to energy price. They are acutely aware of their marginal costs of production and are prepared to respond to price changes. Low use customers and most particularly low income, low use customers tend to think of electricity use in terms of total monthly cost rather than marginal prices.

2. How are purchase arrangements structured? If most energy comes from contractual arrangements, how long are the contracts and are they staggered in both time and size (“laddered”) so as to minimize exposure to price volatility?
3. How much reliance is there on spot markets, which may be unacceptably volatile?
4. How much reliance is there on renewable resources like wind and solar, with no or fixed fuel costs, as a hedge against high fuel price volatility?
5. How much reliance has been placed on financial contracts as compared to physical power contracts and physical power assets?
6. Are the contract terms at odds with underlying market realities? For example, a contract that relies on a fixed or banded gas price may simply be breached if gas prices take an unexpected leap or fall. A fixed price gas contract may not be honored when gas prices rise dramatically.
7. Have environmental costs been internalized or otherwise accounted for?
8. What is the total cost of supplying energy services to customers under the proposed portfolio, and have cost-effective demand-side resources been tapped to lower total costs to customers?
9. Can these resources be delivered to market reliably, or will they impose new contingencies or transmission constraints that raise the risk of outages or the cost of meeting reliability standards?

D. Portfolio Management and Energy Efficiency and Renewable Energy

Energy efficiency and renewables are some of the best the tools available to reduce consumer costs, prices, and risks. But by itself, adoption of portfolio management does nothing to assure that these resources will be of interest to the portfolio manager. Experience shows that even under the best conditions portfolio managers under-invest in these resources. This is the main reason most states that have elected to try retail competition have adopted System Benefit Charges and Renewable Portfolio Standards to assure that at least minimum amounts of these resources are delivered. It will remain a critical responsibility of regulators and lawmakers to keep energy efficiency and renewables a part of portfolio management.

1. Energy Efficiency

Cost-effective energy efficiency (energy efficiency that saves a kWh for less than the marginal cost of producing and delivering a kWh) always reduces customer bills, but it may or may not reduce prices. Making cost-effective energy efficiency a part of its portfolio hinges on two related factors — the incentives faced by the portfolio manager and how the wholesale market is structured.

The incentives faced by the portfolio manager will be determined by the regulatory rules, if the portfolio manager is regulated, or by the contract terms, if the portfolio manager is a competitive supplier. In either case, careful attention to how the portfolio manager makes money is the key to understanding its interest in energy efficiency. For example, if portfolio managers are insulated from the risk of high spot market prices and are allowed to earn a margin on all sales, they will have no reason to invest in energy efficiency, even where efficiency would lower the cost of the portfolio to customers.

Efficiency Response in California

California provided a stark example of how well the right incentives can work. In California, the portfolio manager's (the distribution utilities) prices were fixed when their wholesale supply costs increased to levels well above the default service price. Instead of making money on increased sales, the California utilities suddenly found themselves losing large amounts of money on every kWh they sold. They responded with a newfound and enthusiastic embrace of energy efficiency. Electricity demand was lowered 6.7 % overall, and an average of 10% for the summer peak hours. The Legislature authorized an additional \$859 million for load reduction programs in 2001 and 2002.* Redoubled energy efficiency investment was a major reason the crisis ended faster than predicted. Several of the energy efficiency incentives were not an integral part of the original market design, they were the temporary and unplanned result of unusual circumstances. It remains to be seen how thoroughly California will incorporate these recent energy efficiency lessons in future reforms.

*The Summer 2001 Conservation Report, The California Energy Commission, February 2002

The structure of the market may also influence whether the portfolio manager has an incentive to invest in energy efficiency. In particular, if the value of demand response is fully incorporated in wholesale markets, the portfolio manager will have a much stronger incentive to pursue load management and some limited types of energy efficiency.

2. Renewables

As for renewables, their virtue is their freedom from fossil fuel cost volatility and escalation as well as their insulation from new environmental costs arising from air pollution or climate change mitigation requirements.

Portfolio managers can reduce price and other risks through physical or financial hedges. But, despite oft-repeated assertions about the "sanctity of contracts," all hedges do not have the same level of security, either to producers or to consumers. What types of hedges are best from the consumers' perspective? Coal or nuclear power claim to offer stable long run prices but surely when the risk of additional environmental and security costs are included in the calculation they lose serious attraction as hedges. Nor does nuclear power have a particularly strong reliability history. For many years 60% capacity factors were common.

The most difficult situation is one in which a fundamental cost such as the price of natural gas skyrockets and carries market clearing prices along with it. If market prices greatly exceed the expectations of participants, there is a risk that suppliers, including portfolio managers, will default on their obligations. There are already numerous examples. The bankruptcy of Enron and the subsequently rejected contracts show how the strength of the counter-party in a financial risk management deal can be illusory. Retail suppliers in California and Pennsylvania have ceased service and returned customers to the default provider. For example, an early default service provider in Maine (chosen through a competitive bidding process) had its wholesale providers default when market prices increased thereby causing the Maine PUC to agree to raise the fixed price the retailer had originally agreed to. The lesson is that if market prices increase, suppliers who agreed to deliver fixed prices will be quick to seek relief of one sort or another, including breach of contract. Buyers may also pursue contract rejection or reformation, as demonstrated by recent contract renegotiations and extensive litigation in California. The essential point is that financial promises to deliver fixed prices may be meaningless if market conditions change too much.

Hedges in the form of contracts with renewable generators can provide a higher level of security.¹² Indeed, one of the best hedges is one with a physical asset that has underlying cost characteristics matching the hedged contract prices. A fixed priced contract for the output of a gas-fired power plant provides the appearance of price stability, but there is a risk of non-performance if gas prices increase, while buyers may seek price reformation if gas prices drop significantly. The same contract with a wind facility can provide more security as it lacks the risk of a variable fuel cost. Of course, renewable resources do have some fuel risk: the wind may not blow, the sun may be clouded over and, droughts may occur but the risks are probably small compared to the price volatility of fossil fuels, and they can be hedged by making many small renewable investments rather than a few large ones.

E. Scope of Portfolio Management For Three Types Of States

Thinking about how to apply portfolio management to improve the service offered to retail customers requires understanding the differences among states in how retail service is now provided. Efforts to restructure the electricity industry have created wide variations among states as to how retail service is provided to low use customers. About half of the states have continued to regulate retail service for small-use customers on a cost-of-service basis while the other half have made various attempts to introduce competitive markets for small-use retail electricity service. Of the half trying to develop retail competition, some use the distribution utility as the default provider and other put default service to bid. The need for portfolio management exists in all three types of states but the scope of portfolio management, the allocation of responsibility among different entities, and the regulatory approach are likely to differ significantly. We will divide the various arrangements into three categories.

¹² See, Bolinger and Wisser, Quantifying the Value That Wind Power Provides as a Hedge Against Volatile Natural Gas Prices, presented at Wind Power 2002, Portland, Oregon.

- Competitive Acquisition of Default Service (Category 1)

A few states that have moved to retail competition are committed to establishing standard offer service on a competitive basis. Maine is the best example, having had three cycles of competitive bidding for standard offer service. The first two cycles resulted in viable bids of only one year in duration but the third cycle has resulted in contracts three years in length. Other New England States (Massachusetts and Rhode Island) have solicited competitive bids for default service but did not receive any acceptable responses. New Jersey has recently awarded bids for standard offer service. Pennsylvania has solicited bids for a small portion of standard offer service but no viable bids were received

- Utility Provides Default Service (Category 2)

The larger group of states that have adopted retail competition have arrangements that rely upon the distribution utility to supply default services. These are states where the distribution company, often pursuant to the original negotiated restructuring arrangements, provides standard offer service. Massachusetts, Rhode Island, Connecticut, New York, Maryland, Delaware, and Montana are examples of this arrangement. Pennsylvania largely remains in this category. California was a version of Category 2. Service was provided by the distribution utility under a fixed rate agreement but the utilities were able to recover only the short-term market price for these customers, which seemed to work until the market price soared well above the amounts recoverable under the rate agreements. In most of these states the current rate arrangement will lapse at the end of the restructuring transition period. It is not at all clear what arrangements will be made for standard offer service in these states following the expiration of the rate arrangements. Texas has required default service customers be transferred to a utility's affiliate and served at a rate set by the PUC.

- Vertically Integrate, Fully Regulated (Category 3)

This group contains the largest number of states; they are the states that have not adopted retail completion. They include all states not mentioned in the previous two categories.¹³ Among the states that continue to use traditional cost-of-service regulation, many fail to integrate a full range of demand-side programs into the system, thus losing the cost reduction benefits of a more balanced portfolio. Moreover, concerns about future industry structures and whether competition will grow or decline are preventing states from addressing this problem.

Where electric service is still provided by vertically integrated firms, it remains the utility's obligation to provide "just and reasonable rates" to all customers. This obligation is typically met through integrated resource planning (IRP), with varying levels of regulatory oversight and approval. IRP is the process by which utilities and policymakers manage the portfolio of assets –

¹³ Oregon is an unusual version of Category 3. Retail competition was not extended to residential customers under Oregon's restructuring law but, two of the three types of service options required to be offered to the residential class, the two "clean" options, were successfully put out to competitive bid. See text box page 25.

generation, poles, wires, etc. – needed to meet demand. It provides an analytical framework for assessing the various risks a utility and its customers face – business, financial, market, environmental, political – and for evaluating the full range of options to manage those risks.

1. Competitive Acquisition (Category 1)

a) General

We begin by describing what portfolio management is in the context of a state with retail competition and where default service is provided on a competitive basis. We begin here because the role of the portfolio manager is the most limited and the most clearly separated from other functions that are needed to achieve effective portfolio management but that are performed by other entities.

In Category 1 states, the portfolio manager is not the distribution utility. The portfolio manager is a competitive service provider assembling resources to supply the only the default customer block. Although it is theoretically possible to impose wide ranging portfolio management obligations on the default service provider doing so will be inconsistent with its obvious incentives and its narrow mission.

The portfolio manager only fulfills part of the complete set of integration functions. The portfolio manager can be expected to develop a portfolio that is consistent with its interests and the obligations it has agreed to accept. Thus, for example, if the RFP asks for a fixed amount of energy each year for 10 years, there will be no need to prepare a long-term demand forecast but it will need to assemble resources that allow it to meet long-term fixed price obligations without undue financial risk. On the other hand, if the RFP asks for a bid to serve the default service customers in a specific geographic area, demand forecasting will be important. And, if the RFP asks the portfolio manager to supply default service for just two years and indexes the default service price to natural gas prices, the portfolio manager will assemble a low risk portfolio depending mostly on short-term gas-fired resources.

In no case will the portfolio manager have any reason to consider the full range of transmission, distribution or distributed resource options. The portfolio manager will only consider demand-side options to the extent that the value of these resources is exposed in the design of the wholesale market.

Because the portfolio manager in these states will have a limited planning role, establishing the overall integrated energy plan will remain an important role for state government. IRP (without regard, for the moment, to the particular administrative process by which it is devised and reviewed) would be used to identify the terms and conditions that the portfolio manager will be competing to meet.

The limited role of a default service provider is underscored by considering three key factors in portfolio management: duration, financial risk, and price volatility. These key factors in portfolio management need to be in any RFP for competitive default service. None of which would be expected to be a matter for the portfolio manager to determine in its own planning function. This

means a state agency; perhaps the state agency responsible for planning, however, would use IRP to make these basic decisions that would be reflected in an RFP.

b) Duration

The duration of the default service obligation is critical. Moving customer prices away from excessive exposure to short-term markets will require greater use of long-term commitments. Without long-term default service commitments, customers will be exposed to short-term markets even if the supplier has secured long-term stably priced resources.

c) Financial Risk

Recent experience in the power market underscores the need be concerned about the level of financial risk of the portfolio manager. The RFP should specify limits on the portfolio manager's financial risk arising from reliance on spot market purchases and reliance on financial (rather than physical) contracts. This may also impose fuel diversity and renewable requirements.

d) Price Volatility

Markets in California and elsewhere have demonstrated just how volatile electricity prices can be. Planners and policymakers need to decide the maximum yearly or monthly exposure to price volatility.

e) Energy Efficiency

The responsibility for acquisition of energy efficiency for Category 1 states is best assigned to an entity other than the portfolio manager. The portfolio manager's incentives will likely be to increase sales with the possible exception for the load management that is valued by the market in demand response. The funding responsibility for energy efficiency and renewable resources, such as through familiar system benefit charges (SBC) would not be imposed solely on the portfolio manager but would be implemented in ways that affect all load serving entities.

f) Other Responsibilities

Government policy makers, legislative, executive, or administrative, must undertake other relevant actions that are clearly not the responsibility of the portfolio manager, but will influence the cost, price, and resource mix selected by the portfolio manager. These other critical government roles include:

(1) Market Design

Assuring well-designed wholesale markets that address market power, demand response, and fair treatment of intermittent renewable resources;

(2) Transmission

Pricing and planning transmission to permit the portfolio manager to consider costs and cost saving;

(3) Energy Efficiency and Renewables

Designating the minimum amount of energy efficiency and renewable resources to be included in the state's electricity mix and establishing that green resource options are offered as part of default service.

(4) Distribution Planning

Integrated planning of the distribution system including: design of retail rates such as the use of distributed resource credits designed to encourage customer use of distributed resource in high cost areas.

(5) Align Regulatory Incentives

Consistent regulatory incentives that remove the sales throughout incentives.

2. Distribution Utility (Category 2)

a) General

Category 2 states are those that have moved to retail competition but have imposed the obligation of default service on the existing distribution company. In some of these states, such as New Hampshire, the distribution company still owns generation or has long-term power supply contracts and uses these resources on a cost-of-service basis to provide a significant portion of its default service needs. In other states, such as Massachusetts, the utility owns little or no generation but is required to act as a purchasing agent for default service customers and it has made some long-term supply arrangements.

The wide range of Category 2 states means some details of portfolio management will differ from state to state. However, the common element of these makes portfolio management different from portfolio management in Category 1 states is that default service is provided by the distribution utility. This means the portfolio manager has the ability to incorporate distribution system planning, including the cost-effective applications of distributed resources, as a seamless part its portfolio management function.¹⁴

¹⁴ Many Category 2 states may already have at least some portion of default service provided by long-term resources. So, unlike Category 1 states, the shift to long-term commitments will be relatively easy to make.

b) Other Responsibilities

In other respects, basic decisions such as default service customers' exposure to financial risk and price volatility must rest with a government agency. Otherwise the distribution utility can be expected to develop a portfolio that best meets its interests, which are different than the interest of default service customers.

More Lessons from California: Crisis Response is Messy and Inefficient

The need to have an overall strategy or road map regarding needed resources and the way in which they will be integrated is a key lesson from California where the lack of such a plan has contributed to the costly "clean up" of its 2001 market meltdown. There, in the weeks following the astonishing run-up of generation prices in late 2000 and early 2001, major efforts were launched by state agencies to both contract for new resources and, simultaneously, to stimulate major demand reductions. The lack of integration between these two resource "selections" has led to very high priced – and unneeded – capacity. California was, of course, in a desperate situation but clearly a little advance IRP planning would have gone a long way to ameliorate the crisis and to hold costs down.

A state energy office, division of the utility regulatory agency (or, perhaps, the distribution company under review of a government) need to carry out the responsibility of performing the long-run load forecast, identifying the available demand side resources, and testing various potential portfolio combinations to establish an acceptable level of risk. The use of consumer research such as deliberative polling would be one way of identifying the aggregate customer risk tolerance.

3. Vertically Integrated (Category 3)

a) General

Category 3 states are those that have not moved to retail competition. In these states, portfolio management is similar to IRP and includes all activities with the exception of wholesale market rules. The fact that the portfolio manager is an integrated utility makes some oversight and planning functions much easier. For example, even under traditional regulation, the integrated utility has an incentive to consider load management and some types of distributed resources to address problems in high cost distribution areas.

The primary challenge in these states is for integrated utilities to become adept at making the most effective use of wholesale markets when adding resources, including learning how to maximize the wholesale market value of system demand reduction.

b) Other Responsibilities

Here again, basic decisions such as default service customers' exposure to financial risk and price volatility must rest with a government agency. Otherwise the utility can be expected to develop a portfolio that best meets its interests, which are different than the interest of default service customers

F. Administrative Options

What sort of process should be used to prepare the portfolio plan? Administratively, there are many options ranging from:

1. A full adjudicatory process where all assumptions, methods, and analysis are subject to public filing, discovery, sworn testimony, cross examination, and full rights of appeal. Many states used this process to implement IRP and some still do. The process works better (in terms of efficiency and timeliness rather than outcome) in some states than others. The number of parties, the perceived stakes of the proceeding, the personalities of the participants, and the way practice before the commission has evolved all contribute to any assessment of how well this process works.

2. Legislative or rulemaking style proceedings with opportunities for alternative filings and public comments are another approach that has been used successfully. This may take the form of a state energy office charged with the planning responsibility. A recent example is the recently formed California Consumer Power and Conservation Financing Authority charged with the responsibility to:

- “furnish the citizens of California with reliable, affordable electrical power
- ensure sufficient power reserves
- assure stability and rationality in California’s electricity market,
- encourage energy efficiency and conservation as well as the use of renewable energy resources, and
- protect the public health, welfare and safety.”¹⁵

The Authority conducted its planning and assembled a written “investment plan” which it circulated for public comment. The final plan was submitted to the legislature on February 15, 2002.

¹⁵ CA Public Utilities Code Section 3300, Chapter 10, effective 13 August 2001.

Another good example to these two approaches can be seen in portfolio decisions relating to renewable resources. Again, we use California as an example but a very similar story could be told for many other states:

During the 1980's and early 1990's, the CPUC was deeply engaged in carrying out its approach to IRP, known locally as the Biennial Resource Plan Update (BRPU). Every two years, the CPUC held a lengthy adjudicatory process designed to identify the best mix of new resource additions. There were many parties, most of whom were active in trial type hearings involving every assumption, model, and input used. The outcome was a commission decision specifying what the state's utilities were to buy or build.

By all accounts, the process was exhaustive and exhausting. The quality of the data and analysis was as good as that produced in any state and probably better than most. In the end, commission decisions were based on the data, the analysis, judgment, and the application of state policy as reflected in state laws. The results were not bad but the process was excruciating.¹⁶

In contrast, during and since restructuring California has used a very different process to make fundamentally similar decisions relating to investment in renewables. The California legislature has enacted laws requiring significant investment in renewables. The record upon which these decisions were made is not as easily described or documented as the record in the BRPU proceedings. Yet it appears that the conclusions reached by California lawmakers were based of extensive analysis performed by stakeholders and government agencies. There was ample opportunity for public input.

Whatever administrative approach is used, there must be substantial opportunity for public and stakeholder input must be provided. Portfolio management is a service provided to small customers that for a variety of reasons do not choose their own service directly. Default service customers are essentially captive customers and their interests are being served by the conditions imposed on the provider of default service. No level of analysis can eliminate the judgment that must go into the selection of a reasonable portfolio. If judgment cannot be eliminated, and default service customers are at risk for the resulting portfolio, it is essential that public and stakeholder interests, particularly stakeholders that represent the interests of default service customers, inform the portfolio requirements.

The right option for any one state is best determined by that state, based upon its own history and its restructuring status and goals. For example, a Category 1 state may decide it only needs to establish several fundamental criteria, such as how much year to year volatility it is willing to accept for default service how much financial exposure in terms of reliance of financial contracts

¹⁶ The California BRPU process was undermined by a strange set of FERC rulings that failed to grasp the very different values, including risk reduction, offered by different resources. It is unclear what those FERC decisions might mean today where regional wholesale markets are far more developed and incumbent IOU's more experienced and possibly more accepting of the competitive acquisition of new resources. See, Moskowitz and Bradford, Paved with Good Intentions: Reflection on FERC's Decisions Reversing State Power Procurement Processes. *The Electricity Journal*, August/September 1995.

it is willing to accept. Then it may design a “laddered” system of procurement that solicits 10-year bids each year for 10% or so of its total needs for default service. The criteria will drive bidders to limit the amount of financial versus physical contracts and the amount of exposure to fuel price risk, such as natural gas.

The planning function will determine the level of funding for energy efficiency and any minimum level of investment in renewables. These requirements may be imposed on the portfolio manager directly or may be carried out separately.

For this type of situation legislative approaches may be adequate, provided a responsible state agency has the resources and responsibility to put forward a reasoned plan for comment and amendment.

Oregon's Electric Energy Restructuring

Oregon has created a unique approach to electricity restructuring, allowing all business customers to choose their provider, but also creating a portfolio of PUC regulated choices for small business and residential customers.

Legislation (Senate Bill 1149 (requiring electric industry restructuring Oregon's largest investor-owned utilities went into effect on March 1, 2002.

The restructuring was designed to give customers more options while at the same time encouraging the development of a competitive energy market.

Senate Bill 1149 included a number of key provisions:

- All large business consumers will be allowed to continue to purchase power from their current utility under a regulated cost-of-serve rate or purchase energy directly from an Electricity Service Supplier (ESS). Purchasing power from an ESS is know as "Direct Access." Large customers choosing Direct Access will receive credits for the value of existing generation resources;
- Residential and small business consumers will choose cost-of-service rate or portfolio rate options. Small non-residential consumers may also opt for Direct Access;
- A 3% public purpose charge will be collected from retail customers to fund and encourage energy conservation and development of renewable energy;
- A Low-income bill assistance fee, administered by the Oregon Housing and Community Services Agency, will continue to be collected by PGE and PacifiCorp.

The law established general framework, but it left much of the implementation up to the Oregon Public Utility Commission through its rulemaking and rate setting processes. The following is an outline of how the basic elements of SB 1149 will be implemented.

- The utility isn't required to sell and assets which generate electricity
- Utilities can negotiate long term contracts to protect the consumer from the volatile spot market
- No consumer is forced into the energy market
- All consumers have the choice of receiving a regulated cost-of-service offer from the utility
- All nonresidential consumers will have the ability to purchase electricity either from a provider known as an Electricity Service Supplier (ESS) or their existing utility
- Both large and small nonresidential consumers who buy power from an ESS will have the opportunity to return to a utility offer
- Each utility will provide default emergency rates in case an ESS halts service to a non-residential customer
- Your bill will be redesigned to reflect the various costs that factor into your total bill
- All consumers will receive information so that they may compare the fuel mix and emissions of the electricity supply options that are offered to them

nonresidential is defined as those who use less than 30kW demand monthly. The portfolio includes:

- A traditional basic rate
- A Time-f-Day Supply Service
- A Fixed Renewable Service that includes new renewable resources
- A “Renewable Usage” Service
- A “Habitat Restoration” Service
- Seasonal Flux (PacifiCorp only)

Small business customers can also opt for Direct Access.

A 12-member portfolio advisory committee crafted the options and recommended them to the Commission for approval. The committee included utility representatives, local governments, residential consumer and small nonresidential groups, public/regional interest groups, and staff of the Oregon Public Utility Commission and Oregon Office of Energy.

Public Purpose Fee and Low Income Bill Assistance

The law established an annual expenditure by the utilities of 3% of their revenues to fund “Public Purposes”, including energy efficiency, development of new renewable energy and low-income weatherization. Rates will increase on March 2, 2002 to fund these activities but by less than 3% because money utilities currently spend for these purposes will be removed from rates at the same time. Future expenditures the utility otherwise would have made for these purposes will be included in the 3% fee instead of rates. The public purpose fee will appear as a separate item on your bill.

The law requires 80% of the funds designated for conservation to be spent in the territory of the utility from which they were collected.

The first 10% goes to Education Service Districts for energy audits and subsequent energy efficiency measures.

The remaining funds go into four public purpose accounts:

- 56.7% Conservation
- 17.2% Renewable energy
- 11.7% Low-income weatherization
- 4.5% Low-income housing

The conservation and renewable energy funds are administered through a new nonprofit entity, the Energy Trust of Oregon.

The law also established a \$10 million a year low-income bill assistance fund to be spent in the territory of the utility that collects it. The current amount is 35 cents a month for residential consumers and .035 cents/kWh for nonresidential consumers. The Oregon House and Community Service Agency distributes the money through community action agencies.

Source: Oregon Public Utility Commission website: www.puc.state.or.us

G. Putting It All Together: Options for Portfolio Management

The best approach to portfolio management turns on a combination of specific state experience, how the state has already decided to restructure the electric utility, and the provision of default service. But regardless of these variables, there are a few characteristics of portfolio management that are essential and should therefore be included in any reasonable approach.

The essentials are as follows:

1. High Quality Data and Analysis is Key.

The quality of the data and analysis used to specify the requirements of the portfolio needs to be high. Identifying a reasonable portfolio is not a simple task. The risks, costs, and performance of all options need to be well understood. Careful forecasts of the energy service needs, with sensitivities, to be met by the portfolio manager must be prepared. The mix of supply and demand side resources that strike the right balance between cost, risk, and environmental performance must be identified. Portfolio management is also a dynamic process.

2. Portfolio Management is Dynamic.

The portfolio is not selected in one year and then left static for long periods of time. Every year or two resources are added and resources are lost due to retirements or contract terminations. Demand patterns shift in unforeseen ways. Technology changes and new options become available. Perceptions of risk change such as those that accompany geopolitical shifts, environmental requirements change and a host of other possible factors. This means the analysis underlying the portfolio must be reassessed and the portfolio adjusted.

3. Consider All Supply and Demand-side Options.

All demand and supply options need to be considered even if a particular option, or set of options, is not directly available to the portfolio manager. For example, the portfolio manager may have the responsibility to consider demand-side options, the value of which can be realized in the wholesale market. There may be other demand-side options that are not within the direct purview of the portfolio manager, but which make economic sense to pursue in some other fashion. Long-term efficiency improvements or market transformation programs funded through System Benefit Charges and energy efficiency standards are the best examples.

4. The Wholesale Market Structure Needs to be Well Developed.

Besides having all the usual efficient market characteristics, the key principle should be to reveal the value of all options to all participants and to provide a mechanism for acquiring those options. The best example is demand response. Demand response has substantial value, yet we have too much experience showing how easy it is to design markets that ignore demand response entirely. If the wholesale market has been designed to fully incorporate demand response, the portfolio manager will be able to identify the market value of demand response and include strategic investments in demand side reductions and distributed resources in its business plan.

Who Performs the Portfolio Management Function?

As the discussion above suggests, the questions of who the portfolio manager is (competitive providers, the distribution utility or a state agency) and whether the portfolio manager is regulated or competitive are interesting, but not critical. The paramount consideration is what portfolio management functions the default service provider can perform and what portfolio management functions ultimately rest with government. The answers to these questions turn on an assessment of the interests, risks, and incentives faced by the default service provider and the interests of default service customers.

IV. WHAT ARE THE RISKS OF PORTFOLIO MANAGEMENT TO CONSUMERS AND REGULATORS?

Thus far the discussion has focused on the benefits of portfolio management. It is also important to describe the risks portfolio management imposes on customers and regulators and some of the policies needed to address these risks.

A. Portfolio Management Prices and Short-term Market Prices

Portfolio management reduces price volatility risk but does not guarantee the lowest possible prices to customers at all times. In the same way that the return on a mutual fund will not always exceed the return on the “market”, not even the best electricity portfolio management can guarantee prices that will at all times be less than the price in the short-term market (or less than the prices of other managed portfolios).¹⁷ Indeed, this is the fundamental essence of portfolio management – the averaging out of price volatility over time. Sometimes the portfolio manager’s price will be below the market price, and sometimes it will be above. The greater the volatility of the spot market, the greater is the potential value of portfolio management. The fact that low, short-term prices will occur, and at times may persist for a year or more, presents great political - risk to a portfolio management approach.

Recall that most of the support for restructuring in the mid-90s was fueled by the fact that utilities’ portfolio prices (a blend of competitive and regulated prices) were above prevailing, short-term market prices (in markets where utilities were fully recovering their fixed costs through customer rates). How will consumers, regulators, and legislators react if long-term portfolio management is adopted and market prices again fall below the portfolio manager’s prices? The portfolio of resources recently assembled by the Department of Water Resources on behalf of California consumers in the 2001 market crises in that state were soon found to be more costly than the prices the market produced under the federal price caps imposed in the wake of the crises. These contracts, which totaled over \$42 billion, have been alleged by the California Attorney General to exceed fair market prices by at least \$7 billion due, in part, to

¹⁷ However, the more the short-term market suffers from market power, the more often the portfolio manager’s price will look attractive.

market manipulation. The California PUC has ruled that those excess costs will have to be passed on to customers. There are no easy answers, but from a policy perspective there are two choices. Customers either will be entirely exposed to the price volatility and market power risks inherent in short-term markets, or they will be served from a portfolio of long-, medium-, and short-term supplies. Neither option will make customers happy all of the time. A good process for portfolio management, a process that is transparent and sustains public confidence, will improve the odds of sound outcomes over time.

B. Entry and Exit Policies

If retail access is permitted to coexist with portfolio management, conditions must be placed on consumers' rights to shift between the managed portfolio and competitive retail suppliers. Rigorous application of this principle is essential to avoiding the build-up of potential future stranded costs. Such conditions must be sufficient to reasonably mitigate the risks assumed by the portfolio manager through long- and medium-term commitments. Otherwise, at times when the short-term price is below the portfolio price, customers will leave the portfolio, and the manager may be saddled with stranded costs. The reverse can also occur when market prices rise, as recently seen in both California and Pennsylvania.

How can these problems be addressed? Different options may be pursued depending on a state's desire to encourage competitive entry. For example, open enrollment periods could be allowed whenever the portfolio manager's contractual commitments are less than its customers' load or when its average price is less than or equal to the prevailing market price. Or, open enrollments could be scheduled periodically, such as when the portfolio manager is preparing to contract for additional resources. *Moreover, it is not necessary to offer all portfolio customers the same price.* Those who choose a retail provider and then wish to return to the portfolio may be obliged to pay a portfolio price that reflects current, not historic, conditions, like a homeowner refinancing a mortgage.

V. RAP'S SUGGESTED APPROACH TO PORTFOLIO MANAGEMENT.

A. Overview

With the background of the essential elements of portfolio management and the range of administrative options, we turn to a suggested portfolio management approach. We describe our suggested approach in the context of one of the most difficult situation, a state that has moved to retail competition, and that is prepared to have at least a portion of default service provided by competitive suppliers. When discussing PBR, we also assume that the state is prepared to allow the distribution utility to provide a portion of default service.

B. Planning

Use a comprehensive, credible, and open planning function to determine a few basic criteria that will be incorporated in a competitive solicitation for default service. These basic criteria could be developed and proposed by a responsible state agency having the necessary resources and

responsibility to put forward a reasoned plan. Legislative procedures allowing for comment and amendment may be adequate. The process should consider the following:

1. Short-term Needs

What immediate needs exist to cover today's load?

2. Long-term Needs

The needed resource additions for which commitments must be made in the next one to three years, plus the forecasted demand for the next 10 to 15 years.

3. Least-cost balance of supply and demand-side resources

This includes an assessment of the level of cost-effective funding for energy efficiency and any minimum level of investment in renewables recognizing that these requirements may be imposed on the portfolio manager directly or may be carried out separately.

4. Price volatility

How much year-to-year price volatility is acceptable and achievable for default service.

5. Financial risk

How much financial risk (reliance of financial contracts) it is willing to accept.

6. Procurement Plan

Consistent with these criteria, design a schedule for procurement. For example, the manager may solicit 10 to 15 year bids each year for 10% or so of the total forecasted needs for default service. Keep in mind that renewable resources, because they are almost all capital expense, do better when compared to resources over a period of 15 years or more.

7. Align Incentives

Design a PBR approach to default service that allocates risks reasonably and provides rewards and punishments for superior or inferior service. Removing the throughput incentive for the distribution utility as well as for the PM (if it is an entity separate from the distribution company) are essential parts of such a PBR.

C. Discussion of Suggested Approach

1. The Planning Process

There is no avoiding the fact that some overarching level of planning will be needed. When the lights go out, when prices spike to intolerable levels, or when markets fail to deliver what they were expected (as they may despite all best efforts), the public and their elected officials will ask

how and why it happened. Explaining that “it was the market” and no one had the responsibility to keep a watchful eye on the system will not suffice. Planning provides a road map to remedy when things go unexpectedly haywire. Making “emergency” decisions in a vacuum often leads to further trouble.

The scope of utility planning may be more limited than it was in the past but its importance has not been diminished. Thus, utility planning does not mean that a detailed plan with specific detailed contracts or energy efficiency programs is imposed on different participants. But it does mean that an entity is responsible to assemble all of the important pieces in one comprehensive and comprehensible plan.

Planning will require looking at the wholesale generation market and staying aware of who is building what and where. Planning means assessing how the expansion of the generation market is affecting the transmission system. It also means forecasting consumer demand for energy services, assessing how these demands could be met in the most cost-effective manner, and comparing the results to what the market is delivering. Planning needs to be informed by the market and planning needs to inform market designers of needed reforms and refinements.

Utility planning has never been, nor will it ever be, a simple process. The tools and practice of IRP are well known and well documented. What is needed now is to assign the planning responsibility to a responsible and capable government agency and then use the planning process to inform and coordinate the various participants in the restructured markets

Restructuring which began in the mid-90s did not eliminate the need for use of IRP but it did result in different parts of IRP being parceled out to different entities. The result was the loss of anyone having the big picture clearly before them. Essentially, planning is needed at two levels:

a) Strategic Oversight

A continuing process of strategic oversight, conducted by a government or quasi-government entity, with responsibility to look ahead at the *entire market and grid* (including wholesale, balance of grid, generation, and demand resources, etc.) and assess where things are going. A lot of what is covered in such an assessment will not be under the direct control of the government or a regulated utility, it's in the hands of many actors, including market actors. But particular government policies will be indicated by such an assessment, and can be based upon it. This is what many state energy plans have traditionally done. However, with the emergence of regional wholesale markets, regional planning such as for transmission must also be a part of this overall assessment. If done by government, this is the plan that would broadly set how the minimum level of renewable resources and energy efficiency will be included in the provision of retail electric service, such as the RPS and SBC investments required in several states today as part of their restructuring laws.

b) Investment Plan

Second is an investment plan for default service, designed and implemented by the portfolio manager. The default service provider, if it is to have a long-term franchise, will by

necessity be in the active power management business and thus will need to do its own continuous planning, taking into account its obligation to meet the specific resources requirements which may have been created by government.

2. The Criteria

One reason planning is a government function is that it requires substantial exercise of judgment in matters that are affected with the public interest. For example, one purpose of planning is to assess the likely extent of price volatility of different portfolios. This part is more or less a numerical and statistical exercise. Also needed, however, is an assessment of how much price volatility is acceptable to default service customers. This is not a simple arithmetic exercise easily delegated to a private party.

Our preferred approach is to use the planning process to identify important criteria that can reasonably be incorporated in conditions imposed on competitively procured default service. This combines the strength of a comprehensive and publicly accountable the planning process with the strength, innovation, and efficiency of the competitive market. In some cases all or part of the default service may be provided by the distribution utility. The most important criteria are as follows:

a) Resource Needs

Assessing the resource needs is the most basic outcome of the planning process. This requires a year-by-year forecast of the energy service needs of consumers generally, and default service customers in particular, and the demand and supply-side resources available to meet the need. Given the nature of competitive wholesale markets, reliable information on new resources may be limited to the next few years but the forecasts should nevertheless be long-term (at least 10 years or, better, as far as can be reasonably foreseen).

These long-term planning processes both inform, and are informed by, the wholesale market. Planners see the types and locations of investments that are being made, the types of risk management tools being used, the evolution of markets and market rules to deal with new types of resources, and the types of needs and expectations customers express. Investors, customers, and others see the aggregated size and location of demand and supply, which help make future investment, purchase, and location decisions.

b) Price Volatility

One of the main considerations for portfolio management for default service customers is the acceptable level of price volatility

For the most part, low use customers do not have advanced metering capabilities and, even if they did, they would not choose to take service under the real-time prices that such metering makes possible. Portfolio management for these customers seeks to provide them with competitively and stably priced default service while exposing the portfolio manager to enough

market risk to provide efficiency incentives without exposing them to so much financial risk as to risk default.

Competitive markets can deliver as much or as little price volatility as one is willing to accept. There is of course a cost involved, but the cost, or even whether the cost is positive or negative, is difficult to intuit. For example, consider a proposed ten-year contract from two resources, one based on natural gas and the other based on a mix of wind and hydro. Assume, as is the case in most markets, that spot energy prices are driven by the cost of natural gas. Assume further that based on current conditions and forecasts the 10-year levelized cost (as distinguished from price) of both resources is 5 cents per kWh.

Now, suppose an RFP for default service specifies the desire for a ten-year fixed price contract. The wind/hydro resource costs are essentially fixed so, absent market power, bids for fixed price service will be about 5 cents. In contrast, to meet the bid, the gas based supplier will have to either bear some fuel price risk, or buy some other form of insurance, to cover the risk that gas costs will be above current forecasts. As a consequence, its bid will have to be above 5 cents.

Next, consider the exact opposite situation and the RFP for default service specifies a 10-year contract with separate capacity and energy prices and the energy portion indexed to natural gas. This RFP matches the cost structure of the gas resource so, absent market power, its bid will be about 5 cents. Now it is the wind/hydro resources that face a problem. The wind/hydro resource faces the risk that gas prices will drop and the default service price will fall below its cost. To cover this possibility it will either bear some fuel price risk, or buy some other form of insurance, to cover the risk that gas costs will fall below current forecasts. As a consequence, its bid will have to be above 5 cents.

Thus, how much does price stability cost? Perhaps nothing; it depends on the underlying cost level and cost structure of the resource.

How much price volatility is acceptable is a judgment call. Scenario planning is an effective tool for identifying and quantifying the likely and possible range of hourly, daily, monthly, and annual price volatility that would occur in spot energy markets absent market power. Because default service customers will not be on real-time meters, monthly and annual price volatility is of greatest importance. In general, the “planned” price volatility for default service should be reasonably low and should definitely not be tied to natural gas prices.

Reducing default service price volatility through portfolio management should be combined with good, cost-based rate design. The use of time differentiated rates, seasonal rates, inclined block rates to reflect long run marginal costs should be applied to default service rate design just as they are or should be to fully regulated rates.

Likewise, insulating default service customers from highly volatile spot markets does not mean that the default service provider should be insulated from day to day market prices. A limited level of exposure of the default service provider to the spot market combined with wholesale market rules that give the default service provider an incentive to manage its customers load are desirable features.

Default service customers will be insulated from short-term market volatility but they are not insulated from long-term competitive prices. Default service is a regulatory creation in response to the fact that competitive retail markets have not developed to the point that competitive retail providers are giving customers choices between fixed and variable prices. Regulators are essentially creating a buying agent for default service customers specifying the terms that default service providers compete to meet.

More importantly, although default service customers see a stable price, the default service providers do not. If a provider agreed to a 5 cent fixed price and spot prices go to 20 cents, the default service provider will have a powerful incentive to either reduce its own cost or to free up electricity for sale to the spot market. In either case, the default service provider has an incentive to reduce its customer's use of electricity. How it acts on this incentive may be even more effective than the politically naïve option of increasing default service prices to 20 cents.

3. Financial Risk

Financial risk of the portfolio manager should also be specified. As described earlier the nation has already seen several instances where entities in the position of a portfolio manager have essentially defaulted on their commitments. Thus, consider the example described above where a state's regulators decide that price volatility should be limited and 10-year fixed price contracts are sought. Consider three scenarios:

1. The winning bidder owns gas-fired resources,
2. The winning bidder neither owns nor even has long-term contracts with any resources. The winner intends to rely entirely on spot markets and is betting that spot markets prices will remain stable or will decline, or
3. The winning bidder has no resources or physical contracts but has signed hedging contracts with a party of limited financial capability.

What happens if gas prices double? Spot prices will likely double, raising the risk that the winner will default on the default service contract, leaving default service customers with little or no protection and no option but to buy from the now inflated spot market.

Consider what happens if gas prices double but the winning bidder fit one or more of the following situations:

1. The winner owned renewable or other resources whose costs were unrelated to changes in gas prices,(this might include gas generators who have secured gas supplies on a long term, fixed or moderated-cost basis)
2. The winner held physical contracts with renewable or other resources whose costs were unrelated to gas prices, or

3. The winner had purchased one or another form of insurance from an entity with ample financial resources.

In any of these situations, default service customers are much more likely to be protected. (Of course in our legal system any party is free to break a contract. The difference is that if the supplier in any of these latter situations breaks the contract, there are underlying financial assets to pay damages.)

a. Energy Efficiency and Renewable Resources

To some extent, the steps we have described will result in some levels of energy efficiency and renewables being delivered by the market. Well-designed wholesale markets will include demand response, demand bidding and other related features that will allow some levels of energy efficiency to compete. Most of the demand response measures, however, are better suited to load management than long-term energy efficiency.

Efficient wholesale markets will also eliminate discriminatory barriers to renewable resources, especially intermittent resources. Wholesale market improvements will help distributed resources to some extent, but substantial barriers remain in the retail and distribution utility areas.

Reasonable limits on price volatility and financial exposure will also encourage portfolio managers to invest in renewable resources. Some may suggest that coal or even nuclear power offers the same sort of price stability but both of these sources carry a high level of environmental risk (and for nuclear, security risk) that is not shared by renewable resources.

But, remaining shortcomings of wholesale and retail markets, combined with well known market failures with regard to energy efficiency mean that investment in these resources will fall far below the levels identified as being cost-effective and achievable in the planning process. The failure to accommodate the intermittent nature of renewables in transmission pricing and ancillary market policies is another type of barrier to which public policy must respond. This is why policies such as SBCs and RPSs have been adopted and proven effective in so many places.

Thus, we suggest that the planning process be designed to identify the achievable energy efficiency and renewable resources over and above what is expected to be delivered by portfolio managers. This incremental amount of these resources should be built into the market generally, not just imposed on default service providers.

b. Procurement Schedule

The procurement schedule addresses two related issues. How much should be bought at any one time, and how long should the procurement last? Where default service is being provided competitively now, the tendency has been to buy it all at one time and to commit to relatively short periods of time (one month to 3 years). Portfolio management would yield a different result, one that leans much more toward small periodic purchases for longer periods of time with some, but limited, exposure to spot markets.

The planning process will examine the need for resources over the long-term, but not all the resources need should be procured immediately and not all of the resources should end at the same time. Diversity of contract types and duration is the best way to limit risk.

As any investor knows, there is no simple formula to give the perfect amount of diversity. So the bad news is judgment is required. The good news is when it comes to default service, almost any judgment is better than the ad hoc system in effect in most states today.

While perhaps far from perfect, we suggest phasing into a procurement schedule that makes roughly 10-year commitments each year for 10% of the needs of default service customers would provide a reasonable level of protection.¹⁸ Thus, if default service load requires 10,000mw of supply and demand (and assuming now growth to make the arithmetic easy) each year one would sign 1000 mw of 10-year contracts.

We suggest that individual default service customers will not be assigned to a particular portfolio manager. Instead, the group of portfolio managers (as many as ten, each of whom has about 10% of the default service load) will in the aggregate provide default service. Customer service issues, (signing up customers, bill payment, disconnection, etc) will be delivered by a common entity or the distribution utility.

Consider the following implications of such a series of 10-year laddered contracts:

1. If retail competition becomes a real option, this means 10% of customers could leave default service without stranding any resources. (This is a faster transition to retail competition than has actually been seen in any state.)
2. If market conditions change, exposure of default service customers is limited to the combined effect of price volatility provisions of the non-expiring contracts and the addition of a new 10-year contract.
3. If one of ten contract arrangements defaults, risk is limited.
4. Some amount of default service needs, probably not more than 10% may be in the spot market at any given time.

c. Performance Based Regulation

(1) Basic Principles

Finally, a few words about the incentives faced by the portfolio manager. The regulatory approach taken to portfolio management will result in the portfolio manager facing certain

¹⁸ To phase in to this type of procurement plan from a starting point that has no long-term contracts may require a two or three year period where contracts of 1 to 10 years are signed.

incentives. It is important to understand in any particular instance what those incentives will be and to assure that they are consistent with customer service goals and with sound public policy.

The portfolio manager should face a reasonable set of incentives. For example:

1. If the portfolio manager's sole responsibility is to buy on the wholesale market and pass the costs through to customers, it faces virtually no risk and is subject to no meaningful standard of conduct. This means it has very little incentive to manage the portfolio in a way that controls either price levels or price volatility.
2. If the portfolio manager has a fixed price obligation with an open-ended quantity obligation, it has an incentive to manage costs and increase sales whenever spot prices are in excess of its fixed price.
3. If the portfolio manager has both a fixed price obligation and a fixed quantity obligation, it has no throughput incentive.
4. If the portfolio manager has an obligation to serve a significant population (either as a monopoly utility or as a default service provider) for a significant period, it should be able to count on a predictable, though not static, population to reduce the need for excessive risk management costs

The incentives faced by the portfolio manager will be determined by two primary factors: Who is the portfolio manager, and what is the structure of the contract for default service? We begin by considering the situation where the portfolio manager is a competitive supplier and then the situation where it is the distribution utility.

Broadly speaking the portfolio manager will have two internal incentives: minimize risk and maximize profits. With respect to risk, the conditions we suggest imposing on any portfolio manager addresses most issues so we focus on actions that maximize profits.

Of the many ways the portfolio manager could increase profits there are two that regulators need to worry about and should take steps to protect against. These are cutting costs by reducing service quality and increasing revenues by increasing sales or throughput.

To the extent there are any customer service obligations it is best to include specific measurable service quality standards and related rewards or penalties in the procurement contract. If as we suggest, customer service is provided centrally, the issue is not too serious.

The incentive to increase sales or throughput is a problem for two reasons. First, is the well-known and documented effect on energy efficiency. If the contract is structured so increased sales predictably lead to increased profit, the portfolio manager will have an incentive to discourage increased energy efficiency, no matter how cost-effective for the individual consumers or for society.

Second, many states probably consider default service a temporary stopover on the way to full retail competition. If this is the case, a throughput incentive means the portfolio manager will resist any expansion of competitive retail services.

(2) Competitive Providers

Eliminating the throughput incentive for competitive providers can be accomplished in several ways. The simplest is to structure each of the laddered contracts to specify a given amount of energy. In this way increased sales have no effect on any particular portfolio manager. The increase (or decrease) is made up through spot purchases.

A second alternative is to structure the contract like a two-part tariff. A fixed payment for the bulk of the contract quantity sales and a variable payment set at spot prices of any excess. In this way, increased revenues from increased sales come with increased costs. If most of the contract volume is on a fixed price, the default service provider will still have an incentive to help manage customer loads during periods of high spot prices.

(3) Distribution Utility

If the portfolio manager is a distribution utility we have two issues to address. The first is the throughput issue, which now even more serious because it exists for both default service as well as distribution services. The second issue relates to the portfolio management function of the distribution utility.

If the distribution utility is simply assigned the portfolio management responsibility without having to compete for the job, how do we know that the distribution utility is doing a good job? What benchmarks or performance standards are used to ensure that it does? A distribution utility that is not required to compete for the default service franchise is a monopoly service provider that must be closely supervised. A performance-based regulation plan may be the best means of providing that supervision. How do we construct such a PBR?

In most respects these are not new issues. Most of the issues raised by PBR alternatives to traditional cost of service apply with equal force here. What is new is 1) the focus is on one aspect of utility service, portfolio management for default service customers; and 2) experience with competitively provided default service provides one new possible benchmark.

There is a long and not very successful history of efforts to develop reasonable benchmarks against which to measure a utility' performance. Efforts to find an acceptable benchmark consisting of groups of similar utilities has always failed for one reason or another.

The situation we now face, however, presents a new opportunity. Consider the following for a case in which the distribution utility owns no generation:

1. The planning process and the setting of criteria imposed on competitive default service providers takes place as described above

2. An RFP for default service is issued for a portion of the current period's default service needs.
3. The terms offered by the winning bidder establishes the performance benchmark for the distribution utility.
4. The distribution utility can either (a) agree to perform on the same or better terms than the winning bidder for the remaining default service needs or (b) decline to match those terms, in which case the remaining portions of the standard offer service block are also bid out and provided competitively.
5. Next year the process repeats itself for the next 1/10 of the load which would be coming free from expiring contracts. .

The ability to use the market to provide a benchmark for the same product, at the same time, for the same duration, with the same terms and conditions eliminates most of the major historical technical and historical difficulties associated with regulatory attempts to construct performance benchmarks for electric utilities. The important questions to be addressed are whether the wholesale market is competitive and whether the portion of the default service put out to bid is large enough to provide a reasonable market test.

What California Needs for Effective Portfolio Management

1. Establish a clear responsibility in some entity to periodically prepare a long range (minimum 15 years) electricity resource plan that meets the following goals:
 - a. Economic integration of all electric system resources: generation, transmission, distribution, demand side and supply side;
 - b. Price stability;
 - c. Reliability and adequacy;
 - d. Environmental improvement;
 - e. Resource diversity including substantial and continuing investment in energy efficiency and renewable resources; and,
 - f. Low financial risk within a reasonable range of likely economic futures.
2. Establish implementation responsibility for Portfolio Management (may be multiple entities, each with a different resource responsibility).
3. Eliminate incentives promoting "through-put" sales of electricity for all utilities.
4. Require use of competitive acquisition processes wherever feasible.
5. Limit customer entry and exit. Individual customer realizes gain or loss associated with entry/exit.
6. Establish a procedure for periodic public review of Portfolio Management plan and implementation.

X. CONCLUSION

The vast majority of ordinary customers (non-industrial) will likely be served through the default provider for a long time. Leaving default service tied to the spot market creates unreasonably and imprudently volatile prices as well as greatly contributes to the markets' volatility. Default customers should be served through a diverse set of resources managed over the long term so as to reduce risk and price volatility. The greater use of long term contracts will help to stabilize the markets and will work to reduce market power that has been fueling the instability. The loss of diversity and long term price management has been the largest negative outcome from electric market restructuring to date. There are number of ways in which portfolio management can be designed and implemented to match the philosophies and experience of individual states. We recommend that state regulators and policy makers give the question of portfolio management immediate high priority.