

**CAN ELECTRIC  
UTILITY RESTRUCTURING  
MEET THE CHALLENGES  
IT HAS CREATED?**

**Richard A. Rosen, Ph.D.  
Freyr Sverrisson  
John Stutz, Ph.D.**

**November 2000**

**CAN ELECTRIC  
UTILITY RESTRUCTURING  
MEET THE CHALLENGES  
IT HAS CREATED?**

By:

Richard A. Rosen, Ph.D.  
Freyr Sverrisson  
John Stutz, Ph.D.

Tellus Institute  
11 Arlington Street  
Boston, MA 02116-3411  
Tel: 617/266-5400  
Fax: 617/266-8303  
email: [energy@tellus.org](mailto:energy@tellus.org)

November 2000

## Forward

Over the past five years portions of the US electric utility industry have experienced a sweeping series of changes referred to as restructuring. These changes affect both the structure of the organizations involved in the electric utility industry, and the institutional arrangements by which decisions involving planning and pricing are made. As change usually does, restructuring creates many challenges. This report identifies some of the challenges created by restructuring and then discusses the extent to which restructuring has met, or can likely meet, the challenges it has created.

When restructuring began, the US electric utility industry was composed of firms and public agencies which were generally **vertically integrated**. All of the basic utility functions—generation, transmission, distribution, billing and customer service—were provided by the same organization. The firms providing utility service were regulated as monopolies. Regulation addressed two basic areas:

- **Planning.** Through the application of Integrated Resource Planning (IRP) and related planning practices, regulation sought to ensure that electricity was produced and provided in an efficient, reliable, and environmentally sound fashion.
- **Pricing.** Under rate regulation, a utility's allowed revenues were limited to its cost of providing service. Cost allocation and rate design allowed regulators to set what they found to be equitable prices for different classes of customers.

Restructuring substantially changes the previous arrangements for planning and pricing. While restructuring affects primarily generation, the changes made ripple through to the other utility functions as well.

The basic idea of restructuring is to stop treating electric generation as a monopoly, and instead to treat it as a competitive business. In order to make this shift, three basic changes are undertaken:

- Vertically integrated utilities are broken up, either by the sale of generating plants, or by placing generation assets in separate, "unregulated" generating companies that remain utility subsidiaries.
- Markets are created into which the generating companies can sell, and from which others can buy.
- Consumers of electricity are given direct market access, so that they can purchase their energy and capacity needs from anyone willing to serve them.

Had restructuring stopped with the first two changes, consumers, restructuring would have resulted in **wholesale competition**. However, when the third change is included,

restructuring results in **retail competition** under which restructuring affects all electricity consumers directly.

Through the deregulation of electric generation, restructuring sweeps away both IRP, at least as it was previously practiced, and rate regulation at the generation level. The challenge this creates is for restructuring to be able to handle the issues and to perform the functions previously addressed by IRP and rate regulation. This report identifies and addresses at least five separate challenges:

1. Providing an economically efficient mix of supply- and demand-side resources to meet customers' needs.
2. Ensuring that the electric supply system remains reliable.
3. Addressing the environmental impacts associated with electric generation.
4. Limiting the revenues obtained by electricity generators to levels justified by a competitive market.
5. Ensuring that all types of customers are served in an equitable fashion.

In the past, points #1, #2, and #3 were addressed through IRP. Points #4 and #5 were the focus of rate regulation. With the advent of deregulation, all five need to be addressed in new ways. How well deregulation is doing, and how well it can do in meeting these challenges, are addressed in this report.

Deregulation does embody a strategy which, in principle, could address all five of the challenges listed. That strategy is reliance on well-developed and highly competitive regional markets for electricity which offer customers a wide range of products, ranging from bulk supply to green power. Economic theory tells us that a competitive market could address points #1, #2, and #4. Point #3 can be handled if externalities are internalized; that is, if environmental impacts are assigned a cost which is included in market prices. Finally, it is often argued that point #5 will be addressed by the ingenuity of entrepreneurs, but only if regulators refrain from providing "cut-rate" alternatives. However, reliance on the market does not automatically meet the challenges stated above, it simply reframes them. The challenge now becomes to create a market which is so expansive and competitive that it will satisfactorily address #1 through #5 above. The report focuses on this **Market Creation Challenge**. In doing so, two key points are made:

- Electricity is a very complex commodity to buy and sell. Creating competitive markets for it at both the wholesale and retail level, is a daunting task in which, so far, there has been very limited success.
- All markets do not have a natural tendency to be competitive. Detailed economic analysis, including computer simulations of market operations, shows that opportunities for market power can,

and likely will, undermine attempts to create competitive markets for electricity.

While this report does not (and could not) **prove** that the creation of electricity markets which adequately address all five of the challenges listed above is impossible, it does attempt to explain why the development of such markets will be extremely difficult, and may be impossible.

Using the framework established through the consideration of the challenges facing restructuring as a backdrop, the report presents a brief review of restructuring experience thus far, and a consideration of the prospects for benefits in the future. The report shows that experience to date is primarily consistent with the exercise of market power in wholesale generation markets. Looking ahead, the report discusses a recent study by the Department of Energy (DOE) which claims substantial future benefits from restructuring. This report demonstrates that the results in the DOE study reflect inconsistencies with the historical record, as well as errors in its analysis of the future. More generally, the report shows that the favorable image conveyed by the conventional wisdom about restructuring is unwarranted and inaccurate. Early on, in Chapter 2, the report identifies **Eleven Truisms** which embody restructuring's favorable image for many economic analysts in the U.S. Returning to these truisms in Chapter 10, the report shows that the optimism embodied in these truisms is probably unwarranted.

The next-to-last chapter of the report introduces several options for meeting the five challenges which do not depend solely on the operation of a vigorous competition market. The suggestions put forward include both actions to combat and reduce the extent of market power, and other actions which address aspects of the five challenges discussed above directly. All of this speaks to dangers lurking in the many jurisdictions in which deregulation has already taken place. This chapter also discusses the options facing the majority of states which have yet to embrace deregulation. The basic recommendation is to "go slow," or do not restructure at all. Three specific points are made:

- Stretch out the schedule for consideration of deregulation until events play out to a greater extent where deregulation has already occurred.
- If deregulation must go forward for some reason, consider starting with wholesale competition only, rather than with both wholesale and retail competition simultaneously.
- Take extreme care in the calculation and regulatory treatment of any stranded costs created by the divestiture of generation. If stranded costs are negative, make sure ratepayers get duly credited for these benefits.

If these three cautionary guidelines are followed, then it is likely that some of the egregious mistakes entailed by the rush to restructure in other states can be avoided. However, this report is ultimately quite pessimistic that workably competitive electric generation markets can ever be created that are reasonably equitable to the broad

range of customers. Unfortunately, understanding electric restructuring involves much detailed analysis of many complex issues. Thus, we thank the reader ahead of time for his/her patience in wading through the many issues discussed here.

1	INTRODUCTION.....	1
1.1	STATUS OF ELECTRIC RESTRUCTURING TODAY.....	1
1.2	THE UNIQUE NATURE OF THE ELECTRIC INDUSTRY.....	2
1.3	INITIAL PERCEPTIONS OF STRENGTHS AND WEAKNESSES OF RESTRUCTURING.....	4
2	THE FAVORABLE IMAGE OF RESTRUCTURING.....	7
2.1	PREVAILING TRUISMS BEHIND ELECTRIC UTILITY RESTRUCTURING.....	7
3	AN HISTORICAL PERSPECTIVE.....	10
3.1	HOW AND WHY WE GOT TO THE CURRENT SITUATION.....	10
	A. Impact of the Oil Price Shocks of the Early 1970s.....	10
	B. The Energy Policy Act of 1992.....	13
4	OBJECTIVES AND PRINCIPLES UNDERLYING RESTRUCTURING.....	15
4.1	THE PURSUIT FOR EFFICIENCY.....	15
4.2	NEED FOR CLARITY OF OBJECTIVES.....	16
4.3	FOUR MAJOR GOALS OF ELECTRIC INDUSTRY RESTRUCTURING.....	17
	A. Greater Economic Efficiency.....	18
	B. Lower Electricity Prices.....	18
	C. Increased Consumer Choice.....	19
	D. Maintaining System Reliability.....	20
5	THREATS TO ECONOMIC EFFICIENCY.....	21
5.1	WHAT IS ECONOMIC EFFICIENCY?.....	21
	A. Technical Efficiency in Resource Allocation.....	22
	B. Efficiency of Output.....	22
	C. Price Efficiency.....	24
5.2	WHY ECONOMIC EFFICIENCY MAY NOT BE ACHIEVED UNDER DEREGULATION.....	24
	A. Imperfect Competition.....	25
	B. Externalities.....	26
	C. Public Goods.....	26
5.3	WHY ECONOMIC EFFICIENCY MAY NOT BE ENOUGH TO PROTECT CONSUMERS.....	27
	A. Greater Economic or Price Efficiency May Not Lead to Lower Prices.....	27
	B. Inherent Market Characteristics that can Lead to Higher Prices.....	31
	C. Rate Design: How it Affects the Residential Customer.....	38
6	PROTECTING THE CONSUMER – THE THREAT OF HIGHER PRICES.....	41
6.1	WILL SMALL CUSTOMERS BENEFIT?.....	41
	A. The Incremental Cost of Retail Service – The Retail Margin.....	41
	B. When the Standard Offer Is Set Below Competitive Wholesale Price.....	41
	C. Are Up-Front Rate Reductions Sustainable?.....	44
6.2	MARKET POWER – THE ACHILLES HEEL OF RESTRUCTURING.....	45
	A. The Threat of Market Power Must Not be Ignored.....	45
	B. The Structure of Market Power.....	48
	C. Price Discrimination at the Retail Level.....	55
6.3	STRANDED COSTS – WERE THEY SET CORRECTLY, OR WILL CONSUMERS OVER-PAY?.....	57
	A. What are Stranded Costs?.....	57
	B. Stranded Costs Can Be Negative.....	58
	C. Divestiture Sale Prices and the Effect on Stranded Costs.....	59
	D. How to Treat Negative Stranded Costs.....	60
7	CONSUMER CHOICE AND THE ENVIRONMENTAL PARADIGM.....	62
7.1	LIMITS TO CHOICE.....	62

A.	When the Individual is Called on to Subsidize the Common Good .....	62
B.	The Information Gap .....	64
C.	A Proposed Solution .....	65
8	THE THREAT TO SYSTEM RELIABILITY .....	67
8.1	KEYS TO ACCOUNTABILITY: THE RESERVE MARGIN AND THE CAPACITY MARKET .....	67
A.	How Can Generation Reliability Be Preserved? .....	67
B.	Why Do We Need a <u>Required</u> Reserve Margin? .....	67
C.	Why Do We Need a Capacity Market? .....	71
D.	The Advantage of Simple Markets with Long Time-frames.....	73
8.2	TRANSMISSION PLANNING, OPERATION, AND PRICING.....	74
9	THE RESTRUCTURING EXPERIENCE SO FAR .....	78
9.1	ECONOMIC EFFICIENCY .....	78
A.	Economic Efficiency During the Transition period.....	78
B.	Efficiency in the Long Run .....	79
9.2	MARKET PRICES AND MARKET POWER.....	80
A.	The Rising Spot and Forward Market Prices .....	81
B.	Three Recent Examples of Market Power .....	81
C.	The Experience with Divestitures .....	85
9.3	CONSUMER CHOICE AND THE STANDARD OFFER.....	86
9.4	SYSTEM RELIABILITY.....	89
9.5	SUMMARY .....	91
10	THE POSITIVE IMAGE OF DEREGULATION RECONSIDERED .....	92
10.1	REFUTING THE TRUISMS .....	92
10.2	A CRITIQUE OF DOE'S CECA ANALYSIS .....	101
11	ALTERNATIVE MARKET STRUCTURES? .....	105
11.1	CONSUMER CHOICE SUPPLEMENTED .....	105
A.	Public Funding for Public Goods .....	105
B.	A Standard Offer in Perpetuity?.....	106
C.	Portfolio Standards .....	107
11.2	RELIABILITY CAN BE SECURED .....	108
A.	Establishing Accountability for Reserves.....	108
B.	Transmission Planning Resides with RTOs, Governed by Least-Cost Options .....	108
11.3	DEALING WITH MARKET POWER .....	110
A.	The Need for Divestitures, Not Mergers .....	110
B.	Regulation Needs to Supplement Incomplete Structural Solutions.....	110
12	CONCLUSIONS.....	112



# 1 INTRODUCTION

Approximately four years ago, Tellus Institute issued a report entitled "Potential Costs and Benefits of Electric Industry Restructuring." While some criticized that report as being overly skeptical about the potential benefits of electric restructuring, we believe that it has stood the test of time very well. In particular, it is worth quoting a couple of the conclusions from this report. It stated:

Given the range of costs, benefits and risks likely as a consequence of industry restructuring, regulators and legislators should consider an incremental approach to restructuring, in which the competitiveness of wholesale markets is tested and developed, and the costs and benefits assessed before embarking on retail competition. It may be the case that establishing a truly competitive wholesale generation market in combination with a substantial sharing of strandable costs by utility shareholders may achieve most of the goals of industry restructuring advocates.

We still stand by this conclusion. The experience of the last four years has been discouraging, as utility commissions have struggled to establish retail competition, while the states and FERC have tried to nurture workably competitive regional wholesale markets. Neither task has been very successful. Now we have a more comprehensive understanding of why we were probably correct four years ago. We were probably too optimistic. This new report is an attempt to describe that new understanding in considerable detail.

However, it is not even clear to us now that this first step that we recommended taking four years ago, namely trying to establish competitive wholesale generation markets, can ever be achieved given political and regulatory realities. Thus, it is not clear that consumers, particularly small consumers, will ever be able to be protected from the abuses of market power in this industry. In addition, we know now that a substantial sharing of strandable costs with utility shareholders has **not** occurred. In fact, utility customers have more often overpaid for stranded costs.

Most importantly, based on what we have learned over the last four years, it is not clear to us, given the various trade-offs involved, that establishing retail competition will ever be more economically efficient than maintaining vertically integrated well-regulated electric utilities. Presumably, the desire for increased economic efficiency was the primary goal of electric industry restructuring. But we should not get ahead of ourselves until we have completed our analysis of the current state of electric restructuring in the U.S.

## 1.1 Status of Electric Restructuring Today

As of today, about one-half the states in the U.S. have implemented, or have begun to implement, electric restructuring down to the retail level. Yet, except in Pennsylvania, relatively few customers have actually switched to alternative generation providers. This is especially true among small customers. In fact, in some states, a significant number of large customers who initially switched to alternative providers have already switched back to default service due to increases in wholesale, and therefore, retail market prices. This process is accelerating recently.

All states that have established retail competition have also established a regulated standard offer service, which is the default generation tariff that currently governs service for most retail customers. Thus, nationally, very few customers in the country (perhaps 1-2 percent) are being served at true market prices for retail generation services. For this reason, it has been difficult to determine what such a true retail market price would be for most customers in any particular region. For example, at the same time that a company like utility.com is offering generation to Cambridge Electric customers at 2.8 cents per kWh when the standard offer was 3.5 cents, wholesale market prices are much higher. Even the retail market prices seen thus far may have many cross-subsidies embedded in them, and may not represent sustainable retail prices. Strong indications that retail prices will not linger at current low levels are emerging. One example is that Massachusetts Electric has recently asked regulators to raise the default price from 3.8 cents to 5.86 cents per kWh for the summer of 2000, based on the fear that marketers are switching customers back to default service during periods of high wholesale market prices.<sup>1</sup>

In addition, a few formal regional power exchanges have been established at the wholesale level (California, PJM, NEPOOL, and New York), but these markets are still fairly thin (15-25 percent). Thus, while many power marketers exist, and there are many wholesale trades, most power is still being sold at wholesale under fixed price bilateral contracts or under regulated rates from power plants that are still owned by regulated utilities. Moreover, market power has already become a serious problem. The U.S. Department of Energy has recently acknowledged the preponderance of evidence of market power in some deregulated electric markets. The DOE concludes that both the record of restructured markets and the Department's own simulation analysis suggest that market power could "significantly offset the projected benefits of competition in electricity generation markets."<sup>2</sup> In parallel with efforts to establish formal power exchanges, FERC has pushed utilities through Order No. 888, and then through Order No. 2000, to establish open access to all transmission lines, and to establish independent regional transmission operators (RTOs) which would operate large regional utility grids in a way to guarantee open access to transmission. Thus, FERC is trying to eliminate any vestiges of vertical market power at the wholesale level, but many utilities are still strongly resisting these orders. FERC has also begun to address issues of horizontal market power in its various orders dealing with the structure and function of the four formal power exchanges that it has approved, but FERC has also been very slow in dealing with horizontal market power now that it has appeared. Some claim that FERC will prove incapable of successfully dealing with any form of market power.<sup>3</sup>

## 1.2 The Unique Nature of the Electric Industry

One of the primary problems standing in the way of clear and persuasive economic analyses of the strengths and weaknesses of electric industry restructuring is the tendency of many of its advocates to constantly state the mantra that electricity is just another commodity like wheat or oil. Therefore, they say, competitive electricity markets will be easy to establish. Yet, nothing could be farther from the truth, as we will discuss below. In contrast, it is becoming clear to many other analysts,

---

<sup>1</sup> Electric Utility Week, *Mass Electric, seeking to thwart gaming, seeks to hike default rate this summer*, (May 8, 2000), page 11.

<sup>2</sup> U.S. Department of Energy, Office of Economic, Electricity and Natural Gas Analysis, Office of Policy, *Horizontal Market power in Restructured Electricity Markets*, (March 2000), page vi.

<sup>3</sup> We will soon find out if the events of the summer of 2000 in California will change this sluggishness on FERC's part.

including ourselves, that electricity might be one of the most complex products offered for sale in such large quantities, where the product has become a necessity to almost everyone. Electricity has many characteristics, such as not being able to be stored in significant amounts, having a very low price elasticity in the short term, and requiring instantaneous matching of demand and production, that makes it quite different from most other commodities. An even more significant consequence of the lack of storage, coupled with the fast changing nature of the demand for electricity over just the course of each day, is the fact that the supply of power must also change significantly hour-by-hour in somewhat unpredictable ways. There are also major constraints everywhere in the transmission system. This alone implies that electricity is not a typical commodity, and that competitive markets for electricity will be very hard to construct, even at the wholesale level.

This is especially true when the industry tries to disaggregate or unbundle certain functions which tend to need to be performed simultaneously with each other, such as the provision of electric energy, ancillary generation services, or firm capacity transmission rights over the interconnected grid. It may not be possible to unbundle (or separate) many of these services for which the industry is attempting to establish separate competitive markets. The electricity generation and transmission system is a very complex and delicate machine, and most of its functions (services) are highly interactive. Thus, what a market participant does in one sub-market may have serious consequences for other sub-markets at the same time. In some fundamental sense, then, the electricity supplied in a given hour is a different product from the electricity supplied in the previous hour, because system-wide conditions can be substantially different, and they may **never** return to the exact same state as that which existed in the previous hour. This perspective provides an important antidote to the tendency to see electricity as just another commodity. Electricity cannot be a simple commodity if intrinsic sub-markets are not independent of each other. To a significant degree, electricity sub-markets are inherently “tied” together. To complicate things further, unregulated generation services are inherently tied to regulated transmission services.

The ideological mind-set of electricity as a simple commodity has also interfered with the development of accurate ways of analyzing the potential for market power at all levels within the industry. Once this is understood, then the appropriate types of structural and behavioral economic analyses of the electric industry can proceed in a more open-minded way.

Another problem confronting analysts of the electric industry are the many analogies often made to other industries that have become deregulated, like airlines, or telecommunications. Again, careful analysis demonstrates that there are more critical dissimilarities between such industries and the electric industry, than key similarities. For example, relative to the telecommunications industry, by-pass is not possible in the electric industry, except through self-generation, which is not new. Currently, there is only one way to bring electricity to a customer who does not self-generate; namely, through the transmission and distribution system of wires that is already in place. Technological progress in the electric industry will not change this basic point, and technological progress in the future will likely be very slow, as we have seen over the last 50 years. (The invention of the jet engine in the 1940s was the last significant breakthrough in electric industry generation technologies that have already been commercialized, except for modern windmills which play a minor role to date.) While we all can hope that industry restructuring will tend to speed up the rate of technological progress in the industry relative to what would have happened under a continuation of regulation, this difference is not likely to be significant in the areas of the basic

physics and engineering affecting electric generation and transmission. It is more likely to occur at the level of electronic communications and control of demand and supply, which are fairly low cost aspects of the industry even now. Therefore, improvements in these areas, while useful, will not likely save consumers much money.

### **1.3 Initial Perceptions of Strengths and Weaknesses of Restructuring**

In order to entice the reader as to what lies ahead, we will offer some of our initial impressions of the strengths and weaknesses of electric industry restructuring as it has occurred in the United States. Since these will be stated in summary fashion, they will necessarily somewhat over-simplify the analyses that we will present below.

#### **Strengths:**

1. Allowing consumers to have a choice in selecting their generation provider could be highly desirable.
2. Change is often good to stir things up. Electric restructuring might promote technological innovations in metering, billing, end-use controls, and customer service, for some customers. To some extent these improvements will likely result from the bundling of electricity services with other network services like cable TV, internet, telephone, gas, etc.
3. Labor efficiency may improve relatively more quickly both in maintaining the physical infrastructure of the utility system, as well as in administrative functions. This may also improve the physical availability of equipment. However, if enhanced labor efficiency implies lower wages, then this would not be desirable socially.
4. New generation technologies, like fuel cells, may penetrate the market somewhat faster than they would under a continuation of the current regulatory framework.<sup>4</sup>
5. The more rapid spread of RTOs and formal power exchanges to other regions of the country from where they have previously existed will likely enhance the economic efficiency of wholesale power markets nationwide. One key goal here will be the elimination of pancaked transmission rates, as much as is possible. This may reduce electricity bills by a few percent by itself.

#### **Weaknesses:**

1. The higher cost of capital faced by owners of unregulated generation, and the shorter depreciation periods they desire, will drive up electricity prices.

---

<sup>4</sup> However, given the simultaneous need to reduce environmental emissions from electric generation, whether restructuring occurs or not, this differential rate of improvement is likely to be small. In fact, the reverse could also be true if the financial risks of new generation technology are perceived by investors to be high under restructuring.

2. Both wholesale and retail electricity prices will rise in most states of the U.S. that have restructured above what they would have been under a continuation of restructuring within the next few years, and the difference will continue to grow for many years, **even if** electricity markets are competitive. This is because the existing generation ratebase would have continued to depreciate, independently of what new generation investments were made. Consumers will lose the growing benefits of embedded cost ratemaking for generation relative to the higher marginal cost of new generating units. Thus, prices will be higher even if economic efficiency improves faster under restructuring.
3. Market power is also likely to be a persistent threat to consumers, and will prove very difficult to reduce to acceptable levels. Mergers will become more frequent, and will make it even more difficult for regulators to control market power. More mergers will occur among both generation owners, load-serving entities, and among T&D companies. New approaches to mitigate market power will be needed that have not yet been established.
4. Market prices for electricity will become far more volatile than they were previously, even if wholesale power markets are workably competitive. The exercise of market power will greatly accentuate this volatility.
5. Price discrimination between groups of customers, particularly between small and large customers will exist to a greater degree than under regulation, especially if the cost of electricity becomes aggregated with the cost of other services. Customers may lose track of how much they are paying for electricity when and if generation service providers are allowed to establish different retail electric rates for identical customers once multi-industry services are re-bundled, as occurs now for telecommunications services.
6. Economic efficiency may not improve, even in the long run, relative to regulatory approaches like integrated resource planning. In the short to medium term, during the transition to a restructured industry with full-scale retail competition, economic efficiency will suffer substantially. Whether or not the country ever makes up for the early year losses in economic efficiency (on a present value basis) is an open question. One reason why economic efficiency may not even improve in the long run is that price volatility, and the resulting financial risks, may discourage long-run investments in new technologies that are cost effective. Also, ratepayers may generally over-pay for stranded costs. Higher risks may drive up the cost of equity capital even more, and may drive down depreciation periods.
7. Electric system reliability may decline significantly unless regulated reserve requirements are established or maintained in each power market or RTO. This will require the creation of installed capacity and operating reserve markets in addition to energy markets.

8. Transmission system planning may become more difficult when trying to achieve least cost outcomes if generation is deregulated.
9. The rate of research and development spending may decrease relative to a continuation of regulation, because the cost recovery of those expenditures may become more risky to private investors. This could slow the rate of technological innovation, particular where innovation does not enhance market power. In addition, innovation primarily directed at environmental improvement may decline, since it may be seen as an unnecessary cost.
10. The quality of customer service could decline, if new automated customer service centers are installed as a consequence of trying to lower customer service costs, particularly by the new providers of unregulated generation services. This might be particularly true for small customers.
11. Consumer choice may not protect the environment as effectively as a regulatory-based integrated resource planning process, or as effectively as legislated resource portfolio standards, generation performance standards, and systems benefits charges which could be used to fund energy conservation programs.

Obviously, these conclusions must be justified below. The key point for any analyst of electric restructuring to remember is that any conclusions about restructuring must be drawn from a careful construction of a self-consistent scenario which depicts the likely impact of effective regulation, if it were to continue, versus the likely impacts of competitive markets, if the industry is reformed and restructured. Market distortions, such as the exercise of market power, as well as distortions or weaknesses in regulation must be addressed, but the analyst needs to consider the likelihood of such reforms being possible before a new system can be supported. But first and foremost, the analyst must understand the detailed dynamics and structure of each system on its own, in its ideal state, before the advantages and disadvantages of each, along with likely imperfections, can be weighed.

## **2 THE FAVORABLE IMAGE OF RESTRUCTURING**

Until the summer of 2000, the immensely complex process of restructuring the electric utility industry in the United States had gained tremendous momentum. After years of planning, and mere months of experience with deregulation in a few states that have launched competitive electricity markets, the attention of regulators in most states shifted away from the question as to whether restructuring should take place, to actually making it happen. The actual appropriateness of the deregulation of electric generation in meeting the underlying economic goals of restructuring was no longer questioned by many. Restructuring was going forward, and the general consensus seemed to be that this is all for the better. Of course, “San Diego” may change all that.

### **2.1 Prevailing Truisms behind Electric Utility Restructuring**

Regulators should ask themselves what are the true interests of the consumer in seeing restructuring take place, and how can regulators best serve those consumer interests in implementing restructuring generally, and retail competition in particular? The obvious answer is that their task is to ensure that restructuring is carried out in a fashion that benefits the vast majority of consumers over a sustained period of time. This is not in dispute. However, this task cannot be carried out without making some assumptions about which tools to use in delivering electricity services in this beneficial fashion, or more specifically, assumptions on how certain tools will perform and interact with each other. A variety of assumptions have been made in the process of bringing about restructuring in the electricity industry. These assumptions have gradually fed the established body of truisms that seem to represent the mainstream thinking on the subject. This has happened without much critical analysis, or at least little vocal challenge from stakeholders such as ratepayers.

Why has there been such a revolutionary change in the way we perceive the electric industry over a relatively short period of time? The historical context is important, like the high cost of oil in the 1970s and the failure of nuclear power to live up to expectations. However, over the past decade, the two most important reasons are the lack of accurate information among important stakeholders about the actual conditions in the industry, and a growing and almost blind faith in the “market” to deliver all needed solutions in practically any circumstance. We will state the truisms that prevail in the mainstream thinking on electric industry restructuring in order to lay bare the weaknesses, as well as the potential strong points, of the changing industry. Examining some of the key assumptions that regulators have made during the introduction of restructuring will help to clarify how best to examine, and perhaps adjust, the deregulation process so that it may truly reflect the interests of all consumer, avoid cross-subsidizing and undue cost-shifting between customer classes, and meet the assumptions and expectations underlying the process.

The overarching assumption or truism is that any effort to introduce retail competition would benefit all consumers in a variety of ways. If market failures occur, these are often thought to be a minor concern because the benefits of the new market structure will prevail and ultimately outweigh the costs. We believe that this outlook is irrationally optimistic and has led us to dive head first into retail competition before there is any indication that even wholesale electricity markets alone can be made workably competitive.

Rather than simply anticipating the best possible outcome, regulators have three primary responsibilities when they initiate the restructuring process. One is to explicitly recognize that they are actually making *assumptions* about the practicality and effectiveness of their tools. Secondly, they need to allow for various corrections over time in the implementation of new market rules and market design as real experiences test the validity of their assumptions. Finally, they need to recognize that certain policies may only benefit large-scale customers over the interests of residential and other small-scale customers. While this last issue has often received lip service and is a frequently voiced concern, it has typically not been taken seriously when specific restructuring policies have been developed.

First Truism:

*Making separate markets for every possible unbundled competitive service makes sense as a way to maximize economic efficiency.*

Second Truism:

*It is always in the consumers' interest to have the freedom to choose the provider of any given service if at all possible, and to be able to do so based on their own individual criteria, including the price and quality of the products available. Such choice, and markets in general, are necessary to correctly establish all relevant price signals.*

Third Truism:

*The deregulation of electricity generation services will surely lead to effective competition among generation service providers within a reasonably short transition period, and the need for continued price regulation will disappear.*

Fourth Truism:

*Competition will result in a lower marginal cost for retail generation services and therefore, lower electricity prices over the long run when compared to a continuation of rate regulation for generation.*

Fifth Truism:

*To initiate retail competition for generation services, it is sufficient to give consumers a credit for the generation portion of their current electricity rate, as long as it is equal to or slightly in excess of the wholesale price of power. Competitive service providers will emerge and provide retail generation services at a price that fits within this margin.*

Sixth Truism:

*The current transmission system will work equally well, if not better, in the new competitive retail market, as it did under the regulated utility structure.*

Seventh Truism:

*The inevitable reduction in the wholesale price of electricity under deregulation will be consistent with generating a vibrant retail market and convincing a large number of customers to switch service providers.*



**Eighth Truism:**

*It is appropriate to mandate rate reductions from the outset of deregulation to reflect the eventuality of lower market prices for generation, and to provide consumers an immediate benefit from the inevitable effects of deregulation and retail competition.*

**Ninth Truism:**

*The retail default or standard offer service is merely a transitional necessity and should be phased out over a period of a few years, because the competitive retail market will successfully provide service for all customers at rates that are lower than before restructuring came into effect.*

**Tenth Truism:**

*Restructured electricity markets and retail competition will preserve system reliability because customers value high levels of reliability. The market will determine an optimum level of capacity reserves to maintain reliability at the level customers desire.*

**Eleventh Truism:**

*Restructuring will improve the environment because large numbers of consumers will choose cleaner generating technologies once they have a choice.*

## **3 AN HISTORICAL PERSPECTIVE**

### **3.1 How and Why We Got To The Current Situation**

For many years prior to 1995, the structure of the electric utility industry in the U.S. remained fairly constant. The vast majority of electricity sales were made by about one hundred vertically integrated investor-owned electric utilities. Vertically integrated utilities own their distribution and transmission systems, as well as enough generation capacity to reliably meet their customers' demand. A few large federal power generation agencies sold mostly cheap western hydroelectric power to municipal utilities or to other utilities, while the Tennessee Valley Authority (TVA) sold more coal and nuclear power than hydroelectric power. Finally, there were thousands of small municipal or other public power entities throughout the country that either generated their own power, or purchased power from other utilities, including investor owned utilities, based on long-term contracts. The investor owned utilities were all regulated by state public utility commissions in the states in which they operated, and most public power entities were loosely regulated by either the federal government, or by their local municipal governing boards. A few public power utilities were regulated by their state public utility commissions, and many were not regulated at all.

#### **A. Impact of the Oil Price Shocks of the Early 1970s**

Some brief history of recent U.S. experience is in order. Basically, while small to medium sized nuclear power plants were being built during the mid-late 1960s, the rapid increases in oil prices during the oil crisis of 1974 gave further impetus to the construction of larger nuclear plants. Utilities quickly tried to increase the size of nuclear units from a few hundred megawatts to the 1000 to 1200 megawatt range to achieve economies of scale. Unfortunately, this increase in size was premature, given still evolving state of engineering knowledge about how to build nuclear plants for acceptably safe operation, and large cost increases relative to initial capital cost estimates were experienced.

Due to a series of accidents at U.S. nuclear plants leading up to the near catastrophe at Three Mile Island in 1979, the construction requirements for plants were constantly changing, further escalating the costs of units under construction and the anticipated costs of planned units. Longer construction times also resulted, leading to more interest during construction that had to be capitalized along with direct construction costs. The result was that nuclear generating units went from a capital cost of a few hundred dollars per kilowatt of capacity in the mid-1970s, to several thousand dollars per kilowatt in the mid-1980s. Simultaneously, nuclear plants turned out to run less well than predicted, with high maintenance and unplanned outage times, while operations and maintenance costs and capital additions escalated at rates far above inflation. By the mid-1980s, then, new nuclear plants coming on line were producing baseload power at costs as high as 20-30 cents per kilowatt-hour, in their early years of operation. This was far higher than the cost of power from new coal plants, which was in the range of 5-7 cents per kilowatt-hour. Both the increases in the price of oil and the increases in nuclear power costs led to substantial increases in electric utility rates between 1974 and 1983.

In addition, to try to limit oil use for electric generation, the Public Utilities Regulatory Policy Act (PURPA) became federal law in 1978. This act created a new category of power plants, namely

“qualifying facilities.” These facilities were entitled to be paid for their electricity output at full avoided costs, as defined under the act. Ideally, the avoided costs are the year-by-year gross decreases the combined costs of electricity generation (construction, operation, transmission and distribution, etc.) needed to meet demand in a reliable and least-cost manner that would be caused by the capacity and energy provided by the qualifying facility. While different and conflicting methodologies for computing avoided costs were all too prevalent, many of the purchased power contract prices obtained by qualifying facilities during the 1980s were based on expectations of high oil and coal prices over the next 15-30 years. When, by the early to mid-1990s, avoided costs turned out to be far lower than those upon which many qualifying facility contracts were based, many utilities holding such contracts tried to re-negotiate or buy their way out of these contracts. However, often these cost reduction efforts were not successful.

By the late 1980s demand growth had significantly slowed, and new efficient natural gas combined cycle units became economically and environmentally attractive, with their modular character and smaller size reducing investment (or ratepayer) risk. More than anything else, the dramatic underestimation of the cost of delivering nuclear power and the steady decline in oil prices since the early 1980s, which were the basis for much qualifying facility power, has caused a temporary gap between the average cost of electricity delivered by some of the higher priced utilities, and the marginal cost of new generation from the new gas-fired generating units. The lower price of natural gas had now caused the long-run marginal cost (LRMC) of new generation to be below the average embedded cost of some existing power plants. Naturally, consumers, particularly large consumers, eventually demanded that they no longer suffer from what had become by the early 1990s the enormous opportunity cost of nuclear energy. Competition, particularly retail competition, they believed, would presumably allow consumers to “negotiate” a lower price for energy. Industrial consumers envisioned that their potential market leverage could save them substantial amounts of money in a competitive market, as opposed to small-scale customers, when rate design and cost allocation for generation was no longer regulated.

When industrial customers first started to advocate for electric industry restructuring in the early 1990s, they typically did so in states like California, Pennsylvania and New England where average utility rates were quite high owing to the excess costs of nuclear units and qualifying facility contracts. These customers pointed out that if they could obtain generation directly from new gas-fired combined cycle units, they might be able to obtain this power for a price more like 3.0 cents per kWh, not the 5.0-8.0 cents per kWh they were currently paying. Therefore, they argued, if the monopoly that vertically integrated utilities held on the retail sale of generation could be ended, or if the price of generation could be deregulated, then they could save a lot of money on their utility bills. These arguments were part of a world-wide movement away from government and private monopolies, and toward the market provision of all services.

Of course, in response, many analysts pointed out that someone would have to reimburse the stockholders of the utilities, in part or in whole, for the difference between the net book value of the expensive plants and contracts and their lower value in the emerging competitive markets. This difference between average embedded costs and market price became known as stranded costs. Generally, the largest component of positive stranded costs, where they existed, was due to nuclear power plants, with the second largest component coming from qualifying facility contracts. What most analysts failed to point out, at least initially, was that most old coal plants had **negative**, not

positive, stranded costs, since the concept of negative as well as positive stranded costs took several years to become widely accepted.

Once the concept of stranded costs was properly fleshed out, most people also realized that if utilities received 100 percent reimbursement for stranded costs over some fixed period of years through a distribution system wires charge, which became the agreed upon recovery approach, ratepayers would, by definition, not save any money due to restructuring. This revelation led customers to argue for something less than 100 percent recovery of stranded costs (which rarely happened, in fact), or for the more popular approach of legislating an up-front rate reduction when retail competition was established. Typically, then, state legislatures provided 5-15 percent first year rate reductions, as part of their restructuring legislation. Unfortunately, some of these up-front rate reductions were deceptive.

What few customers realized, then, was that 100 percent recovery of stranded costs implied that customers would, generally, have to pay the utility back for these up-front rate reductions, with interest, over a period of years in the future. This fact was usually not obvious to and, therefore, not understood by most customers. Customers also did not realize that even if restructuring had not occurred, real electricity rates would have fallen steadily under regulation, as they had, on average throughout the U.S. since 1983, especially so with the advent of the new efficient gas generating units. Stranded cost recovery was often structured in a way that naturally allowed for some up-front rate decrease simply by leveling the payment of stranded costs over time, relative to the more front-loading of stranded costs that usually occurs under cost-of-service regulation. Thus, after the first few years of stranded cost recovery, rates were often higher than they would have been under continued regulation, even if they did not increase in current dollars. The key question now becomes, what will happen to market-based generation prices after the recovery of stranded costs ceases, relative to where they would have been under a continuation of regulation.

Another very different but important set of regulatory-related events were also developing during the 1980s as part of the context for restructuring. Following from many of the belated generation planning reviews of the early to mid-1980s, where it was determined that most nuclear units under construction were not part of a least-cost mix of generating units for the utility concerned, better utility planning methodologies were developed. Ultimately, these new methodologies became grouped under the title "integrated resource planning" or IRP. IRP was important for several different reasons. Most importantly, it demonstrated that fairly simple analytical techniques were possible to minimize customers' electric bills over the long term, while providing reliable and environmentally acceptable electricity. Secondly, public utility commission IRP hearings provided opportunities for many stakeholder groups to participate in a more meaningful way than they had in the past. This enabled many more stakeholders to understand and, therefore, to buy into both the goals and outcomes of the IRP process. Thirdly, IRP included the consideration of demand-side (particularly energy conservation) investments on an equal footing with supply-side or generation investments, so that a least-cost mix of all investment options could be pursued. Finally, IRP provided a self-consistent analytical framework for the environmental impacts of electricity generation to be considered in planning and operation.

One important outcome of the practice of IRP in the two dozen, or so, states that adopted this approach, was that utilities began to spend far more on cost-effective demand-side management

(DSM) programs than they had in the past. A secondary side effect of this spending on DSM was that, in some instances, electric rates went up slightly above the level where they would have been otherwise absent the DSM programs. Thus, even though **average** customer bills typically went down, which is the important result, this small rate increase led to small bill increases for non-participants in DSM programs. These increases were often pointed to and protested by industrial customers when they began to advocate electric industry restructuring. This was given as yet another reason why industrial customers should be able to purchase their electric power directly from an unregulated market, so they would no longer have to pay for someone else's DSM investments. Of course, it was also often the case that industrial customers collectively were the largest recipients of DSM funding, and they benefited from utility DSM programs the most.

Thus, regulatory-approved DSM programs became painted as another way in which utility regulators interfered with free markets in energy services. Directly and indirectly, many industrial advocates of restructuring also expressed strong concern about and disapproval of incorporating any environment impact considerations in utility planning and operation, since doing so would also tend to increase their electricity rates. Both opposition to DSM programs and opposition to environmental considerations led to strong attacks by many industrial organizations on the IRP process. The argument developed that a "free" market in electricity generation and DSM services would much more likely ensure the least-cost provision of both electric supplies and environmental protection than could any set of regulators pursuing IRP.

As the arguments against IRP gained momentum, the move towards retail competition, or "retail wheeling," as it was called then, also strengthened. However, if increased retail competition provided the benefits claimed by its proponents, they would not flow from the technological evolution in power plant generation already underway, since these benefits would be possible within wholesale markets alone. Yet, the argument was made, with little analysis, that retail competition was necessary to ensure competitive wholesale markets. The view of many industrial organizations became quite firm that the deregulation of generation leading to competitive wholesale markets would not really be viable, or would not really happen, unless **individual** customers were allowed direct access to generation suppliers. They argued that it would not be sufficient for the development of competitive wholesale markets if distribution utilities remained the regulated purchasing agents in a deregulated wholesale market on behalf of all their customers. Industrials wanted to be able to buy directly from the wholesale market in order to gain greater advantages than other customers. Thus, once the attention of state PUCs shifted to issues related to whether or not restructuring made sense for their state, IRP hearings tended to rapidly die out. Once state restructuring laws were passed, then IRP was formally ended, if it had existed in the first place. Currently, only Colorado seems to have maintained its IRP process, though it too has been negatively affected by the desire of the main investor-owned utility in the state to establish retail competition.

## **B. The Energy Policy Act of 1992**

The forces behind the Energy Policy Act of 1992 (EPAct) continued to push for complete industry restructuring. However, proponents of retail, and even wholesale competition, realized that existing utilities that owned transmission networks would not likely allow for fair open access to these networks unless forced to do so. Thus, momentum built for FERC to issue Order No. 888, which,

among other things, tried to mitigate any vertical market power that incumbent owners of generation would have in a competitive (deregulated) wholesale power market. EPACT '92 also allowed for a new category of generating plant ownership known as Exempt Wholesale Generators, that would be exempt from any sort of price regulation.

Even after FERC Order No. 888 was issued in 1996 there was little support for just deregulating the price of wholesale generation, unless the monopoly supplier status of each local distribution utility at the retail level was also ended. Whether or not this has proved, or will prove, to be a wise decision, is a major issue that we will address below. The consequence of this decision has been that no state has attempted to take a first step towards full restructuring by only deregulating its electric generating plants in order to establish a competitive wholesale generation market without simultaneously establishing retail competition. Perhaps the hesitation to do this has derived from the hesitation to order the divestiture of generating units to third parties, which would probably be necessary to prevent self-dealing and market power. Many, if not most, states probably did not have the authority to order divestiture. This reticence could also derive from concern that without retail competition new market entry at the wholesale level would likely be much less robust. However, it could also stem from conceptual confusion, whereby the two types of competition, wholesale and retail, were conflated. Whatever the reasons for balking at the establishment of competitive wholesale markets first, before rushing to establish competitive retail markets, all states that have restructured are attempting to do both simultaneously. Because of this many unanticipated problems are starting to emerge.

## **4 OBJECTIVES AND PRINCIPLES UNDERLYING RESTRUCTURING**

### **4.1 The Pursuit of Efficiency in the Past**

Electric utility restructuring is the last of several significant shifts in the regulatory approach taken toward the industry over the years. Each change has brought a relative improvement on the preceding framework as regulators have tried to balance the consumer interest in low electricity rates with the needs of utilities to receive a fair return on their investments. In addition, through the move towards adopting integrated resource planning, regulators have attempted to attain various social goods associated with energy procurement, such as by the integration of environmental externalities into the planning for energy production. This was duly justified by the principle that electricity should not be necessarily be procured at a minimal direct economic cost, but at a minimal total cost where economic, social, and environmental considerations are balanced. Least-cost planning was the first step in this reduction. Further reductions in economic costs through efficiency improvements materialized under integrated resource planning and demand-side management. Non-economic costs, or costs that otherwise become externalities to the electricity market were, then, internalized through efforts to promote renewable energy technologies and force power generators to face the cost of pollution through tradable pollution permits.

In contrast, the recent wave of restructuring, aimed at firmly establishing competitive markets for energy services and limiting vertical integration in the industry, is a somewhat discontinuous step in this ongoing adjustment of the regulatory approach. In place of incremental changes, many regulators and legislators have chosen a significant shift in objectives and priorities. It appears that the new market structure has almost become the objective in itself, while prior goals like minimizing the cost of electricity generation and the accurate accounting of externalities have more or less been abandoned on the faith that markets will compensate. While the process of restructuring is not total deregulation but rather re-regulation, the emphasis has been heavily on market solutions replacing regulatory tools that previously did deliver concrete results once least-cost planning and IRP were actually implemented. These recent changes are being made without any certainty that the new market structure will compensate, for example, for the loss of large-scale DSM programs and the like, or even that the wholesale market will mimic least-cost supply planning.

By the early 1990s there certainly was not a perfect wholesale market, and it was very small compared to all the generation capacity still being regulated. However, any market that does not reflect all costs associated with producing a product cannot be considered economically efficient. Integrated resource planning was, and is, an attempt to allow for an adjustment in electric generation costs so that they reflect true social costs. Opponents of IRP were, therefore, wrong when they claimed that such full-cost accounting distorted the market. It may have “distorted” i.e., reduced, their own profit-maximizing potential, or somewhat increased their rates, but without IRP and DSM *of some sort*, whether it be in the existing form or some improved version, the overall energy market cannot be economically efficient, and would be, therefore, distorted by hidden costs. Although the common definition of a perfect market is one where no intervention is

present, it is a naïve version, as it also assumes the perfect availability of all relevant information and the absence of entry barriers. An energy market that is “blind” to externalities may or may not be competitive, but it certainly is not efficient in the wider context of what society needs, and should demand, from the process of energy procurement. It is that kind of efficiency that regulators presumably look for when pursuing competitive markets. Unfortunately, they may have lost sight of the need to supplement market structures in those areas where they fall short of meeting the wider range of objectives. All markets require appropriate constraints.

#### 4.2 Need for Clarity of Objectives

To provide an appropriate context for thinking about the details of electricity restructuring, which are quite complex, policy makers should first think about the relevant problems that they are trying to solve, and the objectives and principles that they are trying to achieve. It is essential that regulators and legislators clearly identify the *problems* with the current industry structure and/or the current regulatory practices used in the electric utility industry, as well as the underlying causes for these problems. Once these problems have been identified, regulators and legislators should establish a clear set of *objectives* that they believe should be met in a restructured electric utility industry. They should also establish a set of key *principles*, which should be upheld as constraints, that should be maintained both during the process of reforming the industry, as well as in the long run, after the reform is complete.

Together, these objectives and principles should provide a framework and a context for evaluating the merits of specific restructuring proposals aimed at trying to solve the problems identified with the current structure. Real world considerations (e.g. generation market failures) and the unique characteristics of the electric industry which could interfere with or alter desired outcomes, must also be recognized and addressed. The evaluation must determine if a specific proposal will be more effective in achieving the stated objectives than either continuation of the status quo, or an alternate restructuring proposal. In addition, the risks of changing the regulatory or industry structure must be assessed if outcomes cannot be completely known ahead of time. Use of this “big picture” evaluation perspective is particularly important in terms of identifying the potential long-term implications of various restructuring proposals and alternative ratemaking proposals on a step-by-step basis. Presumably, no one wants to restructure the electric industry one way today only to discover in a few years that another type of restructuring is needed, or that we rushed into a structure with unjustifiably high risk to consumers. Hopefully, the above approach will help us to avoid proposals that only have an ideological basis.

The importance of fundamental public policy objectives should not diminish, nor necessarily change, under any restructuring proposal. One of the primary objectives of regulating the price of electricity services in the past has been to ensure *reliable* service at *stable* and *reasonable* rates. “Reasonable rates” may not equal the *lowest possible* rates, given that regulators sometimes tried to enhance economic efficiency even if the result is higher rates. Notably, the goal of *stable* rates has generally been achieved in most cases under the current cost-of-service regulatory approach. It is inevitable that rates will be much less stable in a competitive retail generation market. The behavior of the world oil markets over the last 25 years illustrates this point quite well.

In addition, regulation has attempted to help achieve various state and national public policy goals related to *equity*, *environmental quality*, *economic development* and *energy security*. *Equity*



is a concept that is both difficult to define and to achieve. In the case of restructuring, equity considerations can arise in the regulatory treatment of the costs of existing purchased power contracts and of uneconomic costs of generation in ratebase (strandable costs). Equity between customer classes and among individual customers within a class is also an important concern in designing electric rates. Equity arguments can (and have) been made on various sides of the same issue. For utility shareholders, “equity” may require that recovery of all prudently incurred costs be guaranteed, while for customers “equity” requires that they do not bear all of the costs of uneconomical generating capacity. Similarly, another may perceive a condition that is equitable to one customer as a condition of subsidy. *Environmental sustainability* should also be an important objective of public policy, perhaps sometimes in conflict with the goal of low electric rates, but somewhat linked in parallel with economic efficiency and equity. While difficult to define precisely, and challenging to implement in specific policy contexts (e.g., state regulation and legislation regarding electric industry restructuring), the long run sustainability of the ecological foundation of our society and economy is of fundamental importance, and should always be considered when restructuring is debated. In short, state and national public policy goals should operate as constraints on the extent and form of electric industry restructuring implemented in any particular state or region. Table 1 lists the objectives and principles that have been mentioned as either implicit or explicit to the restructuring process, and which should be taken into account.

**Table 1: Restructuring Objectives and Principles**

<b>Objectives</b>	<b>Principles that Should Apply</b>
Greater economic efficiency	Social-cost accounting/Sustainability
Lower prices	“Reasonable” rates
Increased consumer choice	Intra- and intergenerational equity
Preserved system reliability	No more regulation than necessary
More transparent prices	High reliability
Greater environmental protection	Structural simplicity

### **4.3 Four Major Goals of Electric Industry Restructuring**

Of the goals listed in Table 1, enhanced consumer choice of electricity products, greater economic efficiency, and lower electricity prices to all consumers are probably the three **primary** goals that restructuring is meant to deliver, while preserving system reliability. Some proponents of restructuring support a fourth goal, which is to achieve better environmental protection through increased consumer choice and autonomy in the electricity markets. Is increased environmental protection, and any other social goals that are linked to electricity production or consumption, a true objective of restructuring, or simply a benefit that may, or may not, result from greater consumer choice? Is consumer choice a goal in itself, or is it merely the means to achieve economic efficiency? Competitive markets tend to contribute to both economic efficiency and to lower prices. Lower price is a clear objective, but are minimal regulation and expanding competitive markets necessarily desirable if they do not lead to lower

prices? Obviously, it is not entirely clear what the immediate goals of restructuring may be to various stakeholders, although the long-term objective is often defined in vague terms such as enhanced efficiency and competitiveness, in addition to lower prices and greater customer choice. The following questions, then, need to be asked: Which of the four “goals” above constitute a clear long-term objective, which is an intermediate step or means to deliver another objective, and which is merely a secondary effect that may, or may not, be beneficial.

### **A. Greater Economic Efficiency**

Greater economic efficiency is, presumably, the pivotal goal of restructuring. The ultimate long-run objective, which is lower electricity prices, rests on the efficacy of greater efficiency in reducing overall costs of providing electricity services to consumers. It is also widely believed that by creating a competitive environment in the electricity industry, greater economic efficiency will be achieved. For some these may be synonymous. The scope of the competitive environment has come to include generation, metering, billing, and ancillary generation services. The subsequent deduction is that a competitive environment, in turn, will eliminate the need for price regulation, as the competitive market will hold prices at an optimum level while effectively and reliably delivering electricity services to all consumers. Authors Adam Jaffe and Joseph Kalt explain that “the current restructuring debate is driven by economic and historical analysis that suggests that the efficiency of the electricity industry could be enhanced by increasing the role played by competitive market forces in the industry, thereby reducing the need for economic decisions to be governed by regulation.”<sup>5</sup> This suggests that restructuring seeks to find a new balance between the roles played by market forces and by regulation without eliminating or ignoring the place of either in the future. For example, the deregulation of generation creates the potential problem of market power which, itself, requires a regulatory response. Likewise, the goal of greater economic efficiency, whether through regulation or markets, is not always to bring electricity prices to their lowest possible level without regard for some social constraints. For example, Missouri regulations specify that a fundamental objective of the utility regulation is to ensure that the public is provided “with energy services that are safe, reliable and efficient, at just and reasonable rates, in a manner that serves the public interests.”<sup>6</sup> In this context, “reasonable rates” are obviously not the lowest possible rates. In that regard, the premise has not changed from days of electric monopolies when the goal of reasonable rates was met through cost-of-service regulation.

### **B. Lower Electricity Prices**

Arguably, a portion of a reasonable rate could reflect various socially important considerations such as environmental and other externalities, support for low-income customers, and possibly long-term resource planning that benefits society as a whole but may lie beyond the scope and “interest” of the competitive markets in electricity services. This implies that in the past the price for electricity was not intended to be based entirely on the lowest-cost technologies alone, and that competitive markets should be structured in ways that aim to achieve the same social goals. In addition, as is the case in any market, some arbitrariness in the setting of prices will

---

<sup>5</sup> Jaffe, Adam and Joseph Kalt, *An Economic Analysis of the Electricity Industry Restructuring in New England*. Prepared on behalf of Northeast Utilities System Companies by the Economics Resource Group Inc., Cambridge, MA, April 1995; page 1.

<sup>6</sup> Missouri Title 4 CSR 240-22.010 Policy Objectives.

remain even with vigorous competition for various electricity services, because there cannot be absolute transparency for all cost components at each moment in time. Presumably, proponents of competitive electricity markets will accept such ambiguity.

The only realistic new electricity market will, then, be a hybrid of the “perfectly competitive” market, and a fully price-regulated market, designed to address social considerations as defined by the consumer and public interest and, thereby, will attain greater economic efficiency. Moreover, the potentially competitive components of electricity prices may or may not be reduced due to further competition relative to what future regulated prices for these components might have ended up being had restructuring not occurred. In addition, while some kinds of economic efficiencies may be gained in the new electricity markets, others may be lost; e.g., more transmission congestion could lead to more new transmission lines being built than under regulation. Transmission systems will be operated in a manner not intended vs. variable cost dispatch. Some specific aspects of restructuring, like the greater accuracy of price signals, may even lead to higher overall costs.

One purpose of this report is to demonstrate that, despite the many assumptions and the general optimism in the electric industry and among regulators, effective competition in electricity markets may be hard to attain. And, even if workably competitive markets develop, they will not automatically internalize externalities and achieve a high degree of economic efficiency at the social level. As a result, economic efficiency, lower prices, and full cost accounting in production may remain elusive goals. The loss of embedded cost rates in exchange for market rates may turn out to be a serious mistake if the inefficiency of higher transaction costs, market power, and the loss of social cost pricing together amounts to a net loss to society. The worst conceivable outcome of the restructuring process would be significantly higher electricity prices and private investor profits than would have been realized under continued price-regulation, combined with a total loss of consideration for environmental externalities and other social goals that have been addressed under integrated resource planning prior to restructuring.

### **C. Increased Consumer Choice**

Of the three primary goals mentioned, only enhanced consumer choice is not a direct economic objective. The ability of the consumer to choose among alternative services is always considered preferable, on the premise that it will lead to greater innovation and customer satisfaction. The consumer will benefit from the expected improvement in economic efficiency as well as the personal satisfaction inherent in the freedom to make a choice, which will itself cause the markets to become more efficient. Therefore, consumer choice has become both the means to a desired outcome, and an end.

The demand for consumer choice in electricity services is almost entirely new. More accurately, the need to express choice in a retail market is new. It is difficult to argue that this change is coming about because the masses rose up and demanded choice. The truth is that state agencies and other stakeholders have spent a tremendous amount of resources in an effort to sell the idea of retail choice to consumers, and in most cases the results have been dismal (albeit in part due to default pricing schemes). Electricity services used to be perceived (and still are by many) as a homogenous good, provided by a monopoly, with no opportunity (or need) to express personal preferences for the quality or nature of the product. Aside from the potential cost savings to

consumers who are able to shop for the lowest energy prices, electricity now has begun to be differentiated on the basis of both subjective and objective qualities. For example, “green” power is a value-added product or service that some consumers prefer, and many are willing to purchase it at a premium. In that sense, the demand for choice is not entirely new. Opposition to nuclear energy, for example, probably would have been expressed through consumer choice in decades past if the limited individual consumer autonomy in this market had had some outlet other than public protest. It is clear, then, that consumer choice serves an economic purpose because it has the potential to force prices down, but it is also a goal in itself because the ability to make individual choices is of some utility to consumers who strongly value autonomy. In addition, the prevailing belief is that certain consumer preferences may be better communicated to producers through an unregulated market system than they can be under a regulatory system for electric generation. As a result, the market would be likely to produce more of what the consumers want, and thus increase overall economic efficiency. This aspect of enhanced economic efficiency will be further discussed below.

#### **D. Maintaining System Reliability**

System reliability is also a primary concern of all stakeholders. It remains unclear how the reliability of the electric system will be preserved in the future. The valuable work of the North American Electric Reliability Council (NERC), which has been on a voluntary basis, has helped maintain the reliability of the transmission system nationally, and thus the overall reliability of electric service. This work will presumably be continued in some capacity under the auspices of the proposed North American Electric Reliability Organization.

Generation reserves are another matter. Who will have the authority to impose a reasonable generation reserve margin—not a default reserve margin that is generated by the collective decisions of market participants about capacity additions - but a reserve margin that is imposed on all load-serving entities as has been done under traditional regulation? Will this be FERC? Do regulators expect that additions to transmission capacity will make up for the difference and compensate for ever lower reserves, and that tightening supplies, driven by the competitive market, is an acceptable outcome? Reserve margins are shrinking in California where no requirement for a margin is in place. Despite the popular view that the unregulated generation market will be able to equilibrate at a reasonable reserve margin on its own, no concrete proof of this hypothesis has been offered, and there are theoretical reasons to be skeptical. These reasons will be discussed further in Section 8.

## 5 THREATS TO ECONOMIC EFFICIENCY

### 5.1 What is Economic Efficiency?

As described above, the current move towards restructuring is driven by the belief that effective competition will materialize which, in turn, will lead to greater economic efficiency in the electric industry, ultimately delivering lower prices and reducing the need for regulations governing the industry. Competitive generation markets, then, are seen as the means to achieving improvements in both the *quality and cost* of electricity services, in part, through the creation of additional services not previously offered to customers.

Economic efficiency refers to the way in which resources are allocated in the economy. There are two basic components to this concept; one is the production efficiency or “technical efficiency of resource allocation,” and the other is output efficiency or “economic efficiency of resource allocation.” The former addresses the allocation of resources for inputs into the production of goods and services, while the latter focuses on the allocation among outputs; that is, the efficient mix of goods and services produced for consumers, presumably in accordance with their demands. Those demands define the product-quality sought by consumers, given certain cost constraints. Those costs are manifested in the price of the product. How transparent those prices are to consumers, and how closely they reflect the true cost of providing goods and services, defines their relative “price efficiency.”

Obviously, it is impossible to optimize both the quality and price of a product, because there are usually tradeoffs between the two. Consumers also have varying tastes. Therefore, each consumer must weigh the value of different qualitative features of the product against the price, and make a choice accordingly as to whether or not to purchase the product. If information on options is sufficient, and all or most product options are available, the market has the potential to become more economically efficient and to deliver each good at an efficient price to each consumer according to his or her taste and needs.

In the electricity market, quality can mean different things. The obvious element of quality is reliability, defined as uninterrupted service, stable voltage, and lack of harmonics. Other qualitative features relate to types of generation technologies and fuels used for generating the electricity. Some consumers will prefer green power or low emission technologies over fossil-fuel-based generation. For such customers, economic efficiency may be attained if green products are available at a price they are willing to pay. However, there are still obstacles to economic efficiency in this scenario. For example, economic efficiency in the broadest sense demands that all social costs be fully accounted for. However, consumers who use fossil fuel currently do not bear the full cost of the environmental and health risks generated by that consumption. Therefore, strictly from a perspective of economic efficiency, too many of such products may be produced and consumed. This implies that buyers of green power individually subsidize a public good, if it costs more than non-differentiated electricity. The resulting benefit of reduced pollution is not acknowledged by all the consumers that reap the benefits, and the cost is borne unevenly, resulting in less green power being produced and consumed than otherwise would be economically efficient.

## A. Technical Efficiency in Resource Allocation

Technical efficiency of production has been described as such an allocation of resources where it is impossible to increase the output of one good without decreasing the output of another.<sup>7</sup> This rule suggests that when the output from a given pool of resource inputs has been maximized, using current technology, technical efficiency has been achieved. Once the resource stream is fully utilized, no more can be produced of a single product without reducing the production of another, because that would require removal of certain inputs from another production line. However, this concept is not very useful when examining an entire economy. In that case, it would have to include some measure of the *aggregate utility* of the goods produced, since increasing the output of one specific product may be more efficient even if it necessitates reducing the output of another.<sup>8</sup>

Within a single industry or a single firm, the concept is much more useful. In the electric industry, technical efficiency is defined essentially as *least-cost production*. For any given product, such as electricity, the industry must find the optimum mix of resources at the lowest price to produce the output given the demand. Some raw materials (in this case perhaps fossil fuels) may be plentiful and inexpensive, while the technology to use them may be expensive. Alternatively, some raw materials may be more expensive but the technology associated with utilizing that resource might be efficient enough to make it a reasonable alternative. Uranium may not be an expensive energy source considering its energy content, but the cost of extracting that energy has proven to be quite high, mainly due to high capital cost of nuclear plants. Until recently, natural gas has not been an inexpensive fuel for electricity generation but, with modest prices and the higher efficiency of combined-cycle generation plants, it has become the most viable fuel for new power plants. Prompted by such cost considerations, and by internal competition, producers of electricity will strive to achieve technical efficiency on the production level. However, various market failures affecting electricity production have interfered in this process and led to the inefficient allocation of resources. The vast underestimation of the cost of nuclear power early on is perhaps the clearest example of this.

## B. Efficiency of Output

Technical efficiency in production is desirable but it is of limited value if an inappropriate mix of goods and services is being produced. Economic efficiency cannot be achieved until consumer preferences have been incorporated into the decisions about how much of any given good should be produced. Output efficiency, or economically efficient allocation of resources across the economy, relies on the price system to communicate consumer needs to the producers. If

---

<sup>7</sup> Nicholson, Walter, *Intermediate Microeconomics and its Applications*, Fourth edition, (New York, New York: Dryden Press, 1987), page 504.

<sup>8</sup> For example, let us assume that the world has an absolute, measurable limit of fresh water supply. We can also assume that there is a choice between using the last increment of water for either beef production or soybean production. Technical efficiency is neutral to which is produced: Producing more of one will reduce the output of the other so technical efficiency has been achieved. Nonetheless, using the water to make soybeans would have greater “technical utility” because more people could be fed with the beans than the beef produced by use of that incremental amount of water. This should not be confused with consumer preference and the “preference utility” the consumer may derive from the beef compared to soybeans. That question is answered by the quest for output efficiency. Therefore, technical efficiency may get confused with efficiency of output, which weighs production choices against consumer preferences.

consumer demand shifts to apples from oranges, the price of apples will rise until the producers can respond with increased production of apples. Anything else would be economically inefficient, but, again, various market failures can interfere.

It may seem that output efficiency does not apply in the electric market by itself. Currently, there is only a single product, which is electricity, and few apparent opportunities to weigh production options. Nonetheless, output efficiency is very important in this market like any other. For example, the market must find the optimal amount of generating capacity to serve the consumers reliably. This reliability of service is in essence a qualitative measure of the product being offered. The more reliable the service, the higher the quality. Naturally, greater quality commands a higher price. Therefore, it is conceivable that the consumer might want to make some decisions about how much reliability he or she might need at a given price, and make purchasing decisions accordingly. Up until now, capacity reserves have been defined by required capacity reserve margins, which are set by regulators. In the new competitive markets, the prevailing belief is that the market can autonomously decide the appropriate reserve margin, either in response to consumer demands for reliability, or in an effort to retain revenue streams that might be hurt if outages occur. We will see in Section 8 that neither scenario is likely to be as effective in preserving reliability as the regulatory system has been. Reliability is *not a separate commodity* and, therefore, is not subject to the will of the marketplace. The reliability of electricity as provided to one customer is intimately linked to that provided to other customers. Thus, it would be exceedingly difficult to attain efficient amounts of reliability through market mechanisms. Indeed, attempting this would be a challenge to the principle of efficiency in the electric industry.

Output efficiency is also important in the context of implicit services that the electric market has to offer, but which are not treated as such. An example is efficiency improvements in the form of demand-side management. The electric industry is perhaps coming closer to the realization that end-use *energy services*, including DSM, is the bundled product that consumers need and wish for, and not electricity alone. Consumers are interested in hot water, adequate lighting, clean laundry and so forth while their demand for electricity is non-existent, except to the extent that electricity helps them meet those other needs. If the energy service provider focuses on the services actually in demand, economic efficiency of resource allocation can be improved. For example, an energy service provider should lease to a customer a time-controlled water heater that shuts off during hours of peak demand for electricity, if doing so would save the customer money. Emerging deregulated markets may or may not succeed in this regard, but the regulated industry had made significant advances in this direction when IRP was practiced. Now, due to the onset of deregulation, many utility DSM programs are withering away, and the momentum gained in the pursuit of greater energy efficiency, and thus economic efficiency, has been slipping away. Therefore, it is clear that the transition to competitive markets has already been somewhat economically inefficient in this regard, whether or not these markets for DSM ever resume.

Incidentally, the bundling of different kinds of utility services such as telephone and electricity on the retail level in a deregulated market without these efficiency improvements mentioned here may be carried out and presented to consumers under the pretext of efficiency. Yet, they are likely to only mask inefficiencies if and when consumers no longer understand exactly what they

are buying, and at what price, when they pay their integrated utility bill. Both production and price efficiency may have been diminished.

### **C. Price Efficiency**

Price efficiency refers to the accuracy of price signals in the economy. If price efficiency is high, consumers and producers will have a very clear idea of the costs of inputs, and the mix of goods and services purchased, and each service will be sold at the appropriate price relative to cost. Notably, price efficiency demands the absence of undue price discrimination or cross-subsidization between different customers. Even though a producer could discriminate; that is, apply market power, it would not be economically efficient to do so, although it may be operationally efficient from the producer's standpoint (that is, it would be profitable for the producer to do so). The more price efficiency helps to improve relative transparency in the market, the more it increases competitive pressures, keeping various cost components and products within reasonable price ranges. The problem is that if attempts to make prices more transparent are pursued too far, they can defeat their own purpose, and introduce new inefficiencies.

An example may be the design of the New England power market under ISO-New England market rules. Initially, with no less than seven distinct markets for energy, capacity, and ancillary services, the pursuit of price efficiency may have been carried to a point where the added complexity of the market and the interconnectedness of the products may have made it more vulnerable to market power. It may well be that many electricity-based wholesale market products cannot really be priced independently of each other through a separate market mechanism. The complexity of having so many markets may also have caused increased administrative costs, both at the ISO and for individual market participants, which inevitably would increase retail prices. Another example of market complexity leading to price inefficiency is congestion cost price. A credible case has not yet been made that congestion cost pricing will lead to more economically efficient decisions when it comes to making long-term investments. For a transmission system user to see hourly congestion costs at each node of a transmission system may provide little guidance with respect to where to site a power plant for the next 30 years.

## **5.2 Why Economic Efficiency May Not Be Achieved Under Deregulation**

At the core of the argument in favor of competitive markets is the notion that the deregulated market environment will meet the specific needs of both individual consumers and the greater society better than the regulated system ever did before. It is also a laudable goal to give consumers greater choice in the services they purchase if they care. This principle is not challenged here. What is of concern is that electricity service markets, unlike some other markets, may not be the kind of markets where maximizing choice through competitive market structures results in overall net benefits to consumers.

Relying on the price system to move the electric market towards greater efficiency may lead to considerable benefits, but doing so is not likely to achieve optimum economic efficiency. The reason for this is the various market failures that are likely to accompany both emerging and long-term electricity markets, both at the retail and wholesale level. These likely market failures



can be grouped into three categories, which are related to imperfect competition, ignoring externalities, and the treatment of public goods. In addition to market failures, we will explore several innate characteristics of electricity markets that cause problems even when the markets are functioning properly. In addition to leading to higher prices, these traits of the electricity market can be potentially disruptive and can carry a high perceived cost to consumers. One example is the strong price fluctuations to be expected in the wholesale electricity market. The tendency of the market to foster consolidation of control over resources through mergers is also potentially hazardous to efficiency even if some management costs can be reduced, because market power may be increased, as well, and barriers to entry for others can increase.

## **A. Imperfect Competition**

Perfectly competitive prices in generation markets should closely approach the long-run marginal cost of generating electricity,<sup>9</sup> including a reasonable profit that reflects the investment risk profile of the industry. The reason is that, if prices are above this level, new plants will be built until competitive pressure and market saturation bring prices down to the level of the marginal cost of a new generating unit. Prices will not stabilize below this level because it is the marginal unit that sets the price in the competitive market and all generators, regardless of unit-specific short-run marginal cost, will receive that market price. Prices will, of course, fluctuate with demand and reflect the energy cost of the marginal generating unit which sets the market price in any given hour of the year. However, average prices should approach long-run marginal costs since that is the price that determines the entry point for new generation. A higher average price invites new entry, and a lower average price would be irrationally low and would, therefore, not be a likely outcome.

When market power is present in the electricity market, prices will rise above this competitive level, but such a rise in price does not necessarily mean that market power is being exercised. Even in a very well functioning competitive electricity market, it is unreasonable to expect to achieve perfect competition in all hours. Some margin for error is also necessary to account for fluctuations in fuel prices which are less predictable than other operating expenses. FERC's merger guidelines take the position that prices that are no more than 5 percent above perfectly competitive levels are reasonable.<sup>10</sup> However, anything more than a 5 percent rise above marginal cost is an indication of market power at work.

Market power is exercised in two ways in the wholesale electricity markets, through *strategic bidding* and *capacity withholding*. These two means of exercising market power can be quite subtle and that is the most important thing to keep in mind about market failures in the new markets. One danger is that when the electricity market fails to operate efficiently it will probably not be noticed, and high prices will be justified by reference to the autonomy of the marketplace in "correcting" for any changes in conditions that may arise. Market power can also materialize at the retail level if suppliers manage to exercise undue price discrimination against certain customer classes. Vertical market power, even across industries, can also be felt at the

---

<sup>9</sup> Long-run marginal cost would equal the levelized unit cost of generating electricity, based on the generating technology currently best suited to meet average load. However, how, precisely, to levelize capital investments in order to compute the long-run marginal cost is a subject of some controversy by itself.

<sup>10</sup> *Federal Register*, 61, 251, 68607, B.3.a "Delivered Price Test."

retail level if suppliers favor subsidiaries. The details of these methods of exercising market power and their interaction will be discussed further below, along with specific recommendations for monitoring and preventing market power. Fortunately, the electricity market failures due to the exercise of market power that have occurred recently have been quite visible.

## **B. Externalities**

Externalities are costs of production that are non-economic or are not avoidable by the firm producing the goods. The term non-economic would mean that the cost is either hard to determine in economic terms or that it does not lend itself to the traditional accounting of direct economic costs. The obvious example is any form of pollution from electricity generation. Such pollution has now been defined in economic terms by effect of the Clean Air Act, at least to some extent, as generators must acquire tradable emission permits for various pollutants. If no externalities existed in electricity generation, the owners of power plants would directly face all the opportunity costs inherent in the production of electricity. This is not the case.

To some extent, externalities may be incorporated into cost accounting by firms if public opinion, and thus consumer preference, is strongly in favor of protecting public health and the environment. Some firms, in competitive markets, may directly reflect social costs in their production costs by responding to such demands. Many proponents of electric deregulation believe that in a competitive electricity market consumers will demand environmental protection, and the social cost of pollution will be integrated into the market. However, there are serious impediments to this prospect. Individual consumers cannot measure the social cost of pollution on their own. Individual decisions by consumers are, therefore, not an efficient way to account for externalities. Moreover, some individuals may be inclined to pay an unreasonably high price for green power, for example, while others would pay nothing extra. This is fundamentally problematic from an equity standpoint, because the benefit paid for by the one who buys green power is a *public good*.

## **C. Public Goods**

When a particular product is purchased due to its social benefits, in addition to its specific utility for the consumer, that consumer is purchasing a public good. The special quality of the product that is being bought is *indivisible*, and therefore, the product is not the kind of consumer good that lends itself to “customer preference,” such as the flavor and brand of ice-cream. The aggregate social and environmental value of green power relative to conventional energy sources cannot be enjoyed by the person buying it in any reasonable proportion to the cost incurred, if that cost is indeed significantly higher than prices for other sources. The exception is if the consumer perceives adequate personal value in making a “social choice” that makes up for the incremental economic cost, and the fact that the utility of the product is shared with the rest of society.

Even as some consumers attempt to steer the allocation of resources in the “right” direction and encourage the incorporation of externalities by creating a market demand for public goods, this very flawed approach may ultimately be stifled. The problem is that *consumer autonomy* may

well decline (not increase) in a competitive electricity market. It is true that, in theory, the competitive market is supposed to limit market autonomy and maximize consumer autonomy by giving the consumer a say in what kinds of products he or she may purchase. However, for every one consumer who elects to assert this autonomy and demand electricity of higher or different quality (some kind of green power, for example), another consumer may either give up this opportunity due to consideration of price, lack of information, or because the market has consolidated its power to a point where choices are both scarce and expensive.

For example, participation by residential customers in California's competitive retail market has been limited, and most of those who do participate do so for the opportunity to buy green power.<sup>11</sup> Currently, this choice comes at a premium of about 4 to 5 mills per kilowatt-hour, which is approximately 4 to 6 percent of the standard utility rate. When Californians buy green power these days, and pay this premium for the privilege, this small portion of the population is essentially further subsidizing a public good for the entire population of California, and beyond. In fact, they may be paying for a public good that is shared by the people of Arizona and Nevada in the form of reduced air pollution, among other things. In contrast, owners of coal-fired generation plants in the Mid-West are generating incremental profits by consuming a public good, which is the air quality shared by downwind states like New York and New England. If these power plants had to incorporate the full environmental, health, and economic costs of air pollution into their production process, the cost of this resource might even be too high for them to continue operation.

### **5.3 Why Economic Efficiency May Not Be Enough to Protect Consumers**

#### **A. Greater Economic or Price Efficiency May Not Lead to Lower Prices**

Recall our earlier discussion of production efficiency and price efficiency. Restructured electricity markets may bring about greater production efficiency (lower cost per unit of energy generated), and thereby reduce prices. For example, competition may give power producers an added incentive to reduce administrative costs, which translates into increased production efficiency, and, hopefully, lower prices. Conversely, the pursuit of greater pricing efficiency through the competitive market structure may just as likely lead to higher prices. The culprit is the "market price" when compared to the embedded cost of service. We know that a competitive electricity market must replace regulated rates with a market price. As we have discussed, this market price will tend to approach the long-run marginal cost of providing electricity. In contrast, regulated rates are based on average embedded cost of generation. The market price, on the other hand, is not linked to the average cost of providing the service at all. This implies that the market price, or long-run marginal cost, can either be above, or below, the current average embedded cost of generation in any given area or region. If the LRMC is higher than the embedded cost in any given market, rates will rise if generation is deregulated. If the LRMC is lower than the embedded cost, rates may go down for awhile and remain lower than what regulated rates would have been—at least for some period of time. However, they will tend to rise above the embedded cost of service in the longer run.

---

<sup>11</sup> There are currently eleven Energy Service Providers operating in California, registered by the California Energy Commission. Only two of these do not provide green power, while the other nine provide only green power.

*How would regulated prices in the future compare to long-run marginal costs?*

As noted above, the long-run marginal cost of generation is considered to be the total cost of any new generation averaged over the future, since it is assumed that new generation would be built to meet the long-run growth in electricity demand.<sup>12</sup> The generation costs of new combined-cycle units or new combustion turbine units define the long-run marginal cost right now because they are the most cost-effective technologies at this time to meet new load in those areas where the natural gas supply is adequate. If an optimal mix of new gas-fired generating capacity were built from the ground up to serve a typical utility's system load (at average load factors and system losses, including a reserve margin of 15 percent), the generation cost (fixed and variable) levelized in real dollars would be about four cents per kWh, or more. This compares to the three cent per kWh, or less, figure often cited in the early restructuring literature, which is more representative of new high capacity factor combined-cycle plants alone.<sup>13</sup> Both figures were computed prior to recent increases in the price of natural gas. On top of that comes the price of transmission and distribution and customer service, which typically is around three-four cents per kWh, for average load. If that were the total cost of providing electricity service, the total price would be (based on cost of service) in the vicinity of at least seven-eight cents per kWh. When compared to the actual retail price of electricity averaged for the whole country, we see that, as of late, retail prices have been close to this total cost implied by the cost of new generation, or less.<sup>14</sup>

Since the competitive market price for generation will tend to gravitate toward the long-run marginal cost of new production, a key regional issue, then, in the restructuring debate is how does this price compare to the average embedded cost of production that regulated prices are based on? In some areas, like the Pacific Northwest, the LRMC is probably already much higher than the average embedded cost, since large amounts of hydropower in that part of the country keep the average cost of power well below the marginal cost of new combined-cycle natural gas generation.

If the average embedded cost of generation from the existing base of generating facilities were below the long-run marginal cost of new plants, the competitive market would raise prices from the previous regulated levels. Except for the cases where producers may engage in bilateral contracts at a price slightly below anticipated market prices in order to secure long-term sales, most transactions would occur at long-run marginal cost. This is the reason why the Pacific Northwest, among other regions, should be in no hurry to deregulate the electric industry. Market

---

<sup>12</sup> While marginal energy cost or variable cost is essentially the short-term marginal cost of generation, the long-term marginal cost of generation includes capital cost of new capacity as well. Any new capacity would presumably not be built unless and until its capital cost would be captured through current price structures for electricity. By comparison, existing capacity operates effectively based on short-term marginal costs and is dispatched according to variable or fuel costs only, since capital cost is sunk.

<sup>13</sup> This is based on current capital cost and variable cost (fuel) and an estimation of T&D costs being one cent per kWh. Incremental adders such as operations and maintenance are not included.

<sup>14</sup> A few utilities have very high embedded generation costs, primarily due to uneconomic nuclear plant investments, while a few others have very low embedded generation costs, primarily attributable to older hydro-electric and coal resources.

prices in the Pacific Northwest will surely be higher than regulated rates.<sup>15</sup> The same will be true over the next few years in much of the rest of the country.

What about New England? In the Northeast, unlike the Northwest, a relatively high average embedded cost (largely due to nuclear power) makes the lower marginal cost quite attractive, and that spurred early interest in restructuring. Eventually, prices may decline in New England under restructuring where embedded costs are currently higher than long-run marginal costs, and when stranded costs are paid off, provided that market power can be tamed.

*The inauspicious timing of restructuring is of real significance*

Currently, the embedded cost of generation around the country varies significantly. Nonetheless, it is absolutely clear that average prices for electricity nationally have been declining steadily since 1983. Moreover, these prices would tend to continue to decline for some time under conventional cost-of-service ratemaking because the embedded cost of existing assets is declining as generation units, nuclear and other, depreciate but continue to deliver power at relatively low variable cost due to low fuel prices. When new units come on line in a non-deregulated world, their same relative cost advantages (or disadvantages) would accrue as in a competitive deregulated market. Yet, what is lost under deregulation is the effect of average embedded costs in keeping down rate increases under the reasonable assumption that long-run marginal costs will tend to rise over time. Under deregulation, if long-run marginal costs increase, then **average** rates will increase proportionally.<sup>16</sup> When long-run marginal costs increase under regulation, these increases are highly diluted by all the existing embedded costs. Restructuring may just now be happening at the worst time, namely during a time of rising long-run marginal costs and declining average embedded costs. If these trends continue, then restructuring will lead to much higher electric rates all over the country within 10-15 years.

In addition, as will be detailed below, the competitive market does exhibit certain characteristics that tend to make the inherent cost of service higher than under regulation. This can happen even if the market is not suffering the effects of market power.

Figure 1 shows the trend in retail electricity prices nationally for the past nearly two decades, compared with projected prices for Colorado under both competition and continued rate regulation until the year 2017.<sup>17,18</sup> This chart does not include the potential effect of market power. These projections, produced by Stone & Webster Management Consultants (S&W), show that regulated rates would continue to decline while the conclusion about competitive rates is much more ambiguous.

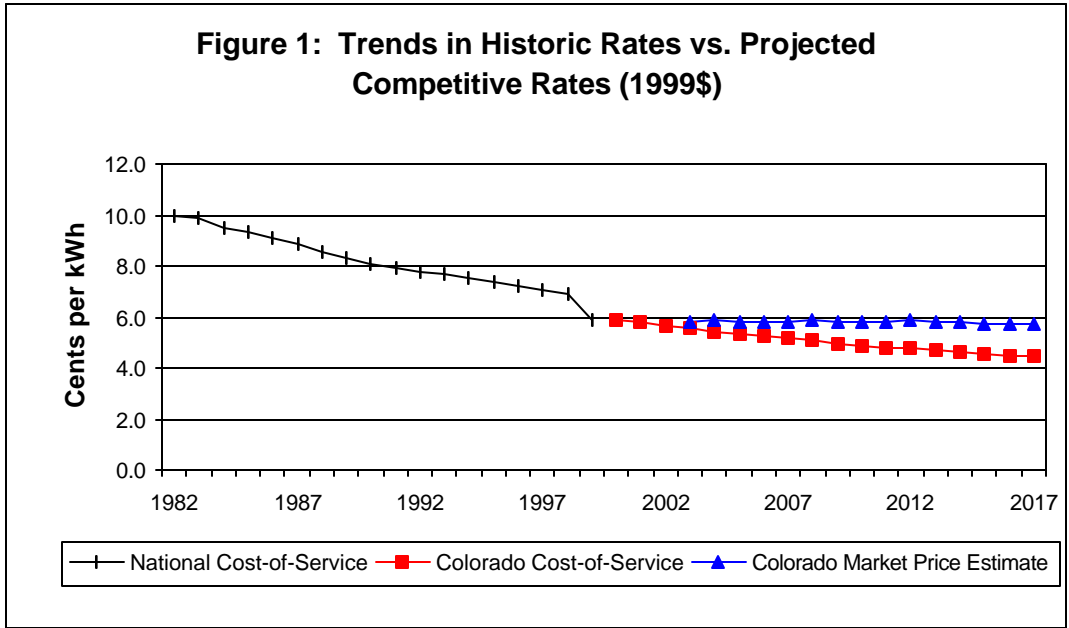
---

<sup>15</sup> A first indication of this inevitable outcome is the news of aluminum manufacturers' in the Northwest concern over rising contract prices which are being forced up by competitive demand from the electricity market in California. See *Electric Utility Week* (June 12, 2000), page 3.

<sup>16</sup> Note that one reason why long-run marginal costs tend to rise over time is just the inevitable impact of inflation.

<sup>17</sup> Historical figures based on EIA's *Annual Energy Review*, Table 8.13 Projections are from Stone & Webster Management Consultants.

<sup>18</sup> Stone & Webster Management Consultants, *Energy and Economic Modeling Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado*, prepared for the Colorado Electric Advisory Panel, May 1999.



Sources: see footnote #18

The trend in cost-of-service prices is clear. These projections are actually a good reflection of what may happen nationally, on average. S&W estimates that market prices for Colorado will decline in real terms only very slightly for the next 15 years, while the rate of decline under cost-of-service regulation would be significantly greater. Much like the Pacific Northwest, Colorado benefits from relatively inexpensive power, because most of the generation in the area is coal-fired. Of course, this is true for much of the U.S. While the marginal cost of new generation for the last few years may have been below the average embedded cost of generation in Colorado, the steady depreciation of existing generation assets and the fact that coal is a very inexpensive fuel combine to bring the forecast of those average costs below the long-run marginal cost in the very near future. In other words, the cost of new generation, up until now, may have been below the historic trend line for retail generation prices implicit in Figure 1, but those lines seem likely to cross in the next couple of years, on a national average basis, as the long-run marginal cost (marginal cost of new generation) plateaus above the declining average embedded cost. Naturally, that average embedded cost will eventually raise again and approach the long-run marginal cost as new capacity is built, but not for many years, probably many decades. However, it is very important to note that, once the average embedded cost is below the LRMC for generation, the average cost will **always** lag market price somewhat, and will, therefore, always be lower. That is the nature of embedded cost ratemaking.

As a result, the timing of electricity market restructuring is perhaps quite inauspicious. The downward pressure on prices from having the LRMC of generation below average costs might have helped to bring lower retail prices in past years, if the existence of stranded costs could have been ignored. Now, or soon, in many places like Colorado, the LRMC is higher than average cost so that downward pressure no longer exists, and will reverse for a time. Market prices will be higher than average costs and stranded costs will be negative—the revenue requirement of the old regulated utility is exceeded due to higher market prices for generation.

The impetus (and justification) for restructuring has, therefore, dissipated in states like Colorado, if it ever existed. As described earlier, it was the industrial customers, in particular, who wanted to escape the weight of high regulated prices and compete in the marketplace for the output from new low-cost sources of power, and possibly shift the burden of the resulting stranded costs on to residential customers. Perhaps they did not realize that all ratepayers had an obligation to pay for the past capital expenditures of regulated utilities not yet recovered through rates. Either way, nationally, we are now at, or very near, a key crossroads where the average cost of generation is no longer above long-run marginal costs, particularly in areas where little investment has been made in nuclear power. Again, higher recent natural gas prices have accelerated the onset of this crossover point. Therefore, it is somewhat ironic that the transition to deregulation is taking place now that regulated rates nationally are at the lowest level they have been in real terms since the onset of the “oil crisis” in 1973. In fact, aside from the period 1968 to 1973, the national average price of electricity has never been lower than it is now (corrected for inflation).

The discussion above has only compared average embedded costs with likely future market prices based on the marginal cost of new gas-fired generation, which currently defines the long-run marginal cost. In a market, every producer receives nearly the same price, for the same product. Thus, the term “market price.” Obviously some producers have specific unit-costs below the LRMC, but they receive a competitive price that is based on the LRMC nonetheless. But there are other reasons why electricity markets will likely bring higher prices that result from the specific structure of those markets being established in some regions of the U.S.

## **B. Inherent Market Characteristics That Can Lead to Higher Prices**

This section will describe those characteristics of the competitive marketplace that tend to have negative effects on consumers, or have the potential to be anti-competitive. In some cases, these characteristics may not actually be considered market failures since they are a likely outcome of a well-functioning market. They are spontaneous market-driven responses to the challenge of operating in a competitive environment, and which, in some instances, serve to reduce efficiency and competitiveness, and raise prices.

### *Trying to unbundle an integrated system*

One of the greatest obstacles to successful restructuring of the electric industry is the need to unbundle various components of the service that previously has been provided by a single entity. The unbundling of generation-related services from transmission and distribution is necessary because the latter functions are to remain under utility control and price regulation. Unbundling is also necessary so that various functions that together make up the entirety of electricity service can be provided by different parties. Separating such different functions as generation, transmission, and distribution may seem simple in principle, but experience has shown that it is not. One reason is that generation and transmission services are highly interactive, and the two are actually substitutable for each other to a considerable extent. This link is both geographical and temporal, and the result is that no single function that any service provider may hope to provide can be fully separated from the services provided by another market participant. The behavior of each market participant at each moment in time affects the physical operations and the economics of the operations of every other market participant. To some extent this is true in many other markets, but in no other market beside electricity are the connections so immediate. This is an obvious problem when the same business

entity attempts to name a price, or collect appropriate compensation for its services, when those services are so obviously linked to the services and behavior of others in the market.

The physical time-dependent constraints relevant to separating various functions of electric services can be demonstrated in several ways. For example, when a generator wants to deliver energy at a given price, the conditions of the transmission system may interfere. If the needed transmission interconnection is congested, there may not be enough capacity in place to deliver the energy as intended. This has several implications. One is that transmission losses increase for all generators trying to deliver energy over the transmission system. This fact alone raises many issues. How should the additional losses associated with the incremental load in any given hour be accounted for by each market participant? Who should pay for that loss? Another consequence is that the decision of any given generator to produce (or not to produce) electricity at a certain level may interfere with the ability of other market participants to get their product to market depending on conditions on the grid. In theory, this is the efficiency of the marketplace at work, deciding who produces what and when, but in reality it can be disruptive and inefficient if responsibilities are not clearly delineated, and prices are not firmly and correctly established for each and every moment in time. Also, events take place so quickly that market actors do not have much time to act.

In an attempt to develop a comprehensive market for electricity services, the initial approach in New England was to establish seven separate markets for generation and ancillary services. Because the sensitivity of these markets to the dynamics among market participants and their activities is so great, and because of the need to account for all activities in very small time intervals, the market rules need to be quite elaborate. However, the simultaneous operation of the seven markets has proven to be cumbersome, and market participants have managed to turn flaws in market design, namely the self-defeating complexity of the rules, into an opportunity to exercise market power. Two of the seven points have already been eliminated in an attempt to prevent this from happening.

#### *Rising transaction costs*

Even if a market structure and associated rules could be developed that were so advanced that every nuance of the physical and temporal complexity of the electricity market were adequately addressed in a way to satisfy the time-sensitive nature of market interactions, it is possible that this perfection of electricity markets would come at considerable additional cost that would not justify the change from regulation. It is not clear at all that the efficiency improvements anticipated from competitive electricity markets will be substantial enough to justify the increased transaction costs, aside from the uneconomic costs associated with potential market power which would itself be facilitated by the complexity of the market. Multiple markets for ancillary services, such as 10-minute spinning reserves and 30-minute non-spinning reserves, break the needed functions of the whole market into sub-markets that can have their own market prices. Even if this can be accomplished and the 30-minute reserve in any given hour ends up carrying a price that is relatively proportional to the cost of other products in that hour, rather than being completely non-cost-based due to market power or some flaws in market rules or operations, the cost to the system operator and each market participant can be high. The key question that emerges from the unbundling process is whether or not the incremental cost of running a specific sub-market is relatively less than the savings that the competitive market delivers relative to what the price of the services would be under regulation. This question has neither been asked nor answered by proponents of restructuring, while regional power exchanges and system operators are learning that implementation of competitive electricity markets is more difficult than most suspected at first.



Thus, transaction costs are likely to increase as the economies of vertical integration are lost, and as separate markets are formed for the various components of electricity services. Furthermore, a whole new layer of costs is introduced when retail competition is established, when customers no longer purchase their energy from their distribution utilities. Utilities were, in effect, the wholesale generators under regulation, selling directly to customers without any intermediary retail entity adding to the cost of service. This added cost, the retail margin, is discussed in detail below.

### *Inefficient load management*

A benefit of the utility regulatory framework is its ability to provide for various social benefits that the competitive market may not be inclined to pursue, even though it would be in the long-term interests of all consumers. An example is the need for cost-effective load control. Under demand-side management schemes, the utility has the opportunity to actively manage load by providing rates for interruptible power in combination with incentives like rebates on energy efficient appliances. Such a scheme is based on a combination of load-factor considerations, long-run avoided costs to society, environmental externalities in some cases, and the consumer's interest in both lower rates and electric bills.

Real-time metering has the potential to bring the burden of load management to the consumer. In theory, the consumer will shift as much demand as possible to the hours of the day when rates are the lowest, which are the lowest load hours. This compares to long-distance telephone services where off-peak minutes are sold at a lower rate. However, it is not evident that accurate price signals through real-time metering in a competitive environment will compel the individual consumer to take these considerations into account. The real-time price variations may be so small that any meaningful response such as investing in structural efficiency measures may not be implemented on an individual basis. To overcome the lack of incentives for the individual consumer to respond to the load-dependent cost variations of electricity, all of society may be better served through a program of integrated resource planning where the utility implements load management programs on a large scale rather than requiring millions of individual consumers to make decisions. The ability of individual customers to respond to price signals over the long run and to correctly incorporate life-cycle variables into their decision making is less likely to materialize in a deregulated environment, which is predisposed to reject regulatory tools like utility demand-side management programs.

### *Cost of capital and risk*

Barriers to entry are closely linked to investment risk calculations through their effect on what happens in the generation market. If a potential new entrant sees considerable risk in counting on the prevailing market price as a basis for new investment, no new capacity will be built. This could be so despite the fact that it would have been economically efficient to build a new power plant in the market under consideration if the risks were lower. In other words, the fact of having a competitive market can, itself, cause at least one form of economic inefficiency, if the recovery of capital investments becomes highly risky. Another way to see this problem is in the context of the cost of capital facing investors in this new market. It is exactly because of the higher risk in

the competitive market that investors must demand a higher expected return on their investment. Money will be borrowed at a higher cost than in the previous price-regulated market, where the rate of return on investment was guaranteed and, thus, where the risk to lenders was minimal. This higher cost of capital will translate into less new market entry. The compound effect of the higher cost of capital and less new market entry will lead to higher retail prices than either effect would produce separately.

### *Marginalized regulatory response*

The argument for government involvement in competitive markets does not need to be made here. Society accepts and prefers regulatory control of various markets to ensure competitive behavior, to protect public health, and so forth. Of course, it is easily conceivable that badly conceived regulation may hurt the market and consumers. However, in the case of electricity markets, the greatest risk to consumers is related to the difficulty in controlling market power. Many analysts believe that new market entry will be a comprehensive substitute for most regulatory involvement in both pricing and securing adequate supplies of electricity. New market entry is thought to be an autonomous and effective market response to high prices and market power. Some would argue that government regulations are still the greatest obstacle to efficiency and low prices in these new electricity markets: “[...]new market] entry indicates whether market rules are attractive. Oppressive or inefficient market rules can deter entry.”<sup>19</sup>

In contrast, the reverse could be true, as well. It could often be the case that complex market rules are the true reason for potentially non-competitive prices since they hinder new entry by increasing risks, and complex markets may prevent adequate checks on market power. The risk here is twofold: first, new markets can be structured and regulated in a way that makes them inherently inefficient; then, in areas where regulators step aside to allow the marketplace to find its own way to deliver electricity services, hopefully gaining efficiency and reducing costs, other market failures may surface that the regulatory authority cannot adequately control. For example, poolcos are a fundamentally inefficient type of market structure, since they will lead to a different mix of generation resources even if they are perfectly competitive when compared to a true least-cost mix of generation resources. To our knowledge, this consequence of poolcos has never previously been discovered, and it certainly has not been acknowledged by the supporters of poolcos, if, indeed, they have been aware of it.

### *Market instability*

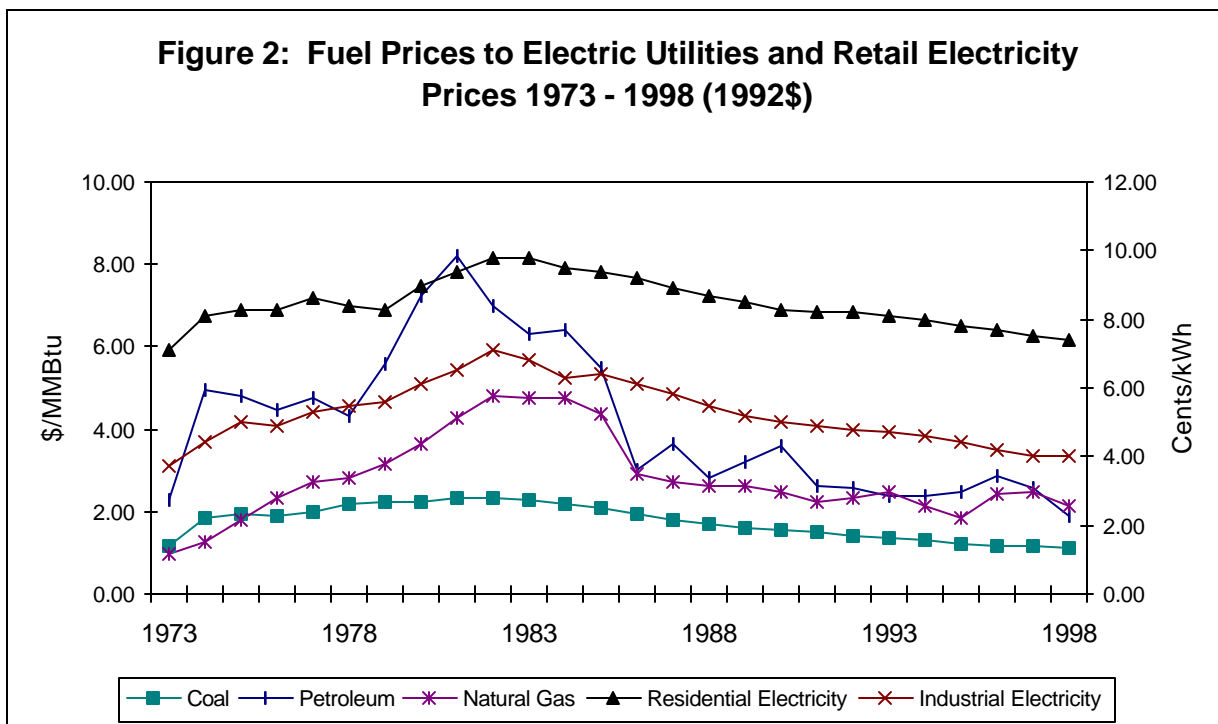
Under utility regulation, price stability has been relatively high because average embedded cost ratemaking has been used. Embedded cost-based prices are inherently stable because, if one cost component changes, its impact on the overall price is diluted if the other cost components do not change. Fuel prices have also declined significantly since the early 1980s, as can be seen in Figure 2, as the cost of other inputs to electricity prices have risen, thus balancing out.<sup>20</sup> For example, the average price that utilities pay for coal has dropped uniformly, in real terms, every year since 1981. The cumulative decline in the average price of coal is 53 percent from 1981

---

<sup>19</sup> The Brattle Group, *PJM Market Competition Evaluation White Paper*, Section 2.9, 1998.

<sup>20</sup> Fuel prices from Monthly Energy Review, Table 9.10 and Electricity prices from Annual Energy Review, Table 8.13

until 1998. Natural gas, which was less expensive than coal before the oil price shock of 1973, has also become less costly in the same period, by 56 percent since 1982, and is about double the price of coal. (These figures are valid as of 1998.) Petroleum prices have been more erratic, but have followed the same general trend. Utilities paid 77 percent less for petroleum in 1998, in real dollars, than they did in 1981. Not surprisingly, then, at the same time, electricity prices have declined in real terms as well, as they have done for most of the history of electric service. Residential customers paid 24 percent less for electricity in 1998, again in real terms, than they did in 1982, while industrial rates declined by 44 percent.



Sources: see footnote #20

The most dramatic fluctuations in electricity prices in future deregulated generation markets are not going to be due to short-term changes in fuel prices. The much larger cyclical changes are going to be generated by the short-term dynamics between supply and demand.<sup>21</sup> We have already seen this effect demonstrated amply in California, PJM, and NEPOOL. Nonetheless, if prices for the fuel used by generating units that usually set the market price during hours of higher demand rise significantly (probably mostly natural gas in coming years), the price of all electricity generated in those hours will be affected by that rise in prices. Thus, spot market energy prices in New England rose close to the ceiling of \$1,000 per MWh several times during

<sup>21</sup> Fuel prices can, in effect, cause large time-of-day changes but the point here is that it is not because the market price for a given fuel has changed. The reason is that, as demand grows during the day, different plants are running on the margin, generating electricity by use of different fuels (unless the marginal unit is a non-fuel renewable source like hydro or wind power) at different efficiency levels (heat rates). This changes the operating cost and the market price of electricity from one hour to the next.

the summer of 1999, and the summer of 2000 was even worse in California. If this price were channeled directly to consumers, as presumably will eventually happen, many households could be devastated by running a large appliance like an air conditioner for extended periods of time. In the case where natural gas-fired generation becomes the marginal generation in all hours of the year, then changes in natural gas prices will greatly compound the volatility of electricity prices. This effect may yield a devastating impact on electricity prices once it compounded with the impact of the effect of market power during any natural gas supply constraints that may develop during winter peak heating demand periods, since electricity demand may peak at the same time. This set of conditions may end up yielding higher average electricity prices, and more volatile prices, than we have seen thus far in poolco-type electricity markets during the summer.

*How can consumers respond to severe price fluctuations?*

Under regulation, changes in fuel prices have often been slow to affect rates; it has taken years in some cases, because changing rates usually requires a new rate case before the regulatory authority, where fuel price trends are reviewed and future rates are adjusted accordingly. However, the use of fuel adjustment clauses (FACs) in the regulatory context allows the utility automatic adjustments in rates to track changes in fuel prices. Those utilities that have no fuel adjustment clauses may attempt to insulate themselves from drastic price fluctuations by hedging their wholesale fuel contracts. Overall, the consumer is probably not acutely aware of fuel price fluctuations in this regulated environment. Even when FACs are applied, the impact on rates is usually not dramatic and fluctuations are not extreme since prices are not changed.

In contrast, the introduction of competitive markets requires making demand more responsive to real costs of electricity at each moment in time. If consumers face electricity price changes when they happen, they could adjust their consumption of electricity accordingly, at least in theory. If certain technological requirements can be met, all fluctuations in fuel markets, even on a daily basis, could affect electricity prices instantly and consumers could respond instantly. Provided that this information can be communicated effectively to consumers, and that they are equipped to respond efficiently to such information, the total efficiency in the market would be increased. The presence of these two conditions is, however, extremely important. The technological conditions would probably require high levels of automation similar to load control under DSM programs, where household appliances are controlled by a computer in the home. Rather than have certain appliances “cycled” during peak hours, or completely turned off for several hours as is the norm for load control programs, the consumer could program the household to respond in a predetermined fashion to a range of electricity prices. Obviously, real-time metering would be a necessary condition for this kind of active consumer response to be possible. Water heaters might be turned off when prices rise just marginally, while air conditioning could be programmed to shut off if prices reach very high levels, even though physical comfort would be a tradeoff for the consumer. Some discomfort might be considered worth enduring so that an hour or two of extremely high electricity prices could be avoided.

The above scenario looks like a promising path to greater economic efficiency in the electricity markets. But there is potentially a high social price to be paid. The high demand that thus far has driven market prices to their highest levels occurs during the summer months, and is linked to air conditioning usage. The demand is high because humans get very uncomfortable at high temperatures and, indeed, such conditions can be life threatening. Many people die each year in

the United States from heat exposure. An example was the heat wave in Chicago in 1998 when a significant number of elderly people died in their homes, either because they did not have air conditioning, or because they considered it too expensive to operate their units. The same conditions occurred in Texas in the summer of 2000. If actual market prices are ever channeled directly to consumers, price efficiency may be improved, but lives may also be lost as a result. Demand during peak hours will be cut, but this may be done mostly by those who can least afford the luxury of air conditioning. Such consumers will, therefore, subsidize the same luxury for those who easily can afford paying more, such as businesses for the office buildings they occupy. By reducing demand, these residential customers are effectively reducing the market clearing price for electricity for the better-off customers who probably would have bought the energy anyway. At extremely high cost to themselves—not economic cost, but one measured in comfort, health, and possibly a person’s life—residential customers may give up a service that others then gain at a “discount.”

If this scenario were to occur, the outcome would not be economically efficient at all, even though all market participants saw the actual prices in real-time and decided accordingly on what and how much to consume. It is not efficient because the human condition is not easily measured in dollars, and there is certainly no mechanism in deregulated energy markets to include such social costs effectively. The price threshold for resuming the consumption of air conditioning will always be lower for residential households than for businesses. That is why the subsidy implied here is almost a certain outcome. The conclusion could be that real-time metering for many residential customers is not a good idea. One could also conclude that social benefits charges need to be in place and used to insure residential customers against this contingency. In general, the conclusion is that rate design can have very serious social consequences, especially if it is changed suddenly and without regard for consequences. Therefore, regulators should not rush to embrace real-time metering and the theoretical benefits that it may bring in a purely economic context before adequate safeguards are designed to protect residential customers, in particular.

Another reason why price instability is bad for the consumer is that not just comfort and health, but also activities of all kinds, will be affected by the price of electricity. This can also carry a real social cost that is not reflected in any market price. A business may slow down production to save money during periods of peak demand. In the form of dispatchable load, this has been a profitable option for many businesses. However, households are different. If daily life becomes adversely affected by the electricity and other energy markets on a regular basis, a new social cost has been introduced, a cost that may overwhelm any economic efficiency gains of greater price and production efficiency.

A final reason why electricity price volatility is of great concern is that it is likely to add to the cost to customers who try to shield themselves from the potential pain of very high intermittent prices. Sometime in the near future, when customers start facing real-time pricing, or they are simply no longer shielded from spot market volatility as is the case generally now, a customer whose average bill was previously \$50 might have to pay \$150 for the month of July if market prices peaked well above average on several hot days. Whatever the reason for the price increase may be, the customer is likely to want some kind of protection against such price spikes. Marketers may put together hedging products so those customers can pay a fixed price, or have a

ceiling of some sort on their monthly bill. Of course, the marketer will incur some risk in providing this service, and must be compensated amply. Thus, the average price for electricity will rise due to another layer of costs accumulating at the feet of the retail customer. Moreover, the hedging instrument would probably dull the customers' sensitivity to price changes and make it less likely that demand would be reduced in the face of higher temporary prices. Ironically, the fact that residential customers are particularly price sensitive might actually lock them into higher prices when they attempt to insulate themselves from the shifting winds of the market. Thus, hedging could negate the whole idea of pricing efficiency. This will probably be the route taken by most residential customers, and they will be insulated from price fluctuations in the wholesale markets. But that insurance will come at a sizable price premium that they did not have to pay under regulated prices. It will be a component of the retail margin.

We can see, then, that the case for real-time metering, price transparency, and full consumer exposure to those prices, raises some serious questions about the resultant economic efficiency that is supposed to be generated. Again, if social costs and other externalities are not included, full transparency to economic costs and economic price indicators is of limited use, or could actually be harmful. In other ways, it may help to internalize some externalities indirectly as consumers may react to this incentive to improve the efficiency of energy use by investing in DSM measures. The benefit of price transparency also rests on the presumption that the prices are appropriately produced in the first place. Yet, if market power has caused massive price spikes in the electricity spot market, rather than the cause being genuinely appropriate market dynamics, it would be disingenuous to tout the virtue of real-time pricing and push the higher prices on to consumers under the banner of either improved efficiency, or as a way to mitigate this very same market power. Forcing an "efficient" consumer response through real-time metering would only add insult to injury, if prices were already tainted by market power. It would be the poorest customers who would suffer so that market power could be mitigated to the advantage of everyone else.

### **C. Rate Design: How it Affects the Residential Customer**

In this section we have discussed how an unregulated market structure can cause electricity prices to be higher than they would have been under regulation, if the average embedded cost of generation is below the long-run marginal cost, as is currently the case in many areas around the country. We have also examined various market characteristics that tend to add transaction costs at both the wholesale and retail level. We do not know how these will add up, but potentially the most devastating of these to residential customers is market instability, if it translates directly to prices in real time. While it would be economically most price-efficient to communicate the true market value of energy in each hour to customers, the social cost could be extremely high, as outlined above.

Residential customers have always paid a higher price for their electricity than large industrial users. This is due, at least in part, to the different cost structures of the two customer classes. Differentiating price based on these cost variations is entirely appropriate. However, regulated rates have always been based on average costs to each customer class, which evens out many of the dips and peaks in real cost over time.

There are two primary factors that make the wholesale price of electricity higher for residential customers than for other customer classes. These are class-specific transmission and distribution losses, and load factors. The transmission of electricity to residential customers involves higher losses than service to large industrial customers because more of the transmission is at lower voltage and is usually over longer total distances per unit of energy delivered. This means that, for every kilowatt-hour delivered to a residential customer, an extra 9 percent, or more, must be generated to cover losses. The comparable figure for a large industrial customer could be 5 percent, or even less. The cost of this additional generation that can be attributed to each class differently must be added directly to the underlying wholesale price. Similarly, residential customers have, on average, a much lower load factor than larger customers. The generation capacity that serves them may be running only 50 percent of the time on average, or less. Conversely, large industrial customers may have very high load factors and, in some instances, they may approach 100 percent. Customers with a 50 percent load factor must have twice as much capacity built to serve them, per unit of energy purchased, than those who have close to a 100 percent load factor. That means that the capacity-cost component of the energy price to those customers will be roughly twice as large. On average, one could expect the cost of capacity for residential service to be about 50 percent higher than for a typical large industrial customer (assuming the load factor of the latter being about 75 percent).

**Table 2: The Effect of Cost Structure on Class-differentiated Rates**

	<b>Residential Class</b>	<b>Industrial Class</b>
Basic Energy Cost	\$22/MWh	\$22/MWh
Transmission Losses	9%	5%
Class-Specific Energy Cost	\$24.2/MWh	\$23.2/MWh
Basic Capacity Cost and O&M	\$80/kW-year	\$80/kW-year
Including Losses	\$87.9/kW-year	\$84.2/kW-year
Load Factor	50 percent	75 percent
Class-Specific Capacity Cost	\$20.1/MWh	\$12.8/MWh
<b>Total Class-Specific Generation Cost:</b>	<b>\$44.3/MWh</b>	<b>\$36.0/MWh</b>

Table 2 shows how transmission losses and load factors affect the wholesale price of electricity to different customer classes. The basic energy (fuel) and capacity costs are reasonable approximates for a new combined-cycle generator running on natural gas. These costs include estimates of generation-related costs such as fixed and variable operations and maintenance costs, and an allowance for a reasonable system reserve margin. Total customer rates would, of course, also include charges for transmission and distribution, additional costs associated with retail service, and a retail profit margin. The point here is that the wholesale cost of generation alone for the residential class can easily be about 20 percent higher, or more, than for a large commercial or industrial customer. All other costs, such as the retail margin, that particularly disfavor residential customers, have a compounding effect on the total price to that customer class, relative to large customers. The fact that transaction costs in the retail market tend to be particularly high for small customers, on a unit basis, suggests that the price differential between

customer classes can grow quickly, and often end up under deregulation being much larger than was the case under cost-of-service regulation. If suppliers can, in addition, outright discriminate against the residential class by the exercise of market power, the compounding effect on the rate differential will be even greater.



## **6 PROTECTING THE CONSUMER – THE THREAT OF HIGHER PRICES**

### **6.1 Will Small Customers Benefit?**

#### **A. The Incremental Cost of Retail Service – The Retail Margin**

Having discussed the effect of different wholesale generation-cost structures on class-specific prices (effect of loss and load factors) we should pay closer attention to a sizable new cost component that is likely to both be a burden on residential customers, and a drag on retail competition for that customer class. This is the retail margin. This intrinsic cost of providing retail generation service must be added to wholesale costs, and it varies among customer classes. The retail margin for retail generation services includes costs such as marketing and advertising, customer service, billing, administrative and general expenses, coordination with the transmission and distribution utilities, the costs of hedging prices, profits, and taxes (including income taxes). Some of the retail margin involves portions of generation-related A&G costs that always have been part of the cost of generation or paid by retail ratepayers. The remainder of the retail margin consists of new and additional costs that are unique to a competitive retail market for generation services. We believe that the retail margin might easily be in the 1.2-1.5 cent per kWh range for small customers, but as low as 0.2-0.3 cents per kWh for very large customers.

A competitive retail service provider, by definition, cannot provide generation to the retail market at wholesale prices alone on a sustainable basis. Therefore, the incremental cost of retail services must be included in shopping credits when a retail market is being launched. Otherwise, retail providers will not attempt to participate in the market because there is little or no hope of their recovering the actual costs of the service, and even less opportunity for profit. It was only after Massachusetts set the standard offer too low that other states, starting with Pennsylvania, became aware of the existence of the retail margin, and the need to include it in the shopping credit. Setting the shopping credit for generation service too low had the effect of eliminating the opportunity for retail competition because there was no room within the standard offer price to provide competitive alternative retail service while recovering retailing expenses, and making a reasonable profit. In some instances, the standard offer may even have been set below a reasonable or likely competitive wholesale price, which obviously precludes any alternative to this default service.

#### **B. When the Standard Offer Is Set Below Competitive Wholesale Price**

The general practice in states that have deregulated their markets is to set a specific price for the standard offer for generation. This price is usually based on, but not equal to, the unbundled regulated rate, where the generation price is simply what is left over of the total cost-of-service price once other components, such as transmission and distribution which will remain regulated, and stranded costs, if any, have been subtracted. Then a “shopping credit,”<sup>22</sup> or default retail price for generation services, is established, usually also allowing for a small 5-10 percent price decrease. Customers who choose to find an alternative supplier for generation services have this

---

<sup>22</sup> Shopping credits are the same as the price of standard offer service or default service.

reference price to compare to when shopping for service. If the shopping credit or standard offer price is sufficiently large, competitive suppliers will be able to provide services at a lower price and, presumably, attract customers away from standard offer service if the reductions are big enough. Conversely, if the shopping credit is set too low, few suppliers will enter the market and retail competition will be stifled. Whether or not a given shopping credit is large enough can be determined by examining its relative success in bringing about competition. This is the market test.

The major problem for establishing retail competition, then, is that the unbundled price of generation in cost-of-service rates does not include the costs of retail operations that alternative suppliers must cover. That means that if the shopping credit or standard offer is set at the unbundled COS rate, or a little less, competitive suppliers must procure their power at a cost that is significantly cheaper than the average embedded cost of generation on which regulated rates have been based. If the shopping credit is not large enough to cover the full cost of providing competitive retail service, plus some margin for profit, plus some additional savings for ratepayers, it will be very difficult for retail competition to both develop and to sustain itself in the long run.

For example, the State of Massachusetts set the initial shopping credit or default retail price at a relatively low \$28 per MWh for 1998 for all customer classes. While this price has since been increased to \$38-\$45 per MWh, it is still the same for all classes, and it is still below wholesale costs. Consequently, only about one percent of total load is now served by competitive suppliers, and most of that fraction is industrial load. The reason it is mostly industrial customers who have sought competitive suppliers is the fact that the cost of supplying them with electricity is lower than for small customers. A competitive supplier may be able to offer a sizable high load factor industrial customer electricity at a price below \$38-\$45 per MWh. However, a residential customer, with a much lower load factor, a greater loss factor, and a much more sizable retail margin per unit of energy sold, simply cannot be served at that price. By comparison, about 21 percent of load in Pennsylvania is currently served by alternative suppliers. That figure is actually down from about 27 percent in mid-year 1999.<sup>23</sup> The early shopping credits in Pennsylvania were generally much higher than they have been in Massachusetts. Even more important, perhaps, is the fact that Pennsylvania, like most states that have established shopping credits, has differentiated among different customer classes in setting the shopping credit. The credit was therefore set at a higher level for residential than for industrial customers, reflecting to some extent the difference in the cost of providing generation service to the different customer classes. This has facilitated the establishment of retail competition.

As hypothesized above, there seems to be a strong correlation between the magnitude of the shopping credit and the share of total load, and particularly the share of residential load, that is served by alternative suppliers. We can examine some utilities in Pennsylvania (within the PJM Interconnection) where participation in the competitive market has been stronger than in most other states. As of late 1999, PP&L had the lowest residential service shopping credit of the three utilities; \$42.6 per MWh including transmission service. The retail credit for generation only was \$38.8 per MWh. Therefore, less than 20 percent of PP&L's customer load had

---

<sup>23</sup> Based on data from the Pennsylvania Office of Consumer Advocate: "PA Electric Shopping Statistics" at <http://www.oca.state.pa.us/> (updated 07-01-00). The mid-year 1999 figure is from same source at a previous date.

converted to alternative suppliers, and most of that load being served by competitive service providers was industrial and commercial load. Only 2.8 percent of PP&L's residential customers purchased their electricity from alternative suppliers. The generation portion of the residential service shopping credit for GPU (Metropolitan Edison) was \$43.5 per MWh and for PECO it was \$51 per MWh. As of July 1999, 40 percent of GPU load was served by competitive suppliers, and 5 percent of residential load. In the service territory of PECO, 37 percent of total load is served by alternative suppliers, but more than 16 percent of residential load is also. It seems, then, that raising the default price from about \$43 to \$50 per MWh greatly increases competition in the residential class while larger customers who would switch service providers have done so already at a lower rate.

However, this is not necessarily an absolutely valid comparison between the penetration of retail competition for the various Pennsylvania utilities because the underlying cost structure is somewhat different between the GPU and PECO service territories. Even at 16 percent of residential load for PECO, it is difficult to argue that competitive service providers have gained significant ground in the competitive market. It seems that a shopping credit of as much as \$50 per MWh is still insufficient, even in the PJM Interconnection which has relatively low average variable costs for plant generation, to generate substantial activity in the competitive retail market, at least for residential services. Furthermore, we do not know yet whether the retail competitors in Pennsylvania are actually making profits from this business, which is necessary for long-run sustainability. Alternatively, they may still be subsidizing this new business to some extent.

Another way to estimate whether the default service price is high enough to sustain retail competition is to examine recent sales of power plants. The purchase price of a plant would give an indication of what the market expects wholesale power prices to be over the remaining lifetime of the plant, reduced for various risk factors. Our analysis of some asset sales in New England suggested that the average wholesale price would have to be in the range of about \$38 - \$55 per MWh (in real 1999 dollars) to justify the actual purchase price in each instance. It is reasonable to expect that a new combined-cycle plant running in New England would have a revenue requirement around the middle of that range, or around \$48 per MWh or slightly less.<sup>24</sup>

The real question may not be whether the standard offer or the initial default service price is set high enough to generate an opportunity for retail competition to materialize. Rather, the question is whether expectations about lower prices in a deregulated environment are reasonable. Actual marginal costs of new generation and prices paid for existing generation plants indicate otherwise. Actual wholesale market prices have since made it abundantly clear that initial default prices have generally been too low to reflect the reality of the deregulated marketplace. A good example of this is the situation in Massachusetts in the spring of 2000 where regulators approved

---

<sup>24</sup> In *Public Utilities Fortnightly* (November 1, 1999), Art Holland compared the revenue requirement derived from the sale of the Central Maine Power assets with his own estimates of a probable market price for wholesale power. The revenue requirement for the sold assets, based on the purchase price, was in the range of \$49 - \$55 per MWh but the same figure for a new combined-cycle unit was \$48 per MWh in his estimation at CMP's 33 percent average capacity factor. At a typical load factor of 60 percent, the revenue requirement would be somewhat less. Obviously, the purchase price for the CMP assets was high, whether that was due to miscalculation or expectation of being able to exercise market power.

a proposal by default service providers to allow the price to be adjusted upwards to reflect the rising market rates for wholesale power.

### **C. Are Up-Front Rate Reductions Sustainable?**

In the process of negotiating the terms of deregulation, regulators and legislators have also routinely insisted on some up-front rate reduction, as noted above. Such rate reductions have been designed on the premise that market prices would eventually be lower than regulated rates and that consumers should be guaranteed some benefits due to restructuring from the start. This has been accomplished through standard offer or transitional rates that are established at a fixed level, or on a pre-determined upward curve as in Massachusetts, but which are meant to expire after several years and give way to free market pricing. A more cynical view of the typical 5-10 percent up-front rate reductions is that they are used to buy-off any justifiable opposition to restructuring on the part of consumer advocates.

Generally, these initial rate reductions may have been of great disservice to consumers. The reasons are as follows:

1. *Transitional rate reductions may not be rate reductions at all.*  
The initial standard offer rate may have been lower than previous regulated rates, but the regulators generally could not force the LSE to absorb the long-term cost of that reduction. If the LSE must generate or purchase power at a cost that is higher than the transitional rate, the regulator has no choice but to let the LSE recover the difference later, once the transition period is over, or even just later in the transition period, with interest. Thus, on a long-run present value basis, most nominal up-front rate reductions will probably evaporate.
2. *The customers are fooled into believing that cost of service for generation has been reduced.*  
This is very useful if the regulators and lawmakers want to convince the public that deregulation is a good thing. However, it is misleading, as customers must pay the difference between the artificially reduced rate and a real market rate later on, plus interest charges. This distortion makes it appear that restructuring has reduced the cost of generation overnight, which, of course, is not true.
3. *An artificially low standard offer price will prevent competition from taking hold.*  
This is essentially the problem of ignoring or underestimating the retail margin, as discussed above. If the transitional rate is set closer to a competitive wholesale price rather than a probable retail price, as has been the case in most states thus far, it is impossible for potential competitive service providers to enter the market until transitional rates expire. Meanwhile, wholesale prices may be swelling, for reasons explained later in this paper, without the knowledge of the public at large. Eventually, as transitional rates expire, consumers may face the stark and ugly reality of much higher retail market prices for generation. By that time, it will be too late to raise complaints about restructuring, and their rates may be much higher than they would have been under regulation.

Ironically, in addition to making the expected benefits of restructuring materialize up front, transitional pricing and mandated rate reductions were intended to protect the consumer from price volatility and other negative characteristics of the unregulated marketplace. When the decision is made to restructure the industry, it is usually done on the basis of the belief that market-based prices would lead to greater efficiencies that eluded the previous regulated structure. However, this may not happen. (In actuality, the regulated structure was well on its way to solve those remaining issues through integrated resource planning, including demand-side management). Transitional pricing can be thought of as putting blinders on the public that prevent them from identifying the true impact of restructuring on wholesale and retail market prices. What happens in the retail markets when or if standard offers expire, remains to be seen.

## **6.2 Market Power – The Achilles Heel of Restructuring**

### **A. The Threat of Market Power Must Not be Ignored**

A critical element in the discussion of the restructured electric industry should be the possession and potential exercise of market power by market participants, both now and in the future. Market power, if exercised effectively, will lead to prices that are well above perfectly competitive levels, which, in theory, should be closely aligned with the long run marginal cost of electricity generation. Since the core feature of electric industry restructuring is the move from regulated rates for generation based on cost, to market-based rates, regulators and consumers should be as sensitive to the potential danger of market power in this industry as for any other market, if not more so. In fact, market power is probably much easier to exercise in electric generation markets, than in other markets, for reasons we will try to explain below. Moreover, it is in the interest of many market participants themselves to see this issue recognized and treated as a grave concern, since market power may seriously damage their prospects in current markets as well as in those yet to be established.

There seems to a strong inclination in mainstream economic thinking to make excuses for market power. The argument made often is that currently markets are in transition and that markets need time to settle down. Market entry will, then, eventually neutralize any short-term market power problems. Conversely, we would argue that the problem is potentially much more serious than that. Market power may be much more insidious and pervasive over the long run than the industry is currently willing to consider.

The reasons why market power cannot be dismissed on assumptions of anticipated market functionality are summarized as follows:

1. No amount of market power is acceptable. Once market power exists, it will be exercised. In fact, it is already being exercised.
2. The mere existence of a market does not guarantee effective competition. The structure may have to be modified periodically as problems arise.
3. Market power disrupts markets and increases total costs, affecting both consumers and market participants. The effect of market power is not a simple addition to price

at the wholesale or retail level. It can corrupt investment decisions, causing the sub-optimal allocation of resources and raising the total costs of electricity to society in subtle ways. This effect may be compounded over time as unnecessary cost increases are solidified in the evolving resource mix.

4. Market power, alone, might eliminate any possible economic benefit of restructuring.
5. Rather than being a small effect and having a tendency to dissipate rapidly, the effect of market power can be potentially large and very persistent even prior to the impact of merger. Thus, the current and future wave of mergers and acquisitions that impact the ownership patterns of generating units must be dealt with by regulators with a high degree of skepticism.

We will elaborate on each of these assertions. First, as long as a market participant has an edge over its competitors due simply to market structure and standing within the market, rather than simply due to quality of products and services provided by that firm, the market has failed. This is no less true in the event that other market effects, like improved production efficiency, counteracts some of the negative effects of market power. In fact, market power can also be a serious disincentive to improved efficiency. Any firm will take advantage of an opportunity to increase its revenues relative to costs if the market structure presents an obvious way to do so. A firm may legitimately acquire so-called “pricing power” and increase its revenue per unit sold if it distinguishes its product by quality and service, but a rise in price of an undistinguishable product, like electricity, generally is due to the effect of market power, and is never acceptable.

Second, competition among electricity generators may cause prices to decline *in a well-functioning market*. However, a competitive market structure alone can not necessarily be relied on for bringing this well-functioning market into place. Despite the general exuberance percolating through society regarding the value of markets in place of regulation, there is no reason to believe that electric generation markets can regulate themselves any more than other markets can. Restructuring of the electric industry should not mean total deregulation any more than it can in aviation, health care, banking, etc. The functioning of the market must be based on well-structured rules, and those will have an integral effect on the outcome.

Third, when the intended functioning of the market breaks down, and price bids are no longer placed in some reasonable relationship to the costs of production, some firms will reap large benefits while other firms, otherwise viable contenders in the marketplace, will falter. For example, a firm that is forced to buy energy at a large premium, which is generated by market power, may go bankrupt. Thus, there is potentially a substantial social cost involved, beyond just an increase in electricity prices. In addition to causing rising prices, market power can hurt competition further and can cause a bankruptcy which carries a substantial economic cost of its own. The whole “system” can suffer from this type of economic inefficiency if it occurs, not merely electricity consumers because of higher electricity rates.

Fourth, market power defeats economic efficiency, not only in its effects on prices but also in the long-term effect on capital investments. Market power can have complex interactions with decision-making on capacity development over a long period of time, including renewable

resources. Sub-optimal markets can lead to sub-optimal investment decisions. It is generally assumed that the exercise of market power will spawn the new construction of generating capacity that will ultimately bring prices down again. This may not be true for three reasons.

The first, and most important, reason is that investors may be aware that it is market power that is maintaining the high prices. Making investment decisions based on those prices alone would be very dangerous because, if the prophecy holds, the prices would decline upon entry and the initial foundation for the decision to build a new generation plant would have dissipated. The new investment would defeat its own economic viability.

The second reason is that firms controlling existing generation will find it preferable, and quite possible given their high profiles, to build new generation themselves in an effort to preempt new entrants and thereby maintain their market power. That is a probable outcome because existing generators have an advantage over the outsider who faces greater risk about his future in the market. In addition, owners of existing units can often make more money than non-owners when introducing new units into a market.

The third reason is that the effects of market power are not uniform geographically across any given market when it comes to evaluating new capacity additions. The existence of load pockets, the effects of which are exacerbated by market power, may cause new capacity to be built in a location that would not be optimal if the market were truly competitive. Therefore, a certain compounding effect can be expected that can grow in severity over time, the longer market power is left to fester in the market. Ultimately, it is not just current prices that will have risen above competitive levels, but embedded costs of the system that will have risen, making the consequences of market power an integral part of the market and its cost structure. Even if market power were eliminated at this point, some of the cost would still remain with consumers in the form of uneconomical investments. It is not certain at all that the cost of such uneconomical investments will be absorbed entirely by investors. The risk of that is exactly the reason for a higher risk premium for electricity-related capital investments in a competitive market; if all market participants act rationally, capacity is not built until prices are high enough to justify the higher risk. That risk threshold is far higher in competitive markets than under price regulation.

Fifth, similar to the effect on investment decisions explained above, market power may undermine the many assumptions about cost reductions and efficiency improvements that the argument for restructuring rests on. Whether those assumptions come true is not independent of market power. In the presence of market power, a market participant may not have the assumed incentive to improve operations and introduce new efficiencies when “competitiveness” becomes understood by market participants as their ability to “play” the market. As a result, efforts to increase efficiency could take a back seat to attempts to manipulate the market. Also, the price increase from the exercise of market power could just plain outweigh the cost reductions due to competitive pressures.

Finally, the effects of market power can be potentially large and persistent unless the initial structure of electricity markets is changed. This may imply eliminating poolco-type markets. Whether market power is exercised through strategic bidding or capacity withholding, it is likely

to be done as a matter of routine, once market power exists.<sup>25</sup> There are three main reasons for this. It is in the interest of all generators to increase their revenues, and they can do so by bidding their output well above marginal cost in the energy and ancillary services markets, even in the absence of outright collusion. Second, capacity withholding does not need to be obvious and can be done on a small scale and, therefore, routinely. Third, because even small amounts of withheld capacity, or a relatively small marginal increase in energy market bids, can have a substantial impact on total revenues and on profits, it is unlikely that the exercise of market power will be easily identified, while the impact may be severely underestimated. For example, if profits were 10 percent of gross revenues, a price increase as small as 5 percent would increase profits by 50 percent. Clearly, there are strong incentives to exercise market power in electricity markets.

## **B. How Market Power Is Exercised**

Market power is possibly the most important—and least understood—long-term issue that arises in the debate over electric industry restructuring. When electricity generation prices are unregulated, the exercise of market power has the potential to significantly elevate the prices above those that would exist in a perfectly competitive market.

Market power is the ability of firms to raise prices because one firm or several firms each control a significant share of the market for a product or related set of products. In the case of electricity, the related set of products consists of generation, transmission, ancillary services, distribution, metering, meter reading, billing, etc.

Under traditional regulation, electric utilities have local electric service market shares approaching 100 percent. However, regulation has prevented them from exercising market power in both the wholesale and retail markets. The deregulation of some electric services, notably generation and ancillary services, could allow companies to exercise market power in the provision of these services. In many regional electricity markets, much of the generation capacity is concentrated in the hands of one or a few companies. Of course, the degree of ownership concentration depends on the size of the market under consideration. Furthermore, electricity generation is more prone to the exercise of market power than most commodities are because, in addition to other factors, storage is expensive or non-existent, transport is capital-intensive and costly, thus seriously limiting the geographical size of markets, and demand is relatively price-inelastic and highly variable within the course of each day. Demand is also somewhat uncertain in each hour. Finally, and quite importantly, the marginal cost of supply also varies greatly in direct proportion to demand. All of these factors combine to make the exercise of market power relatively easy in electric generation markets.

Market power is either “horizontal” or “vertical.” Both horizontal and vertical market power could exist at both the wholesale and retail levels. Of course, the impact of wholesale market power tends to flow through to prices at the retail level, as well.

Horizontal market power is a firm’s ability to raise prices based on its share of the market for a single product. Naturally, a larger share tends to allow a company to exercise more horizontal

---

<sup>25</sup> These mechanisms for exercising market power will be explained in more detail below.



market power. However, the way each owner's generating units are distributed across the marginal cost supply curve is also very important.

Vertical market power is the ability of a firm providing a competitive service, such as generation, to increase the price for that service as a result of controlling another aspect of electricity supply, such as transmission, ancillary services, or distribution. At the retail level, an example of vertical market power is that of competitive generation affiliates of local regulated utilities controlling retail prices. The competitive affiliates could have an advantage in marketing themselves because they are associated by name with the familiar utility.

For an example of vertical market power at the wholesale level, suppose a utility has a competitive affiliate which owns a substantial share of the generation in the utility's service territory. If the utility limits the import of power to its territory, either by influencing policy decisions about the transmission system, or by preventing other companies from using a portion of the transmission capacity, then the utility is exercising vertical market power. Also, in this example, the utility's vertical market power would most likely enhance the horizontal market power that its competitive generation affiliate possesses as a result of owning a share of the local generation assets.

Retail market power, or market power at the level of directly providing service to end-use customers, becomes an issue if retail choice is implemented. The ability of firms to exercise market power at the retail level stems both from concentration in the ownership of generation and from a variety of competitive advantages that may be held by one or a few competitive service providers at the retail level. Affiliates of local utilities are the most likely firms that could hold such advantages, and these advantages may be as simple as name recognition, or as perverse as subtle utility actions that help affiliates to win customers or which complicate the efforts of non-affiliated competitive providers.

#### *Market structure and its implications for market power*

"Poolco" is a term for a particular electricity trading structure. It is not the only possible structure, but it is the predominant one for deregulated generation markets so far, as in California; PJM (PA, NJ, DE and MD); NEPOOL (New England); and New York. In a poolco-type market, firms bid a fixed price for the output (either energy or ancillary services) of each generation unit for each hour unit during the coming day. The units are then dispatched in the order of their bid prices, from lowest to highest.

Electricity generators place bids into those markets where they commit themselves to generate a certain amount of power at a given price. The distribution utilities supply estimates of how much electricity they are going to need the following day to serve all their customers. Therefore, supply and demand is matched roughly one day in advance, but because demand is not entirely predictable, in some cases an hourly energy market is used to supplement the day-ahead market to help respond to the hourly demand variations from the previous day's estimates.

The cost of generating electricity is different for each power plant. If the energy market were perfectly competitive, the market price per kilowatt-hour (kWh) would be equal to the marginal cost, which is the lowest cost at which the next required kilowatt-hour can be supplied. This price rises as more expensive units come on line when the system moves into high-demand hours

of the day. For example, the wholesale price of electricity around midnight can be around \$15-\$20 per megawatt-hour (1.5-2 cents per kWh) but can rise to \$30-\$40 in the afternoon on a normal day. On extremely hot days, very expensive power plants are turned on to provide enough short-term power to supply the huge extra demand generated by power-thirsty air conditioning. On those days the marginal price can rise in some areas to \$100-\$150 per MWh which could be a very high price for a jet-engine generator—a unit that is designed to meet peak-load or emergency demand only. However, this is not a problem if the market clearing price truly reflects the cost of running generating units, and does not reflect market power. It is most economical to have a mix of generating units that have different operating characteristics exactly because demand fluctuates so much in any given day.

In a poolco, it is the most expensive unit dispatched in each hour that sets the market clearing price for that hour, and all of the lower-priced units receive that same clearing price rather than their bid price. This last aspect of a poolco is its essential feature. Everyone gets the same price completely independently of their variable operating costs, if they are dispatched. Therefore, everyone who buys electricity in the wholesale market during any given hour pays the same market price even though most of the power being sold in that market is not as expensive to generate as the power coming from the marginal generating unit. If the marginal unit were to only bid its variable operating costs, this last unit would not recover any of its fixed cost in the energy market, because it is the marginal unit and it sets the market price at its unit cost of generating power. On the other hand, all other units selling into the market during that hour will receive a price that is above their variable cost of production. In some cases, that price will be quite far above cost. Thus, all dispatched plants except the marginal unit will earn income above their costs of production that can be used to pay for their fixed costs. This aspect of a poolco-type market will tend to drive the average cost of electricity up from previous regulated rates, which were based on the average cost of generating that power in each hour, not on a single market price at each hour of the day equal to the cost of operating the most expensive plant.

In a competitive market, when demand rises just slightly above average load, the price should not rise much because there is still a significant amount of capacity available with low unit operating costs. But as demand rises to higher levels, increasingly expensive units often make the cost curve rise exponentially. This makes the potential for market power particularly troublesome when demand is strong. Prices in a poolco naturally rise very fast in high demand periods and, because supply is also tight, market power is probably more prominent during those hours also. If a market participant is in a position to manipulate the market, it will be easiest to do during peak demand periods, which are also the times when it is most profitable. Market power in the wholesale electricity market can be exercised in two ways, as we will now describe.

#### *Strategies for exercising market power: Capacity withholding and strategic bidding*

Capacity withholding and strategic bidding are the two major profit-maximizing strategies for all firms when attempting to exercise market power. Capacity withholding seems to be fairly well understood among current analysts of market power, but the potential role of strategic bidding seems to be little understood, or generally is excused as a short-term deviation from competitive market behavior. Note that firms with a relatively small fraction of generating capacity can still exercise market power, if others with larger ownership shares do also. In an electricity market,

capacity withholding is the practice of not offering a generation unit's potential output in a given region for some period of time. If a generation owner has more than one unit, under some circumstances it can increase its total profits through capacity withholding. Suppose there are ten units of equal size in a particular market, labeled 1 through 10 in order of increasing bid prices. Suppose that Unit 9 would set the market clearing price if all units bid into the market. Withholding Unit 9 would shift the market clearing price up to Unit 10. Since Unit 10 has a higher marginal cost than Unit 9, then the revenue foregone from Unit 9 by withholding Unit 9 could be less than the additional revenue gained by the firm as a result of receiving the higher market clearing price for the output of all the eight lower-bidding units it owns.

Strategic bidding, the profit-maximizing alternative to marginal cost bidding, is the other strategy that firms can and will use to raise market clearing prices above what they would be under perfect competition.<sup>26</sup> Suppose a unit's owner bids the unit's generation at 10 percent above marginal cost. The unit would probably be dispatched less and so lose some revenue, but during those hours in which that unit set the market clearing price, the price for all of the owner's lower-priced units would be 10 percent higher. Thus, the increased market clearing price could increase profits more than the reduced dispatch time for the unit in question would lower profits. How exactly an owner of a power plant would bid its output depends on various details. For example, how many and how varied the various types of plants are that any given market participant owns is critical to his bidding behavior. If you only owned baseload units you could not affect the market clearing price very often, and if you only owned peaking units, you could not apply any leverage to baseload units. However, a good distribution of plants along the supply curve, e.g., plants with varied variable cost, gives the greatest amount of leverage to any market participant, and such a participant is in a good position to increase profits.

It has been shown that bidding strategies in a poolco-type market will follow the Nash Equilibrium.<sup>27</sup> In essence, the Nash Equilibrium means that all generators will learn quickly that bidding a certain amount above production cost will maximize their profits. How much they should bid will depend on the shape of the supply curve (variable production cost of each generating unit relative to other units). A simple way to think of this is the following: When each owner of a power plant has an approximate knowledge of the marginal costs of all the other plants in the market, it would be foolish to bid one's own plant at its marginal cost of operation. The reason is that the next more expensive unit cannot bid lower than its own marginal cost, or it would lose money. It is, therefore, safe to bid at least as much as the marginal cost of the next unit above it in the supply curve. Now, since the owner of that next unit will think the same way, he will also bid above his marginal cost. Knowing that, the owner of the first (less expensive) plant can be fairly confident that he can bid his plant even more above the marginal cost of the next more expensive unit and still be dispatched by the System Operator ahead of that unit, avoiding being bid out of the market. In actuality, the picture is more complicated than this and the potential effect on prices is greater as a result. The Nash Equilibrium indicates that the production costs of units that are not dispatched in a given hour but that are only slightly above the market clearing price in the dispatch order do affect the Nash Equilibrium for those units that

---

<sup>26</sup> For detailed discussion of the mechanics of strategic bidding see: Alexander Rudkevich, Max Duckworth, and Richard Rosen, "Modeling Electricity Pricing in a Deregulated Generation Industry: The Potential for Oligopoly Pricing in a Poolco," *The Energy Journal*, Vol. 19, Number 3, 1998.

<sup>27</sup> *Ibid.*

are actually dispatched in that hour. This means that as the supply curve's slope rises, bid prices start to rise before demand has risen to a level that would justify those prices, based on production costs alone. In other words, the market sees the demand rise and it preemptively raises bids.

Because of this sensitivity to the slope of the supply curve, the effect of multi-lateral strategic bidding (bidding by many owners of generation) is particularly strong near peak demand where the supply curve is the steepest, but it can still occur to a lesser extent at any time. When the marginal cost increment between units is wider (steeper slope of cost-of-supply curve) there is more room to bid up prices above competitive prices, which already are high. For example, strategic bidding during hours of average demand could raise prices from \$30 to \$31 per MWh but when demand is higher, the same bidding behavior could, perhaps, raise prices from a competitive level of \$50 to \$55 per MWh. The incremental effect is often much larger when demand is higher, and it is compounded by the fact that a much larger amount of energy is changing hands at that higher price because demand is near its peak. For the hypothetical example above, if total demand in the market were 10 MW on average, additional revenue in each hour might be \$10 at times of average demand ( $\$1 \times 10$  MW) but at time of peak demand of 15 MW, the additional revenue would be \$75 per hour ( $\$5 \times 15$  MW).

#### *The problem with mergers in generation sector*

Another innate problem deriving from the restructured electricity market is the likely consolidation of power through mergers of generation-owning firms. The large number of recent mergers in the electric industry in the United States indicates that consolidation is strongly associated with the transition to a competitive market. Much of this merger trend is probably driven by fear on the part of utilities that they will be overrun by competitors in the new market, unless they gain strength, initially through sheer size, and in the long run through efficiency gains generated by cost-savings. Another, somewhat more subtle, reason may be the tremendous pressure from shareholders to increase perceived value in the firm during times when a strong economy has brought expectations in the stock market to historically high levels. With severely limited options for rapid growth, since the demand for electricity grows by only about two percent per year, utilities in the electricity market must, therefore, rely on mergers to increase faith in the firm among investors who may have become accustomed to explosive growth in other sectors over the last few years. Even well-operated and profitable utilities can fall out of favor among investors under such conditions.

One key downside to the increased numbers of mergers is the threat of increased market power, at both the wholesale and retail level. Even though the cost of operations may be reduced through mergers, potentially leading to lower prices, this advantage may easily be cancelled out by the effect of increased market power. The fewer and larger the firms are in the market, the less vigorous will be the competition among them. The reality of increased power in the market may, indeed, even reduce the incentive among the firms participating to pursue efficiency gains in production.

FERC would usually be one of the key regulatory bodies to address the market power implications of a proposed merger. FERC's guidelines for examining mergers, which are consistent with those that have been used by the Department of Justice in other industries in the

past, rely on the Herfindahl-Hirschman Index (HHI) as an indicator of potential market power. The HHI is the sum of the squares of the market shares of all the suppliers in a given market. For example, a market that is made up of five firms with equal market shares has an HHI of 2,000, and ten such firms would yield an HHI of 1,000. If the HHI for any given market falls below 1,000, FERC would typically consider the market to be unconcentrated, and the risk of market power would be deemed to be very low. If the same HHI were above 1,800, FERC would consider the market to be concentrated, and might be concerned about the potential for market power. Therefore, the HHI is an analytical screen that gives FERC an indication as to whether or not market power may be likely to exist in the wholesale power markets. Unfortunately, this screen is an inadequate tool for the task of assessing market power because it is too simplistic. It is in fact not built on any theoretical economic foundation, nor is it supported by empirical evidence that an HHI value is a particularly good measure of market power in wholesale electricity markets.<sup>28</sup> In fact, computer simulations done by the Tellus Institute indicate that, for a given utility system, the impact of market power does not always increase when the HHI for that system increases. The relationship between market price and ownership concentration is more complex than that.

There are six primary reasons why the HHI is not very useful as an index of market power:

- *The HHI fails to account for market structure.* The HHI may or may not be a useful tool for assessing market power in other industries, but the electric industry is far too complicated to lend itself to such simple methodology. Also, with multiple product markets in the deregulated electric industry, the HHI only looks at concentration by capacity ownership. For example, the HHI cannot deliver a simultaneous measure of market power potential in a ten-minute capacity reserve market and an energy spot market. It is the interreaction between these markets and the rules that govern them that will determine how market power will be exercised if it exists. The HHI does not recognize those behavioral dynamics. It is a simple structural index.
- *It does not recognize the shape of the supply curve.* Strategic bidding will be affected by the shape of the supply curve. Taking an HHI “sample” at a given price point or for the entire market does not recognize this fact.
- *It ignores the distribution of ownership of supply.* Not all market shares of the same size have an equal impact on an owner’s ability to exercise market power. Actual market power may vary among different market participants with equal market shares, depending on the distribution of generation resources held by each along the supply curve. The mix of resources determines the behavior of a market participant in context of strategic bidding and potential withholding of capacity. Indeed, FERC has not looked at the risk of capacity withholding in its methodology for market power analysis at all.
- *HHI does not match load with resources.* Looking at ever larger periphery of supply beyond the test area load, perhaps over several transmission tariffs, will falsely indicate an absence of market power if the load served by the supply in the peripheral areas is ignored. Yet, this is what FERC’s methodology does. It inherently assumes that more supply is available to meet any given load than really would be available.

---

<sup>28</sup> For more detailed discussion of FERC’s Merger Guidelines, see: Heidi Kroll and Dr. Richard Rosen, “Market Power, Mergers, and Deregulation: A Critique of FERC’s New Merger Guidelines”, in *The National Regulatory Research Institute Quarterly Bulletin*, May 30, 1997.

- *HHI ignores transmission costs and physical constraints.* The HHI is insensitive to load-pockets and the way in which they can generate localized market power problems.
- *There is no recognized method for aggregating multiple HHIs for different sub-markets.* Even though HHIs could be calculated for different submarkets, there is no clear methodology for aggregating or weighing different HHI values and deriving a single numerical value for market power potential across all product markets in a geographic region.

Fortunately, FERC is reconsidering the simple structural approach implied by using HHIs, and has launched the development of a behavioral model for the analysis of potential market power. In April of 1998, FERC initiated this process by issuing a Notice of Proposed Rulemaking on revised filing requirements in relation to market power analysis.<sup>29</sup>

While FERC and the state PUCs currently share authority over most utility mergers, they may have little or no authority in the future over mergers and acquisitions of unregulated generation units. Thus, it is not at all clear whether or not sufficiently regulatory mechanisms currently exist to prevent inappropriately large aggregations of generating units. This is especially true since most analysts agree that anti-trust approaches to prevent market power are likely to be too slow, expensive, and cumbersome.

#### *Market-induced barriers to entry*

Another way in which the consolidation of power in the generation market can have anti-competitive effects is through increased barriers to entry. In theory, the “threat” of new market entry will hold prices in the market at the long-run marginal cost, or slightly above that level. Reciprocally, it could be argued that the “threat” of lower prices in the electricity market in the face of new entry can be sufficient to prevent new capacity construction, particularly in a market with such volatile prices and high initial capital costs for entry. If existing market participants could conceivably intimidate potential new entrants by effect of their current market stature (or that gained by the current wave of mergers in the industry) they might be able to do so, and keep out new entrants, without actually lowering prices. There are two main reasons why this could happen. One is the sensitivity of new capital investment to tight profit margins, as noted above. This is particularly true for generating units designed to meet peak load. Because such capacity enters the market near the margin, it would take very small reductions in prices to make the new capacity uncompetitive. Also, if there is no ISO-operated capacity market, as in California, the risk of not recovering the fixed costs of a new peaking unit in the energy market might be quite high, given the uncertainty in peak demand from year to year. This would be especially true wherever there is neither a capacity market nor a capacity reserve requirement, as in California. Thus, having a required reserve margin for load-serving entities may prove to be crucial for achieving effective and continuous new market entry in poolcos. The current situation in California, where the relative capacity surplus of past years has dried up since the onset of deregulation, is a clear indication that this may be the case. Another reason why market entry may be postponed in a poolco energy market is the time lag inherent in bringing new power plants on line, and the risks that this also generates for investors. If this logic holds, the practical effect is that any new entry may not have any real effect in moderating market prices until the

---

<sup>29</sup> Federal Energy Regulatory Commission, *Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Notice of Proposed Rulemaking, Docket No. RM98-4-000, (April 16, 1998). Unfortunately, FERC has yet to complete the development of this behavioral model.

capacity is actually built, and starts producing energy. Yet, there is no reason to believe that the “market” will build much more capacity than the required reserve margin implies.

### *Dysfunction on the demand side*

As discussed above, one market solution for market power proposed by many analysts is to enhance demand responsiveness. In fact, whether or not consumers have the ability to respond to competitive prices should be an important consideration when restructuring occurs because demand responsiveness can dampen market power. In reality, regulators paved the way for restructuring without having any notion of how consumers were supposed to respond to changes in market prices in a way to enhance efficiency, once fluctuations in the wholesale markets began to flow through to the retail level.

If consumers are shielded from real market prices during the transition period in most states that have restructured, only to have to pay the difference later, it is impossible for them to know when and how to adjust their demand to prepare for the post-transition period. However, as pointed out above, inelastic demand among residential customers is a serious impediment to “market responsiveness” for those customers who are most vulnerable to market price fluctuations. To the extent that a “demand market” can develop to quell the effects of market power despite inelastic demand, a technological challenge remains to achieve that outcome. It is unlikely that residential customers will be able to be responsive until households are equipped with automated demand control technology that can respond instantaneously to changes in real-time energy prices according to a pre-determined schedule of priorities. This technology may soon be within reach, but may be expensive relative to the benefits provided to each customer. Nonetheless, current discussions about the initially attractive concept of real-time metering and demand responsiveness do not usually recognize the reality that electric service is a vital service to the public that should not always be subject to individual economic choices at times of severe shortage and high prices. For example, regulators must ask themselves whether they are willing to trade the potential negative impacts on public health for increased economic efficiency in energy markets on sweltering summer days. Demand responsiveness as a particular weapon against market power needs to be carefully implemented because it can backfire if not designed properly.

### **C. Price Discrimination at the Retail Level**

Price discrimination is a goal of any retail merchant. It is the means by which retailers can boost their profit margin, but for most, it is difficult to achieve on a consistent basis. Price discrimination maximizes revenue while a single retail price for all customers will, by necessity, always result in a lower revenue stream. The reason for this is simple. Once a retail price has been set for a given product, there will always be large number of customers who are not ready to make a purchase at that price but would be tempted if the price were lower. Similarly, there will always be customers who would be willing to pay even more than the initially set retail price. Clearly it would be best for the retail supplier if the price could be set at different levels for each customer. The most common and simplest way of attaining some level of price discrimination is to have periodic sales. Although no one is barred from purchasing at the sale price, it is likely that those customers who are less price-sensitive may already have made a purchase at a higher price, when more options are available. Those who clasped their purses

tightly before the sale are now tempted to make a purchase. This is price discrimination “by effect.”

In some sectors of the economy, such as the airline industry, price discrimination can be more deliberate and controlled. Business travelers routinely pay a much higher fare than the occasional traveler does. The business traveler’s company is willing and able to pay more for the airfare because it is less sensitive to price than most individuals making travel plans in advance. The business traveler would, of course, prefer to pay less, but the airline has a way to make it inconvenient for the business to purchase the lower fare by requiring, for example, the less expensive travel to extend over a weekend. The picture is complicated by the fact that the product offered to different customers is not always identical. Sometimes, business travelers are rewarded with greater comfort and various privileges that are designed to promote more expensive options while suggesting greater value.

Price discrimination usually has a very negative connotation. It seems to suggest that someone is being cheated. That is not necessarily true. First, price discrimination does not necessarily mean that market power is at play. A segmented pricing structure can well materialize in a very competitive industry, and arguably, can be a matter of necessity because of strong competition. Going back to the airline industry, one can imagine that an “oligopolistic consensus” has developed among the airlines for the necessity to charge business travelers a higher fare than the general public. Then, wherein lies the problem with price discrimination, particularly as it might occur in the electricity industry?

It must be recognized that the distinction in reality between “justified” price differentiation and pure market power is quite unclear. There is a useful distinction to be made between three different kinds of price discrimination. First is price discrimination that seeks to allocate prices according to the “willingness to pay.” By itself, this kind of price discrimination is beneficial because it makes service more universal and egalitarian. However, this can only happen where there is a substantial price elasticity of demand. It is probably the closest the market can come to fulfilling the idealist principle that people should pay what they can afford and receive according to their needs. The second form of price discrimination is the one where price is based on proper cost allocation. This is what has defined rate design in the electric industry under regulation. Residential customers have paid more than industrial customers have because their load factors are lower and distribution costs higher per unit of energy consumed, than is true for industrial customers. Therefore, it is only appropriate for residential customers to pay a higher charge for each kilowatt-hour consumed. The third form of price discrimination is where the problem lies; price structures based on the leveraged power of the wholesale or retail entity against a particular group of customers. This can more easily occur when the price elasticity of demand is low, as it happens to be with electricity, particularly for residential customers.

When price discrimination is not based on the “willingness to pay” but, rather, on the consumers’ inability to negotiate the terms of the sales contract, or some other manifestations of market power that turns a particular customer class into price takers, particularly for a necessity of life, then it is clear that price discrimination has taken a negative turn. It is also clear that such price discrimination is likely to hurt small customers, while large customers are likely to benefit. Specifically, businesses are likely to benefit at the expense of the general public because



individuals are at a disadvantage relative to industrial users of electricity when it comes to negotiating prices, unlike the business/public dichotomy in the airline industry. Again, the public also has a much lower price elasticity for electricity consumption. Also, because the residential customer has a higher cost structure, it is easier for electricity suppliers to hide additional and unjustified price differential as cost-based, making it harder to detect as a product of market power.

Is it defensible to advocate price discrimination, or price differentiation, in the airline industry that favors the general public, while objecting to price discrimination that does the opposite, favoring industrial customers over residential households? It can be argued that business travelers are leveraged by the industry to buy at a higher price than other customers, therefore raising the question whether market power may have some role in the pricing structure. Market power certainly could be relevant to the extent that business customers are probably less willing to take anything but a non-stop flight, which are often limited by the market concentration of gates owned by airlines at their hubs. Likewise, if we justify such differentiation by reference to "willingness to pay," should we not do the same in the electric industry and conclude that residential customers are "willing" to pay more than industrial customers, and thus any pricing scheme that reflects that reality is fully justified?

No, such price discrimination is unacceptable due to the nature of electricity service. Electricity is a vital service and an absolute necessity, particularly to residential customers. It is a serious ethical issue whether an industrial entity which regards electricity merely as an economic input, should benefit from price discrimination against residential customers, to whom electricity is a necessity. The fact that electricity is a vital service to households affects residential customers in two ways. First, because it is a necessity, special precautions should be made to ensure that this service is not disrupted in any way because of the customers' inability to meet price demands that discriminate beyond pure cost-of-service considerations. Secondly, it is that very dependence on the resource that makes residential customers particularly vulnerable to market power at the retail level and subsequent price increases that are leveraged specifically against that customer class.

### **6.3 Stranded Costs – Were They Set Correctly, or Will Consumers Over-Pay?**

#### **A. What are Stranded Costs?**

As with most aspects of electric industry restructuring, the issues involving the proper definition of, and quantification of, stranded costs did not receive sufficient attention prior to the attempts by various states to actually restructure. Thus, before we can discuss whether or not stranded costs were set correctly, we must clarify what stranded costs are, even though this has been one of the most extensively discussed issues within restructuring.

First of all, stranded costs should have been called "strandable costs" or the "uneconomic costs of generation." If generation is the only component of electric service that could be deregulated, then all the strandable costs of having provided utility service in the past would have been generation-related. No distribution or transmission costs could become stranded if the recovery of those types of investments were always to be regulated. Secondly, no one initially made a distinction between

wholesale market prices and retail market prices when discussing stranded costs. This meant that when analysts generally considered stranded costs to be the difference between the embedded costs of generating units for ratemaking purposes, and their market value, they were not clear about which set of market prices reflected their market value. As Tellus pointed out in various publications over the past few years, the difference between these two market values can be significant.

Of course, most analysts intended the wholesale market price of power to provide the baseline for computing stranded costs. Consistent with this perspective was the use of the results of divestiture-related sales of power plants as a baseline for computing stranded costs. This perspective is acceptable as long as calculations of stranded costs are made on an "apples to apples", or wholesale to wholesale level of comparison. What most analysts did not realize is that once the generation component of electric rates was unbundled, the equivalent of the "wholesale" part of that rate was the total unbundled rate net of the generation-related A&G (administrative and general) component. Potentially forgetting to net out generation A&G in computing stranded costs is a significant issue, because this component averaged more than 5 mills per kWh nationally in the mid-1990s. This downward correction to many stranded cost estimates would have represented a significant fraction of many of the stranded cost recovery charges set in the last few years, if it had been made properly.

## **B. Stranded Costs Can Be Negative**

One important consequence of the definition of stranded costs that was not appreciated for several years into the restructuring debate was that stranded costs can be negative as well as positive. This fact is quite obvious when you think about the likely possibility that many low cost or highly depreciated power plants will sell for more than their net book value, if divested. One reason why negative values for stranded costs rarely, if ever, arose in the early days of restructuring is that many utilities made administration determinations of stranded costs by only considering the difference between unbundled generation rates and wholesale market prices for five years, or so, out into the future. In contrast, they should have calculated stranded costs for the entire projected remaining lifetime of the generating units under consideration, since this is what the market would do implicitly, if those units were divested to third parties. Either way, it is likely that most existing fossil and hydro units would show negative stranded costs, because they already have been considerably depreciated. Yet, the broad policy implications of entire utilities have substantial negative stranded costs were not part of the initial policy debate surrounding restructuring. This was particularly surprising given that possible rate reductions where stranded costs were strongly positive was one of the major factors that pushed the restructuring debate forward in the first place.

One of the most troubling consequences of the lack of policy recognition given to the possible existence of negative stranded costs for many, if not most, utilities was the general impression being communicated both to policy makers and to the public, that electric restructuring would be good for the country precisely because of the existence of stranded costs, and because they were positive. Again, people were given the impression that restructuring would somehow get ratepayers out from under paying stranded or strandable costs, **at least to some extent**. This would, presumably, lower their rates relative to not restructuring the electric utility industry. Few, if any, public utility commissions, when making stranded cost rulings during the initial process of restructuring, ever seriously considered that stranded costs could be negative, nor did they consider what the implications of negative stranded costs would be for restructuring in their states. Most became

convinced that all of their utilities had positive stranded costs, as the utilities urged them to believe, which was almost certainly wrong. Only the Delaware Public Service Commission officially recognized, just this year (2000), that one of their utilities had negative stranded costs (and one other had no stranded costs).

### **C. Divestiture Sale Prices and the Effect on Stranded Costs**

The belief that restructuring would lead to rate reductions because stranded costs were positive seems to have been based on two fallacies. The first, and most significant fallacy, was that rate reductions could result even where regulatory commissions (including FERC) opposed the sharing of stranded costs between ratepayers and utility shareholders. But, the reality is that, if stranded costs are calculated correctly, and paid one hundred percent by ratepayers, then by definition, on a present value basis, ratepayers can not save any money from this aspect of restructuring. Of course, as in Massachusetts and California, this fact was often disguised by legislated rate reductions, in spite of which all stranded costs were scheduled to be fully paid by ratepayers over the long run. The second major fallacy, or problem, was that public utility commissions did not understand how easy it was to over-estimate stranded costs, and they did not adopt any sort of a true-up mechanism to refund the excess collections for stranded costs to ratepayers in the future. One reason why stranded costs were often over-estimated was because divested power plants often sold for less than their likely long-term value in the market to their new owners. Yet, most PUCs simply assumed that the sale of power plants by auction would produce an accurate estimate of their future worth in the wholesale market. Thus, many ratepayers in states that have restructured their electric utilities will pay more for stranded cost recovery over the next ten years on a present value basis than they ever would have paid without restructuring.

Recent generation-asset liquidations, on the scale of gigawatts of capacity each, have been allowed to set stranded costs “in stone,” based on a single purchase price at one moment in time. The simple fact that such transactions take place in a market environment does not guarantee that the price, which is intricately linked to perceptions of future energy prices, reflects the true value that the asset will end up having over time. The scale of the error here can easily mirror that of the overvalued QF price schedules of the past two decades that were based on the expectation of ever-rising fossil fuel prices. This is especially true considering that such uncertainty is mostly a concern of the buyer, since the seller may be quite indifferent about the selling price if full stranded cost recovery is allowed based on the sale price. Without true-ups, as market conditions change, the sale price is, then, likely to be below a fair market value.

In fact, the recent sales of nuclear plants indicate that nuclear technology is out of favor with the market and the prices for these units are suppressed. Three Mile Island Unit 1 was sold for \$100 million in 1998, three-quarters of which was for nuclear fuel. That makes the purchase price for capacity at less than \$30 per kW, which is just about 5-10 percent of the capital cost of a new combined-cycle plant. Boston Edison sold its Pilgrim plant for even less in that same year, or \$80 million. Excluding the fuel portion of the price yields a capacity price of less than \$20 per kW. Stranded costs, then, could be inflated, even though the nuclear plant may be a profitable and well-maintained facility that could deliver energy at an attractive price. Instead, consumers boost the profit margins of the new owners by subsidizing the acquisition of the plant through higher stranded cost charges, but must then purchase the energy from the plant in the

marketplace at market rates. This is why a true-up for stranded costs might be appropriate as a consumer protection measure, even though the generation assets have already been sold, if it is imposed on the selling utility. Such a policy would surely encourage the selling utility to get the best price possible for the plants sold during a divestiture.

Regulators and others, who are concerned about impediments to the economic efficiency of DSM programs, for example, and their ultimate effect on the consumer, should particularly consider the situation that exists when power plants are sold at deflated prices. At stake is the potentially enormous economic loss to consumers when assets they have largely paid for may be sold at a price well below a fair market value, generating further stranded costs to be collected from the same consumers, now for the second time. Excessive confidence in the ability of the market to set an efficient clearing price for these plants can hurt consumers as much or more than any assumptions made by regulators in making an administrative determination of stranded costs. After all, the market is nothing more than the collective wisdom of its participants, driven by self-interest. They face the same uncertainties and constraints, as do regulators. The only difference is that the market as a whole has no responsibility in minimizing cost to the consumer. The “bottom-line” is, then, that we tend to favor administrative determination of stranded costs, with true-ups. If the utility owner of the generation then wants to sell the units, it can take the risk of receiving low prices, not the consumer. Consumers should never have to pay twice for stranded costs. Paying once is bad enough.

#### **D. How to Treat Negative Stranded Costs**

The flip side of the misunderstandings that flowed from the belief that all stranded costs were positive, is the lack of any serious discussion at the national level as to how ratemaking would be done for any utility that had negative stranded costs in a state that restructured. The natural approach to dealing with this issue, would, of course, have been to simply credit ratepayers for the negative stranded costs by applying a negative stranded cost recovery charge to their rates for some period of time. This would, of course, lead to a cash flow problem for many utilities, if they did not actually divest their units and receive more than their depreciated net book value for them. But, of course, it was precisely the utilities that privately realized that they had negative stranded costs that generally refused to sell their plants, in the realistic expectation that if they could continue to own these units on an unregulated basis, they would make super-profits. This would be the case as long as they could prevent a negative stranded cost charge from being implemented. And because of the general lack of the recognition of negative stranded costs and their implications for ratepayers, PUCs were very hesitant to even consider implementing a negative stranded cost charge as a way to deal with utilities that had negative stranded costs.

Again, the major reason why restructuring was advocated was the belief that in the long run electric generation prices would be lower with restructuring than they would be in the absence of competition, as we have discussed at length above. This is because if the market for divested plants had perfect foresight as to their future value, or if PUCs performed administrative calculations for stranded costs based on perfect forecasts of wholesale market prices, then ratepayers would only save money on electric generation on a present-value basis after most existing generating units had retired. Thus, it might take restructuring at least 20 years to deliver present value rate reductions to ratepayers, or until the period utilized for calculating stranded costs ended. At that point, the

incremental cost reductions for new generation units induced by restructuring would, presumably, lead to reductions in the wholesale generation market price.

Yet, this is another major misconception of the entire stranded cost and restructuring debate that analysts did not understand what would likely happen to rates after the stranded cost recovery period was over, relative to what rates would have been without restructuring. As indicated above, due to the difference between embedded cost rate making under regulation and marginal cost-based pricing in deregulated markets, rates will almost assuredly be higher under restructuring within 10 years in most, if not all, parts of the US, compared to what they will likely be under restructuring. Thus, even if ratepayers were to save some money over the next decade or so, due to sharing of stranded costs with utility stockholders, or due to a rare under-estimate of utility stranded costs, they will end up paying more each year after that.

What is the bottom line, then, as to whether or not stranded costs have typically been set correctly, or whether or not consumers have, on average, over-paid for stranded costs thus far? Certainly, we can conclude that stranded costs have, generally, not been calculated correctly for the reasons cited above. Whatever methodology is used to determine stranded costs, significant errors in forecasting future market prices are likely. Furthermore, PUCs have not incorporated any kind of a true-up mechanism into the stranded cost recovery mechanism so that errors can be corrected. We tend to think, then, that consumers have, in fact, systematically overpaid stranded costs.

Another reason for this belief not listed above is that wholesale market prices are turning out to be substantially higher than most analysts anticipated just a few years ago. Whether or not this is due to the exercise of market power, or is just due to the underlying economics of new market entry, time will tell. But the cause of the higher market prices does not matter from the perspective of the accurate setting of stranded costs in the past. If market prices remain higher than were previously expected, assuming that stranded cost recovery is not adjusted downward in most instances, ratepayers will have learned the hard way that restructuring will not benefit them, at least not in the first decade.

## **7 CONSUMER CHOICE AND THE ENVIRONMENTAL PARADIGM**

### **7.1 Limits to Choice**

Unfortunately, consumer choice as a key ingredient within a restructured electric industry is not a panacea to guarantee economic efficiency. Consumer choice is specific to each individual and follows personal preference. It does not account for the great variety of common social goals that local and federal regulation of facility siting, the environment, and utilities has attempted to integrate into the process of delivering electricity services. Of course, being able to choose green power—as opposed to just the least expensive supply—is of some value in itself, because it allows the individual to express preference and make a statement about personal goals for society as a whole. Yet, it may not lead to greater innovation because it may not have the force and momentum of collective action to cross the threshold needed for real change. Also, while the individual may vote with their pocketbook, this approach may not be an economically efficient way to bring change due to lack of concerted momentum generated. In fact, relying solely on consumer choice could even result in backsliding on environment benefits.

In general, the complexity of electricity services may render electricity an unsuitable product for the competitive marketplace. The fact that the electric industry is very technical may also make it impossible for consumers to make an informed choice unless awareness about the likely consequences of their choices is improved dramatically. Consumers are already assisted by the Federal government in making purchase decisions when shopping for automobiles and appliances through the mandatory disclosure of energy efficiency. Similarly, electricity consumers must be provided with adequate information about product content, emission profiles, and unbundled cost. Without such information there is no possibility of informed consumer choice. But even with such information in hand, the consumer may still be incapable of making any useful decision about how to accomplish the kind of resource allocation in the electric industry that, on balance, maximizes economic efficiency and social benefit.

One common perception is that retail competition in electric generation markets will help push dirty coal generation out of the generation mix in favor of renewable energy as consumers make their preference known for clean power. However, in a competitive market, high capacity factors and low cost make coal-fired generation very profitable. This is because there are very few coal plants that are still operational that have operating costs higher than new gas plants, so almost all existing coal plants ought to perform well in a deregulated market. Even when the consumer desires something different, the market will gravitate, by default, to low-cost options. Wind may have zero variable cost, but new wind generation has a high capital cost that must be recovered, so it can not replace existing coal due to coal power's much lower generating costs.

#### **A. When the Individual is Called on to Subsidize the Common Good**

##### *Tragedy of the Commons*

The “Tragedy of the Commons” refers to the incentive to consume, without restraint, those desirable resources that are not protected by ownership, or other means of creating an incentive

to conserve the resource. Without restrictions, all able bodies will race to consume such a resource as quickly as possible until it is exhausted. This is clearly inefficient for a variety of reasons. A parallel can be found in electricity markets where individual choice in isolation is called upon to bring about efficient allocation of resources in relation to all cost considerations, including social and environmental. Environmental quality, as it is affected by electricity consumption, is a common resource that no individual controls and no one has an exclusive personal stake in preserving.

When it comes to making choices about electricity purchases, specifically type of generation technology, consumers have every incentive to remain inactive in the hope that others will make the necessary decisions to move the market in the desired direction. This is because such preferences would be expressed through additional expenditure of money because green power costs more than conventional sources. First, each consumer sees the incremental cost of purchasing green power as potentially avoidable if others make the choice first. Second, the incremental cost of green power to the consumer is higher than the incremental benefit to that same consumer from improved environmental conditions. The reason is that the cost is indeed not borne evenly by all those who benefit. The one who buys a kilowatt-hour of green power carries the full economic cost of that decision but shares the environmental benefit with all other consumers in the market. A vicious cycle develops where the higher incremental cost to individuals to benefit the environment reduces the number of consumers who make that choice, again raising further the cost burden on each individual who actually makes the choice to buy green power.

*Who will buy an indivisible (non-exclusive) good?*

If society wants green power consumed in large amounts, for example, the consumer-driven approach requires all consumers to meet their needs by buying green power. However, without a public policy in place, in this case a collective decision to share the cost of producing green power, a consumer is likely to refrain from making his or her preference known through purchasing decisions. This is an example of how a public good may not be realized by society if it can only be brought about in a marketplace based on individual initiative rather than on concerted effort where the costs and benefits are borne equally by all consumers.

Consumers may also decide not to wait for others and to allocate financial resources to express their preference. This is already happening to some extent, particularly in California. That, however, does not refute the argument being made here. In reality, the consumer preference for green power may be even greater than what is implied by market demand in states like California. For each customer who decides to pay an extra penny or two for green power, there may be another two customers who desire green power but do not express that desire through the financial mechanism at hand. Arguably, if such customers chose not to pay the extra cost of green power, then this would appear to be a perfect example of the market working correctly: Only those pay extra who are willing, and, thus, the correct amount of green power is produced. However, this argument, is not valid. Again, the hope that “others” will carry the burden of paying for reduced air pollution and other benefits of green power may be tempting and many may simply not possess the knowledge of the market and its offerings to make an informed choice.

Finally, even if all consumers did purchase green power in equal quantities, it would not mean that the “correct” amount of green power was being purchased. Individual purchase decisions regarding public goods usually are not optimal. The individual does not know the marginal cost-to-benefit ratio of the last kilowatt-hour of green power that he or she purchased. The aggregate sum of such individual choices yields no better outcome. It is safe to assume that buying green power right now benefits the environment, but how great is the benefit and at what cost? The only solution to achieving an economically efficient allocation of resources in this context is to make a single “decision” for the entire system at each moment in time. That requires some curtailing of individual choice but that is not a viable option under retail competition. Consumer choice is doing great service to the environment and the objective of introducing non-economic costs into the market as long as some people purchase green power. However, it is a flawed approach and it is simply not enough.

Some form of regulatory policy, either in the form of renewable portfolio standards that are based on economic sound analysis, or traditional integrated resource planning, is also needed. That should serve as a foundation that provides the bulk of the resource re-allocation needed to achieve greater economic efficiency. We should not rely on consumer choice to make the primary impact of efficient allocation of public goods because it cannot, but it could be a valuable supplement where the individual can decide to exceed the basic performance standard of the system by incurring additional personal expense. It is certainly a challenge for any regulatory authority to establish some measure of an efficient allocation of resources through mandatory changes in the resource mix. But they must realize that individual consumers cannot perform that function alone, nor is it fair to ask them to shoulder the economic cost of providing a public good on a voluntary basis.

## **B. The Information Gap**

### *The Consumer May Know His Preference but Can He Define the Product?*

Not only is it unreasonable to expect individual consumers to provide a public good; it is also difficult for them to understand the nature of that public good and how to attain it. How many electricity service customers know the relative benefit of purchasing wind power if it is available? Should the public have to shoulder the responsibility of knowing why a particular generation technology is of greater social value than another one, and then attempt to make informed decisions on purchases? Hopefully, a growing segment of the customer base will become informed on such matters, but it is unreasonable to expect such behavior from most of the public—and that is a necessary condition if regulators are going to transfer the role of resource “planning” to the public.

The lack of knowledge among individual consumers is exacerbated by dissonance in action. Two different consumers may have similar preferences and the willingness to express them in the market. Nonetheless, even though these two consumers possess the knowledge necessary to make an informed choice, they may not act in unison. In fact, for them to do so would be quite unlikely. Their expressions of preference may also be communicated at different moments in time, causing their message in the marketplace to be diluted. Furthermore, a consumer may be discouraged when acting in isolation. For example, a decision to purchase green power one



month, may be followed by a reversal to a generic product in the next month when another brave consumer makes the decision to make his preference known. This could lead to great inefficiency in communicating consumer preferences, dilution of effort and results, and perhaps diminished resolve and stamina on part of the individual consumer who believes his modest attempts to influence the market have carried little or no weight on their own.

### **C. A Proposed Solution**

Instead of replacing entirely the old regulated structure with one of purely market-driven supply decisions, what is needed is a balanced approach where the best aspects of planning to achieve least economic and social cost is supplemented with new mechanisms for exercising customer choice and autonomy. In the past, the problem of unrealized public goods and imprecise or diluted communication of consumer preference has in the past been resolved, in part, through Integrated Resource Planning (IRP). Externalities in the marketplace have been ameliorated through the promotion of environmentally benign energy technologies, and economic efficiency has been improved through demand-side management (DSM). Such mechanisms have allowed “social choices” to be implemented in contrast to the overwhelming reliance on “individual choices” that characterize most markets.

This is not meant to imply that regulations would always be better than the market in bringing about a socially optimal allocation of resources. There are ample examples to the contrary, but not in the electric industry. Table 3 lists some of the strengths and weaknesses of both individual choice and integrated resource planning as a means for attaining the efficient use of energy resources. Integrated resource planning benefits from larger scope and greater access to more complete information. It has a long-term perspective, maintains a steady course toward the objective, and allocates costs equitably. On the other hand, perceived consumer autonomy may suffer as consumers have less opportunity to express preferences, except through the regulatory process. An ideal arrangement would be a combination of the two approaches as described above, where integrated planning provides a solid foundation, while consumer choice acts as a supplementary source of information, nudging the market towards a greater balance of economic efficiency and responsiveness to consumer preference.

**Table 3: Strengths and Weaknesses of Different “Choice Mechanisms”**

<b>Integrated Resource Planning (Regulated)</b>	<b>Individual Purchase Decisions</b>
Strengths	Strengths
<ul style="list-style-type: none"> <li>- Large scope, weighted preferences</li> <li>- Better informed on all issues</li> <li>- Long-term perspective</li> <li>- Inclusive, costs shared equitably</li> <li>- Consonant effort, clear focus</li> </ul>	<ul style="list-style-type: none"> <li>- Consumer preference communicated directly</li> <li>- Perception of high consumer autonomy</li> </ul>
Weaknesses	Weaknesses
<ul style="list-style-type: none"> <li>- Less direct</li> <li>- Less perceived consumer autonomy</li> <li>- Less direct communication route</li> <li>- Uncertainty about non-economic consumer preferences</li> </ul>	<ul style="list-style-type: none"> <li>- Tragedy of the Commons possible</li> <li>- Limited knowledge</li> <li>- Short-term considerations</li> <li>- Driven by economic cost over social cost</li> <li>- Dissonance and low momentum/focus</li> <li>- Consumer autonomy can become diffused</li> </ul>

The conclusion, then, is that the ways in which consumer choice is made possible are critical to a beneficial outcome. However, relying entirely on individual choice in the marketplace, expressed through purchase decisions, is probably going to undermine the potential benefit of greater consumer autonomy. Individual choice in the marketplace must play a role, but it must be supplemented with a method for synthesizing consumer preferences into collective decision-making through the kind of mechanisms that IRP and DSM programs have provided in the past. This combination of approaches would potentially provide an adequate scale of effort to bring about meaningful change in an efficient manner. Thus, substantial regulatory safeguards are needed that are aimed at protecting the consumer and providing for collectively determined environmental and social objectives.

## **8 THE THREAT TO SYSTEM RELIABILITY**

### **8.1 Keys to Accountability: The Reserve Margin and the Capacity Market**

#### **A. How Can Generation Reliability Be Preserved?**

Historically, system reliability has been preserved primarily through the efforts of the regional Reliability Councils, and the voluntary cooperation of the utilities. They have generally calculated reserve margins for each region that are sufficient to bring the probable loss of load down to one day in 10 years. There are two interrelated elements that contribute to reliability. One is the generating capacity that is on hand for meeting load in a given area. The other element is the transmission capability to reach other resources outside this region. Naturally, reliability is affected by the capabilities of each generating unit, its location relative to load and transmission lines, and characteristics of load in an area. The list of relevant factors is extensive, but total generation capability and transmission inter-ties are most important. However, knowing the capability of the system (both local generation and import capability during emergencies) is of little use unless some authority imposes a requirement for the amount of generation capability on that system. Up until now, load-serving entities (LSEs) have generally faced a certain reserve requirement where they must own, or control through contract, enough generation capacity to meet their load plus a given reserve, which is typically around 18 percent of peak load.

In contrast, it is unclear how system reliability is to be preserved in a deregulated market-based environment. Obviously, no one can be forced to build generation capacity after deregulation, though load-serving entities can be required to purchase a sufficient level of reserves. This situation has many people focused on building new transmission capacity (which will remain regulated) as the key to preserving reliability. The general perception seems to be that increased transmission capacity, combined with FERC's Open Access rules, will improve reliability and support competition by giving competing generators access to more markets that previously were served by single utilities. Some might suggest that improved transmission capacity and access alone is sufficient for maintaining system reliability, and that required reserve margins are redundant. That approach, however, seems very risky. The clear accountability that the old system imposed on LSEs will be lost in the competitive market if required reserve margins are abandoned. The following discussion is aimed at explaining in some greater detail the relationship between deregulated capacity markets and the required reserve margin, and why a reserve margin is still needed in a competitive market.

#### **B. Why Do We Need a Required Reserve Margin?**

The purpose of the required reserve margin is to maintain system reliability. It is necessary for load-serving entities to have sufficient capacity, either by ownership or by contract, exceeding their average peak load in any given year, so that unscheduled outages or unusually high peaks in demand do not cause a disruption of service. If a required reserve margin were not imposed on the market, supply would likely fall short of demand much more frequently than the generally accepted standard, which is defined as the probability of lost load (blackouts) not exceeding one day in 10 years.

Having a required reserve margin is the conventional approach under cost-of-service regulation. Would competitive markets not automatically recognize this need to maintain adequate system reliability and supply the necessary capacity at an economically efficient price?

There are actually two questions, then, that need to be addressed. One question is whether or not competitive generation markets, in the absence of reserve requirements, would provide the same reliability as we are accustomed to under regulation. The other question is whether this reliability, if provided to current loss-of-load standards, would come at a higher or lower cost than under regulated rates.

*Will reliability be preserved by unregulated generation markets?*

The first thing to recognize is that an adequate reserve margin will not necessarily be a constant in percentage terms. A current required reserve margin of 20 percent somewhere in the country may drop to something like 17 percent in a few years, as more new gas-fired generating units are built that are inherently more reliable than older units, and, therefore, cause average reliability in the system to rise. As a result, fewer additional units, above peak demand, need be maintained to preserve the same level of system reliability. On the other hand, if demand grows while the configuration of the transmission system basically stays the same, then relatively more generation when compared to peak loads may be needed. The key issue, then, is not the size of the reserve margin itself, but the degree of reliability it provides. In light of this, the question of maintaining reliability under competition can be refined further: Would a competitive market provide the same reserve margin as a regulated structure would impose on itself at any given moment in time, and is there any specific aspect of competitive markets that would allow the required reserve margin to be reduced below what it would need to be under regulation?

The competitive market would only maintain the same level of reliability if it were profitable to do so. Therefore, this service depends on how great the cost of maintaining adequate reliability is, and the ability to pass this cost on to consumers in the market-based price they pay for reliable electricity service value under competition. The trade-off would be with the social cost of poor reliability, which would differ greatly from customer to customer, but would not be paid by load-serving entities that have chosen to only provide a low level of capacity reserves.

The fact that reliability is more critical to some customers than others does raise a certain problem. Reliability is not a tradable commodity that customers can purchase in varying amounts according to their needs, defined by their relative aversion to risk. Rather, it is a *public good*, much like the relative environmental quality provided through pollution standards, demand management, and renewable (generation technology) portfolio standards. This quality alone is the reason why, in the past, the costs of reliability have been socialized, and it is the reason why it is difficult for the marketplace to assume the role of the regulator in this regard. How can a market price for reliability be set when the “product” is not a commodity?

In a competitive environment, then, reliability is one of many aspects of electricity service that the market will struggle to provide. There may well be a number of economic constraints that prevent this service from being profitable after restructuring occurs at its current levels. Ultimately, even if reserve margins continue to be regulated by FERC, for example, whether

reliability is actually preserved will depend on regulators' willingness to maintain standards on load-serving entities, and on penalties for non-compliance. In a pure market context, reliability is almost certain to deteriorate because it is in the economic interest of market participants, other than consumers, to let that happen. This is because lower levels of reserves lead to higher prices, since market power is easier to exercise. Even ignoring market power, lower levels of reserves increase the probability that a particular generation unit will be dispatched and, therefore, that its fixed costs can be recovered.

*At what cost is reliability maintained in a competitive market?*

Setting aside for a moment the debate whether required reserve margins are needed or not, common sense dictates that the current level of reliability, which is defined by the amount of total available generating capacity, would come at a higher (not lower) price in a competitive market than under cost-of-service regulation. The reason for this is the higher risk and therefore higher cost of capital, that the potential investor faces who may consider building the marginal peaking unit in the competitive market. After all, this marginal unit might run only a few hours a year, but even that could vary significantly from year to year. Indeed, in many years, the marginal unit might not be dispatched at all if there is an energy-only market. It might not even be chosen as installed capacity in a capacity market, if there were any excess capacity at all. Instead of the current system where the unit is built to meet calculated reserves, and then (implicitly) allocated appropriate revenues to cover costs and profits, the independent investor in a competitive market would face a much higher cost of capital because recovery of fixed costs would be very uncertain for peaking units on or near the margin. Therefore, the inherent risk would force that generation owner to bid its energy and capacity into the market at a very large premium over what the regulated cost of service would be. Since all fixed costs of the least efficient peakers may have to be covered in just a few hours of the year, with great annual variability in the number of hours the unit would be dispatched, the market bid of that unit may have to be many times higher than the revenue per unit of energy which that plant would receive in a regulated environment. This approach to bidding into competitive energy markets (especially if there were no capacity market) would greatly raise the market clearing price above competitive levels, probably in both energy and capacity markets. Moreover, these higher market clearing prices needed to provide adequate reliability would apply to all capacity and energy (in certain peak hours), raising the average price of wholesale power to customers even more. This effect of a poolco-type energy market raises the market-based cost of providing reserves even more.

In summary, the economic risk of providing higher levels of system reliability in a competitive market may make it very expensive to do so. A generating unit operating on the margin will not have a guaranteed rate of return, as it would under price regulation. Therefore, the risk that it may not be dispatched enough to cover fixed costs will result in one of two outcomes. One option is for the owner to bid the unit's capacity and energy at a much higher price than would be the case under a guaranteed rate of return (regulation) to secure sufficient revenue in hours of actual dispatch to cover the risk of insufficient dispatch. The other possibility is that the unit may never be built, thus sacrificing reliability. Fortunately, the variable cost of new gas-fired peaking units is lower now than it used to be due to higher efficiency, and this implies that those units will be dispatched more frequently, reducing the risk on the margin. However, the last unit that

meets the incremental reserve requirement will always be constrained by risky economics, exactly because it is the marginal unit.

Apparently, then, it will be more profitable and less risky for the market to reduce reliability below current levels, as happened over the last few years in California. Reducing investment in reserves reduces reliability, and the cost of that is borne entirely by consumers through more frequent service disruption, unless a penalty for either lack of reserves or for outright disruption is imposed on service providers. But, unless total reliability is preserved, customers will absorb the impact without the market internalizing that cost. From the perspective of economic efficiency as discussed above, this clearly would be less than an optimal outcome. On top of that cost, a decrease in reserves tightens the supply in the market, which, in turn, creates an upward pressure on prices. Generators may realize their collective interest in letting reserves decline since that is less costly (in the absence of heavy penalties), and generators may see an opportunity to let prices rise. In the end, the customer will pay for all of this inefficiency both in the form of higher average rates and less reliability. In other words, worse service for more money will result, unless the cost of reduced reliability as an economic externality is internalized via appropriate penalties.

#### *Mitigating circumstances?*

On the other hand, there may be something inherent to competitive markets that reduces the level of reserve margins needed to maintain any given level of reliability. Some would argue, including US DOE, that increased trading across inter-ties in the competitive world would reduce the reserve requirement.<sup>30</sup> However, as noted earlier, the argument against this perspective is that as long as the physical characteristics of the system have not changed; namely, neither the amount of transmission capacity, nor the reliability of generating units, the reserve requirement must be the same since the total available power is constant. The fact that there may be a greater number of *economic* transactions on paper (contracts) cannot change the physical laws of energy flows during times of system *emergencies*. Any control area needs a certain amount of internal generating capacity to maintain reliable service, based on the level of its transmission inter-ties to other control areas, whether a de-regulated power market exists or not. A good control area operator will always take advantage of load diversity between its system and its neighbors but, once these possibilities are factored into determining the appropriate reserve margin, further economic transactions can not further reduce the need for reserves.

If the argument would hold that increased economic trading would lower the reserve requirement, some might argue further that this would be enough to bring the marginal unit out of this risky “territory” where annualized fixed costs must be recovered in very few hours. In other words, a lower reserve margin, coupled to price-elasticity impacts on demand, would reflect a more stable supply margin so that the marginal unit would run more hours on average. But this is probably also a false argument. If the margin declines while reliability is maintained rather than reduced, it probably means that the marginal unit is still serving the same handful of hours each year that necessarily falls to the marginal unit to maintain reliability. Again, an increased number of economic trades does not flatten the demand curve (increase the load factor)

---

<sup>30</sup> U.S. Department of Energy, Office of Policy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, (May 1999), page 91.

like increased elasticity of demand effects would do (see below). Therefore, the marginal peaking unit should run about the same number of hours each year, regardless of trading frequency. If the marginal units were running more hours, it would probably mean that supply and demand are much too tight.

One often-mentioned and promising aspect of competitive markets for electricity services is the possibility of increasing the elasticity of demand among electricity consumers due to the “transparency” of market prices. If consumers could effectively respond to price spikes by immediately reducing demand, the load would be flattened during times of highest demand. For those who argue that required reserve margins are unnecessary, the reasoning could be that demand might decline just as fast as a system emergency drives prices up. But this would be wrong. The demand would still need to be measured, and subsequently, the required reserve margins would be recalculated for a lower level of demand, reflecting the lesser extremes in demand fluctuations. However, even with a significant amount of demand responsiveness, a required reserve level for a somewhat lower level of demand would still be required.

### **C. Why Do We Need a Capacity Market?**

#### *The purpose of the Capacity Market*

The issue of whether or not a separate capacity market is needed where an energy poolco has been established is proving to be quite controversial. Of course, the primary objective of having a capacity market in place is to ensure that sufficient generating capacity is available to serve the electricity demand. The purpose of the capacity market is to clear surpluses and deficiencies of capacity among load-serving entities, whether on a seasonal, monthly, or hourly basis. All capacity that was not already allocated through bilateral contracts could be bid into the capacity market. Those LSEs that are short on capacity in any given hour, day, or month will automatically be charged the market clearing price for capacity in that timeframe. Those who have excess capacity will receive the clearing price if they are assigned to load or reserves, which is done in an ascending order of bids. This purpose of the capacity market is closely linked to the reliability issue and the required reserve margin. It would probably be impossible for LSEs to exactly meet their reserve obligations without having such a spot market which would allow for adjustments to be made to account for various contingencies, and to prevent capacity withholding from the overall market.

A second, but related, purpose of the capacity market is to communicate to the market when, and how much, new capacity to build. The capacity market, which deals with megawatts of capacity, would relieve the energy market, which clears megawatt-hours, of the burden of signaling the need for capacity additions. Ideally, the capacity market prices would just equal the annual fixed cost of a new peaker net of any fixed costs for the peaker that might be recovered in the energy market. In turn, a competitive energy market should be content to produce prices that closely resemble the short-run marginal cost or variable cost (fuel cost) of generation. If the capacity market is working properly, there should not be any need for high price spikes in the energy market, up to a level of many multiples of variable cost, to signal the need for new construction.

### *Two different market models*

Some might argue that a competitive market is not fully autonomous, thus somehow flawed, as long as a regulatory authority imposes a capacity requirement. Therefore, the argument might be, the energy market should be allowed to express shortages through severe price spikes which would quickly prompt response in the form of new entry. The need for a capacity market would vanish. Alternatively, as we suggest here, a deregulated wholesale market needs a capacity market to indicate a clear price-point for new capacity, rather than potentially enormous but erratic swings in energy prices that are hard to translate into a clear signal for market entry for new capacity. There are several examples of each model. California has not relied on a capacity market, while having one has been a cornerstone of the PJM power market. New England is now abandoning its capacity markets due to problems with market power. However, New England is maintaining a required reserve margin that will have to be met through the bilateral contract market, at least temporarily. The difference is that areas with capacity markets impose a capacity obligation on all LSEs, and they clear deficits and surpluses of capacity independently from the energy market. Since California did not even establish a reserve requirement when the wholesale market was deregulated, that may be the main reason for tightening demand and supply there. The California experience may be an indication that, left to its own devices, an energy-only market will tend to tighten supply up to a critical level, driving wholesale prices (and eventually retail prices) well above long-run marginal cost, and sacrificing regional reliability as well. It is important to note that FERC, in its November 1, 2000 order, has just tentatively ordered the California ISO to establish a regional reserve margin.

An alternative to establishing a formal capacity market is to maintain the capacity obligation (including the reserve requirement) but let LSEs and generators allocate capacity through bilateral contracts only. The system operator would not provide a clearinghouse for capacity like a monthly or hourly capacity market. Nonetheless, the system operator would have to monitor LSEs for compliance, and issue penalties for failure to meet obligations. When a capacity spot market is in place, it is essentially designed to clear trades among those who are either short or long on capacity and, thereby, supplement the bilateral market which handles most capacity arrangements.

### *More Benefits of Capacity Markets*

If the full costs of meeting demand in any given hour were reflected in an energy market alone, it is entirely unclear what the cost of providing capacity in that hour would be, and who would bear that cost. More importantly, the compensation for providing capacity would be entirely indiscriminate, as all units would receive the full energy market clearing price during peak hours, including the premium paid for supplying reserve capability (at least in a poolco-type energy market). If a capacity market were also in place, particularly one that distinguishes between long-term and short-term capacity commitments, including separate ancillary reserve markets, probably only the units that were chosen as reserve units would fetch the clearing price in that market. The presence of separate markets for different services (i.e., energy, installed capacity, and reserves) may, therefore, secure substantial savings for consumers, as well as make the market prices more transparent as to which service one is actually paying for.



Finally, the inclusion of capacity markets allows for the possibility that bids into energy markets could closely approximate variable cost, as they should in a competitive market. As a result, monitoring for market power would also be facilitated, since bids reflecting market power that were well above variable costs could not be hidden under the pretext of fixed-cost recovery over and above variable-cost recovery. However, experience thus far in markets like NEPOOL demonstrates that energy markets will “frequently” clear well above short-run marginal cost despite the presence of multiple capacity and reserve markets. Having a capacity market would also make it easier for system operators to look for the effects of market power on the capacity side of the market. If the system operator does not maintain a market for capacity but only imposes a capacity obligation, the price and availability of capacity in the informal bilateral market would be much harder to discern. Therefore, it would be difficult to even identify potential capacity withholding or unreasonable prices, and it would be very difficult to actually do something to prevent the exercise of market power in such informal capacity markets.

In summary, we believe that capacity markets deliver certain benefits:

- Capacity markets allow for the proper allocation of costs and revenues between the energy and capacity markets, and provide more unambiguous price points for new market entry.
- Relying on energy markets alone increases the risk of not recovering fixed capacity costs, inviting another large risk premium to be introduced into wholesale prices.
- Capacity markets facilitate the monitoring and mitigation of market power, both in the capacity market and in the energy market.

#### **D. The Advantage of Simple Markets with Long Time-frames**

Having established the need for a capacity market of some sort, the question arises as to whether it is necessary to maintain multiple markets for capacity and ancillary services. Again, the primary purpose of the capacity market is to guarantee that sufficient capacity is available to meet peak demand. A secondary purpose is to provide for the appropriate allocation of costs once the capacity market has cleared, and the system operator knows exactly which market participant was a net purchaser and who was a net seller of capacity in any given year, month, or hour. These objectives are probably served by the combination of having a required reserve margin and a single capacity market that is cleared only once a peak season or once month, at most, to reduce price volatility. It is not that, at least initially, ancillary services shouldn't just be provided on a cost-of-service basis. For example, market operating rules could govern which units are used to provide spinning reserves, with cost-based reimbursement for the relatively low marginal cost of doing so. It is important to understand that all possible markets, such as markets for each separate ancillary service, do not need to be established at the very beginning of restructuring, especially until the behavior of the more important markets such as energy and capacity becomes well understood.

The advantages of reducing the number of capacity-related markets to a bare minimum are greater efficiency, lower transaction costs, and less likelihood of market abuse. It may be worth sacrificing the potential for greater pricing accuracy expected from segmented capacity markets, if that accuracy comes at the cost of greater transaction costs, possible inconsistency in market

clearing prices, and increased market power. Multiple capacity/ancillary service markets could also lead to implicit double-counting of costs in prices. A greater number of separate capacity-related markets may increase instances of speculative and strategic bidding behavior between the various markets, causing effective market power to grow while the system operator's ability to monitor and control market power may be diminished due to market complexity. In addition, the actual fraction of the total competitive wholesale electricity prices represented by capacity-related ancillary services may be so small that the potential savings from establishing a separate competitive market for these services may not be worth the potential cost and risks involved.

It is also beneficial to make the time-frame for the capacity market relatively long. Daily markets for capacity, except for making small, last-minute adjustments, seem redundant, and they invite speculative behavior on the part of generators. When the weather forecast suggests that electricity demand may be on the rise the following day, generators will respond accordingly. Prices will rise, not only because supply will likely be tight, but because of the anticipation of being able to squeeze the market. It would be much more appropriate for generators to place monthly, seasonal or semi-annual bids that account for average weather conditions over that period. Prices may also be lower in a long-term market as long-term bilateral contracts improve the economies of providing baseload power. Longer-term capacity markets (longer than a day) will also tend to flatten the price so that the average capacity price may rise in April and October, relative to current levels but decline in July and August. This would generally be beneficial. Most importantly, it would work against gaming behavior during periods of high demand, and the subsequent reduction in market power-induced price inflation would probably far outweigh the risk premium for long-term contracts.

## **8.2 Transmission Planning, Operation, and Pricing**

Transmission access and transmission system expansion have become one of the most frequently invoked topics in the context of the issue of maintaining system reliability. The transmission system has always been an important element for improving reliability because it reduces the need to build and maintain large, duplicative capacity reserves by letting LSEs "share" capacity for this purpose over a larger area, due to load and generation outage diversity. To some extent, increased interconnection is a substitute for more generating capacity to meet reserves because it is less likely that generating reserves will be exhausted over a larger area at any given moment when a larger total amount of resources can be pooled. Therefore, localized generation plant outages do not need to pose as great a threat as they might if interconnection to surrounding areas were limited. Individual plant outages become a smaller fraction of the generation capacity over a larger region. However, this substitution has certain limits. For example, if the entire eastern seaboard is experiencing a heat wave, no amount of interconnection is going to compensate for an absolute limit in generating capacity. Nonetheless, the discourse on reliability seems heavily focused on transmission expansion to facilitate competitive generation markets. What is the reason for this? Quite simply, the regulatory authorities that would impose the standards that are designed to secure adequate system reliability may feel that they have lost their control over generation reserve requirements with the onset of deregulation. For now, it is impossible for regulators to force generators in a deregulated environment to build more capacity to meet appropriate reserve requirements. Thus, they are turning their attention to transmission instead.

### *Regional Transmission Organizations*

FERC has taken the lead in attempting to advance the efficient and fair planning and operation of transmission systems by promoting Regional Transmission Organizations (RTO) in FERC Order 2000. The purpose is twofold. First, the system must be operated in a way that secures open access in accordance with FERC Order 888. Second, RTOs are meant to deliver greater economic efficiency and to secure reliability. Unfortunately, this focus on reliability through transmission is only one-half of the picture, understating the critical link to achieving economic efficiency when planning generating capacity. Nonetheless, independently governed RTOs, with control over the operation and expansion of regional transmission systems, have the potential to provide non-discriminatory access to transmission, and to reduce average transmission rates through efficiency improvements. This would diminish transmission-related impediments to robust competition in deregulated wholesale and retail markets for electric energy and ancillary services. The structure of the RTOs to come is still under consideration. Of course, independence must be the hallmark of RTOs. Without it, RTOs will fall far short of their potential to provide non-discriminatory access and efficiency improvements. This independence and strength of an RTO will be the only line of defense against market power in both the transmission system and in any power markets operated by the RTO.

Over the years, we have emphasized the need to think of transmission planning, pricing, and operation as three interacting, but separate, functions. However, in the search for market-based solutions for improved efficiency in the electric industry, the three functions often become blurred, particularly when market-based *pricing* for transmission is assumed to be able to address all key issues in the planning and operations area as well. Transmission planning needs to be of sufficient regional scale to improve economic efficiency, uniformity of pricing, and provide a reasonably equal footing for market participants. At the same time, some claim that adequate incentives may need to be provided for private investment in transmission lines. The challenge is to know how to integrate planning functions with the role of private investment. What is the purpose and scope of each, and how are they reconcilable? The unbundling of services in the electric industry and the establishment of markets for some of these unbundled services, has left regulators with a significant dilemma. Unfortunately, FERC is only looking at one-half of the picture when it focuses on transmission alone as a potential solution to the reliability issue. Ultimately, a mechanism will have to be established to ensure that all RTOs do true least-cost planning to consider all relevant economic trade-offs with generation and DSM investments as well, before new transmission system upgrades are approved so that the transmission system is not overbuilt.

### *RTOs, least-cost planning, and the environment*

Ultimately, the successful development of RTOs will pivot on the delicate balancing of market solutions against the planning of the transmission system by a state or federal regulatory authority. Some form of a pricing structure may be set in place that communicates to investors in both generation and transmission what the scale and location of the most economically efficient projects may be. But the success of such a pricing structure depends on the scope of information implicit in the market price. Unfortunately, it is all too easy for a pricing mechanism for transmission to miss some of the most important cost considerations, particularly social and

environmental costs, and result in actions that overlook least-cost options from a system-wide, or social cost perspective.

Thus, it would be impossible for an RTO to come up with an adequate planning strategy if the cost and potential location of generation is left outside the equation. This is particularly true in the context of non-hydro renewable energy. Wind energy, for example, can provide significant social benefit by reducing pollution, but it could, in some instances, also serve as a distributed-resource alternative to increased transmission capacity. It may also be the case that increased wind generation might call for more transmission capability to bring that power to load centers, but that is exactly the kind of question that integrated resource planning or least-cost planning must address. Otherwise, a valuable option may be overlooked, resulting in a sub-optimal allocation of resources, both economic and environmental.

Wind energy is also likely to be at a disadvantage relative to other generation technologies due to the emerging market structure for firm transmission capacity rights. The greatest drawback for wind power in this emerging transmission market environment is the low capacity factor inherent in the technology. Some remedies have been suggested like “banking” of the intermittent resource by the local LSE, whereby they would back down fossil-fueled generation to accommodate wind generation. However, because wind energy is intermittent and weather conditions cannot be predicted with absolute certainty, wind generators will always shoulder a huge risk if they have to compete with other generators for firm transmission rights. Wind generators would consistently be purchasing either too much or too little transmission capacity, which translates into higher costs to them for each kilowatt-hour sold. Even with perfect foresight, wind power would be at a disadvantage because some transmission rights would have to be secured in the short-term markets where prices would presumably be higher than for the type of long-term firm transmission rights that baseload coal power could take advantage of. In a world where market prices for transmission help determine which resource gets dispatched, it is inevitable that wind power will suffer.

The solution probably lies in one of wind’s greatest asset, which is the fact that wind power has zero variable cost. The principle of least-cost dispatch, which pool operators have adhered to in the past, dictates that resources should be dispatched in the order of variable cost. But because of the relatively low capacity factor, wind is not in the favorable position that hydropower would be (another zero variable cost resource), and certainly faces a sizeable market barrier in the form of higher transmission costs per kWh. Therefore, the RTO rules should be designed so that the resources with the lowest variable cost should be dispatched first, at least for renewables, not because that is preferential treatment for wind, but because that rule ensures the lowest economic and social cost of generation for everyone, and the objective of enhanced economic efficiency is served. This should apply in either a bid-based pool, or in a traditional power pool. The RTO should also make the necessary transmission pathways available when the wind power is dispatched automatically, even if other contracts have to be interrupted.

Thus, in our opinion, the first principle should be that the RTO should operate the transmission system based on least variable cost (or bid price for energy). The cost of transmission, which has no significant variable cost component, could then be allocated to load-serving entities after the fact so that it would not distort in any way the variable cost dispatch of generation. This is the

way that FERC used to charge for transmission. Also, transmission pricing should be changed from being a one hundred percent demand charge to having an energy-based price component. While the costs of transmission grids are basically all fixed costs, the design of the grid does not, as some might think, depend solely on being able to meet annual peak load. The overall energy flows in off-peak periods also impact the design of the transmission grid and, therefore, some of its costs should be priced on an energy basis.

There is no clear advantage to having markets for firm transmission, and many disadvantages. Specifically, contracting for transmission rights should be eliminated, as they would no longer be needed. Contracting for transmission rights is economically inefficient as it implicitly converts the fixed investment costs of transmission into variable market-based prices, thus favoring generating resources with the highest capacity factors. It also completely ignores environmental costs, and can help coal power to overcome the cost of emissions controls and quotas, and, thus, can have negative environmental impacts.

In summary, transmission *planning* should be directly affected by the rules for system *operations* (defined by the principle of variable cost or energy bid dispatch), and by a transmission *pricing* structure that was cost-based rather than market-based. With this approach, planning would account for the need to bring zero variable cost resources to load whenever available. This would have many benefits; for example, this would ensure that renewable power would have an appropriate place among other generation technologies—not preferential treatment, but a fair one that helps to deliver an economically efficient mix of resources to load.

## **9 THE RESTRUCTURING EXPERIENCE SO FAR**

### **9.1 Economic Efficiency**

#### **A. Economic Efficiency During the Transition period**

While increased economic efficiency was a major motivation for many supporters of electric industry restructuring, it is almost certain that restructuring has decreased economic efficiency in the short term. This is primarily because of the huge expenditure that most stakeholders are spending on transition costs. If some utilities thought that the regulatory costs of integrated resource planning were too high, then we are quite sure that the regulatory costs of restructuring will be vastly higher during the first decade, at least. Of course, electric ratepayers may not pay many of those costs directly, but they are still a major source of overall economic inefficiency in the economy. In a sense, these transition costs are an investment in the future that may or may not pay off.

One reason that transition costs have been so high over the last few years is that the technical and policy issues raised by restructuring have ended up being far more numerous and complex than anyone anticipated. The underlying reason for that, in our view, is that there was a valid reason why most utilities in the US were vertically integrated in the past; they were probably more economically efficient than would have been implied by other industry structures. Disentangling the complex web of services and functions that vertically integrated utilities have performed in order to unbundle and restructure the industry is very difficult. Even certain activities that used to be performed voluntarily between utilities, such as the maintenance of system reliability, has now become much more contentious as different economic stakeholders begin to understand the economic benefits or dis-benefits of various operational issues and rules.

One key question that arises is whether or not we have tried to marketize too many utility services and functions, or at least whether we have tried to change the industry structure too quickly without having a clear idea of what the final structure should look like. What we have learned so far in attempting to marketize certain functions of the utility business, such as developing open access to transmission capacity, is that one may need to develop so many rules governing markets in services like transmission capacity rights, that the resulting markets may not be capable of being competitive or fair. Sometimes cooperative arrangements between institutions where there are only weakly competing economic interests work better than when arrangements become highly competitive, as in transmission. Thus, the conclusion as to whether services like electric transmission have become more economically efficient during restructuring thus far, is often in the eyes of the beholder.

Specifically, it is very unlikely that utilization of the transmission system will ever become more efficient than it was prior to restructuring for the regions of the US that were previously organized into tight power pools like New England, New York, and the PJM region. This conclusion follows from the fact that a tight power pool, if run well, is already operating at maximum economic efficiency. In fact, that is true for electric generation as well as the transmission system. A power pool that is centrally dispatched in a least-cost manner based strictly on the variable operating costs of each generating unit, subject to transmission constraints is, by definition, operating in the least costly way possible. It can not be run more efficiently just by marketizing transmission and

generation separately. Any other system of operation will be less efficient, and, therefore, more costly to society and ratepayers. That is because dispatching a power pool subject to transmission constraints is a relatively simple mathematical problem to solve, and there is just one solution. Setting up bid-based power pools with congestion cost pricing for transmission can only serve to increase costs. The mathematics are clear on this point. Whether the additional costs are worth incurring depends, obviously, on whether or not additional savings are realized in other aspects of the generation markets.

However, the major other cost component of electric generation that must be considered when measuring economic efficiency, in addition to the variable costs of plant operation, are the capital investments in power plants. There, too, the pre-restructuring regulatory tradition had developed IRP as a means of helping to insure a high degree of economic efficiency when deciding what new generating plants to build. Whether the existence of various fragmented markets for energy, capacity, ancillary services, transmission, etc ends up more successful than IRP at yielding an economically efficient electricity industry in the long run is, of course, yet to be seen, but we are very skeptical.

## **B. Efficiency in the Long Run**

One thing that we do know about long-term economic efficiency, is that unregulated markets may not perform well in optimizing long run capital investments, because their time horizon for profitability is shorter than for regulated industries. This point is, of course, closely related to the fact that the cost of capital for unregulated industries is higher, and, therefore, their discount rate is higher. In addition, unregulated businesses typically have internal rates of return hurdles for key investments that substantially exceed their external cost of capital. If this is true for new investors in electric generating plants, then the net social costs of a restructured electric industry might easily be higher than those of a regulated industry, due to the fact that the unregulated generation markets will lead to economically inefficient outcomes.

Many restructuring advocates claim that electricity prices will fall due to restructuring because better management at power plants and other locations will cause labor costs to fall relative to these costs under regulation. The implicit implication is that regulated utilities have little or no incentive to keep labor costs to a minimum because these costs are just passed through to ratepayers. The assumption is also made that these lower labor costs will lead to higher levels of economic efficiency. However, this argument raises two separate issues.

The first point in response to the above argument is that due to regulatory lag, utilities do have strong incentives to reduce costs between rate cases, because if they do they can keep the difference as profits. Secondly, there is a subtle issue as to whether reducing labor costs always does make society more economically efficient. Clearly, getting more work measured on a physical basis out of each work hour makes society more efficient, though there is a fairly clear limit on labor productivity for any given job at which point a worker will become too stressed. However, just reducing the pay for a given worker, even if that worker performs that same amount of work, is not really an efficiency improvement, even though doing so might appear to increase economic efficiency if the cause of the increase is not known. Basically, paying less for the same work is just greater exploitation of workers. Thus, if restructuring advocates believe that electricity may get

cheaper under restructuring because it will be easier for independent power producers rather than regulated utilities to hire non-union (and, therefore, lower paid) workers to operate power plants, that is not what we would consider to be an increase in economic efficiency.

Looking back over the history of some costly mistakes like the imprudent push to construct large nuclear generating units in decades past, the argument is often made that deregulation will place the risk of such mistakes on the shoulders of shareholders. Consequently, ratepayers will be shielded from these excessive costs, and accountability for imprudent investments will be assured. This is largely a false argument. Any prudent investor should be aware of the risks involved when contemplating construction of a new power plant, and should insist on an estimated rate of return that would compensate him for that risk. In other words, the investor would come out even *on average* (the average being the net outcome for the industry as a whole, which is the sum of all returns). This has already been discussed above as the additional risk premium that must be a part of future electricity rates in a deregulated environment where a set rate of return is not guaranteed. Prices, then, will also tend to be higher on average due to the higher cost of capital when rate of return is uncertain. Therefore, the total social costs of electricity service, ultimately borne by consumers, could easily rise, even though accountability for risk is theoretically transferred to investors. Capital markets could even over-react to the new investment risk environment by raising the ROE for generation investors even further than the actual risk will end up justifying.

## **9.2 Market Prices and Market Power**

Ultimately, the success or failure of the effort to restructure the US electric utility industry probably depends on whether the wholesale electricity markets can be made workably competitive. Even if they can be made workably competitive other fatal flaws may crop up, as we have discussed above relative to trying to unbundle and marketize all utility functions. Yet, we see the high potential for the exercise of significant levels of market power in wholesale electricity markets as the most likely stumbling block for restructuring as a whole. Even worse, we already see significant levels of market power affecting wholesale prices in the electricity markets established to date. Once much more electricity is generated using natural gas, market power in the electric markets may also spill over into natural gas markets, causing additional problems for consumers as these two unregulated markets interact.

Several things alarm us about current directions in attempting to establish competitive wholesale generation markets. Firstly, little thought seems to have been given to the strengths and weaknesses of alternative market structures prior to setting up these new markets. For example, little thought was given to the potential interactions between energy and capacity markets, and how to structure each. The effect of this rush to establish markets is that every one of the four formal power exchanges that has been made operational thus far is structured differently. Furthermore, each seems to be trying to fix problems independently of each other, and FERC does not have a clear set of policy prescriptions that it is willing to impose on all markets. Finally, the potential for the exercise of market power in each possible structure has yet to be thoroughly explored analytically. Our concern, then, is that different parts of the US may get locked into different wholesale market structures for no good reason. Yet, these structures may be hard to change later without generation owners complaining that they made their investment decisions based on one set of market rules, thus making it unfair to change the rules.



## **A. The Rising Spot and Forward Market Prices**

As soon as the formal power markets opened, we began to see the impact of market power on wholesale electricity prices. This has been true in California, NEPOOL, New York, and PJM, especially on hot days when electric demand has peaked. Both the two main mechanisms for exercising market power, capacity withholding and multi-lateral strategic bidding have been prevalent. In fact, market power has increased the wholesale price of electricity to such an extent that forward prices for power for the summer of 2000 were so high that no market participant was willing to serve large unregulated retail customers in Rhode Island or Massachusetts at a price less than the standard offer. Thus, in late spring 2000, many large commercial and industrial customers who had left the standard offer service in the prior year or two, rushed back to the regulated default service in order not to pay market prices for power. Ironically, many of these customers were the very ones who supported electric restructuring in the first place. In addition, studies of the California energy market showed excess profits of upward of \$800 million per year due to market power in 1999.

Market power impacts have also been apparent in the ancillary service markets in addition to the capacity and energy markets. Market power in the installed capacity markets has led PJM to make several changes in their market rules since the market opened, and NEPOOL has already eliminated the operating capacity market, and the installed capacity market. What impact these changes will have on regional reserve margins in the long run, is not clear. In addition, price caps are still in place in several of the energy and capacity markets in an effort by FERC to limit the negative impacts of horizontal market power in wholesale markets. In summary, no region has yet discovered how to create workably competitive wholesale markets, and as the summer of 2000 concludes, things seem to be getting worse, especially in the California and the informal Western power markets. Wholesale prices seem to be stuck at very high levels. Rolling blackouts have struck California again, and the California Energy Commission has warned of the potential for more severe regional blackouts over the next few years.

One question which arises in considering the potential downside of restructuring is, to what extent will the behavior of wholesale markets translate into undue price discrimination (as opposed to reasonable price differentiation) at the retail level? The problem in finding out the answer is closely linked to the fact that no region has workably competitive retail markets yet. Thus, on a long-term equilibrium basis, we do not know to what extent undue price discrimination will occur in the future. However, price discrimination is quite likely to occur in retail electric markets just as it persists in retail telecommunications markets today. Customer inertia is, of course, one of the factors that allow market power to be exercised in the form of undue price discrimination. As we will discuss below, providing regulated standard offer rates in perpetuity might be a way to solve this problem, but it is certainly not in the spirit of creating competitive retail markets.

## **B. Three Recent Examples of Market Power**

While few people may need to be convinced any longer that market power will be a problem in wholesale electric markets after the events in San Diego this summer, we present three earlier examples of market power:

*New York Control Area, February 2000*

In late March, the New York ISO filed a petition with the Federal Energy Regulatory Commission, requesting that market prices for 10-minute reserves be suspended and replaced with cost-based bids until those markets could be demonstrated to be workably competitive. The ISO itself had found that the market for 10-minute reserves had “clearly not been functioning as a competitive market.”<sup>31</sup> The market for reserves is separate from the energy market and is designed to procure enough generating capacity for the ISO to respond to short-term fluctuations in demand. Non-synchronized reserves (NSR) are those that can come on line within 10 minutes from a cold start as opposed to spinning reserves, which come from units that are already running.

Prior to January 29, the 10-minute NSR market cleared at between \$0 and \$2.52 per megawatt-hour. Once certain owners of generation realized their hold on the market, those prices started changing. On February 12, the average daily price for 10-minute NSR peaked at almost \$125 per MWh and the day after, the hourly price peaked at \$302 per MWh. The mean price for the month of February was close to \$66 per MWh compared to a mean of just over \$1 per MWh in the previous November and December. The net effect on expenditures was that the total cost of reserves rose from \$6.5 million in December to almost \$75 million in February. It would not be unreasonable to conclude that the owners of those reserve units collected close to \$70 million in additional profits in the month of February due to their market power.

This example of market power was due to capacity withholding. It was made easier by the fact that most of the capacity that could provide 10-minute non-spinning reserves (NSR), or 97 percent, was owned by only three different companies.

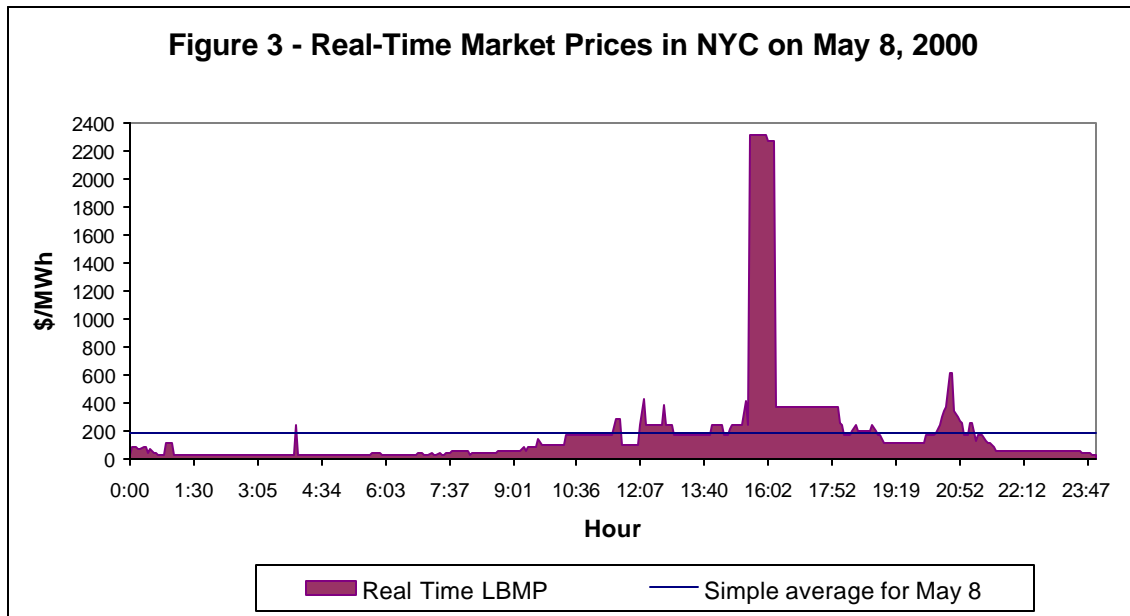
*New York City, May 8, 2000*

May 8 was a warm day in New York City. It was also a good day for those wholesale generators who had energy to sell. Demand was strong and supply was tight. Around 4 PM, the wholesale market price for electricity delivered in New York City rose to over \$2,300 per MWh. If that price had been channeled directly to retail customers in real time, it would have meant \$2.30 per kilowatt-hour for generation alone, as compared to the average full retail rate in New York of about 11 cents per kWh.

Arguably, occasional high prices are useful indicators that prompt generation owners to build needed generation capacity, thereby increasing supply. Some electricity markets, like that in California, explicitly rely on price spikes to accomplish this. However, New York, New England (NEPOOL), and the Mid-Atlantic region (PJM) have separate capacity markets that *should* perform that function entirely, leaving the energy market largely immune to short-term demand peaks, except to the extent that marginal price rises as described before due to market power. In other words, the energy market (where megawatt-hours are traded as opposed to megawatts of generating capacity) should never have market clearing prices that exceed the marginal generating cost of the most expensive generating unit. That means that in New York, any price above \$100-\$150 per MWh, or so, must be the product of market power.

---

<sup>31</sup> Petition filed by New York ISO, *Request of New York independent System operator, Inc. for Suspension of Market-Based Pricing for 10-Minute Reserves and to Shorten Notice Period*, (March 27, 2000).



The effect of price spikes on total revenues in the energy market can be significant. Figure 3 shows the hourly real-time prices in the energy market for New York City on May 8. The horizontal line shows the simple average price for the entire 24-hour period. This average price of nearly \$200 is clearly much too high to reflect a competitive market, because the marginal cost of generation for most hours of the day must have been close to a system average, which could be around \$30-40 per MWh but not much more. The Summer 2000 peak load is estimated at about 30,000 MW.<sup>32</sup> If a price of \$2,300 per MWh prevailed throughout the New York Control Area for just one hour during demand peak, compared to an upper limit for a competitive peak-price of \$150 per MWh, the additional profit attributable to market power, accruing to all generation owners in that one hour, would be \$65 million. Just a handful of hours at such high market prices, scattered throughout the summer (or winter) months, could cost electricity customers in New York hundreds of millions of dollars each year.

*Summer of 1999 in New England and the Mid-Atlantic Region*

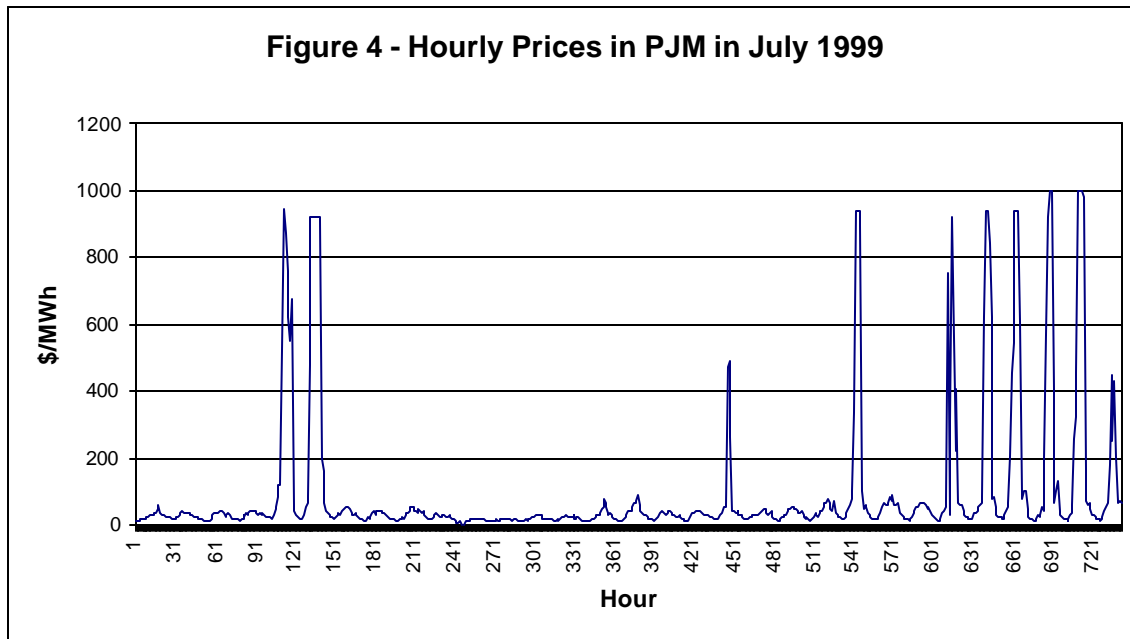
Unlike the New York market, the deregulated power markets for NEPOOL and PJM<sup>33</sup> already have been through the test of summer peak demands. Unfortunately, neither market made it through last summer without some periods of extremely high prices that cannot be explained reasonably without reference to market power.

PJM, especially, saw very high prices in the month of July of 1999. Most days in July followed a stable pattern where prices rise during afternoon peak demand but decline at night. But on ten days, when the weather was hot and humid, prices rose to very high levels. This repeated pattern of price spikes, which were completely disproportional to prices on a normal day, was enough to

<sup>32</sup> NYISO web site: <http://www.nyiso.com/markets/icapinfo.html> (June, 2000).

<sup>33</sup> PJM refers to the power pool that includes Pennsylvania, New Jersey, and Maryland.

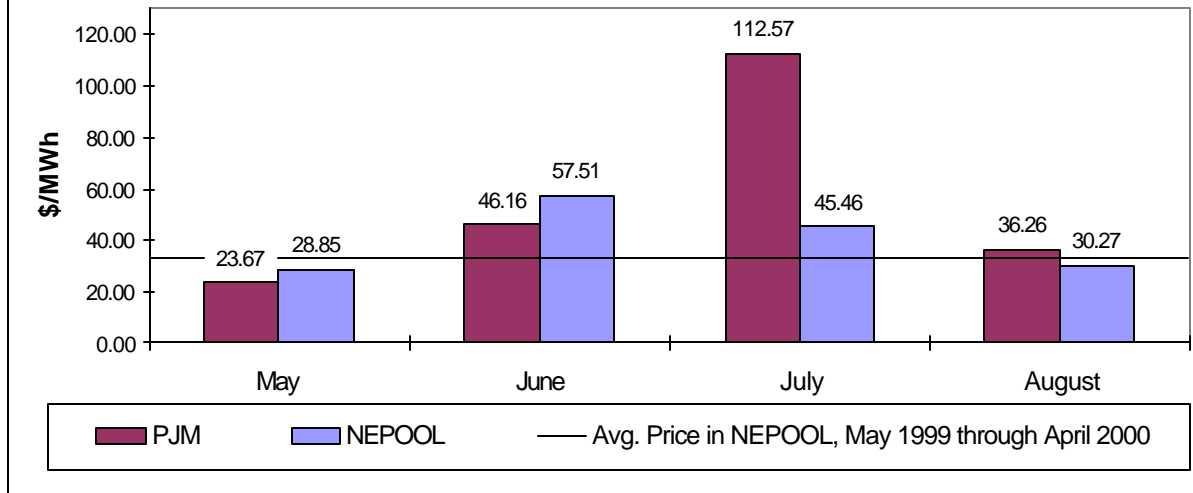
dramatically raise average prices. This could happen even if the spike lasts for only a brief period of time each day. This can be seen in Figure 4.



The load-weighted average price in PJM for the whole month of July 1999 rose to almost \$113/MWh. Weighing prices by demand is important because more energy is traded during hours of high demand, which is also the time when prices are high. Average hourly load (demand) in PJM in July 1999 was 37,000 MW. If all demand in the PJM market had to be met through the energy market, and we assumed that the competitive price would have been about a third of the actual average price, or about \$34/MWh, the additional revenue due to market power would have exceeded \$2 billion in that month alone.

Prices in NEPOOL showed very similar patterns to those observed in PJM but the number and scale of price spikes were smaller. Therefore, the effect on average market prices was smaller but still quite substantial. (Figure 5)

**Figure 5 - Weighted Average Prices in PJM and NEPOOL Energy Markets Summer 1999**



The fact that market power is having an effect on prices in any one of the power pools, PJM, NEPOOL, or New York which lies between the two, has significance for each of the other adjoining power pools. Even though these are separate control areas, energy is traded between them on a daily basis. When market prices rise in one area due to market power, prices in the adjoining area will tend to rise as well, because generators can normally export their energy to customers who are willing to pay a higher price in a neighboring region. While the availability of power for import will tend to suppress market power in one control area by increasing supply in the face of higher prices, the same mechanism will raise prices in the area that is exporting the power. This will tend to equalize prices over a larger area but also make everyone vulnerable to market power. When large operators in these markets decide to merge, such as Con Edison and Northeast Utilities, it is their reach in this larger market, which encompasses many control areas, that makes large-scale mergers a formidable threat to competition. We will now turn to this issue.

### **C. The Experience with Divestitures**

A long-term and potentially fundamental flaw in the attempt to restructure electricity markets is the tendency of the owners of generation, as well as transmission and distribution system owners, to merge. Thus, while many regulators had hoped that one purpose that the divestiture of utility power plants might serve would be to diversify the ownership mix of generation in the newly deregulated power markets, often this did not occur since existing plant owners have bought up many of the divested units. Also, new owners of electric generation are often attempting to acquire ownership of the divested units. The problem is that neither state nor federal regulators have made much of an effort first to quantify the potential harm to regional prices as a function of who merges with whom, nor have they done much to protest proposed mergers on market power grounds. An additional problem is that the FERC/DOJ/FTC methodologies for analyzing the potential market power implications of mergers are very weak. In particular, the archaic use of the HHI index as the major

indicator of potential market power problems has allowed several problematic mergers to take place when a more robust market power analysis would have raised significant questions. While FERC has promised to develop behavioral methodologies rather than simplistic structural methodologies (like the HHI approach) for evaluating the potential for generation owners to exercise market power, they have not applied these new methodologies to actual merger cases yet.

The long-term problem with divestiture is that even though it may tend to provide the appearance of helping to deal with the market power problem, it may, in actuality, make things worse. This will be particularly true if the concentration of ownership in a region begins to increase once the first owner of divested plants re-sells to existing owners of other plants. This will surely occur assuming that not all plant owners will find it equally profitable to remain in the generation business. In addition, even though many distribution utilities have divested their power plants does not imply that they will no longer have market power in wholesale power markets. These utilities, as load-serving entities, will still continue to serve a large fraction of their former customers under standard offer service through purchased power contracts. They will also be unregulated sellers of retail generation, and may therefore control almost as many megawatts of generation resources through contracts after divestiture, as they did before divestiture. The worst situation relative to the potential for serious market power problems to develop may be in the desert Southwest. Both Arizona and New Mexico are attempting to establish competitive wholesale markets without any divestiture whatsoever, a situation that immediately conjures up images of unregulated monopoly. Given the serious transmission constraints throughout the Southwest where population centers are so distant from each other, it is extremely hard to see how those power markets can ever be made competitive. Certainly, with Public Service of New Mexico and Arizona Public Service continuing to own all the generation that they used to own, if not more, market power issues must move to the forefront of public utility commission concerns in the region.

In conclusion, it is important to realize that even where divestiture has occurred it has not necessarily helped eliminate the potential for market power in the long run to any significant degree, or in any permanent way, since mergers have also been allowed. Thus, new rules and regulations for monitoring and mitigating market power will have to be developed. In fact, until effective rules are developed to deal with the fundamental problem of market power, it might be wise to slow down or stop the divestiture trend before regulators lose any of the control that they may currently have over which entities should be able to purchase generating units currently owned by regulated utilities, and under what conditions.

### **9.3 Consumer Choice and the Standard Offer**

Thus far, the attempts to create competitive retail markets for electric generation have basically been a failure. Even the relatively more positive experience in Pennsylvania does not alter this conclusion for reasons we shall discuss below. Retail markets have thus far failed for both large and small customers, even though it was correctly expected that it would be harder to establish competitive retail markets for small customers. However, while many analysts anticipated that it would be more difficult to establish competitive markets for small customers, especially a market that would yield significant rate reductions for small customers, few analysts understood why this would prove to be true.

A related question, of course, is do consumers have real choices yet in the retail markets? Again, the answer is fundamentally "no", with limited exceptions in Pennsylvania that may also prove to be temporary. However, let us consider the case of California first. Details aside, the retail price for standard offer service in California was basically set exactly equal to the wholesale market price. The problem with this approach to trying to create competitive retail markets in the electric industry illustrates the fundamental flaw in a key argument in favor of structuring, which is that it would be economically more efficient. Unfortunately, almost everyone neglected to realize the existence of the "retail margin" that would make it very difficult if not impossible to accomplish all three of the goals of restructuring simultaneously; lower rates, give 100 percent recovery of stranded costs to utilities, and initiate retail competition.

As discussed above, the retail margin is the difference between the retail and wholesale price of electricity for any given customer, or customer class, that alternative providers of power need to recover in the long run in order to be able stay in business, including a profit. While retail markets are not yet sufficiently vibrant to determine the exact level of the retail margin for each type of customer, it has become clear from both theoretical and empirical considerations that this margin might be quite small (1-2 mills per kWh) for the largest customers, and quite large (1-1.5 cents per kWh) for most small residential customers. The implication of this realization is that regulators in both California, New England, and many others states (again, Pennsylvania being a possible exception) established standard offer rates in a way that could not possibly lead to retail competition, especially for small customers. The reason for this is that they did not set the rates for standard offer service sufficiently high for each customer class. In this light, it should not have been a surprise to anyone when Enron pulled out of developing residential retail markets all across the U.S. Even where the standard offer rates have initially led to what appears to be customer choice, especially for large customers, it is not clear yet that the retail margins being earned by alternative providers are sufficiently high to sustain these providers in business over the long run, especially when wholesale prices rise. Many may have, and may still be subsidizing large customers as well as small customers just to attract initial market share.

Another problem for establishing competitive retail markets is that for many customers, especially small customers, even competitive wholesale prices are a lot higher than most policy makers expected. This is especially true for relatively low load factor customers. For example, the residential classes for many utilities have load factors that average less than 50 percent. As we showed earlier, this implies that once competitive capacity-related charges are spread over relatively few kWh per kW of generation capacity, and once losses are included (which also increase as load factor decreases), competitive wholesale prices for the residential class might often be in the 4.5-5.0 cents per kWh range. This is even true with modest natural gas prices. Higher gas prices, as we have seen recently, would increase that range significantly. If a retail margin of 1.0-1.5 cents per kWh for small customers is then added in, a total retail price of 5.5-6.5 cents per kWh emerges. Since very few standard offers have included prices (without transmission) in this range, we believe that this clearly explains why retail competition for small customers has not developed, and why the level of retail competition we are currently seeing could even shrink. The current level of retail competition could shrink because alternative providers may soon feel a greater need not to subsidize initial market share. It could also shrink in Pennsylvania because higher wholesale prices may cause standard offer rates to bump up against the legislated price cap, causing customers who had left standard offer service to return.

The other main implication of the size of the retail margin for each customer class is that the size of the average retail margin which alternative providers need to collect for all customers may exceed the average administrative and general (A&G) costs expended by the old vertically integrated utilities to perform the equivalent of the same "retailing" tasks. In fact, it is quite likely that the average retail margin for many alternative providers operating in a given geographical region will exceed the average A&G costs of the pre-existing vertically integrated utility. This would be due to the economic efficiencies of being vertically integrated, the lack of marketing and advertising costs now required to solicit customers, and the efficiencies of dealing with all customers in a given geographic region, as opposed to only a portion of those customers.

Subsumed in the retail margin are many of the coordination-type tasks made necessary by unbundling various utility functions that were not even necessary when utilities were vertically integrated, especially those that were part of working power pools or regional holding companies. In addition, regulated utilities never were entitled to make a profit on their "retailing" functions, because A&G expenses were just that, expenses. There were few if any ratebased investments associated with carrying out this part of the business. Initial indications are that investor-owned utilities spent about 5 mills per kWh on generation-related A&G activities. This, then, becomes a baseline from which to measure the long run economic efficiency of the unregulated retail market for power. If the average retail margins turn out to be higher than 5 mills per kWh, as we believe they will be, then this aspect of restructuring will prove to subtract from any efficiency gains deriving from more efficient wholesale markets.

Hopefully, it is now clearer why it was considered "necessary" to set standard offer rates in most states that have restructured below the level that would actually allow retail competition to occur, whether done consciously or unconsciously. It was necessary because the standard offer rate for generation (sometimes known as the "shopping credit") had to be lower than the unbundled generation rate was previously. The previous unbundled generation rate consisted of the "wholesale" portion of generation costs, including the impact of losses, plus the generation-related A&G. The new standard offer rate had to be lower than the unbundled generation rate in order to allow for two items—some amount of rate decrease, and stranded cost recovery charges, if applicable. Given the usually inflated amounts allocated for stranded cost recovery, this combination of factors led to a severe squeeze on either the standard offer rate, or the rate reduction. Rate reductions were deemed to be a high priority politically, because how else could restructuring be justified in the mind of the public, if it did not result in lower rates overall. Thus, rate reductions of 5-10 percent became common, either through legislation or PUC order. What was not made clear to the public was that most if not all of the rate reductions were quite artificial, in that they resulted from a levelization of stranded cost recovery relative to the more front-loaded rate of recovery that would have pertained under a continuation of regulation. Thus, most up-front rate "reductions" due to restructuring will be paid back over time by ratepayers, with interest. Within a few years standard offer rates in many states will be higher than rates would have been if restructuring had never occurred, and this gap will continue to get worse as long as stranded cost recovery continues. Either way, the public has probably ended up believing that the rate reductions achieved have been the result of the introduction of competitive power markets, whereas nothing could be further from the truth.



Another aspect of the question as to whether or not consumers now have retail choice in certain states that have undergone electric restructuring concerns green power. However, even with respect to the fact that many consumers have chosen to buy green power in California and Pennsylvania, things are not so rosy. And the implications of this aspect of choice are not clear for the future. The first problem is that green power markets in California are heavily subsidized by a 1.5 cents per kWh systems benefits charge credit. The result of this subsidy has been that the price of green power offerings has not been much, if any, above the price of regular electricity. Thus, the California green power market does not provide a good test of whether even well intentioned consumers will be willing to pay more for green power than for regular electricity. Secondly, again, some green power providers are probably still losing money, and thus are further subsidizing the product for that reason. This effect likely extends to Pennsylvania. Once profit margins reach sustainable levels, the increased price of green power might lead to a decline in the number of buyers. On the other hand, green power offerings have not even been made yet in many states that have restructured. Presumably this is because it may not be economical for providers of green power to market and service customers in states where an active retail market for regular power has not yet begun.

Another key issue that arises from the creation of standard offer service for those customers who choose not to participate in the competitive retail markets is for how long will standard offer service be available? Obviously, if consumers are forced to enter the retail market in the next few years, then their rates may go up substantially, depending on conditions in the wholesale market. This is especially true wherever standard offer rates were set well below sustainable retail rates.

Thus, most states that have restructured have committed to providing some sort of default service that will have market-based prices. The conundrum is, however, that if the default service is procured through bids from the wholesale market, and if only those costs are charged to default service customers, then the price for generation will be not much more than a wholesale cost not a retail price, and retail competition will still not become possible. In fact, this approach to pricing default service could cause retail competition to come to a complete halt, since not even a large customer should be able to get power for less than a large aggregation of all customers wanting default service could achieve. Thus, unless consumers are forcibly ejected from standard offer or default service into the unregulated retail market, it is not clear how retail competition will really ever get off the ground. However, if this implies large rate increases, particularly for small customers, it does not seem like a politically viable strategy. In addition, if ratepayers experience significant rate increases due to the disappearance of the standard offer as a safety net, then this situation will be further evidence that they have been overcharged for stranded costs. Thus, the future of retail competition is very unclear.

#### **9.4 System Reliability**

Thus far, the restructuring of the electric utility industry in the US has not had a beneficial impact on system reliability. Nationally, reserve margins have been falling for more than 10 years, and they continue to fall. Locally, we have seen rolling blackouts in the Northeast, Colorado, and California during the last two summers. This could have happened for at least four reasons. The first is that just by anticipating the onset of restructuring, many utilities have under-invested in either generating plant, transmission, or both, because they were waiting for the entire regulatory framework to be

clarified in their state or region. The second is that during the transition to completely deregulated generation markets, alternative investors in generation have not yet had sufficient time to bring enough new units online to bring reserve margins back up to reasonable levels. Evidence for this view is that far more new generating units have been announced as planned for the Northeast than are needed. Thirdly, the energy and capacity markets that have been set up to-date have already failed to function properly, and reserve margins will continue to fall in order that market power can be exercised by existing generation owners to a greater degree than before. A similar reason is that in order to exercise market power generation owners have been actively withholding capacity during times of peak demand, and thus less capacity has been available to meet peak load than system operators would have expected given the system reserve margins. Fourthly, where required reserve margins have been mandated by regulatory authorities (or ISOs), they may have been set too low.

What, in fact, has been the cause of the system reliability problems that we have witnessed over the past two years or more. Probably, the truth is "all of the above." If all of the above phenomena have been occurring to varying degrees in different parts of the US, then, again, it is not at all clear yet how restructuring will play out in practice, as more and more generation becomes deregulated in some regions. We do not know yet which market structures might either contribute to enhanced system reliability, or detract from it. However, our analyses tend to indicate that many analysts have been overly optimistic about the quantity of new market entry that will occur where either formal power exchanges or informal bilateral contract markets have been established. And even if there is an initial flurry of new market entry, as in New England, for example, this level of entry may cease for a while, if it all the new power plants do not prove to be profitable, as we are sure they will not be. So, as in most markets, we expect to see significant cycles or waves of new market entry, followed by slowdowns in order to allow the amount of capacity to return to the minimum level of required reserves or required profitability. This may, then, lead to cycles in system reliability, in which good years are repeatedly followed by years of significant unreliability, especially if unusual heat or cold waves correspond with those years of low reserve margins. Whether these cycles will lead to a major national crisis and reaction against restructuring, as some have forecast, is impossible to predict, but that is one of the risks that the country is facing by starting down the restructuring road.

One issue that relates directly to the issue of system reliability under restructuring that has not received much public attention is the issue of who is responsible as a last resort for constructing an adequate amount of generating capacity if this capacity does not result from "market forces," or even from capacity shortfall penalties. Since, as least nominally, FERC is responsible for regulating wholesale electric markets at least indirectly through ISOs, power pools, etc., FERC will have to insure that adequate capacity is built. But, as far as we know, FERC has never played such a role, and most if not all ISOs do not have the authority to order some entity (or themselves) to build new capacity if load-serving entities do not meet their contractual obligations, and are willing to simply pay penalties that the ISO imposes. Presumably, in such circumstances ISOs can raise the penalties for capacity shortfalls so high that the market will respond positively, but correcting a problem could take time, during which blackouts could occur. This issue, then, translates into the issue as to whether or not ISOs will play merely reactive roles in dealing with the important system reliability (and market power and other) issues that will confront them, or whether they will plan ahead and try to proactively intervene with sufficient lead time to incentivize the market to perform "properly".

As indicated above, ultimately problems with system reliability translate directly into market power problems. While market power can be exercised successfully at many times when system reliability is not threatened, it is far easier to exercise when system reliability is threatened. In fact, as we have also stated above, we believe that attempts to exercise market power, such as capacity withholding, have already led to system reliability problems. System operators and ISOs will likely find that they are forced to put a wide array of special rules in place during periods of reliability threats in order to prevent the potential market power impacts from impacting electricity prices to consumers. Many such provisions have already been adopted by ISOs, such as imposing price caps, etc. Unfortunately, the price caps that have adopted thus far are still far too high to dis-incentivize the exercise of market power in most hours. (After all, a price cap as low as \$200 per MWH does little to prevent market power at most times of the year when the marginal cost of the plant setting the market clearing price is only \$30 or \$40 per MWH.) ISOs may need to impose much stricter price caps in the future, such as limiting bidding into the various markets to cost of service, whenever they declare reliability emergencies. However, even when there are no reliability emergencies, market power will be hard to control.

## **9.5 Summary**

So what has the US experience with restructuring thus far implied about the future prospects for restructuring? Will economic efficiency be enhanced? Will electricity markets ever be competitive? Will consumers have real choices that they actually care about exercising? Will system reliability be preserved?

While in the short to medium term maintaining system reliability may prove to be a significant problem, in the long run we have confidence that the relevant regulators and/or legislators will find an appropriate way to protect system reliability. That confidence flows from the perspective that if adequate system reliability is not preserved, restructuring will be stopped in its tracks long before other problems become critical.

What we are not nearly so confident about is that economic efficiency will be enhanced by electric industry restructuring. We see no basis yet for reaching this conclusion, and we see many reasons why the economic efficiency of the electric industry will decline relative to what the continued practice of integrated resource planning, or even just least-cost planning (IRP without consideration of environmental externalities) would have achieved.

## 10 THE POSITIVE IMAGE OF DEREGULATION RECONSIDERED

### 10.1 Refuting the Truisms

Having presented the analyses above, we are now in a position to question or refute the many truisms that have floated around in the restructuring debate for the last six years or so. We will now discuss each of the ten truisms we listed in Chapter 2. Since Section 10.1 necessarily repeats much of the material previously presented but in a different format, some readers may wish to skip ahead to Section 10.2.

First Truism:

*Making separate markets for every possible unbundled competitive service makes sense as a way to maximize economic efficiency.*

The belief in this assumption throughout the regulatory community appears to be extremely strong. Even though economic thinking recognizes the possibility of market failures and the existence of externalities, the belief remains that market solutions are, at worst, the lesser of two evils when compared to price regulation. This thinking has now overtaken the notion of the “natural monopoly,” asserting that even when there are serious structural and technical impediments to efficient implementation of a competitive market structure, it is still preferable to price regulation. The reasoning is that the relevant regulatory authority cannot have as good a sense of the true costs of inputs, and value of goods produced, as a competitive market would. As a result, critics believe that economic efficiency is compromised by regulatory intervention, and prices would, therefore, tend to be either too high or too low to reflect that inefficiency. The widespread, but untested, belief in this truism is, in fact, what precludes regulators from recognizing it as a mere assumption in the case of utility restructuring, and one which is worthy of explicit re-evaluation as evidence as to its validity is gathered.

On the other hand, the increased cost of creating a competitive market for a given product could easily be greater than the relative savings generated by competition, relative to a well functioning regulatory environment. Obviously, examining the relative quality of past price regulation, when combined with integrated resource planning which incorporates full cost accounting, is just as important as questioning the likely effectiveness of competition when markets are created. However, the shortcomings of either institution do not render them useless. Regulators should consider building on the strengths of the existing regulatory system when introducing competitive markets. One outcome of this could be a hybrid design where aspects of regulated DSM programs, for example, are combined with a competitive wholesale energy market, if a workably competitive market can be sustained. However, trying to create a competitive market for billing, or for ancillary generation services, or for transmission rights may just not be cost-effective.

Second Truism:

*It is always in the consumers’ interest to have the freedom to choose the provider of any given service if at all possible, and to be able to do so based on their own individual criteria, including the price and quality of the product. Such choice, and markets in general, are necessary to correctly establish all relevant price signals.*

Consumer choice is certainly important, as mentioned above, as long as the consumer finds value in possessing the choice itself, and as long as there are interesting and important differences between the products offered. Beyond that, the value of having choice is critically dependent on whether it is going to bring about such a significant structural change in the supply of services that either costs will be reduced, or profit margins will be tightened enough to result in a reduction of the overall price to the consumer. However, as noted above, structural change in the electricity marketplace, moving from a regulated environment to a competitive one, may result in higher costs to electricity service providers, especially at the retail level, depending on the product at issue. Also, deregulated rates of return on equity may be significantly higher than regulated ROEs. The luxury of choice at the retail level for electricity may, therefore, come at the cost of higher electricity prices. For example, the administrative and marketing costs of a competitive retail market may well exceed the marginal reduction in production costs generated over time by competition in wholesale markets. In this case, the consumer would attain choice but at the cost of higher transaction fees. If the consumers, in general, were satisfied with the substitution of higher transaction costs for greater choice, assuming for the moment that no other benefits or costs accrued from generating customer choice, this outcome would be economically efficient. Unfortunately, it is very hard to ascertain whether or not this is the case. Consumer choice, in itself, is either brought about by regulatory change or it is not, again assuming that the regulation actually brings meaningful consumer choice. The demand for consumer choice is, therefore, not expressed and generated through the market and, as a result, it will always be difficult to establish whether it is economically efficient to generate choice at the penalty of higher retail prices for electricity.

Competition on the basis of price is only one element facing the customer with choices to make in the marketplace. The relative *quality* of the product, as defined in added value terms, like a higher renewable resource mix and thus lower emissions, could be a valuable choice that did not exist previously. Some consumers would even be willing to pay a premium for such added value. Nonetheless, the option of allowing consumers to express preference for green power, and allowing them to voluntarily pay for such social goods through higher rates, is not limited to a deregulated competitive market. A regulated market could provide the same types of choices by allowing customers to purchase power that has a different resource content than the average supply. In exchange, the customer would pay a higher price that reflects the short-term economic cost of resources like renewables and DSM. The long-term benefits would accrue to all of society, in the same fashion envisioned by the competitive market. Thus, many choices desired by customers may be able to be offered in a regulated environment just as efficiently, if not more efficiently.

Some would claim that there is an ethical problem either way, with increased reliance on a small group of consumers for funding and support for socially benign energy technologies, whether on the supply or demand side. Environmental protection and resource conservation is a public good that should be secured through an integrated approach that shares cost equitably among all electricity buyers, and has the scope and focus to be effective and efficient.

If markets for all potential competitive electricity services were established, with the result being either higher or lower prices, can we conclude that at least the price signals in the marketplace

would be correct? That might perhaps be the result but the cost could be high. The transaction costs might be much higher, for one thing. New price differentiation might shift some cost onto residential customers that they did not have to contend with before. Essentially, the benefit would be ambiguous and “correct” pricing would remain equally ambiguous because the proper allocation of common costs is as much a matter of social choice as it is an economic issue.

While some price signals may be improved, other price signals may be entirely lost under deregulation. Again, the new markets for electricity services are not likely to effectively account for various externalities. The individual consumer cannot possess all the relevant information necessary to integrate externalities efficiently. Most customers would be making their choices somewhat blindly, on an individual basis, without knowing the full system-wide long-term avoided cost of production. Despite growing faith in real-time metering, such metering may not be as effective as centralized demand-side management in controlling load, and thus reducing the long-term economic and social costs of energy procurement. Also, and more importantly, the value of price transparency is often very limited because giving customers clear price signals on a short-term basis will not allow them to consider price forecasts for the lifetime of a potential investment in order to determine its cost-effectiveness. This is an inherent limit in markets which tend to reflect short-term events and take a short-term perspective, because the price signals they generate are often not fully helpful in giving customers the information they need to make important investment decisions over the long run. This is especially true for market mechanisms established to quantify transmission congestion costs. The price signals produced by such a market will change from hour to hour and thus can not possibly be expected to induce market participants to construct a least-cost mix of new generation and transmission facilities from the perspective of a 20- or 30-year planning period.

Third Truism:

*The deregulation of electricity generation services will surely lead to effective competition among generation service providers within a reasonably short transition period, and the need for continued price regulation will disappear.*

When the framework for a competitive electricity market has been established, the desired level of competition can not be a foregone conclusion. Potential new participants in the market face various constraints such as barriers to market entry, some of which may be the direct product of how restructuring is implemented. Another setback to the effective introduction of competition will be the exercise of market power by existing service providers or owners of generation. Market power may result in prices rising substantially above perfectly competitive levels, but it can also allow existing owners and service providers with relatively large market shares to undermine the competition by cross-subsidizing new generating units to exclude new entrants. Measures like the divestitures of generating assets to mitigate horizontal market power do not necessarily solve this problem. The liquidation of generating assets by utilities is in fact an opportunity for a few parties to increase their horizontal market power if it allows them to aggregate significant portions of the generating capacity within a region, which is likely to happen in the medium-long term. Those owners of the least profitable generating units will probably end up selling out to the owners of the most profitable units, thus enhancing market power.

#### Fourth Truism:

*Competition will result in a lower marginal cost for retail generation services and, therefore, lower electricity prices over the long run when compared to a continuation of rate regulation for generation.*

If the above misgivings about the likely and effective introduction of true competition are accepted, one must concede that the assumed pressure to lower marginal costs of new production will largely be absent. More importantly, the pressure to lower retail prices to consumers will be completely absent. Moreover, even if the market turns out to be vibrant and effectively competitive, there is no assurance that such competition will result in a net reduction in the cost of retail generation services. Again, there are three main reasons for this. One has to do with the inherent structure of a deregulated market for electricity. In this new market the net change in economic efficiencies may or may not be positive. Potential improvements on cost due to new generating units replacing costlier units in the dispatch order may be cancelled out by structural cost increases for retail generation services such as marketing and administration. The other reason has to do with the way in which restructuring is carried out, and specifically, the treatment of stranded costs. If care is not taken in establishing a correct level for stranded costs, the associated effect on electricity prices may far outweigh the benefits of competition for electricity services. In other words, the distortion of the retail price resulting from inaccurate stranded cost assessment, either too high or too low, may overwhelm the relative price decreases that competition is expected to generate. Finally, and most importantly, deregulation implies a loss of the benefits of average embedded cost ratemaking. If the long-run marginal costs of new generation are higher than average embedded cost rates would have been, then rates will be higher under deregulation no matter how efficient the markets are.

#### Fifth Truism:

*To initiate retail competition for generation services, it is sufficient to give consumers a credit for the generation portion of their current electricity rate, as long as it is equal to or slightly in excess of the wholesale price of power. Competitive service providers will emerge and provide retail generation services at a price that fits within this margin.*

While this was probably a widespread belief a few years ago, experience shows that this is not true, and theory supports this experience. In the states that have implemented competition for generation services, all but Pennsylvania set the “shopping credit” or the standard offer too low to generate much interest among consumers to switch providers. In California, the average PX price serves as the basis for the customer’s shopping credit. All that a customer has to offer an alternative supplier is this credit, which amounts to no more than the wholesale market price. Unless the consumer is willing to pay something extra to cover any retailing costs, the provider will have difficulty selling the product, with the one exception of green power. In Massachusetts and Rhode Island, the initial standard offer has been widely considered to be below retail market prices, even below wholesale market prices.<sup>34</sup> On the other hand, Pennsylvania showed a much higher rate of customers switching to new providers. This was presumably due to the decision of the Public Utility Commission to set the “price to compare” significantly above wholesale cost of power to cover any unforeseen costs of retail generation services and to provide a strong

---

<sup>34</sup> Edison Electric Institute, *Retail Competition: The Utility Experience in Four States*, (Washington, DC: Edison Electric Institute, 1999) page 18.

incentive for both providers and customers to engage in the market. We now understand that the main problem in getting the retail market off the ground derived from regulators not clearly distinguishing between wholesale and retail market prices. They did not allow for the retail margin when establishing standard offer rates.

Sixth Truism:

*The current transmission system will work equally as well, if not better, in the new competitive retail market, as it did under the regulated utility structure.*

The structure of the transmission system at the time when states embark on restructuring is not inconsequential to the likely outcome. Independent system operators can be established to manage the scheduling and dispatch of capacity and load, and to establish a clearing price in each hour in each market. They can also attempt to reflect transmission constraints of the system in the price of energy (congestion costs) and allocate that cost to the purchasers who cause the constraint. Yet, this approach may not live up to the expectations of a healthy competitive market that has parted with the regulatory environment of the past.

The new market faces structural constraints in the transmission system that are completely exogenous to the framework of the new market, a remnant of the regulated environment. This is because the existing transmission system was initially designed to deliver the services of the utility monopoly based on variable cost dispatch only. When a power market deviates from least-cost dispatch, new constraints will tend to develop in the transmission system. The transmission system was, therefore, conceived around a single central utility at the core, serving the vast periphery of all consumers in the service area. The competitive market is conceived in an entirely different manner that does not follow this core/periphery design. In the restructured market, a large number of generation service providers have replaced the generation function of the old utility, which is now entrusted with distribution alone. These service providers deliver their product to relatively few customers scattered over a larger geographic area (assuming that competition generates an active retail market). The result will likely be the creation of more transmission constraints than before, as well as sizable charges to certain consumers to reflect the cost of those constraints, until and unless the transmission system is upgraded to overcome the problem.

Obviously, a large-scale reorganization and expansion of the transmission system is not a likely outcome. The reason is difficulty in attaining siting permits for new transmission lines, and the uncertainty for potential investors about future revenues for transmission service. The generation service providers cannot compensate for the inefficiencies that the existing transmission system creates for the new market because it is a structural problem, represented by existing poles and lines, and cannot be changed any time soon by maneuvers in the marketplace. In the absence of major changes to the transmission system, and regulated investment in new transmission, compensation for building new lines might require consolidation of assets to emulate the former regulated market structure of vertically integrated utilities for which the transmission system was optimized. This consolidation is already under way, through *horizontal* integration of generation owners and distribution utilities, whether or not the transmission system may be a contributing factor.



Seventh Truism:

*The inevitable reduction in the wholesale price of electricity under deregulation will be consistent with generating a vibrant retail market and convincing a large number of customers to switch service providers.*

Again, as explained above, the short-term standard offer may not be high enough nor the long-run marginal cost of new generation low enough to generate this change. By far the most important component of electricity rates that is subject to competition is generation services. Transmission and distribution remain price-regulated components under traditional monopoly structure of the distribution utility. The cost of generation is generally only about half of the total price of electricity. This fraction is even smaller now than before restructuring began, since the cost of generation has typically been declining around the country in recent years due to the continued depreciation of generation assets at a rate greater than new generation investments have been made. Net of stranded costs, generation services may, therefore, constitute only about 40 percent of the total rate, particularly in areas where total costs are high. For example, in a state where the rate to residential customers is 12 cents per kWh, the “wholesale” generation portion of that rate may be only about 4 cents per kWh. If a competitive service provider could manage to sell generation to the residential class for 10 percent less, which would be a substantial savings, that same reduction would translate into a mere 3 percent reduction in the total rate to the customer, or about four mills. Thus, the potential savings due to deregulation might be small, especially to residential customers. Moreover, the problem is that four mills may not be a large enough savings for most residential customers to be motivated to respond and change service providers. In such a situation, if a 10 percent reduction in total electric bills proves necessary to get customers to switch generation service providers, then a 30 percent reduction in the price of generation (net of stranded costs) would be needed, which would probably be impossible to achieve even under the most optimistic restructuring scenario.

Another reason why customers might be disenchanted with such modest price reductions is the effect on them of the transition or default service price typically available during a transition period, and for some time after full competition has been introduced. Default service is usually either provided by the incumbent utility on a wholesale cost-of-service basis, or it is auctioned to the lowest bidder at wholesale. Because the cost structure for default service is very different from that required to directly service the competitive market for generation at the retail level, the cost of default service would typically be lower than a retail market price for any customer class, even for industrial customers. If all types of customer classes are included, the pool of customers is larger, and the load factor reflects class diversity, while various costs of participating in the retail market such as marketing are absent. The cost of providing default service, and therefore its price, should, then, be very close to wholesale prices. A customer who has the option of such low prices as an alternative to the competitive retail market will probably stay with the default provider forever, unless default service is priced higher by the regulatory authority to encourage retail competition. Thus, whether retail competition is a useful step to take beyond wholesale competition becomes a pressing question if a competitive wholesale market, and auctions for default service, can deliver most, if not all, of the benefits of restructuring without the necessary cost-adders and potential inefficiencies introduced by retail competition.

#### Eighth Truism:

*It is appropriate to mandate rate reductions from the outset of deregulation to reflect the eventuality of lower market prices for generation, and to provide consumers an immediate benefit from the inevitable effects of deregulation and retail competition.*

Strong faith in the ability of the marketplace to deliver lower prices to consumers in the long run has prompted most regulators to integrate initial rate reductions into the earliest stages of restructuring. From the consumer's perspective, this is very beneficial if it reflects true cost reductions that are likely to occur over the long run. On the other hand, if that is not the case, near-term rate reductions may ultimately hurt the consumer. First, depending on how stranded cost recovery is handled, the utility would eventually collect the value of this rate reduction through higher rates after the transition period is over. Secondly, by focusing on initial rate reductions, regulators may yield too much to the utilities on negotiations on stranded costs by allowing excessive stranded cost recovery charges for too long into the future. Thus, the excess stranded costs could increase ratepayers' costs on a net basis in the long-run. Such arbitrary rate reductions might also act as a barrier to market entry by new electricity service providers. It might also dull the consumers' interest in seeking further rate reductions through competitive markets if generation prices have already been reduced by a much wider margin than retail competition alone could likely generate in the near future. The most cynical of skeptics might argue that such reductions seem less focused on consumer interest and more geared to "sell" the idea of restructuring to the public, in the absence of any concrete basis for the many assumptions made about the economic benefits expected to accrue from deregulation later.

#### Ninth Truism:

*The retail default service is merely a transitional necessity and should be phased out over a period of a few years, because the competitive retail market will successfully provide service for all customers at rates that are lower than before restructuring came into effect.*

In light of the many uncertainties about the actual viability of deregulation in bringing consumers lower prices, it might be prudent not to preclude the possibility of allowing consumers continued access to a regulated standard offer indefinitely, or at least until competitive markets prove that they can deliver electricity services at lower prices than what regulated rates would have been. This can remain as the ultimate goal of restructuring. If regulators do not want to see retail prices increase more than is necessary under deregulation, they may need to always offer a default service based on bidding out the service to the wholesale market. But this, again, would preclude retail competition from ever developing.

#### Tenth Truism:

*Restructured electricity markets and retail competition will preserve system reliability because customers value high levels of reliability. The market will determine an optimum level of capacity reserves to maintain reliability at the level customers desire.*

There are two basic reasons why the wholesale energy market for electricity has the potential to self-regulate capacity reserves, even if there is no capacity market. Analysts have claimed that one is that a shortage will call on the construction of new capacity whenever reliability becomes a concern. This is because prices will soar when a true shortage materializes, and the market will

learn to anticipate this and preempt such events with adequate new capacity. New market entry will occur in anticipation of shortages because it will be profitable for this to happen. The other reason is that effective transmission pricing approaches such as congestion cost pricing will be implemented in the new markets so that a potential shortage is communicated clearly through price signals. Again, capacity construction is the answer. The more complete and the more nuances the transmission pricing scheme has, the more efficient it will be in communicating the need for new generation (and transmission) capacity in certain locations. Some have envisioned (and implemented) a congestion pricing approach to be applied at hundreds of distinct nodes in the transmission system to more accurately define constraints in location, scale, and cost.

But, we need to ask, will the above mechanism be sufficient to assure system reliability? The answer is that reliability is not a product that generation service providers are selling, and even if they tried to, they could not sell different levels of reliability to different customers. If the level of capacity reserves is not still regulated, the penalty to generation providers for not having enough capacity on hand may be lower than the cost of securing that capacity. Moreover, a shortage brings up prices and that inflates profit margins. Therefore, it may be economically rational for generation providers to reduce reliability, not only because it is cheaper not to have extra capacity on hand, but also because profits will rise when demand is at the highest levels. The market will likely be more concerned with balancing obligations for capacity, where market participants need to minimize their exposure to contract liability, rather than focusing on preventing blackouts.

Thus, it is becoming clear that the level of capacity reserves will have to continue to be regulated even if the price of capacity and energy is no longer regulated. In NEPOOL, each load-serving entity (LSE) has a certain *capacity obligation* that needs to be met either by own generating capacity or through contracts that bring capacity owned by others under that LSE's control. Falling short of this obligation brings penalties from the ISO. Alternatively, if the LSE that does not have enough capacity on hand in any given hour, it becomes a default purchaser in the capacity market at the market clearing price in that hour. PJM has adopted a similar approach to NEPOOL. In contrast, no requirements for capacity reserves were imposed on the California PX. This was, in part, due to the excess capacity in the market at the time. What has happened since, as is now well-known, is that this excess has fallen precipitously and prices have increased greatly. A deregulated generation market without a required reserve margin is almost certain to reduce reserves to unacceptable levels.

Eleventh Truism:

*Restructuring will improve the environment because large numbers of consumers will choose cleaner generating technologies once they have a choice.*

We envision very few positive results from restructuring of the electric industry but there is one aspect of it that is quite promising. It is increased consumer autonomy that can help convey a message from individual consumers to generators of electricity, that they care about the quality of their product; not how reliable it is because that is a system-wide characteristic, but how it is generated. Up until now, individual consumers have had little direct say in the decision-making process about what types of generating resources are built, except through the IRP process. Now, they can increasingly express their preference through the retail electricity market. Realistically,

the major qualitative feature that will be considered is the relative environmental impact of different sources of electricity. While this is a potentially positive development, we have identified some issues of concern that detract from our excitement about consumer choice as a vehicle for positive change. The most important concerns relate to equity and economic efficiency.

*Equity* is a concern because relying on individual consumers to purchase green power results in an unfair distribution of the burden of providing what is essentially a public good. This assumes, of course, that green power will carry a price premium. As long as that is the case, those who choose to buy green power will be personally subsidizing the common good. There will always be “freeriders” and that is both an equity and efficiency concern, but mostly, the equity issue is about society sharing the cost of shared benefits in a reasonable way. Another equity issue is the possibility that marketers will learn that a segment of society can be counted on to pay a premium for green power and that they will take advantage of that market segment by charging them unnecessarily high prices. If the market realizes this potential, mere competition may not help keep prices reasonable than it does in other “specialty markets.”

*Economic efficiency* is a concern because the same reliance on individual initiative to provide society with a benefit that is generally desired is an extremely imprecise approach to determine how much green power should be produced. Individuals have no measure of what the collective desire of society is, and thus cannot know how much to purchase to satisfy that desire. The aggregate amount of green power purchased would be totally arbitrary. This is important because people do buy green power, in part, for their own benefit. Yet, the benefits of green power are common to all of society, even though individuals can take personal pleasure in making such purchases. Efficiency is also compromised by this volunteerist approach because individuals do not have the scope and focus that a regional integrated resource plan can provide. Also, individuals will not work in unison in their purchasing decisions, and can even work against each other by making different decisions at different moments in time that conflict. The purchasing power of those individual consumers who buy green power will therefore be dissipated. It will not be economically efficient. That is not to say that centralized plans to promote green power like tax incentives, government purchasing plans, etc. have been entirely successful. Some have been better than others. However, an integrated resource plan has a better chance of getting close to the desired social target of increasing the total amount of green power in the energy supply, at the relative least cost.

Consumer choice is of real value and it must have its role in the future energy markets, but three conditions need to be met. First, consumers must be protected from manipulation by marketers and from market power. Second, consumer choice must be supplemented with some form of resource planning that provides scope, focus, and a more thorough integration of environmental externalities and other social costs of energy procurement. It is a real possibility that green power will never amount to much more than “boutique power” that a select few will buy for noble reasons, but reasons that the market may ultimately trivialize and reduce to mere novelty status. Third, green power offerings must be established for standard offer and default service, and in those states where generation is still regulated.

## 10.2 A Critique of DOE's CECA Analysis

This paper has dealt with the issues of restructuring in relatively abstract terms, without much quantitative analysis. The main quantitative analysis of electric industry restructuring that has been performed to assess its likely benefits for the entire country is the *Supporting Analysis of the Comprehensive Electricity Competition Act (CECA)*, completed by the U.S. Department of Energy in May 1999.

The DOE came to very favorable conclusions about restructuring and found that electricity prices would decline in almost every state as a result. We have examined DOE's results and compared them to the results and methodology applied by Stone & Webster Management Consultants in their review of the potential effects of restructuring in Colorado.<sup>35</sup> Stone & Webster found that prices would rise in Colorado under market pricing relative to regulated rates while the DOE came to the opposite conclusion for Colorado. The result of our review of the DOE analysis was that it appears to have several fatal flaws which render its conclusions invalid.

### *What Are the Major Differences in the Results of the Two Studies?*

The long-term (2015) prediction for *total* electricity prices in the competitive market scenarios was almost the same in the two studies, if differences in assumptions about stranded cost recovery were ignored. However, this agreement turned out to be mere coincidence, since the key price components underlying these future rates were very different. These differences simply happened to cancel each other out when total rates were added up. S&W reports about 55 percent lower non-generation (transmission and distribution) costs than DOE in the competitive market in 2015 (adjusted for each study's inflation assumptions). At the same time, S&W's generation cost projections for 2015 are about 54 percent higher than those of DOE (Figure 6).

### *How Past Trends and Internal Inconsistencies Discredit DOE's Analysis*

There are several indications that DOE made significant errors in its treatment of the competitive market case. This conclusion is not dependent on a direct comparison with S&W results. Rather, it is derived from careful examination of the assumptions applied, to the extent available, and on the discovery of some internal inconsistencies in DOE's analysis.

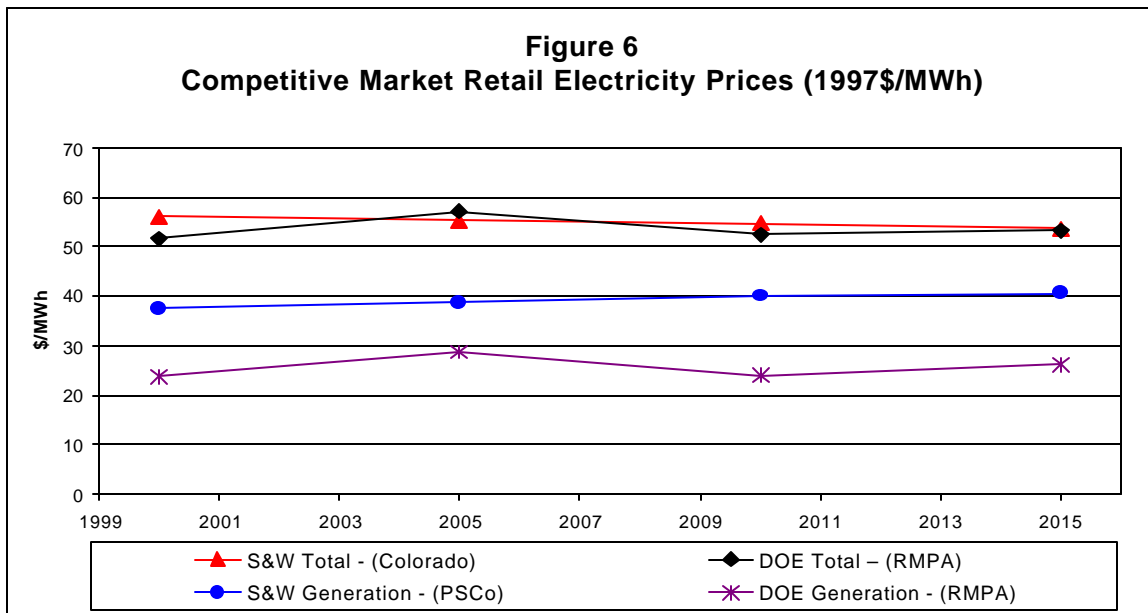
#### *1. Substantial amounts of stranded cost appear to be missing in DOE's analysis.*

The most compelling indication that the Department of Energy has failed to perform an accurate analysis of restructured electricity markets is what appears to be an underestimation of stranded costs, both at the national level, and for Colorado. The DOE anticipates that competitive markets will yield substantial savings that are almost entirely derived from a reduction in generation prices. These generation savings of almost \$400 billion (present value) at the national level through 2015 materialize immediately upon transition to competitive markets. For that reason, a large share of these savings should necessarily appear on the cost side as stranded costs that would need to be recovered because the savings are immediate, and, therefore, cannot be explained primarily by reductions in actual production costs relative to the non-restructuring case, which presumably would take a longer time to develop. Nonetheless, less than \$100 billion

---

<sup>35</sup> Tellus Institute, *A Comparison of Studies by U.S. DOE and Stone & Webster on the Effect of Electric Restructuring in Colorado*, September 1999.

(present value) in stranded cost recovery is actually charged to ratepayers by the DOE. Even if relative production efficiency improvements could be implemented as rapidly as envisioned by the DOE, such improvements in productivity could explain only about an additional \$100 billion (present value) in savings. This leaves about \$200 billion (present value) in apparent stranded costs that are not accounted for in the DOE study.<sup>36</sup>



*2. The DOE reference case is inconsistent with historical trends in electricity prices.*

The DOE's price forecast under a continuation of rate regulation is less consistent with historical price trends than S&W's reference case. In fact, DOE's reference forecast reverses the recent downward trend for electricity prices (in real dollars) in the Colorado area over the past decade.

*3. The DOE expects an immediate reduction in generation prices at the onset of competition.*

The large reductions in generation prices due to competition in the DOE report occur immediately in the year 2000. This means that DOE's favorable results for the competitive case do not rely significantly on the gradual introduction of competitive new capacity and competition-induced gains in economic efficiency for new generating capacity over the long-run, as DOE itself claims. Instead, it is DOE's assumptions about the structure of the competitive market that yield competitive prices well below regulated prices at the very start of competition. This initial difference, more or less, carries through the entire period covered by the studies without much additional decrease relative to regulated rates. Again, these price reductions should have just contributed to higher stranded costs than DOE actually computed.

*4. Sharply declining competitive generation prices in Colorado are inconsistent with the expectation of negative stranded costs.*

<sup>36</sup> Note that a full year after releasing its critique of the DOE study, DOE has not challenged Tellus' conclusion that there are large amounts of missing stranded costs in its study.

Both DOE and S&W projected negative stranded costs for Colorado. While this is a reasonable expectation in the context of the S&W results, an inconsistency arises with DOE's projection that generation prices will decline sharply at the onset of competition. DOE expects generation prices in Colorado in the year 2000 to be 27 percent lower under competition than under continued regulation. This is a difference of almost 9 mills/kWh (1997\$). Based on the very limited data available from DOE's analysis, the negative stranded cost in Colorado from 2000 to 2010 seems to average only about 1.1 mills/kWh. How could generation prices drop so dramatically early on due to competition and still produce negative as opposed to positive stranded costs? Given DOE's very low price of generation under competition, stranded costs should probably be strongly positive, if their stranded costs were computed correctly for Colorado. DOE's national results also suggest that stranded costs may be computed incorrectly, as noted above.

#### *How Can the Different Results for Generation Prices Under Competition Be Explained?*

The differences in results for the competitive cases between the two studies can be explained by the different methodologies applied. Some of the causes of the differences seem to be evident. However, the exact nature and impact of each of these different approaches cannot be evaluated fully without running the relevant models again under new assumptions. Tellus has identified two primary assumptions on the part of the DOE that are probably the most significant causes of the different competitive generation prices in the two studies:

##### *1. DOE ignored the need to allocate capacity payments to all generating units.*

In a deregulated marketplace, all load-serving entities must control sufficient capacity to meet their load and required reserves. This capacity will come at a price set by the market. DOE has applied capacity charges to only about 10 percent of all capacity in the Rocky Mountain Region. S&W assumed that all capacity would receive the capacity market clearing price. DOE does not explain how the fixed costs of the other generating capacity would be paid, unless through stranded cost recovery.

##### *2. DOE assumed an unrealistically low 8 percent required reserve margin.*

In contrast, S&W assumed a more realistic 18-22 percent required reserve margin for Colorado, given the significant transmission constraints in the region. This assumption on the part of the DOE makes the effect of limiting capacity payments to a small portion of all generating units even worse because it artificially underestimates the amount of required capacity reserves.

#### *How Can the "Missing" Stranded Cost Be Explained?*

This is an issue that must be resolved by further examining the DOE study and its assumptions rather than by comparing it with the S&W results, which only DOE can do. In addition to the possibility that the lack of adequate generation capacity charges may explain the precipitous drop in generation prices, various other costs seem to have been understated or omitted in DOE's competitive scenario. The possible omissions that could explain some of the missing stranded costs are the following:

- retail margin;
- cost of capital additions.

DOE did not include a retail margin in the retail price of generation in the competitive case. The retail margin is the difference between the wholesale and retail price of electricity. It is to be expected that retail services will carry some new and additional costs such as marketing once retail competition becomes fully established. Various other costs such as generation-related A&G, fuel costs of existing generating plants, and O&M costs were decreased in DOE's analysis of the competitive case at an accelerated rate compared to the reference case. Whether these assumptions are reasonable or not, they are not sufficient to explain the sudden drop in generation prices in the year 2000, because these assumptions lead to gradual changes. Until more is known about the details of DOE's methodology, what is referred to here as the "missing stranded cost" will remain a mystery.

One of the most important lessons to draw from the comparison of the two studies is that many of the improvements in efficiency and environmental impact of electricity generation promoted and supported in the DOE modeling of the competitive scenario should not be considered to be a consequence of the competitive retail market. Most of these advancements are a matter of policy, and not dependent on the dynamics of the marketplace. Others, like efficiency improvements of older plants, are technological in nature, rather than economic, and can be implemented regardless of regulatory structure. The otherwise valid argument that competitive markets create an incentive for improved productivity does not preclude generating plants under regulated rate structure from incorporating new design and technology, as it becomes available. Regulatory lag always provides an incentive for this to happen, as firms try to maximize their profit margins between rate cases, especially investor-owned utilities.

### *Market Power*

S&W estimated the potential impact of market power in Colorado. Their conclusion was that prices would rise by as much as 13 percent over competitive levels, but that this increase in prices would decline over several years, when the exercise of market power due to unilateral strategic bidding would become unprofitable. Tellus has found several problems with the methodology applied despite some of its merits. Overall, Tellus believes that S&W has significantly underestimated the scale and pervasiveness of the potential effect of market power in Colorado. This is because S&W did not analyze the potential impact of multi-lateral strategic bidding and capacity withholding on generation prices in the region over the long run.

The Department of Energy failed completely to recognize the importance of potential market power in raising prices in competitive generation markets, and chose to ignore it altogether in its analysis. While this omission does not explain the different results between the competitive cases of the two studies (S&W modeled market power in a separate case), it is an additional element contributing to what amounts to a substantial misrepresentation by DOE of what future competitive electricity prices may be compared to prices that consumers would pay if traditional rate regulation continued.



## **11 ALTERNATIVE MARKET STRUCTURES?**

### **11.1 Consumer Choice Supplemented**

We have now examined how the four major objectives of restructuring are threatened by the competitive marketplace. We have also hinted at several solutions if policy makers want to persist in trying to make restructuring work. Those remedies aim to supplement competitive market structures so that economic efficiency, lower prices, consumer choice, and system reliability can all be advanced beyond the level that deregulated markets alone are likely to provide. With almost one-half of the states having restructured their electric industries, it is imperative to come up with meaningful solutions that supplement the changes already made. For the remaining states, these suggestions are equally valid to the extent they supplement the current structure of the regulated industry. Of course, if restructuring does not lead to lower prices in the next 5-10 years, it should probably be completely abandoned.

#### **A. Public Funding for Public Goods**

Economic efficiency will never be served until public goods are paid for through public funding mechanisms. We have detailed how public goods are non-exclusive and cannot, by definition, be produced and purchased in economically efficient quantities if this is left to the market. In the electric industry, public goods are mostly related to the environmental and public health effects of providing electricity. Markets, through the actions of individual consumers, may be relatively successful in reaching efficient prices based on economic costs alone, but when individuals need to incorporate non-economic externalities like air pollution into their decisions on how much and what kind of electricity to purchase, the outcome of markets will always be inefficient.

There is no way around the fact that funding public goods involves long-range planning. That poses a certain problem because old-fashioned planning is often considered antithetical to competitive restructured markets. In fact, as we discussed in the context of transmission planning, it is hard to imagine how any public planning can be reconciled with a market based purely on private decision making. That remains one of the greatest challenges for regulators who must still maintain their function as planners for regulated electric services like transmission and distribution, even though these functions are intricately linked to the deregulated generation market, particularly in context of monitoring system reliability and balancing of resources between generation and transmission in order to achieve a least-cost mix. Despite the difficulties, this problem must be solved.

Due to the market structure, it might be impractical to fund certain energy projects directly with public funds once the market has been deregulated. Therefore, it may be more prudent to rely on economic tools like tax credits, purchasing credits, and resource portfolio standards to steer investment and purchases in the right direction. Here we will not discuss further what economic tools would be most appropriate since that is a very complicated issue in itself. An economically efficient resource mix might be determined by regional planners and, then, compared to current purchasing and investment trends. Incentives would then be designed, based on empirical evidence of their effectiveness, to adjust those trends toward a least-cost allocation of resources.

This process may in some instances interfere with otherwise autonomous decisions made by consumers and investors, but it does not mandate a specific decision on an individual level. It simply brings the full social and economic cost of electricity into the decision-making process, to the extent possible, while preserving the principle of consumer choice and free enterprise. The joining of resource planning and consumer autonomy should always be regarded as complementary rather than adversarial whenever possible.

## **B. A Standard Offer in Perpetuity?**

In Chapter 5, we discussed how various cost-adders at the wholesale and retail levels could easily bring market prices above the average embedded cost of generation in most, if not all, areas around the country. When transitional standard offer rates were set in various states and a default price for generation service was offered to customers, it became clear how significant these added costs can be. The retail margin alone makes it hard for a competitive retail supplier to compete with a default service that is set at or near the wholesale cost of service. We discussed how this default service certainly needed to be priced much higher than market wholesale price, and higher than the likely level of a competitive retail price, in order to facilitate competition and not fool consumers into believing that competitive retail service could actually be so inexpensive. Of course, this could imply that retail competition is not worth pursuing.

But there is a different message here as well, as discussed earlier. Default service, when provided on an aggregated basis to many customers, is inherently less expensive than retail service. This is so because the default supplier has a potentially large pool of customers with no retailing expenses to worry about. A default provider does not need to market his product. This service can therefore be provided at a price that is close to the wholesale price and certainly always lower than the prevailing retail price. Therefore, we must ask whether a market-based default service should not be provided in perpetuity, and not just as an interim measure, if it truly benefits consumers? It would undermine a full retail market but it would probably still allow for a slim retail market that already has formed around distinguishable products like green power.

This default service market would probably be served by auction, as has become the norm. The regulatory authority solicits bids from potential suppliers and makes a decision based on price and perhaps some reliability considerations. When an auction for transition and default service takes place, it is unreasonable to expect that bidders will offer service for the entire load based on average cost, unless they are convinced that not even industrial customers will choose alternative providers. This single price might be too high for some industrial customers, who would expect a price somewhat below average system-wide cost. Naturally, such industrial customers would seek alternative sources, or they would demand that the state PUC allow rate differentiation by customer class. If rates were not differentiated by class, and if industrial customers did have the default service, this would raise the cost-basis of the remaining transition service or default load, reducing the potential profitability of the original bid. Knowing this to be a likely outcome, the bidder would raise the original bid to account for the risk of losing industrial load. The result would be a bid that was heavily weighted toward the cost-basis of the residential load. Industrial customers would, therefore, have good reason and opportunity to seek competitive suppliers, while residential customers would still be without practical choice due to the fact that the default price would still be below the actual cost of providing that service by alternative retail service providers. Default service by auction would, therefore, probably always be the least expensive

option to residential customers because any bid for such a substantial aggregated load would be close to wholesale prices.

### *Standard offer for green power*

One option is to combine the effort to encourage use of environmentally benign energy sources with the standard offer. A standard offer for green power could be offered as an alternative to the undifferentiated standard service. The disadvantage would be that this green standard offer might undermine the developing retail market for green power since it would be less expensive to provide than regular retail service for the same product. On the positive side, it would be an effective way to bring the green option to consumers at the lowest possible price, and it would be likely to accomplish the objective of achieving an efficient resource mix more quickly and effectively. This option of a green power offering is not limited to deregulated markets, of course. States like Colorado and Iowa have been providing a regulated standard offer for wind power, which shows that various mechanisms are available to improve economic efficiency outside the context of markets, and in fact, outside the context of deregulation. These regulated green options should be explored and implemented much more widely.

## **C. Portfolio Standards**

In all probability, the U.S. DOE's Supporting Analysis for the Comprehensive Electricity Competition Act, that we criticized in the last chapter, had two distinct objectives. One was to underline the value of restructuring, and we have already challenged its findings in that area. The other goal appears to have been to show that renewable energy could be brought into the national energy mix on a substantial scale without causing a significant rise in cost to consumers. This conclusion seems to be correct.

The DOE incorporated a Renewable Portfolio Standard (RPS) in its modeling of the national competitive scenario. It was based on the Administration's plan of a 7.5 percent share for non-hydroelectric renewables by 2010, but with a cost cap limitation of \$15 per MWh over the market price for electricity. This RPS was assumed to work in conjunction with current tax credits designed to encourage the use of renewable energy. It was also assumed that consumers would purchase additional amounts of green power voluntarily, although the report acknowledged that the RPS would displace some of these voluntary purchases. In DOE's modeling results, the use of renewable energy rises rapidly under the competitive market structure. Early on, the increase is mostly in the form of biomass, but then it is wind power that gains the lead. The report suggested that immediately in the year 2000, the market in renewable energy would be twice as large as it would be under price-regulation, or 3 percent of total supply. That amount would grow to 6.4 percent of total generation in 2015.

There are two significant conclusions in DOE's results. One is that wind power generation could grow twenty times larger by 2015, or from 6 million MWh today to 117 million MWh. The other significant conclusion is that this could happen without a significant price premium. We found this conclusion to be consistent with the study by Stone & Webster for the State of Colorado. That study tested the effect of introducing 50 MW of wind power to the Colorado capacity pool each year from 2000 to 2015, for a total of 800 MW or 7.3 percent of peak load in 2015. Although this is a smaller amount than DOE's estimation of 2,880 MW for the Rocky Mountain

Area, the results are the same as they showed no rise in prices under competition beyond the rate of increase that S&W predicted for the baseline (non-wind power) competitive case. In fact, wind power was found to be neutral to projected retail rates. The same results were found in S&W's cost-of-service regulated modeling scenario as prices rose only slightly (less than 2 mills) due to the same rapid introduction of wind generation. These results suggest that renewable energy, and particularly wind energy, could be developed on a significant scale in areas with good wind resources, without causing an added burden on consumers.

### *The need for tracking*

Portfolio standards and sales of green power are of little use unless compliance with any environmental choices can be verified. Regulators must know that a specific amount of renewable energy has actually been generated and received by a load-serving entity. It is also important that consumers can know with some certainty what mix of power supplies they have actually purchased from their load-serving entity. Green power offerings are not all equal, and customers must have a way of comparing those through some form of a rating structure that regulators can provide, based on a tracking mechanism. In other words, tracking is needed as a method of ensuring the delivery of a product. It can also help to keep track of qualitative characteristics of that product and, thus, assist consumers in making their choices.

## **11.2 Reliability Can Be Secured**

### **A. Establishing Accountability for Reserves**

In a deregulated environment, regulators must find a way to make their role as planners consistent with the role of the marketplace. We have discussed the need to integrate regulated and unregulated aspects of electricity service where regulators must balance their responsibility for maintaining system reliability with the autonomy allowed to the market participants. Generators cannot be forced to build capacity when capacity reserves drop to dangerously low levels. In fact, left to itself, the market is likely to seek a state of low reserve margins because it is more profitable to investors. Unfortunately, the social cost of having low reserves does not evaporate. It is simply transferred onto consumers who must contend with less reliability, while paying almost as much for their power as before. The only viable solution is to mandate generation reserve requirements under competitive generation markets, as before. However, the target of that mandate must now be the load-serving entity rather than the yesterday's vertically-integrated utility.

### **B. Transmission Planning Resides with RTOs, Governed by Least-Cost Options**

One of the greatest challenges facing the emerging regional transmission organizations will be the need to integrate planning for expanded transmission grids with the role of private investment. FERC concludes in its Order 2000 that the RTO must have the ultimate responsibility for both transmission planning and expansion, in coordination with state authorities.<sup>37</sup> The RTO must also be equipped to direct and arrange for the construction of

---

<sup>37</sup> Federal Energy Regulatory Commission, 18 CFR Part 35, (Docket No. RM99-2-000; Order No. 2000), *Regional Transmission Organizations*, (Issued December 20, 1999), page 485.

transmission projects that are deemed to be necessary.<sup>38</sup> The rationale for allocating this responsibility on the RTO is that “a single entity must coordinate these actions to ensure a least cost outcome that maintains or improves existing reliability levels.”<sup>39</sup> However, the Commission also expresses a strong preference for “market-motivated operating and investment actions.”<sup>40</sup> That means that the Commission does not believe all transmission expansions have to be centrally planned by the RTO, but that a successful market approach will allow decisions to be “driven by economic considerations.”<sup>41</sup> The Order goes on to point out that many comments to the original RTO NOPR agreed with FERC in that RTOs should rely on market solutions to assure that the least costly option is pursued.<sup>42</sup> The Commission concludes that although it must insist on the use of price signals in the process of transmission expansion, it is not their intention to either mandate a market approach to the exclusion of an executive decision by the RTO, or to mandate any particular market approach.<sup>43</sup>

### *Conclusions about Securing System Reliability*

To summarize our discussion of system reliability issues, we want to remind state and federal policy makers of the concerns that we have previously raised that must be taken into account when establishing new market structures like RTOs:

- Future reliability is a matter of faith in a deregulated world. In contrast, legislation is required, and both FERC and state regulators must not assume that market mechanisms will always bring a solution, or that such solutions will always be reasonably least cost.
- A generation reserve requirement is necessary because the demand for adequate system reliability cannot be translated into a market context. Reliability is not a commodity in itself.
- Higher uncertainty and risk will drive up the cost of incremental reserves in a market context. The effect is that either the level of reserves will decline, (and thus reliability will decline, and social costs of outages will rise) or the direct economic cost of electricity service will unnecessarily rise.
- The increased economic trading of power based on open access does not increase reliability at times of crisis.
- Due to the loss of control over generation, state and federal utility regulators may tend to rely more on investment in new transmission to provide reliability. This is not reasonable because it looks at only half the picture and is, therefore, likely to be uneconomic and in contradiction with the principle of least-cost planning.

---

<sup>38</sup> Id., 487.

<sup>39</sup> Id., 486.

<sup>40</sup> Id., 487.

<sup>41</sup> Id., 488.

<sup>42</sup> Id., 488.

<sup>43</sup> Id., 489.

## **11.3 Dealing with Market Power**

### **A. The Need for Divestitures, Not Mergers**

Just as regulators are forcing divestitures of integrated utilities to improve the chances of effective competition in restructured electricity markets, the same divested generation assets are now being continuously re-aggregated through mergers into ever-larger energy service corporations. This cannot be good news for the future of competitive markets. While the popular belief is that mergers are a key to efficiency improvements, they also open the door to increased market power. In fact, future cost savings from mergers are quite uncertain, and may prove to be elusive despite the lofty claims made by merger applicants before state and federal regulators. But the potential impact of market power due to mergers will be instantaneous and it is probably already with us to a substantial degree.

The solution is much tougher criteria for allowing mergers. The current methods of HHI-based market power analysis must be abandoned for methodologies that include the modeling of market behavior. If modeling results indicate the potential for increased market power, mergers should simply be denied. Such modeling methods must also be supplemented with careful observation of market activity. Regulators should establish specific criteria or “thresholds” of activity and conditions that will be deemed to constitute the exercise of market power, or proof of its existence. For example, the prices in poolco-type wholesale electric energy markets should be compared to a “competitive price baseline” based on a variable cost profile of the generation resources in the market. When market prices exceed this baseline by some specific (small) margin, regulators should declare a condition of market abuse, and replace all market bids with variable cost bids. That would be a powerful incentive for the market participants to refrain from market manipulation and, therefore, would be a valuable safeguard for consumers. In essence, it would be a pro-active and preventive measure, and in every aspect preferential to some convoluted scheme of protracted negotiations between an RTO and individual market participants suspected of market power abuse. Such schemes, which ISOs and emerging RTOs seem most fond of, are reactive rather than pro-active because they only take effect after the market power has done its damage, and may only bring partial or, more likely, no remedy. A clear competitive price baseline also takes the guesswork out of market monitoring, and market participants will not be tempted to speculate regarding what they can get away with.

The culture of deregulation has reached its apex now. This means that since the deregulation ball got rolling, it has gained momentum, but that momentum is now reversing. Until recently, that momentum meant that few people dared to ask critical questions, and chose instead to “go with the flow.” Arguably, this impetus may have also made it very difficult for regulators to actually deny mergers. Any commission that even now might want to deny a merger because it has serious concerns about market power, still faces stiff political challenges in standing by that conclusion.

### **B. Regulation Needs to Supplement Incomplete Structural Solutions**

Divestitures without adequate criteria for controlling the future re-aggregation of assets through subsequent mergers will be useless. Establishing those criteria will be impossible without

detailed information about the cost and performance characteristics of the businesses involved in the electricity markets. The “competitive price baseline” mentioned above requires that regulators be provided with actual cost data from market participants. The use of such a market monitoring approach would, of course, meet objections from the marketplace, and the objections would rest, in part, on concerns about confidentiality of commercially sensitive information. This is a common concern among electricity suppliers, and is well documented in FERC Order 2000. However, such information is already gathered by several ISOs without confidentiality being an obstacle. The only additional step required is for the system operator or RTO to compare that data with bids in the markets and come to some conclusions, on a continuous basis, if market power has raised its head. FERC has generally supported the ability of ISOs to collect cost data. What market monitoring must not do is simply compare recent price bids by generation owners to similar bids made previously, as FERC has allowed at the ISO-NE. This self-referential approach will never control market power.

Such mandatory cost and performance disclosures have their precedent from other industries. For example, federal regulations require appliance and automobile manufacturers to provide certain performance and cost information to consumers so that they may make informed decision about their purchases. In the case of the electric industry, no information about individual electricity service suppliers would have to be disclosed publicly. It would be sufficient if the ISO or RTO had all the relevant and critical information needed to gauge whether and when market power is affecting market prices. Thus, even though the market may hopefully be structured in a way that reduces the risk of market power, there is no substitute for active monitoring and mitigation procedures. Those monitoring procedures might be sufficient to keep anti-competitive behavior at bay so that mitigation can be the exception rather than the rule, allowing the markets to function without too many disruptions. Every child needs discipline, and in this case, adequate higher authority may even make for a content market.

## 12 CONCLUSIONS

The objective of this white paper has been to express a warning as to what may happen if blind faith in the positive powers of so-called “competitive markets” is never adequately questioned during the transition away from a regulated monopoly structure. That is exactly what we believe happened in most states that have restructured the electric industry. In contrast, the outlook for electric industry deregulation presented above is bleak, even in the long run. We do not believe that the problems with deregulation that are cropping up ever more frequently are simply just “transitional” problems, as many have claimed. We believe that the case has not yet been made satisfactorily that retail competition can ever deliver average retail rate reductions relative to continued traditional rate regulation. Nor do we believe that any convincing evidence at all has been presented that deregulated, competitive wholesale generation markets will ever exist. Our next white paper may be on the topic of how to re-regulate your local utilities.

A key question that needs an answer is: What blinded most industry analysts to the perils of restructuring as implementation progressed? In part, we believe that some of the more negative aspects of regulating the electric industry provided enough fuel to propel these analysts beyond the scope of reason. There was the legacy of nuclear power and its high cost, and the high cost of power from Qualifying Facilities, all driven by the price shocks in the oil industry of the 1970s and 1980s. Then, as industrial customers saw the potential to purchase electricity directly from newer and less expensive sources, the pressure for deregulation rose, and the ball got rolling.

Unfortunately, two important facts got left out of the restructuring debate. The first important fact neglected was that the average embedded cost of generation was declining throughout the country, and that average electricity rates in the country had been declining in real terms ever since 1983 and were likely to continue to do so for quite awhile. So even in states where the average cost of generation was higher than the marginal cost of new generation, it was only a matter of time until regulated rates would slide down to, and below, long-run marginal costs. This has already happened, or is about to happen soon in most states. This is important to remember because the competitive price in a deregulated market will be defined by the long-run marginal cost of new generation, and not average embedded cost as was the case under regulation. That means, by definition, that most states cannot expect market prices to be lower than regulated rates would have been in the near future, unless deregulated markets can generate large efficiency improvements that regulated markets cannot. Even if those improvements could be made, a reduction in average prices would require the absolute absence of market power.

The second important aspect left out of the restructuring debate was the fate of stranded costs. If market prices were to be lower than regulated rates, the difference, by definition, would have to be collected in the form of stranded cost charges until the generation assets were fully depreciated. Thus, full stranded cost recovery means no savings to ratepayers at least in the short-to-medium term (0-10 years) by definition, unless restructuring leads to significant incremental generation efficiency improvements, but this is unlikely.

In retrospect, it is quite simple. Even in the best case, the whole benefit of deregulation depends on the industry being able to generate operational efficiency improvements at both the wholesale



and retail levels that are unrealistically large. In present value terms, these operational savings would have to outweigh all the additional costs to consumers generated by restructuring itself, including the fact that prices follow long-run marginal cost and not average embedded costs, and all the economic inefficiencies generated by the destruction of vertically integrated utilities. Also, on the cost side of the equation, one must add the significant amount of money that ratepayers have overpaid for stranded costs, given the higher-than-expected market prices that have developed since many stranded cost charges were determined. Then, on top of these substantial costs, is the reality of market power, making the prospect of any savings at all from deregulation even less promising. In fact, we believe that even if many of the structural improvements that we recommend above are implemented, such as eliminating poolcos, regulators will never be able to adequately control market power.

What, then, is the worst that can happen? In a worst-case deregulation scenario, electricity markets would reverse course from the current gradual real-dollar decline in average regulated rates to a sharp increase in market prices. Those prices would be driven both by rampant market power, exercised by market participants who see much greater gain in gaming the market than in going after the elusive and difficult goal of streamlining their business for competitive advantage, as well as by higher oil and natural gas prices which will raise the market prices of relatively cheap coal, nuclear, and hydro power, as well as fossil-fueled power. That would be a double betrayal of the objectives of restructuring; the market would be gamed while few efficiency improvements would be gained, even though such improvements were supposed to be the greatest advantage of “competition.” And the cost of all electricity would become subject to the volatility and potential long-run increases inherent in world oil and natural gas prices. Thus, the country could lose the huge benefits that we previously had from low embedded cost types of electric generation such as hydro and coal.<sup>44</sup> The complete failure of deregulation would be defined by this scenario in combination with a total loss of consideration for environmental externalities and other social objectives that previously have been addressed under integrated resource planning. In fact, unless stranded costs are adjusted strongly downwards in the near future, ratepayers may lose more money by overpaying for these stranded costs than they had lost by the existence of stranded costs in the first place. This can happen if ratepayers are not credited with large negative stranded costs, where appropriate, and if they are not protected from market power.

In the best of worlds, market participants would ignore their own self-interest and refuse to engage in strategic bidding and other means of exercising market power even though the market structures established so far beg them to do so. Energy suppliers would also work hard to improve their efficiency of operations even though the absolute potential for efficiency improvements is quite limited if system reliability is not to suffer, and even though possible efficiency improvements will always be limited to a small portion of the total cost of electricity. At best, then, the process of restructuring will deliver some small efficiency improvements that may begin to make up part, but only part, of the differential between the marginal cost of new supply, which is the basis for competitive rates, and the generally lower, or soon to be lower, average embedded cost of supply, which was the basis for regulated rates. Therefore, we conclude that, even under the best of circumstances, the deregulation of the electric industry cannot be trusted to deliver on its many promises. In the worst case, we suspect that the political

---

<sup>44</sup> This is happening to New England Electric System’s customers.

process will take over and will try to reverse the more egregious aspects of restructuring. In reacting to the developing problems with restructuring the electric industry, politicians may attempt to implement the past advantages of rate regulation for electric generation without killing off any of the possible positive benefits of restructuring. We hope that this time more careful analysis of the relevant issues will be performed before new mistakes are made.