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Critical Issues in the Regulation of Electric Utilities in Wisconsin

REPORT FROM THE SENIOR FELLOW:

To portray a serious flaw in Wisconsin's utility regulation, a power company executive expounded that he would make a profit painting his office. But his company made no more money by being more efficient in their basic business — generating and distributing power. Unlike other industries, the Wisconsin regulatory model does little to encourage the electric industry to be efficient and innovative.

This anecdote provides an ominous backdrop today as Wisconsin faces steeply rising costs. The man's comment took dead aim at the Wisconsin's approach to regulation. We look to the regulatory capabilities of the Public Service Commission rather than natural market forces to set prices. But how relevant is the Wisconsin regulatory model?

To answer that question we asked Karl McDermott and his colleagues at the National Economic Research Association to review how well Wisconsin's electric regulation is positioned for the future. Dr. McDermott is a rare individual who has experience as a state regulator, an academic and an internationally recognized consultant on utility regulation.

Dr. McDermott notes that in the near term Wisconsin consumers should brace themselves for price increases fueled by the rising cost of gas and coal as well as the cost of capital expansion to meet the state's generation and transmission demands. Now is an opportune time to review how well Wisconsin's approach to regulation will serve to encourage reliable, cost effective electricity in the future.

Dr. McDermott's findings are disquieting. While Wisconsin's regulatory system has served the state well in the past, it is not up to the future task. The traditional Rate of Return model used in Wisconsin provides inadequate incentives or opportunities to both consumers and producers to make smart, efficient decisions. As a result, consumers will pay needlessly high prices.

Market forces are playing an increasingly important role in the electric industry: factories yearn to purchase electricity on the spot market, consumers want to be rewarded for conservation, and utilities forego riskier, yet more innovative approaches to the generation and distribution of electricity. The current rate of return regulatory model disregards these developments.

Dr. McDermott calls on the WPSC to set conventional thinking aside and move to an incentive-based regulatory model. This approach, currently used in the United Kingdom, Illinois, New Jersey and many other places, will allow both electricity producers and consumers to have lower prices and more pricing options in the future. It is our hope that this report will spur the State Legislature and the Public Service Commission to seriously look at revamping Wisconsin's regulatory model.

George Lightbourn

WISCONSIN POLICY RESEARCH INSTITUTE, INC.
P.O. Box 487 • Thiensville, WI 53092
(262) 242-6409 • Fax: (262) 242-6459
E-mail: wpri@wpri.org • Internet: www.wpri.org

CRITICAL ISSUES IN THE REGULATION OF ELECTRIC UTILITIES IN WISCONSIN

KARL A. MCDERMOTT, PH.D.
CARL R. PETERSON, PH.D. (A.B.D.)
ROSS C. HEMPHILL, PH.D.

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It is not too much to say that the future of democracy will depend on its success in dealing with the problems of public ownership and regulation. Professor Frank Taussig (1921)

Executive Summary

Purpose

This report examines both the nature of the regulatory framework and the potential future market conditions within which it must operate and examines the implications of these potential conjunctures of forces for the design of future policies for regulating electric utilities in the state of Wisconsin. The report will examine potential alternative regulatory models and evaluate the policies for use in Wisconsin.

Assessment of the Wisconsin Regulatory Environment

Wisconsin has a long and distinguished history in the field of regulation. Wisconsin has been a leader in establishing regulation designed to fill the gap when markets seemingly could not protect consumers. Wisconsin continued this leadership role through the years by implementing marginal cost pricing, comprehensive planning and other measures that improved efficiency in both consumption and production decisions, mimicking the outcomes that would have been delivered had markets been able to play their proper role.

The current Wisconsin regulatory model has provided certain benefits to consumers. This report concludes that traditional regulation, as practiced in Wisconsin, has provided consumers with the basic services and certainty of future service that is part of the regulatory bargain. However, given the uncertainty that characterizes the future energy markets and the rapid nature of changes that do arise, certain observations are warranted. Specifically:

- Investment in Wisconsin, in generation, distribution and transmission has been forthcoming from the utilities.
- While prices have been increasing steadily in Wisconsin, this has also occurred across the nation as a whole and will likely continue for the near-term as price inflation continues in energy markets.
- Wisconsin was at one time a leader in promoting efficient price signals for customers. However, the state has not continued that leadership.
- Wisconsin consumers will have safe and reliable service for the near and intermediate term.

The Electric Industry has and Will Continue to Undergo Fundamental Change

Market forces and underlying technological factors are placing pressure for change in the electric industry nationally and in Wisconsin. Specifically this report finds that:

- **Wholesale markets will continue to evolve:** Federal and certain state policies toward competition are not likely to be overturned. Regional transmission organizations will continue to grow and expand their roles in supporting regional markets. External economic forces in the energy market will continue to provide the impetus for markets to solve the resource allocation problem. The implications for Wisconsin are that market prices will continue to play a role in setting benchmarks for both customers (searching for lower prices) and utilities (seeking profitable markets for surplus supply).

- **Demand-side of market will be of growing importance:** Market price signals and growing recognition of the need for an active demand-side will provide incentives for demand response from customers (including energy efficiency, conservation and load control). These programs will help the wholesale markets to evolve toward a more competitive state. For Wisconsin this implies developing new utility services that will enhance reliability of the supply system and improved efficiency in the development of future supply additions.

- **Unbundling of products and services will continue:** The forces of competition and the attention of policymakers will continue to promote unbundled products and services to address competitive pressures at the margin. New technologies that are implemented as a result of evolution of the energy marketplace will put pressure on traditionally bundled cost recovery. This will make traditional rate structures less sustainable over time. Wisconsin will need to continue exploring the rationale for the functional unbundling of distribution and generation services in preparation for the developments in the wholesale market.

- **Input prices for electric generation will continue rise, at least in the near term:** Prices of fossil fuels and in turn rates for consumers are likely to continue to rise in the near term. Given the role of natural gas in serving peak demands Wisconsin will need to consider expanding its mix of demand response services in order to mitigate potential price shocks.

- **Incentive regulation can be a valuable policy in both providing better price signals as well as efficiency incentives:** Incentive regulation can be superior to traditional regulation in that it provides both efficiency incentives and incentives to price in an economic manner.

- **Incentive regulation is becoming more prevalent in the regulation of public utilities:** Beginning with the telecom industry, incentive regulation has been introduced to the electric industry in both the United States and in Europe. While European energy utilities are more likely to be under some form of incentive regulation, but this approach is being adopted for US energy utilities, albeit at a much slower pace.

Analysis of Alternative Regulatory Models

Four basic models have been used in the electric industry in the United States and Europe. There are as follows:

- § **Traditional Regulation:** Profit is controlled through direct price regulation, entry is limited and risk is allocated through prices that are based on a total revenue requirement. Obligation to serve is assigned to the local utility.

- § **Incentive Regulation:** Provides a different allocation of risks through the provision of incentives for performance by the regulated company. This model provides utilities with an environment that more closely mimics competitive markets. Obligation to serve is assigned to the local utility.

- § **Markets:** Liberalization in electric markets provides for the unbundling of transmission and distribution from generation with generation prices being determined by market forces. Obligation to serve can be assigned to the local utility or assigned to another utility.

- § **Hybrid Models:** These models are some combination of the above models. The hybrid models are generally characterized by open access for some or all customers, but vertically integrated and regulated utilities remain in place.

In analyzing these models we concentrated on the following common variations of regulatory models:

1. **Traditional Regulation (RoRR):** This policy is defined as the revenue requirement approach to setting annual allowed revenue along with a used and useful and prudence review of investment.

   a. **Leased Generation**: Is an approach to address the regulatory risk associated with generation investment in an evolving market. Leases are pre-approved by the regulator and put into rates over the length of the lease.

   b. **Pre-approval of Regulatory Parameters:** This approach approves the return on investment and equity for the life of a project prior to construction. This is to address the ability of a future Commission to change the financial parameters.

   c. **Competitive Bidding for Generation:** In this approach generation would be bid out but the utility would be the single buyer of that generation. This could be done through an RFP for relatively short time frames or through contractual arrangements (through bidding) for longer.

2. **Performance-Based Regulation:** PBR is aimed at providing incentives for efficiency in production and investment as well as pricing efficiency. Two forms of PBR will be reviewed here:

   a. **Sliding-Scale Regulation:** This provides utilities incentives through allowing profits to rise and fall with utility effectiveness.

   b. **Price-Cap Regulation:** Price cap regulation sets a formula by which prices can change over time. This assumes that a set of quality of service targets are included in the plan. Price-cap regulation may included a sliding-scale as well.

   c. **Revenue-Cap Regulation**: Similar to price caps, but instead caps the level of revenue that is allowed to be recovered in any time period. This assumes that qualities of service targets are included in the plan. Revenue caps may include a sliding-scale as well.

3. **Restructuring:** This policy refers to providing retail access to consumers (either all consumers or some subset.) Restructuring would include a transition period in which the utility would be required to provide supply services, after the transition period a decision would be made as to how long the utility's obligation to provide supply services would remain and how those services would be procured. Distribution and transmission would be regulated, and distribution may or may not be unbundled.

The report next analyzes each of these models based on seven characteristics:

1. ***Investment for reliability***. This metric measures the ability of the policy to induce enough investment to maintain safe and reliable service.

2. ***Cost Efficiency:*** This covers general production efficiency, but not investment efficiency.

3. ***Efficient Investment:*** Efficient investment refers to the proper level and timing of investment as opposed to simply enough investment for reliability purposes. This also includes the incentive for non-utility investment in generation.

4. ***Price levels:*** Price levels refer to the overall level of prices. Under various regulatory models different customers may be charged different levels relative to the current model of regulation (due to implicit subsidies currently embedded in rates).

5. ***Pricing Efficiency:*** Pricing efficiency refers to the ability of the policy to create and enforce efficient prices.

6. ***Customer Options:*** Consumer options may include multiple types of pricing arrangements, different services, differentiated customer service, etc.

7. ***Ease of Implementation***: This metric is a "catch-all" measure that attempts to measure both the ease of regulatory implementation (i.e., is legislation necessary, can PSCW do without legislation, etc.), and practical implementation (i.e., is there a learning process for the new model that both customers and utilities will have to go through, etc.)

Next different policy options are rated on the following scale: 1.0(=poor), 2.0(=unsatisfactory), 3.0(=neutral), 4.0(=good) and 5.0(=excellent). It must be understood that these rankings are based on the evidence provided in this report and the authors' judgment concerning the viability of each model in Wisconsin in the short-term and the robustness of these policies to uncertainties in the long-run. Table ES-1 table presents the results:

Table ES-1: Ranking Policy Options

Model (Total Points)	Investment for Reliability	Cost Efficiency	Investment Efficiency	Price Levels	Pricing Efficiency	Customer Options	Ease of Implementation
Traditional RORR (17.0 -18.0)	4.0	1.0	3.0	1.5 – 2.0	1.5 - 2.0	1.0	5.0
Leased Generation (17.5 – 19.5)	5.0	1.0	3.5	1.0 – 2.0	1.0 – 2.0	1.0	5.0
Pre-Approval (16.0 – 18.5)	4.0	1.0	3.5	1.5 – 2.5	1.0 – 2.0	1.0	4.0
Competitive Bidding (17.0 – 19.0)	4.0	1.0	3.5	1.5 – 2.5	1.0 – 2.0	1.0	5.0
IR- Sliding Scale (23.0 – 25.0)	4.0	3.5	4.0	3.0	3.0	1.0 – 3.0	4.5
IR- Price Caps (26.0 – 29.0)	4.0	4.5 (4.0)*	4.0	3.5 – 4.0	3.5 – 4.0	3.0 – 4.5	4.0
IR –Revenue Caps* (18.0 – 21.5)	4.0	3.0 (2.5)*	4.0	1.5 – 2.0	1.0 – 1.5	1.0 – 3.0	4.0
Restructuring (24.5 – 26.5)	3.0	5.0	4.5	1.0 – 3.0	5.0	5.0	1.0

* Score without an Earnings Sharing Mechanism (With ESM)

The above table provides one clear message. Traditional rate of return regulation, while very good at inducing investment for reliability purposes, scores very low in economic performance measures such as level and efficiency of prices. With the expectation that markets will play a larger role in the industry in future years, failure to induce efficiency in both production and consumption is a major drawback of traditional regulation. Incentive regulation, provides similar incentives for reliability investments, but provides better incentives for economic efficiency. One conclusion that can be drawn from this analysis is that incentive regulation will provide sufficient incentives for reliability investment while moving the industry toward a more economically efficient production frontier. Therefore, Wisconsin could benefit from harnessing the value that has been left on the table by utilizing traditional methods of regulation, by moving utilities toward some form of incentive regulation.

Recommendations for Reforms that Could Benefit Wisconsin

This report recognizes that Wisconsin policy-makers must decide whether a change should occur, the direction of such change and the pace at which the change is undertaken. After evaluating the alternatives, we recommend the direction of regulatory policy that would be useful for this state. Our recommendations are predicated on two critical presumptions. First, market evolution cannot be held off forever. Markets will continue to evolve and will continue to impact Wisconsin. Second, there are policies that can help Wisconsin move to a more efficient electric industry, that are compatible with future market changes, but are also appropriate if the market does not evolve in the manner posited here. Therefore these changes can be made, without relying on outcomes of future events.

Recommendation 1: Explore Implementation of Incentive Regulation

Incentive regulation of some form should be explored. We describe three forms of incentive regulation in this report, which could be implemented singly or in combination. Price caps, especially if based on a UK style approach, could be very useful to address both capital additions and pricing efficiency. As noted above, capital additions over the next ten years will increase utility rates by a substantial figure. Providing utilities with better incentives to control costs and to price efficiently will provide benefits to consumers. Utilities should be encouraged to develop incentive rate plans to file with the PSCW.

Recommendation 2: Provide Utilities Option of Unbundling Prices

In addition to pricing efficiently, price unbundling may be an approach to provide better price signals to consumers. Price unbundling (i.e., separately pricing distribution services and generation services) would facilitate the ability to utilize a separate incentive program for generation and distribution. Furthermore, to the extent that retail markets evolve, utilities will be in a better position to respond to these changes, should they occur.

Recommendation 3: Modify Legislation to Allow Incentive Regulation To Operate More Effectively

While we believe that the PSCW has sufficient authority to implement some form of incentive regulation, we believe that certain modification to the legislation would allow incentive regulation to perform more effectively. A useful modification would be to allow utilities to use formula rates if in the context of a PSCW-approved alternative regulation plan. Currently Wisconsin law requires rate hearings for rate increases. While this is appropriate under in the traditional model, it is less important under an alternative regulation plan.

Recommendation 4: Promote the Expansion of Utility Service Options

In the 1990s many proponents of restructuring pointed to the varied products and choices that markets can provide. Such options are likely to be beneficial to customers and will educate customers concerning energy choices. While we are not providing a recommendation of the exact products that should be provided, many different options and combinations of options are possible such as:

- Green products;
- Real-time pricing;
- Market-based demand response programs;
- Energy efficiency products and programs;
- Multiple pricing options with various levels of price certainty; and,
- Reliability pricing.

Customers could be given this menu of products that would simulate the competitive market place and provide customers with additional service options. (Some of these programs are demand response programs and will also be addressed in the next recommendation.)

Recommendation 5: Promote the Expansion of Demand Response Programs

Demand response programs are designed to "motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized." Demand response programs are critical to the efficient operation of competitive markets. Further, these programs are beneficial to utilities, customers and society through improved grid reliability, lowering peak prices through removing demand during high-price periods and providing customers benefits through compensation for changing consumption behavior.

The programs come in two forms. First, price-based programs include real-time price, critical peak pricing and other forms of time-varying pricing. Second, incentive-base programs pay customers to drop off or reduce usage based on a pre-defined trigger (e.g., high prices or grid reliability issues) and are generally implemented by the local utility.

In the short-run price based programs will be difficult to implement due to the need for more sophisticated metering that currently is not provided to most customers. However, incentive programs, such as those currently offered by most utilities in Wisconsin, could be promoted (as the PSCW did as part of We Energies demand-side management plan filed in response to the Oak Creek Order.) The PSCW should therefore explore ways to improve and expand incentive base programs, while determining the feasibility and desirability of expanding price-based programs through additional investment in the distribution system (e.g., meters, metering capabilities, etc.)

It is not too much to say that the future of democracy will depend on its success in dealing with the problems of public ownership and regulation. Taussig (1921)

I. Background and Introduction

Perhaps Professor Taussig's flare for the dramatic overstates the case. Yet the issues of regulation and public ownership have indeed been central in much of the discussion concerning economic growth and the evolution of democracy in the last sixty years. Public utilities, in particular, provide the basic inputs to the modern economy and therefore do loom large in the growth of modern economies and, in turn, in the health of modern democracy. Wisconsin has a long and distinguished history in the field of regulation beginning with the passage of the so-called Granger laws to the early establishment of the state regulatory commission. Prior to the Potter Law of 1874 the governor and legislature of Wisconsin addressed, on a regular basis, the concern of, as then Governor Fairchild put it in 1864, "great complaints of unjust exactions of railroad companies in relation to prices charged for freight, and unjust discriminations against some localities in favor of others." Miller (1971, p. 145) These themes of allowing a fair profit and of setting rates without undue discrimination would be a hallmark of the regulation to come whether of railroads, electric, natural gas, or telephone service. What was once termed the "strong" type of regulation was established after the experiments with railroad regulation by states. Glaesser (1927) In 1907, under Governor LaFollette, Wisconsin, along with New York under then Governor Hughes, became the first states to establish a strong regulatory commission. Following the example of these two states, and the legal framework developed in Wisconsin, others followed by expanding the jurisdiction of the regulatory body to encompass a number of other public utilities. Today, the Public Service Commission of Wisconsin (PSCW or Commission) is an independent state agency that oversees more than 1,100 Wisconsin public utilities that provide electricity, heat, water, and telecommunication services.

Wisconsin has been a leader in establishing regulation designed to fill the gap when markets seemingly could not protect consumers. Wisconsin continued this leadership role through the years by implementing marginal cost pricing, comprehensive planning and other measures that improved efficiency in both consumption and production decisions, mimicking the outcomes that would have been delivered had markets been able to play their proper role. In today's marketplace where the electric industry has been largely restructured at the wholesale level as a result of technical innovations and policy decisions, Wisconsin has once again taken the steps to explore the role of markets and regulation through renewed conservation programs, the creation of statewide transmission organization (American Transmission Corporation (ATC)) and the combined use of competitive bidding and long term contracting to secure generation resources for the state.

The purpose of this report is to examine both the nature of the regulatory framework and the potential future market conditions within which it must operate, and examine the implications of the conjunction of forces for the design of future regulatory policies. This analysis will take into account historic, current and expected future trends in energy markets in combination with the existing purpose and design of regulatory institutions in order to identify potential areas in which regulatory changes may prove beneficial in protecting the public interest. These changes can range from greater reliance on markets for certain activities to adjustments in the process of regulation in order to more effectively capture the incentive effects where markets are not deemed effective.

Section II provides a review of the electric industry and the factors driving reform in both the US and Europe. Section III provides a brief summary of the factors driving costs and rates in Wisconsin. Section IV provides a review of regulation, its objectives and how regulation has been implemented in practice. Section V provides a status report on regulation in Wisconsin. Section VI reviews regulatory models in the US and Europe. Finally, Section VII concludes with an analysis of Wisconsin's potential future and the role that alternative regulatory policies can play in enhancing the role of markets where it is feasible and reinforcing regulatory incentives where that will enhance the protection of the public interest.

II. The Electric Industry and Factors Driving Reform in the US and Europe

A. The Electric Industry in Transition

The traditional regulatory bargain required that utilities meet all current supply obligations and plan for meeting future supply obligations in return for a *franchise* in which entry by alternative suppliers was regulated. Utilities have traditionally provided electric service through *bundled* rates. These rates recovered the cost of the three basic functions of electric service—generation, distribution and transmission. G*eneration* involves the creation of electric energy through various means such as the burning of fossil fuels, atomic reactions, or any number of renewable sources such as moving water, sunlight, wind currents, etc. *Distribution* includes the connection of retail customers to the electric grid, the provision of the "wires" service over the low-voltage local area grid, and a number of retailing functions such as metering, billing, customer services, procurement of power and tariff administration. ***Transmission*** involves the transportation of electricity over high-voltage wires between generation sources and distribution centers and the provision of *ancillary services* that maintain the balance between supply and demand and provides for system security.[1]

The electric industry is commonly referred as a ***network industry***. ***See e.g.,*** Economides (1996) or Shy (2001). Network industries have specific characteristics that differentiate them from other industries. Generally, network industries have some or all of the following characteristics:

- *Complementarity, compatibility and standards* Firms compete by selling bundled products that are generally combinations of complementary intermediate goods.[2]
- *Network externalities*. Consumers may be made better off when the network is used by more consumers. For example, subscription to telephone service would not make sense unless the consumer knows that other consumers will also subscribe to the service.
- *Switching Costs and Lock-in*. The costs of switching suppliers can be significant for many customers and this will tend to lock customers into a particular supplier. In the electric industry switching costs can arise from the use of contracts that lock customers into fixed term commitments, the cost of searching for new suppliers and/or technologies when most suppliers are new to the area, and brand loyalty that raises the cost of inducing customers to switch.

[1] Ancillary services include generation-related services such as spinning reserves, non-spinning reserves, standby reserves, frequency regulation, blackstart and non-generation related services such as scheduling and dispatching. The generation-related ancillary services are differentiated by the speed at which they can be called upon to maintain the balance of supply and demand (except for blackstart which refers to generation resources that can be self-started after a network has lost stability). This can range from instant response to 30- or 60-minute response. The non-generation related ancillary services refer to services provided by the transmission operator that are necessary for generation to be placed online.

[2] Consumers are shopping for final products that are made up of (possibly) multiple sub-products. Each sub-product must be compatible with the other sub-products, which in turn means that the market players must "agree" upon standards of compatibility. Firms compete by selling bundled products that are generally combinations of intermediate goods that are self-supplied or procured from multiple suppliers

- *Economies of scale*. Economies of scale in, for example, transmission and distribution are important in network industries. This implies that network industries are likely to be imperfectly competitive and concentrated.

Electric networks require the continual balance between supply and demand such that the network meets certain physical reliability characteristics, such as frequency and voltage control along with network stability and network constraints such as thermal line limits and contingency constraints. Electricity cannot (yet) be economically stored; therefore network supply must be ready to meet demand on a continual or real-time basis. As electricity flows according to the laws of physics (i.e., Kirchoff's laws), it follows the path of least resistance. Coordination of the generating facilities is required in order to maintain the reliability and quality of the power on both the transmission and distribution grid.

Nevertheless, during the last two decades the electric industry in the United States and the European Union has undergone a series of changes that have fundamentally altered the wholesale electricity market and, in some cases, the retail electric markets as well.[3] These changes were brought about by a confluence of forces including legislative and regulatory changes along with economic and technical changes. Traditionally, the argument for regulating electric utilities was that they constituted natural monopolies.[4]

In the US, Federal legislation in 1978 (Public Utility Regulatory Policies Act or PURPA) and in 1992 (Energy Policy Act or EPAct) promoted the installation of generation capacity by non-utility entities along with promoting other pro-competitive policies.[5] In addition, the Federal Energy Regulatory Commission (FERC), in a series of orders beginning in the mid 1990s with Order 888 and 889 and more recently with Order 2000, has used its authority to promote "non-discrimination" in rates and charges for transmission services to open the transmission grid. In addition, using its general authority to divide the country into regional energy grids in order to promote "open access" to the interstate transmission grids, FERC encouraged the formation of large transmission controlling entities that can better facilitate the creation of competitive wholesale power markets. Retail markets also began to be opened up in the 1990s as states from Maine to California passed legislation restructuring their electric services markets and promoting entry by third-party suppliers, while maintaining regulatory authority over the delivery function of the incumbent utilities.

In Europe, the trend toward liberalization and privatization began in the early 1980s. With the economic integration of Europe through the European Union (EU), economic policies began to be normalized across nations. ***See e.g.,*** Vickers and Yarrows, (1988), Armstrong ***et al.*** (1994) or Newberry (1999). The electric industry was no exception. The European Commission (EC)[6] envisaged a large market for electricity and issued its first Electricity Directive in 1996 that created a roadmap for a

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[3] In the United States, the electric industry has been overwhelmingly privately owned and operated. Restructuring in other industrialized nations also included the step of privatization. ***See e.g.,*** Green and Newbery (1998) and Newbery (2000) (UK), Guasch and Spiller(1999) (Latin America), and *The Electricity Journal*, April 1999 (Global Restructuring).

[4] A "natural monopoly" exists when, relative to the market demand, the minimum efficient scale of production implies that only one firm can profitably enter the market and produce at the lowest possible cost.

[5] Although the purpose of PURPA was to promote the expanded use of cogeneration technology and renewable resources, its effect was to alter the common perception concerning vertical integration.

[6] The European Commission (EC) is an institution of the European Union and is made of a member from each of the EU's member states. The EC is charged with implementing common policies, proposing legislation and managing the EU's programs.

common electricity market through reforms of the electric supply industry and regulatory institutions.[7] For example, in the first Electricity Directive retail competition was to be phased in such that roughly one-third of each retail market was to be open to competition by early 2003. In addition, transmission networks were to be open to users for competitive transactions and cross boarder exchange was to occur in an open and transparent manner. In 2003, the EC released a second electricity directive to tighten regulation on the access to networks and require independent regulators. *See* Directive 2003/54/EC, OJ L 176, 15.7.2003 The second directive creates a goal of 2007 to create unbundling of the transmission and distribution operators, free entry of generation, monitoring of supply competition, full open markets, promote renewable resources, strengthen the role of the regulator and create regulatory body or bodies that will govern the industry. (Germany was the last country to institute an independent regulatory body in 2005.) The change in European policy over time is illustrated in Table 1. Appendix 1 provides more detail on the definitions and policies contained in the directives.

Table 1: Changes in EU Electric Industry Policy

	Common Pre-1996 Policy	**First EU Electric Directive (1996)**	**Second EU Electric Directive (2003)**
Generation	Monopoly	Authorization Tendering	Authorization
Transmission (T) Distribution (D)	Monopoly	Regulated Third-Party Access (TPA) Negotiated TPA Single Buyer	Regulated TPA
Supply*	Monopoly	Accounting Separation**	Legal Separation from T&D**
Customers	No Choice	Eligible customers (≈1/3)	All non-residential (2004) All customers (2007)
Cross-Border Trade	Monopoly	Negotiated	Regulated
Regulation	Controlled by Government Department	Not Specified	Independent Regulatory Authority***

Adapted from Vasconcelos (2004)
* Supply, under EU Electricity Directives, refers to the sale, including resale, of electricity to customers.
** Accounting separation refers to utilizing separate accounts for the different functions of the utility. Legal separation refers to separation of decision making, and can include, but does not require divesture.
*** The regulatory body is not only independent of the industry, but also of the government.

In the US, the factors driving restructuring varied among jurisdictions at both the Federal and state levels. However, there is an important aspect of regulation in the United States that is often overlooked when comparisons are made with other countries and systems of regulation. The constitutional structure, primarily the takings clause, establishes a unique set of conditions that many countries do not have as a constraint. In balancing the Police Powers and the prerogatives of management to control their private property, regulation has developed a complex set of laws and precedent that together present a rather unique set of conditions. That said, in the US, different jurisdictions placed differing weights on different factors. As discussed later in this report, Wisconsin has placed a very high value on reliability and made the determination that restructuring did not provide enough certainty with

[7] Directive 96/92/EC, OJ L 27, 30.1.1997. Peterson and McDermott (2002) discuss the implementation of the first Electric Directive in the prospective EU member states in Eastern Europe.

respect to the issue of reliability. Other states made similar choices based not only on reliability but also volatile prices and other uncertainties that surrounded restructuring. However, while some of these factors may have been less emphasized since the early 1990s, as a result of failures, and subsequent learning, in the implementation of certain regulatory schemes, in the early 1990s the movement toward restructuring of the electric industry was impacted by three main factors: Economic, political and technological.

B. Political Factors Affecting Reform

A natural place to begin to understand why restructuring has taken place in the United States is the economic performance of the industry over time. Comparing the pre-restructuring US electric sector with pre-restructuring electric industries in other countries, the US electric industry has generally had a decent record with respect to high levels of reliability; investment has generally kept up or even exceeded demand growth; technical aspects of the system have generally been favorable, (e.g., losses from theft and from the physical characteristics of the network are generally low); electricity is available to most people in most parts of the country; and the average price in the US is generally on the low end when compared to our Western European counterparts. Table 2 provides a comparison of electricity prices in Western European countries and the US.

Table 2: Electric Prices in Western Europe and US in 1995 (cents/kWh)

Country	All Sectors
Germany	11.88
Italy	10.00
Portugal	9.65
Belgium	9.12
Spain	8.50
United Kingdom	8.09
Luxembourg	7.62
Ireland	7.40
France	7.39
Netherlands	7.27
United States	7.01
Greece	6.87
Denmark	5.89
Finland	5.72
Norway	4.72
Sweden	4.22

Source: Electricity Association Ltd. cited in Guasch and Spiller (1999, Table 1.9)

Table 2 implies that the US electric sector was operating relatively efficiently compared to similar industrialized countries.[8] Still, many utilities in the US have been saddled with large costs of

[8] There are various aspects of doing business beyond the efficiency of operating the utility that could impact the final price paid by customers. For example, the Scandinavian countries have vast, reliable and low-cost hydroelectric resources. In addition, some countries have high costs of doing business in general for a variety of reasons such as restrictive work laws, costs of social programs and other government-enforced restrictions. Guasch and Spiller (1999) review some of the non-productivity aspects that may cause prices to differ among countries.

generation, either through state-mandated long-term power contracts or the high cost of large base-load generation plants, namely nuclear stations. There is the perception that the longer run performance of the industry, e.g., generation investment, could be improved through the promotion of competition at the retail and wholesale levels. [9] The primary manifestation of long-run performance in the US electric industry is the rates charged by utilities.[10] Table 3 provides the 1995 average electricity price for selected states.[11] Joskow (1997, p.127) notes that during this same period, the short-run unregulated price of electricity was around 2.5 cents/kWh and the long-run marginal cost between 3-4 cents/kWh.[12] Table 3 suggests that states where the industrial prices were above the *expected* unregulated price of about 4 cents/kWh, are likely to have been the first to restructure their markets.[13]

Table 3: Electric Prices in Selected States, 1995 (cents/kWh)

State	All Sectors	Residential	Industrial	Beginning of Restructuring
Massachusetts	10.3	11.4	8.6	1996*
Connecticut	10.5	12.0	8.1	1995**
New York	11.1	14.0	5.6	1996
Virginia	6.3	7.9	4.2	1999
Florida	7.1	7.8	5.2	--
Indiana	5.3	6.8	3.9	--
Wisconsin	5.4	7.2	3.8	--
Illinois	7.7	10.4	5.3	1997
Texas	6.1	7.7	4.0	1999
Arizona	6.2	9.1	5.3	1998
Oregon	4.7	5.5	3.5	1999***
California	9.9	11.6	7.5	1994
South Dakota	6.3	7.1	4.5	--
Minnesota	5.7	7.3	4.3	--
US Average	6.9[+]	8.4	4.7	--

Source for Prices: Table 27, Electric Power Annual, 1995, Vol. 1, Energy Information Administration
[+] The "All Sectors" price in Table 2 and Table 3 do not match due to differences in calculation techniques.
* Regulator issued first restructuring plan. Final plan issued in 1997.
** Regulator issued report calling for restructuring.
*** Legislation allows for partial retail access.

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[9] Prior to privatization in Britain, the British Monopolies and Mergers Commission (MMC) undertook efficiency studies of the industry and found that implicit subsidies had been created for British coal miners and that problems existed in investment, especially power plant construction times, costs and evaluation of investment, but that technical operating efficiency was reasonably good. *See* MMC (1981).

[10] This is long run in nature because rates tend to be based on the embedded or historical book costs of the utility. Therefore, if the utility entered into high-cost power contracts or has high fixed cost generation that should show up in the final rate paid by consumers.

[11] 1995 was chosen because many states began discussions concerning retail competition around this time.

[12] The prices cited here are for the commodity only and do not include the transmission and distribution (T&D) portion of the final delivered price. Table 3 is a final delivered price, *including* T&D costs. Assuming that T&D costs are around 1.0 cent/kWh for industrial customers, those states that exceed 5.0 cents/kWh for the final delivered product are likely to feel pressure from industrial customers for retail access before others.

[13] The California Public Utilities Commission (CPUC) Staff noted the existence of a "price-cost gap" as one of the economic factors that drives bypass opportunities. (Yellow Book, p. 107) Also *see* e.g., White (1996) and Joskow (1996).

The political factors behind the move to wholesale and retail competition in the electric industry are varied. However, some trends are clearly visible. Due to a combination of the "price-cost gap" and "price envy," where industrial firms operating in multiple states could compare rates across jurisdictions, many large industrial customers began to focus on "choice" as a means of prompting local utilities to move prices closer to incremental costs or to force a movement to open access. There were also superficial comparisons made between other industries undergoing restructuring such as the natural gas, airlines, trucking, telecommunications and the electric industry.[14] As the 1980s wore on, the political culture in the United States, as with many industrialized nations, moved toward greater acceptance of market forces to determine the allocation of resources in industries previously considered too "essential" to leave to the whims of market forces. In addition, the promise of lower electric rates from eliminating the price-cost gap appeared to be one policy that state governments could use to encourage more business and commercial operations in their states.[15]

C. Economic and Technological Factors Affecting Reform

An oft-cited benefit of electric industry reform is the private incentive to build generation. Many observers looked at the surplus capacity situation in the 1970s and 1980s and placed the blame at the feet of monopoly institutions and inept government planning. Placing the planning function in the hands of private industry, through the introduction of competition, was thought to result in more efficient deployment of generation. Indeed, since the creation of wholesale independent power companies by PURPA, the repeal of the 1978 ***Power Plant and Industrial Use Act*** in 1987, which removed the restrictions on the use of natural gas in the production of electric energy, and the greatly expanded role of competitive generators by the 1992 Energy Policy Act, the increase in non-utility owned generation has been precipitous. The Energy Information Administration (EIA) noted that between 1998 and 1999, the total generation capacity owned by US utilities fell nearly 50,000 MW or about seven percent and the amount owned by non-utilities rose by about seventy percent.[16] Regionally, approximately 12,000 MW of new generation was built in Illinois in the years after the restructuring of the state's electric industry in 1997. ***See e.g.,*** McNeil (2005) In Indiana, the Indiana Utility Regulatory Commission reports that nearly 4000 MW of merchant generation is currently operating.[17] In Wisconsin, as late as 1996 there were no merchant generation plants in the state. Yet by 2004, 2200 MW of generation used by electric utilities in Wisconsin is under contract from merchant power plants. (2004 SEA Report, p. 16) While these figures are expected to decline over the next few years as new utility-generation comes on line, the capacity from merchant plants will still be available to sell into the wholesale market.

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[14] There is some evidence that deregulation in many of these other industries has been beneficial. Guasch and Spiller (1999, pp. 9-25) review some of this evidence.

[15] It is somewhat ironic that in the 1993 Yellow Book, the CPUC Staff notes that California was in the midst of one of the worst economic downturns since the 1930s with all of the resulting problems such as high unemployment and state government budget shortfalls. (Yellow Book, p.116) It is commonly thought today that one of the reasons California's electric supply problems are so acute is the tremendous growth in economic activity since the mid-1990s. *See e.g.,* Newton (2001).

[16] The large rise in non-utility ownership is due to the divesture of generation assets by incumbent utilities. Although around 20 percent of the increase was due to new non-utility plants. In 1999, the EIA reports that about 20 percent of the total industrial capacity is now owned by non-utility entities. *See* "Inventory of Electric Utility Power Plants in the United States 1999," and "Inventory of Electric Non-Utility Power Plants in the United States 1999," EIA Data Reports. (These reports were discontinued in 2000)

[17] "Indiana Merchant Power Plants" at www.in.gov/iurc/utilities/energy/power/power_index.html (visited on 2/18/2006)

A significant question remains concerning the optimal mix of generation that will be forthcoming from the marketplace.[18] To date most non-utility generation that has been built, as opposed to plants purchased from existing owners, are fired with natural gas. Natural gas was a very attractive fuel in the late 1990s due to the low capital costs of the generation units and low operating costs because of low gas prices. However, since the early part of this century natural gas prices have risen to levels that were largely unpredicted and are unprecedented (in nominal value). While gas-fired units remain low cost in terms of the capital outlays, the incremental costs have increased dramatically in the past few years. Since these plants are normally used to provide service during peak times and are generally the last units dispatched, they have a tremendous effect on the market price of electricity in those hours when they are dispatched. This debate over the value of decentralized generation planning will continue into the future.[19]

While generation competition came to forefront in the 1990s, the case against strong economies of scale in the generation business had largely been settled for thirty years. *See e.g.,* Shepherd (1973), Klass and Shepherd (1976), or Joskow and Schmalensee (1983). Rather, the case for vertical integration, and in turn regulation of natural monopolies, was largely a result of the attributes of the transmission network via the aggregation and coordination of generation assets over a wide area. Many of the attributes of the transmission of energy noted above, e.g., instantaneous matching of supply and demand, the flow of power via laws of physics and the maintaining of system security have attributes of a ***public good.*** For example, maintaining system reliability benefits all who receive power through the network, yet each individual would prefer that others pay for this service.[20] From an economic point of view, this makes it attractive for one entity to solve these problems through vertical integration and charge ***all*** users for these services. However, it is likely that technological innovation has begun to reduce the coordination problem on the transmission network. For example, information technology has made great strides even compared to a few years ago. Current information processing technology helps break down some of the barriers to coordination of generation on the transmission network. Indeed, it is difficult to imagine operating modern transmission networks, while allowing open access, without modern information technology. These technological innovations have made wholesale competition between and among multiple players much more feasible than it would have been even thirty years ago when it became apparent that generation scale economies were beginning to subside.

III. Key Factors Driving Electric Costs and Rates in Wisconsin

A. Current Situation in Wisconsin

After nearly a decade of flat or falling electric rates in the United States, rates for the major end-use sectors have begun to increase since the beginning of this decade. Wisconsin has not been immune to this trend.(*See* Figure 1) End-use rates are composed of the costs to provide generation, transmission and distribution services as well taxes and other "adders" that recover costs otherwise not included in the bundled rates (e.g., the costs of variable items such as fuel, societal benefits charge, etc.). While currently

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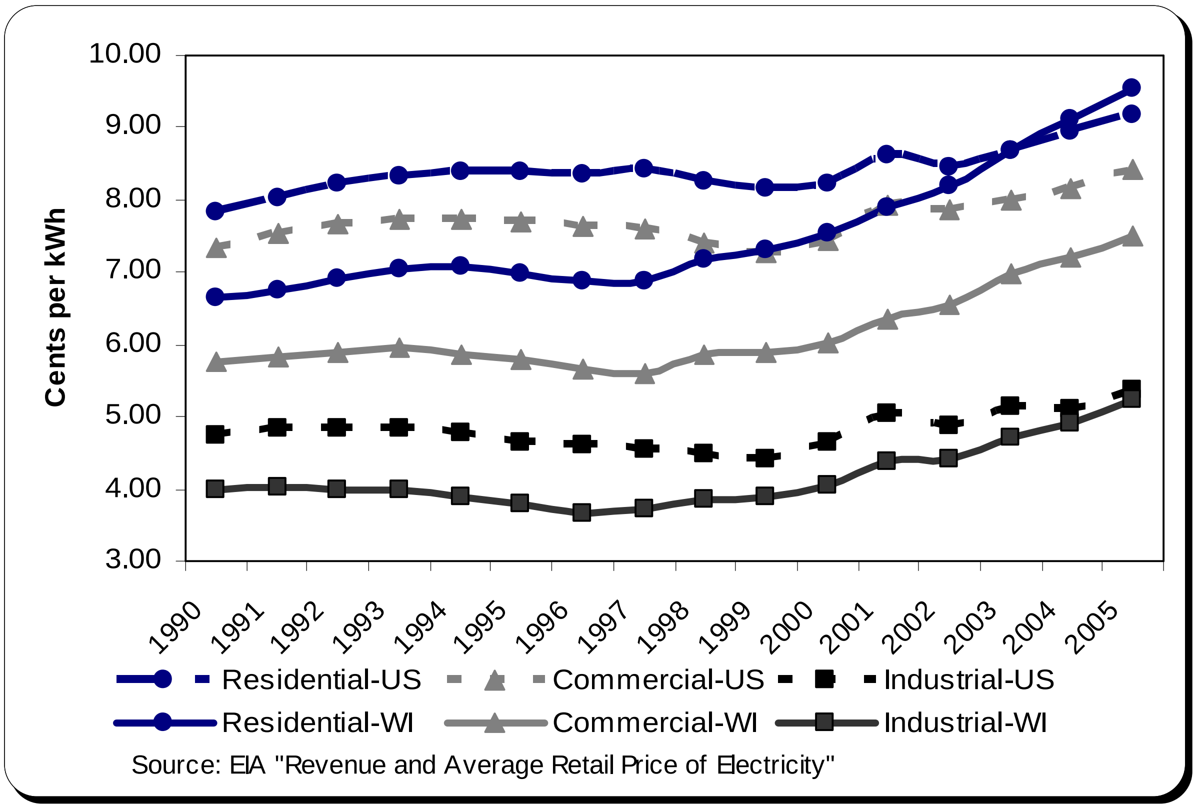
[18] In its 2004 SEA Report, the PSCW notes that concerns over supply diversity (i.e., optimal mix of generation) contributed to the PSCW's approval of the PTF coal plants. (Chapter 6, citing the Oak Creek Order at 31) Specifically, the PSCW rejected the use of an additional gas-fired resource proposed by an independent power producer because "relying upon natural gas to meet WEPCO's baseload needs as well as its intermediate and peaking requirements would raise the risk of not properly diversifying the utility's fuel mix." (*Id.)*

[19] Decentralized markets have been shown to produce optimal generation investment, if demand is sufficiently price-elastic, such that supply and demand curves will always intersect. (***See e.g.,*** Caramanis ***et al.*** (1982). However, as discussed below, demand has been largely ignored in the rush to competition and therefore the assumption of a strong demand side of the market may not hold true.

[20] Although this is true in the regulated world, a market could be allowed to price such that security is no longer a public good. *See e.g.,* NERA (2005, p.10)

the generation and distribution costs are not separately identified in the tariffs of any of the electric utilities in Wisconsin, it is commonly understood that generation is the largest portion of the average electric bill (e.g., perhaps 50 to 60 percent of the total bill). The rest of the bill is comprised of transmission (≈15-20%), distribution (≈15-25%) and other charges (such as taxes and adders).[21] Costs, and in turn, rates, are driven by both supply and demand side factors. Figure 2 illustrates the actual and expected demand through 2010 in Wisconsin.

Figure 1 US and Wisconsin Electric Rates (Nominal) by Sector 1990-2005



On the supply side, Wisconsin utilities had 12,293 MW of generation in 2003, yet by 2010 it is expected that demand will exceed 15,000 MW. (2004 SEA Report, Table 2-01) Therefore, capital additions in the form of new generation stations will be necessary over the next few years in order to meet expected demand and to replace retired equipment. Accordingly, both utilities and independent power producers are expected to build new power plants.

Figure 3 shows the expected capacity additions by IOUs over the next five years. The 2004 SEA report suggests that as a result of this building, customers of Wisconsin utilities will be paying an additional $430 million annually in capital costs. (*Id.,* p. 15) In addition, purchase power costs included in rates was $675 million in 2002 (*Id.,* p. 48) Also, generation, whether utility-owned or owned by independent entities, must operate in the national and global fuel markets. These markets have been particularly heated in the last few years as demand for fossil fuels (natural gas, coal and oil) has increased. In the global oil market, emerging economies and domestic demand has sustained large increases in world oil prices over the past five years. The domestic natural gas and coal prices have also increased in this

[21] For very large customers, generation can reach upwards of 80 percent of the customer's bill.

same time. (*See* Figure 4) While purchase power levels are likely to decrease in the short term due to construction of new power plants, the conclusion that "there will be continued pressure on rates due to fluctuating natural gas prices as well as to the proposed…construction program," appears to be accurate. (*Id.* p. 147). In addition to generation investment, network investment in the transmission system will also increase over the next ten years. According to the 2005 ten-year assessment by the ATC, projects totaling $3.4 billion will be necessary through 2014. (ATC 2005 10-Year Assessment, Executive Summary) According to the ATC's 2004 Annual Report (p. 1), net transmission investment had been relatively constant from 1989 through 2001 at roughly half a billion dollars. Therefore, transmission investment is expected to be significantly higher in the next ten years relative to the last ten years. In addition, continued investment in the distribution system will be necessary to retain and improve system reliability and to meet increasing demand. All of these factors suggest that the cost of providing electric service in Wisconsin, and in turn the rates customers pay for electric service, will continue to rise in the near term.

Figure 2 Wisconsin's Electric Demand-Historical and Forecast

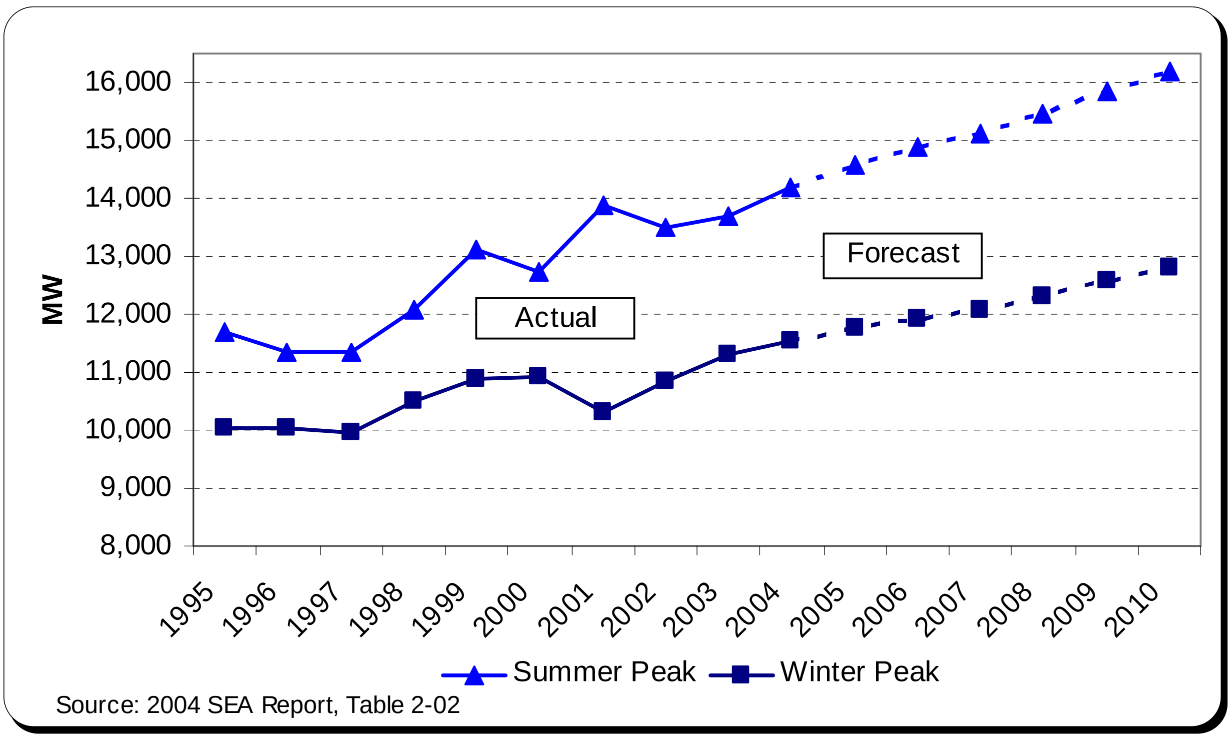


Figure 3 Proposed Generation Additions by Wisconsin Investor-owned Utilities

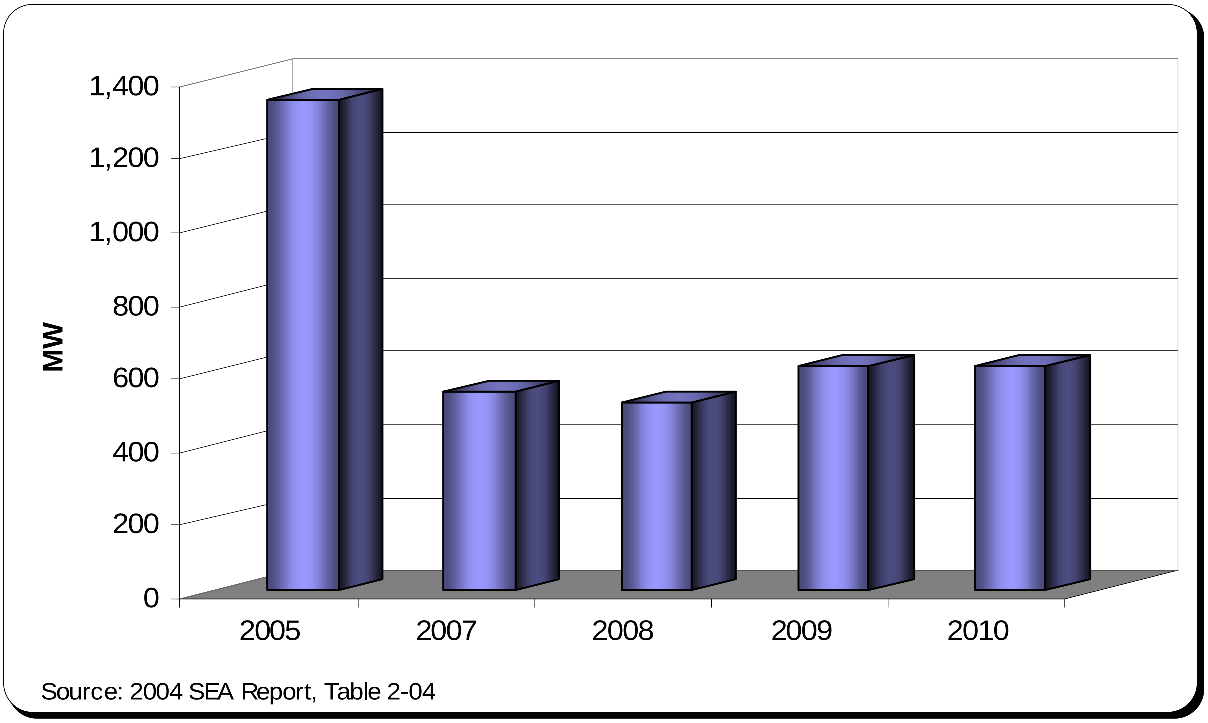
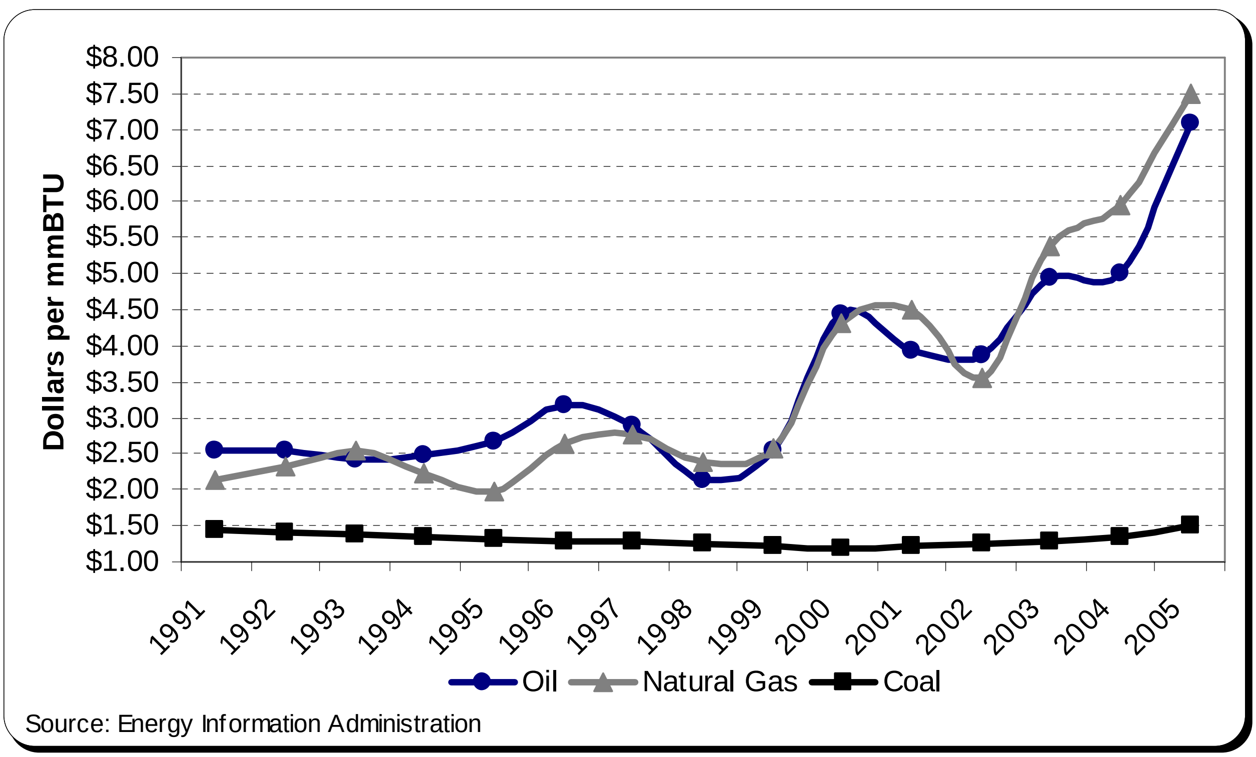


Figure 4 Fossil Fuel Prices for Use in Electric Generation



B. Trends in Cost Factors and Markets

The trends identified above are likely to affect not only Wisconsin but also the nation as a whole. States that have restructured electric markets will experience the effect of the fossil fuels market more directly through the pricing of end-use electricity supply. However, Wisconsin and other states that have not restructured electric markets will not be immune to the market forces in the fossil fuel markets and electric markets. While Wisconsin has a large number of proposed new coal-fired power plants that can serve as a hedge against the oil and natural gas price volatility, large base-load units such as this have large capital costs. Figure 5 presents the overnight capital costs used by the US Energy Information Administration in its energy market modeling. New coal-fired plants, scrubbed to meet the latest environmental requirements, are roughly twice the unit cost of gas-fired plants. New integrated gasification combined cycle (IGCC) plants that utilize coal as a fuel stock and use combined cycle technology, are promising from an environmental standpoint, but have yet to be embraced by the industry or by regulators. For example, the PSCW recently declined to allow We Energies to include an IGCC as part of its Power the Future construction program.[22,23] In addition, as noted above, recent coal market activity shows a marked increase in the price of coal. Therefore, with the additional capital costs of the coal-fired power plants entering the Wisconsin market, in addition to the prices of fossil fuels, these factors will place upward pressure on rates.

There is also the outstanding issue of power plant investment in restructured markets. Some observers are concerned that energy-only markets will not provide sufficient incentive for non-utility investment in base load plants and therefore capacity markets must be established.[24] This concern is generally raised in the context of building new coal-fired, and even nuclear, power plants that have relatively low operating costs but large capital costs. (Figure 5) If energy-only markets are not sufficient to elicit new investment, regional markets may have even larger increase in prices due to the over reliance on gas-fired technology.[25] This will place significant pressure on utilities with lower cost generation to sell into the market to take advantage of the higher market prices and will therefore tend to equalize the wholesale market price across regions. However, if these markets do operate as advertised then investment should occur whenever the energy cost savings exceeds the additional capital costs. However, this may still mean that prices will have to increase significantly in more hours of the year to support the large capital investments required to build these plants.

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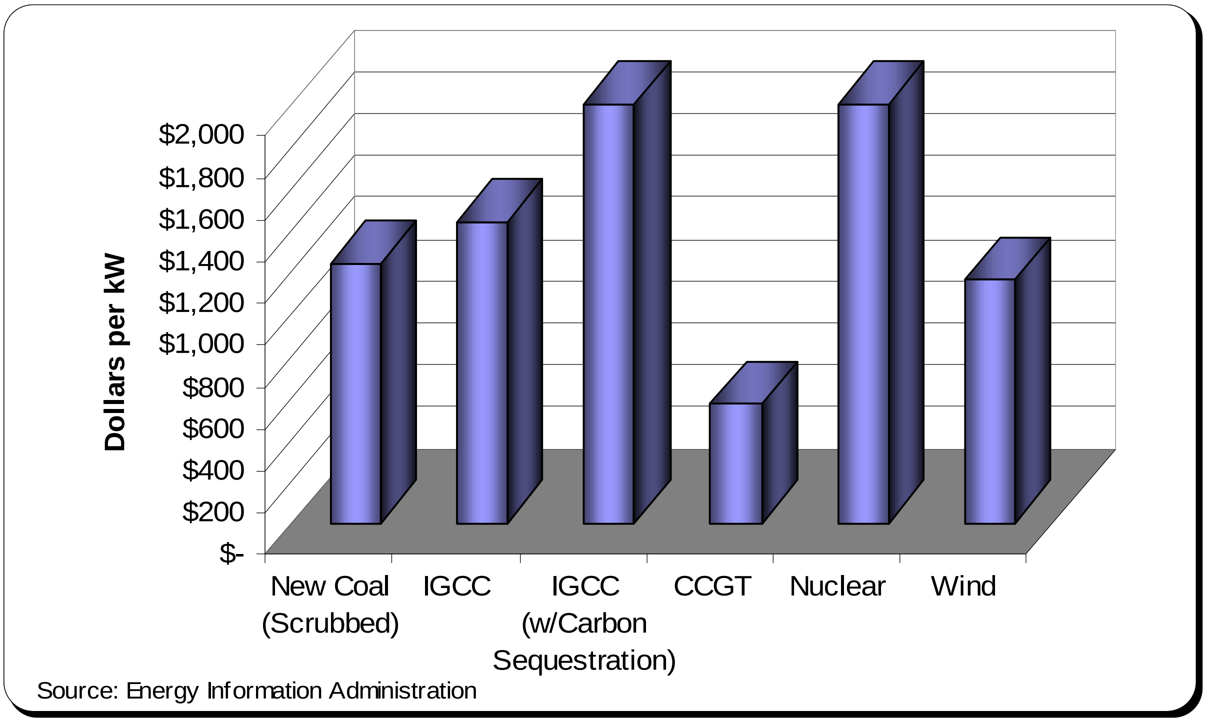
[22] The PSCW found that the IGCC would increase the generation expansion plan costs by $349 million due to its relativity high capital costs ($1,579/kW as opposed to approximately $1,400/kW for the other two coal units). In addition, the Commission found that the units are not as efficient as the other proposed coal units (i.e., super-critical pulverized). *See* Order in PSCW Docket Nos. 05-CE-130 and 05-AE-118 at 26, mailed November 10, 2003.

[23] The US DOE recently did a survey of industry participants and found that IGCC's capital costs are a significant deterrent to investment, but not the only deterrent. Issues such as excessive downtime, lack of standardization, regulatory uncertainty, and financing difficulties are all key factors that have retarded the market penetration of IGCC's. *See e.g.,* Berg (2004).

[24] The form of the market may not be the only factor with an effect on current generation investment decisions. It can be argued that regulatory uncertainty concerning the type and form of restructuring creates an option value from delaying investment until more information is known about the restructured market. *See e.g.,* Ishii and Yan (2004).

[25] Real-time markets clear based on the highest cost unit bid into the market. While the Midwest has traditionally relied overwhelming on coal-fired generation, for an increasing number of hours of the year, gas-fired units will be the last units dispatched to meet load. Therefore, market price will be more reflective of the cost of producing electricity utilizing natural gas and to the extent that natural gas prices remain high, electricity market prices will continue to remain high in those hours of the year that gas sets the price.

Figure 5 Overnight Capital Costs for Common Generation Technologies



IV. Regulation of Public Utilities: Objectives, Methods and Outcomes

A. Objectives of Regulation

The basic premise for regulation has traditionally been the inability of the competitive market to control prices and to provide for recovery of investment over a long period. In the United States, utilities most often operated as privately-owned companies under a franchise provided by a local government unit. In Western Europe, utilities often operated under the social management of either a national agency or a local council.[26] However, in both the US and Western Europe, the basic objective was to provide for the needed investment in facilities while providing customers with reasonable prices for the service. Phillips (1985) provides a list of the common objectives of public utility regulators:

- Prevent the exercise of monopoly power;
- Assure the utility adequate earnings;

[26] The industry did evolve slightly differently in different countries in Western Europe For example, in Britain, the initial approach, as in the United States, was *laissez faire* capitalism, which was reinforced by the strong private property ethic. As Newbery (1999, Chapter 3) notes, "[I]t was not until the imperial and class confidence was shaken after the First World War, the Russian Revolution and the General Strike of 1926" that general dissatisfaction with the utility sector in Britain lead to widespread nationalization. Nationalization of the electric supply business in Britain did not occur until after World War II. *See e.g.* ,Vickers and Yarrow (1988) or Armstrong *et al.* (1994). In other countries, ideology, in the form of attaching a larger weight to public welfare, as opposed to private profits, moved governments in the direction of nationalization. (Newbery 1999, Chapter 3).

- § Universal service coverage;
- § Promote the development of industry;
- § Insuring public safety and management efficiency;

Breyer (1982, p.37) also lists the objectives of traditional regulation as "(1) preventing excess profits; (2) holding prices down to costs (including reasonable profit); (3) avoiding economic allocative waste--that is, minimizing shortages and surpluses as well as directing resources to where they satisfy the greatest demand; (4) eliminating inefficient production methods; and (5) assuring administrative ease." That the fifth goal, that is, the ease of administration, often conflicts with the first four goals is a point that Breyer strongly emphasizes.

Beyond these goals regulators also may have social objectives including attention to the environment, ensuring fair treatment of consumers both in pricing and in the terms of service, and, with the advent of competition, regulators also have the goal of ensuring non-discrimination in access to the network and a ensuring development of efficient competition.

In implementing policies to address these objectives, regulators have found that many of these goals imply trade-offs. For example, in Wisconsin, the PSCW has made it clear that reliability and price entail trade offs:

> The Commission has and continues to maintain a policy of ensuring financially strong electric utilities because it provides managerial wherewithal to deal with emergencies and contingencies to ensure safe and reliable electric service for all customers. Lowering an authorized return on shareholder equity by 100 basis points from 12.0 percent to 11.0 percent for a utility about the size of WPSC or WP&L would reduce revenue requirement around $9 million and represent less than a 1.5 percent decrease in overall rates. (2004 SEA Report, p. 107)

Therefore, given these often incongruent objectives, no single policy can ever hope to satisfy all these objectives. Regulation, due to its very nature, creates conflicts between valued ends (***e.g.***, efficiency versus equity), yet this is the same problem policymakers have in implementing markets in infrastructure industries. There may be no way to harmonize these ends completely. Solutions must be designed to address the problems faced by the industry at a given time and those solutions may be different based on the facts of the situation. However, as counterproductive as this may sound, there is still room for action by regulators to improve the efficiency of the industry.

B. Public Utility Regulation in Practice

Regulation originally evolved through three phases.[27] The first phase was that of "weak" regulators with the role of "advisor." Several states, mostly in New England, established regulatory bodies between the 1830s and 1860s. These bodies did not have the power to establish rates, but generally oversaw safety and other issues and collected data to provide to the state legislatures. During the Granger[28] movement, several state legislatures in the upper Midwest, and selected other states,

[27] The discussion of the phases of regulation relies on Garfield and Lovejoy (1964, Chapter 3). The rest of this section is based on McDermott (1995).

[28] The Granger movement was so-known due to its association with the National Grange of the Patrons of Husbandry.

implemented maximum rates for railroads or authorized a state commission to set these rates. However, largely as a result of the panic of 1873, this type of regulation was phased out. The third phase of "strong" regulation was ushered in partly as a result of the progressive movement in Wisconsin.[29,30] Concepts such as reasonable value of assets and rate of return were strong influences on the design of economic regulation.[31] For example, in 1905 Wisconsin passed the Railroad Regulation Bill which incorporated the concept of an accounting rate of return to ensure a "fair" return to owners and reasonable prices for consumers. ***See e.g.,*** Covaleski ***et al.*** (1995). In 1907, Wisconsin established the Public Utility Law, which served as a model for other states.[32] The underlying philosophical rationale embodied in the 1907 law was a result of the perceived need to protect the public from exploitation by monopoly interests while at the same time attempting to provide incentives to exploit the inherent cost efficiencies of the natural monopoly.[33]

1. Regulation and the Competitive Market Model

While it is difficult to draw bright lines that connect the prevailing attitude toward competition and laissez-faire philosophy to the design of the standard regulatory instruments, an argument can be made that the US style rate-base, rate-of-return regulation was based on a static notion of competitive equilibrium in the neo-classical economic paradigm.[34] A typical understanding of the regulatory process is found in Bonbright (1961, p. 93).[35]

> Regulation it is said, is a substitute for competition. Hence its objectives should be to compel a regulated enterprise, despite its possession of complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation but subject to the market forces of competition. In short, regulation should be not only a substitute for competition, but a closely imitative substitute.

[29] Wisconsin Governor Robert LaFollette and John Commons of the University of Wisconsin were important early figures in the move toward strong regulation.

[30] The adoption of regulation of public utilities in the early twentieth century has long been assumed to result from the industry's concern over its own profits (i.e., to limit competition). ***See e.g.,*** Jarrell (1978). However, this view has been challenged recently with evidence suggesting that interest groups (e.g., coal miners, customers, etc.) and the move toward correcting regulatory inefficiencies played a significant role in the decision to adopt state regulation of electric utilities. ***See e.g.,*** Knittel (2006).

[31] Commons wrote a report in 1907 that likely lead to rate of return regulation adopted by 29 states and the federal government by 1913. ***See e.g.,*** Trebing (1984).

[32] New York passed a similar measure one month before Wisconsin. However, the New York law did not provide the level of authority the Wisconsin statute provided the regulator. ***See e.g.,*** Jones and Bigham (1931, pp. 163-174).

[33] The 1907 law embodied most of the standard concepts still in practice today such as asset valuation, uniform system of accounts, rate setting and general oversight of the utility by the regulatory body. Jones and Bigham (1931, pp. 174-188) provide a more detailed description of the design of the Wisconsin legislation.

[34] Neoclassical economics refers to the branch of economic theory that focuses on the choices economic actors make on the margin. This paradigm is premised on the assumptions that economic units maximize their private benefits (e.g., utility for consumers, profit for firms), consumers have rational preferences among outcomes and all actors act independently of one another and have complete information concerning their choices.

[35] This is a very common sentiment. ***See also e.g.,*** Kahn (1988, Vol. I p. 17), Baumol and Sidak (1994, p.5) and Phillips (1985, p. 154). Hausman (1996, p. 264) dissents from this position and suggests that such an approach is "ill-conceived…since the technology that leads to regulation would not lead to a competitive outcome."

By focusing regulation on the neoclassical competitive equilibrium conditions, the motive force inherent in the operation of a market, namely super-normal profit, was lost and regulation was saddled with an incentive problem from its inception. The equilibrium conditions identified with perfect competition can be summarized as: (1) the firm earns a normal profit (rate of return); (2) the minimum efficient scale of production is achieved, and (3) prices equal the marginal and average total cost of production. In this static view of a competitive equilibrium, a firm would earn a normal or ***fair*** return while charging prices that reflected the incremental costs associated with the efficient level of production. However, as noted above, the electric industry was a natural monopoly. Therefore, setting prices specifically based on the competitive equilibrium model, while promoting the efficient level of output, will not provide firms with the incentive to invest.[36] The solution, based on the equilibrium concept, was to calculate the total cost of serving customers and set prices to recover total revenues to match the total costs exactly. This is the ***revenue requirement*** approach to regulation that has been pervasive in the United States for most of the last one hundred years.

However, the history of regulation in Wisconsin, and other states, could be described as a long struggle to address the inherent contradictions of applying a static equilibrium-oriented system of regulation when the world seems to be characterized by a dynamic markets often reflecting disequilibrium. Although traditional regulation appears to have worked reasonably well during periods of economic stability or periods of stable growth, it can be argued that the crux of the problem lies in addressing periods of rapid change and disequilibrium. In part, this is the result of the incentive structure created under the static approach to regulation. That traditional regulation has generally constituted an incentive failure should not give rise to false hopes that a system of regulation can be designed that embodies a set of ideal dynamic incentives compatible with and capable of inducing "optimal" behavior.[37] The truth is far messier than most would like to admit.

In some sense the disequilibrium experienced by the electric industry in the 1970-80s confirmed that traditional regulation could not duplicate the effects of competition or the market.[38] The most glaring aspect of this failure was that the increase in generation capacity, as a result of unrealized forecasted demand, resulted in end-use rates rising. Simple economics would suggest that the opposite should occur. Interestingly enough, over time, as the surplus built up, utilities began to shop surplus supply in the wholesale markets and, in part, created the arguments to restructure the industry and shift to the use of markets as opposed to regulation. Restructured markets operate such that when supply exceeds demand prices fall and the risk of bankruptcy is borne by stockholders and not ratepayers. This was never more clearly illustrated than in the rush to build gas-fired power plants in the wake of the restructuring occurring in the late 1990s. When gas prices were low, these low-cost plants were able to turn a profit, as gas prices increased, many generation companies came under financial pressure and many billions of dollars of private investment was squandered as bankruptcies occurred.[39] Therefore, while many

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[36] This is a result of the high fixed cost of production relative to the incremental or marginal cost. Regulators could choose to set prices based on the efficient price *once investment has been made*. Such a policy would deprive investors of capital cost recovery. Obviously, investors would never invest without the prospect of recovering capital costs.

[37] There is a long literature based on the concept of "optimal" regulation that has provided many valuable insights. ***See e.g.,*** Train (1991).

[38] In the 1970s and 1980s, in addition to high inflation, any utilities moved into a situation of surplus capacity or were saddled with high costs from wholesale contracts required by state regulators in implementing PURPA as well as cost overruns in constructing large power plants. For example, between 1985 and 1991 approximately $19 billion of plant costs were disallowed in rates by state regulators. ***See*** Lyon and Mayo (2000, p. 46)

[39] One way to measure the losses is the change in market capitalization of firms. Including Enron, the change (i.e., loss) in the market capitalization of the eight largest energy merchant trading companies between January 2001

stakeholders lamented the days of excess capacity in the regulated utility industry as a waste of societal resources, restructured markets appear to be just as susceptible to these same mistakes. However, losses in the private market are only borne by customers to the extent that those prices can be passed on through the final price.

2. The Traditional Regulatory Framework

In taking the competitive market outcomes as its starting point, traditional regulation substituted an administrative review process for the discipline of the market process. While implicit in the traditional approach to regulation is the goal of replicating the outcome of a perfectly competitive market, in achieving that goal, the inequity that appertains to the power inherent in the natural monopoly is purportedly effectively counter balanced. The problem is the model of the competitive market employed by regulators was based on that of the long-run competitive equilibrium. This model was undoubtedly selected because it is characterized by a long-run equilibrium price that results in total revenues covering long-run total costs, inclusive of a normal profit or fair rate of return.

a. The Revenue Requirement

Under the equilibrium principle, the regulator starts with the notion that it can identify the total prudent costs of service, associated with the regulated services, and then establish a total revenue requirement for the firm based on these just and reasonable costs. The Total Revenue Requirement employed by traditional regulation is shown below in Equation (1). This equation identifies the necessary costs that will allow investors a fair return, and therefore provide them an incentive to invest, while charging customers only for those costs that are necessary to provide utility service. Equation (1) masks the complexities of the process somewhat as each component involves a series of decisions as well as policies supported by the regulatory environment.[40] The revenue requirement is given by the following components:

$$TR = TC = [RB - D]ROR + OE + d + T \qquad (1)$$

Where,
TR = Total Revenue
TC = Total Cost
RB = Ratebase or value of capital
D = Accumulated depreciation
ROR = Rate of Return
OE = Operating Expenses
d = annual depreciation cost
T = Taxes

and January 2003 was $194 billion (Ernon’s loss was roughly $60 billion) Another measure is the difference in market price of power plants. For those plants sold in 2003 and 2004 the total loss (i.e., the sale price minus the original price) was $784 million. The misallocation of private capital is not limited to restructured electric markets. The well-known “dot-com” bust of the early part of this decade provides ample evidence that decentralized market players have no crystal ball and therefore mistakes in forecasting the future are just as likely in a decentralized market as in the tightly regulated markets of electric utilities. McDermott and Peterson (2002, pp. 18-19) identify this issue as one of the misconceptions concerning electric industry restructuring.

[40] The regulatory environment consists of the actions of regulators as well as statutes, rules and court action.

In implementing Equation (1) regulators are guided by certain principles. These include:

- *Prohibition on single-issue ratemaking:* Regulation focuses on the total cost of service, this totality principle is adopted in order to avoid the problem of piecemeal or single-issue ratemaking.[41] That is, no single cost item, such as inventory, should be the factor which drives the ratemaking decision, it is the net result of all cost increases and decreases as well as productivity changes that matter to regulators in setting the revenue requirement.[42]

- *Prohibition on retroactive ratemaking:* The revenue requirement and in turn rates are set prospectively. Equation (1) is intended to reflect the costs of providing service going into the future. All attempts at setting just and reasonable rates are for the purposes of looking forward, justice is not achieved by attempting to rectify past outcomes, in terms of making up for lost or excess profits. *See e.g.*, (Kreieger, 1991)

- *Prudent investment standard:* Prudence is generally defined in terms of the *reasonable person standard*. That is, given the information known, or that should have been known, at the time a decision is made, if that decision could have been made by a reasonable person, then that decision is prudent (i.e., prudence is <u>not</u> a 20/20 hindsight review). Imprudent management can lead to the exclusion of the costs associated with those actions from the revenue requirement. *See e.g.,* Allison (1985)

- *Used and Useful Standard:* This standard requires that utility assets be sized at any given time such that they are, or can be, used to provide service to customers. *See* e.g., Lesser (2002)

- *Test year:* The test year is used to ensure a matching of revenues and costs. The simplest method is to employ an historic test year where all costs and revenues are known.[43] However, forecasted or future test years have been employed as well as mixtures of historic and future test years. See *e.g.*, (Downs, 1972).

In measuring Equation (1) the regulator will apply these principles to the physical costs of the system (e.g., the rate base and the associated expenses). While measuring the costs of the system are not without controversy, the calculation of the firm's allowed profit level, which is used to calculate the ROR in Equation (1), is potentially one of the most contentious issues. The ROR is the utility's *weighted average cost of capital* or WACC. Each of the sources of capital, debt and equity, are weighted by their respective levels and costs to obtain the WACC. While debt costs and levels may be controversial, the level of profit allowed on the utility's equity and the amount of equity in the utility's cost structure will very often be at issue. This is because the return on equity must be estimated from market data as it

[41] Single issue ratemaking is discussed in: *Citizens Utility Board v. Illinois Commerce Commission*, 166 Ill.2d 111, 651 N.E.2d 1089 (1995); *Business and Professional People for the Public Interest v. Illinois Commerce Commission*, 146 Ill.2d 175, 585 N.E.2d 1032 (1991); *State ex rel. Utility Consumers Council of Missouri, Inc. v. Public Service Commission of Missouri*, 585 S.W.2d 41 (Mo. 1979); and *Pennsylvania Indus. Energy Coalition v. Pennsylvania Pub. Util. Comm'n*, 653 A.2d 1336, 1350 (Pa. Comm. Ct. 1995), aff'd, 670 A.2d 1152 (Pa. 1996).

[42] This net result concept is consistent with the idea of the "end result doctrine" stated in the Hope Natural Gas Case. *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[43] Historical test years can be adjusted through *known and measurable* changes to costs that will occur with a very high probability in the short-term.

cannot be directly observed. Utilities compete for sources of capital with all potential sinks of capital in the world economy. This requires that regulators determine the cost of capital for the utility based on the costs of borrowing money that a firm of similar risk faced in the capital markets, otherwise the utility will not be able to obtain financing. Changes in the industry over the past few decades have made this process somewhat more difficult. There are very few, if any, stand alone utility stocks traded on the equities markets. Most utilities are held within a holding company and may have many affiliate companies in the same holding company. Using market data to estimate the cost of equity for the utility must be done very carefully to avoid imputing risk associated with a utility's affiliate into Equation (1).[44] While the setting of the rate of return does not guarantee the utility the right to earn that return, it does create an opportunity for the utility to earn that return if it manages its costs well.

Furthermore, Equation (1) is established *prospectively* giving the utility the opportunity—but not a guarantee—to earn a fair rate of return. Under this framework, the primary incentive for utilities to control their operating costs comes from the existence of *regulatory lag*. Even though regulation has been characterized as a ratebase, rate-of-return; or cost-plus regulation, the primary source of efficiency incentives comes from the setting of a price that is fixed until the next rate case. This form of price regulation is not all that dissimilar to the price-cap regulations that will be discussed below. It is regulatory lag that provides the incentives and moreover, lag functions similarly in the competitive world. Wein (1968, p. 63) observed:

> For it is not only lag in regulation which provides incentives and penalties towards improvement. It is lag in the non-regulated world which does the same. If all competition were perfect and all readjustments instantaneous in the competitive world, there would be no financial incentives to change…The advantage which the innovator gets is time: his competitors cannot imitate him too quickly.

Wein is not alone in supporting the importance of regulatory lag. Kahn (1971, p. 48) has noted that:

> Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites: companies can for a time keep the higher profits they reap from superior performance and have to suffer the losses from a poorer one.

However, Kahn (1971, p. 326) also warned that "…regulation is ill equipped to treat the more important aspects of performance- efficiency, service innovation, risk taking, and probing the elasticity of demand." Thus, by accident—if not by design—regulation has some of the characteristics that Baumol and Sidak (1994) have suggested are necessary to induce efficient behavior on the part of utilities. In terms of investments and capital expenditures, the regulator serves as the judge of efficient behavior as plant and other capital expenditures allowed in the rate base must represent prudent expenditures.[45] This requires regulators to be somewhat active in their oversight activities; a condition that has not always

[44] The alternative is to be avoided as well, where the cost of equity of utility is artificially lowered because of its position in the holding company. While this may be rare, as competitive affiliates are likely to be more risky than the utility, for complete separation of utility costs from holding company costs the principle still should be applied. This is a large literature on estimating the cost of capital, of which Bruner *et al.* (1998) and Kolbe *et al.* (1984) provide two examples.

[45] *See* Justice Brandeis' seminal separate opinion in the *Southwestern Bell* case. *Missouri ex rel. Southwestern Bell Tel. v. Missouri Pub. Serv. Comm'n*, 262 U.S. 276 (1923).

been fulfilled. The incentives operative in this stylized regulatory framework can be summarized as follows:

- § Regulators review the prudence of expenditures for operations and rate base items. Experience will lead commissions to disallow expenses that are out of line with normal conditions.
- § The historic test year establishes a level of efficiency that is used to set prices on a prospective basis. Regulatory lag will force utilities to control costs over time.
- § The rates are designed on a collective or aggregate basis, i.e., "the residential class." As a result, individuals may face incentives to alter behavior beyond those examined in the collective rate-setting process.
- § Rates that are based on average cost causation may produce incentives for decisions that result in externalities. That is, costs that will be borne by customers who do not cause them. For example, by under pricing peak usage, capacity costs will increase for all customers.

b. Costing and Rate Design

The second phase of rate regulation involves the transformation of the revenue requirement into a set of prices or rates.[46] Simplifying, this process generally takes two steps. First the costs are segregated by function of the utility and allocated to revenue classes. Second, the actual prices paid by the customers are determined. Costs for rate design purposes can be calculated based on embedded cost or marginal costs. Embedded cost studies use historical accounting and system data to allocate costs. Marginal costs calculate the forward-looking costs of the system. The embedded cost study will exactly match the revenue requirement, whereas the marginal cost study will not, except by chance. Therefore, the marginal study will be adjusted in some manner such that the rates set by that study will recover the revenue requirement. While economists prefer the marginal cost approach to the embedded cost approach for its efficiency properties, many regulators (and advocates) prefer the embedded cost approach because it is easier to understand conceptually, and it allows for wide discretion in its application.

Rates play two fundamental roles. Rates provide both an incentive to consumers to make rational consumption decisions and rates ration the available supply in any given period. In designing rates, the cost causality principle has been a central concept employed by regulators. Cost causality suggests that customers be allocated those costs that they cause the utility to incur to provide service. Regulators have employed the use of average cost as a reasonable approximation of the cost causality consistent with the long-run equilibrium framework. For example, in long-run equilibrium the LRMC=SRMC=LRAC where LRMC=long-run marginal cost, SRMC=short-run marginal cost, SRAC = short-run average cost, and LRAC=long-run average cost. Average cost could be justified under these conditions as an approximation of the more appropriate marginal cost pricing concepts.

In designing rates, regulators have often attempted to achieve or at least balance the numerous objectives. This balancing has been achieved through the use of aggregated or bundled service offerings. For example, the three traditional rate classes of residential, commercial, and industrial masks the numerous differences between individual customer needs. The ability to bundle arises from the costs of

[46] Harbeson (1936) provides a review of the early rate design debates. Bonbright (1961) is probably the best known text on rate design.

production being largely common costs. The public utility was designed to serve the public collectively and without discrimination. Recognition of this collective service principle also supported the use of average cost pricing concepts. The connection also can be made here with the principle of non-discrimination in the design of rates. Similar customers should be treated similarly and where differences existed and were clear, different prices were charged. However, this principle of non-discrimination can conflict with promoting overall social welfare. For example, marginal cost prices imply an optimal level of output, yet committing to a policy of pricing solely on the basis of marginal cost will not provide an incentive to invest. Therefore, a second-best solution is to attempt to set prices such that the actual output is distorted from the optimal output by the least amount. This implies that prices should be higher for those customers less likely to reduce consumption from the optimal level. This is the so-called Ramsey pricing rule. Yet many regulators are unwilling to promote this type of pricing, even though it means society is worse off. Finally, pricing in the utility industry has taken on new importance since the advent of competition. Competitive markets work through the interaction of supply and demand. However, without correct price signals, the demand side of the market cannot function efficiently.

3. Modifications to Traditional Regulation

Traditional regulation has been modified over time as the pressures of inflation and surplus capacity forced regulators to critically examine regulation. In order to systematize the description of the odyssey taken by state regulators, the traditional industrial organization concept of the structure-conduct-performance (S-C-P) will be used in conjunction with a characterization of the organizational choice made between market and command and control policies to classify the forms of modifications

Using these two dimensions, a typology of regulatory policy options is constructed to identify those options that have been employed, to one degree or another, by state public utility commissions over the last quarter century. (*See* Table 4) The S-C-P paradigm suggests that if there is a competitive market structure then this will lead to competitive conduct by the firms in the market and ultimately to competitive performance, e.g. efficient production and pricing of products and services. If the structure is less than competitive, such as the natural monopoly that characterizes most public utility settings, then the conduct of the firm may be less than competitive and the outcomes less than optimal. Regulators could therefore focus on the problems of market structure, the conduct of firms or the performance aspects of the regulatory policy in order to "repair" the perceived problems.

Table 4: Characteristics of Regulatory Policy Options

	Structure	Conduct	Performance
Command and Control Regulation	Strong Pool	LCUP	Traditional Regulation
Incentives	Value-based	Bidding	Performance-based Regulation

Starting from traditional regulation with its focus on equilibrium competitive performance, regulators found themselves facing ever increasing costs during the 1970s.. As demand for energy began to fluctuate more widely and the costs of fuel and other inputs were affected by inflation, regulators looked for new policies to address the problems facing utilities. In the case of fuel inputs some states adopted Fuel Adjustment Clauses (FAC's), in effect regulators were willing to abandon the prohibition on single issue rate-making because of the magnitude of the effect of the changes in fuel costs on utility finances from the lag in cost recovery associated with traditional regulation. *See e.g.*, Trigg (1958), US Senate (1977) and Schmidt (1980). For capital expenditures, policies such as Construction Work in Progress (CWIP) were employed to accelerate the recovery of construction costs before the plant was completed (traditional regulation would generally require the plant be completed and used and useful before any cost recovery was allowed). The financial stress of significant expenditures and deteriorating cash flow made breaking with tradition seem imperative at the time. These policies resulted in new procedures to assess the prudence of the various cost and were supported by court decisions recognizing that regulators were not abdicating their authority by switching to these new methods.

More fundamentally questions were also raised about the conduct of, and incentives facing utility management. This lead to regulators questioning of the conduct, or behavior of utilities, with the result that, regulators experimented with three different policies. As a result policies such as Least Cost planning (LCUP) (often called Integrated Resource Planning or IRP); competitive bidding; incentive or performance-based regulation and industry restructuring were implemented. The concern was that utility management operating in a world where the discipline of competition was absent, required regulators to either perform the role of competition or inject a form of competition into the regulatory process to force the utility to behave more efficiently.

a. Least Cost Planning

LCUP was implemented at a time when, for many states, the real problems were over. LCUP was a reaction to the surplus capacity situation that already existed.[47] With excess capacity as the standard problem the idea of better planning for the next round of capacity would not be an issue for many years. As a result the focus shifted to conservation and demand management but with the effect of creating lost revenues at a time when utilities were desperate for additional revenues to cover the costs of the existing surplus capacity. In certain cases the energy efficiency programs implemented and demand side management that occurred did have a significant impact in postponing new capacity additions. Unfortunately, these benefits were often obscured by the debates over lost revenues.

LCUP also suffered from a focus on results as opposed to process. In many ways LCUP was an attempt to broaden the set of information and view points on how to cost effectively meet future energy needs. By focusing on results, that is the lowest present value of revenue requirements (PVRR), LCUP suffered the same fate as traditional regulation by utilizing simple decision rules, such as PVRR, rather than recognizing the value of project management.[48] For example, the very concept of option value in planning for new capacity additions was often rejected because regulators retained a static approach for evaluating choices. When considered in the context of minimizing the present value of revenue requirements (PVRR), any plan that required money spent early on in the planning horizon in order to create option value was rejected because of a higher PVRR.

The value of flexibility was forsaken and exposure to uncertainty increased all in order to preserve the current level of rates. This focus on outcomes rather than on creating a flexible process helped to doom IRP/LCUP framework, since it could not address the key issue of how to deal with uncertainty and disequilibrium. Ironically, it was this very set of issues that called for the change in utility regulation in the first place. The absence of policies to address the cancellation of plants, the definition of, and recovery of prudent costs and the inability of the regulator to commit future regulators to any policy destroyed the incentives to engage those activities that current information would deem prudent, and eschew those activities when new information deems them imprudent. The issue of lost revenues

[47] Jensen (1990) provides an overview of LCUP in Illinois.

[48] Option theory as applied to financial investments can also be applied to managerial flexibility and strategic interaction. These represent ***real options*** that can be analyzed in a similar fashion to financial options. These options can dramatically change the value of projects over time and affect decisions concerning project management. ***See e.g.,*** Trigeorgis (2000).

associated with demand side management and conservation presented similar problems. Rather than create a profit motive by divorcing revenues from sales, regulators dabbled by experimenting with incentives rather than address the issue head on.[49]

b. Competitive Bidding

Finding this LCUP unworkable, a number of sate regulatory commissions opted to explore competitive bidding with the aim of injecting more competitive forces into the generation market. The issue in the post-PURPA world was how to encourage cogeneration and new capacity on an economic basis. PURPA employed an administrative pricing rule, known as avoided costs, to compensate independent power producers (IPPs) and co-generators.[50] Through the bad design of avoided cost rules the resulting avoided cost calculations in many cases resulted in a surplus of what turned out to be uneconomic capacity. In addition the rules often encouraged or required the use of long term contracts in order to obtain financing for the new capacity. This created a contractual version of the traditional utility with a set of rigidities that exacerbated the future disequilibrium problems rather than eliminate them. Must take provisions, fixed prices, and other characteristics of these contracts resulted in an adjustment mechanism that was no better than the adjustment process of traditional regulation[51].

c. Incentive Mechanisms

While some states battled with competitive bidding others examined the use of incentive mechanisms. Depending on the style of mechanism some of these experiments have been a success. Where incentives are broad based, focusing on overall profits and in employing a sharing mechanism such that both customers and stockholders have benefited incentive regulation has been a success.[52] Table 5 illustrates the variety of incentive and performance types of regulation that have been adopted in the last twenty years in the US. These incentive mechanisms can be categorized in two classes: targeted and general. Targeted plans address particular aspects of costs such as availability of power plants (i.e., capacity factors), energy efficiency spending, procurement of fuel, or sale of power on the wholesale markets as well as other specific cost areas that are of concern. General plans tend to address the overall cost structure of the utility. General plans can be either performance-based, that is, the utility's earnings are linked to overall (or specific) measures of performance. These performance measures may include safety, reliability, customer satisfaction, as well as other measures. The performance plans also use a measure of profit (e.g., return on equity) to provide the incentive for greater efficiency. The second type of general plan is one that sets prices according to external indices (as opposed to the utility's own costs). These plans come under the heading of price caps and use some measure of the changes in costs (e.g., inflation minus productivity increases) to escalate prices year-to-year. A second type of price cap that has been used recently, especially in states that have restructured markets or in which mergers have occurred,

[49] Some regulators have implemented a divorcing (or decoupling) of revenues from sales. Since the early 1980s California, Florida, Kentucky, Maine, Montana, New York, Oregon, and Washington (state) have used full or partial decoupling. While, currently only California and Oregon have decoupling plans operating, in the last two years, Idaho, New York, Washington (state) and Wisconsin have addressed the issue in some manner. Although none of these states has implemented a decoupling plan as of February 2005. (Authors' research)

[50] Co-generation involves the production of both heat and electricity. The heat (i.e., steam) can be used as a space-heating source or in a production process.

[51] Early competitive bidding such as this was largely not successful although Virginia remains a notable counter example. Today almost all utilities purchase some amount of power through a competitive process.

[52] On the rational for earnings sharing see McDermott and Peterson (2002a).

is the price freeze or the prohibition on rate cases for a certain time. This policy is used to provide an incentive to reduce costs as the utility is allowed to retain any profit it can make during the price freeze.[53]

Table 5: Incentive Mechanisms

Issue	Mechanism	Examples
Production/Procurement Efficiency (Targeted Plans)	Capacity Factors Standards Banded Fuel Clauses Shared Savings	California-SoCalEdison Wisconsin-All Utilities Florida- Florida Power
Performance-based Regulation	Banded Return on Equity combined with Performance Metrics	North Dakota- NSP and Otter Tail Mississippi – MSPower and Entergy
Overall Efficiency	Price Caps	California-SDG&E Maine- Central Maine Power
	Rate Freeze or Rate Case Moratorium	Illinois – All Utilities* Delaware – Delamarva P&L North Carolina- CP&L**

* Illinois also includes a price benchmark and an earnings sharing mechanism. *See* Illinois Public Utilities Act Section 16-111(b), (d) and (e).
** Also links fuel cost recovery to nuclear capacity factors

d. Industry Restructuring

Finally, some states have utilized restructuring to provide incentives for efficiency improvements. There are several aspects of efficiency in which markets may be particularly useful. For example, power pools that are now in place in the many countries in Europe including those in Scandinavia, England and Wales, Germany, and Poland to name a few, as well as most of the Northeast, mid-Atlantic and large areas of the Midwest in the United States, use bidding and nodal pricing to provide incentives for production efficiency and efficient use of the transmission system. In other states an auction (or other competitive bidding) mechanism is used to procure power and energy for customers of the utility that have not chosen to buy power from a third party. New Jersey, Maryland, Washington DC, Delaware, Maine, Massachusetts, Connecticut, and Rhode Island currently have such mechanisms in place.[54] Pennsylvania held an auction for PECO's medium and large customers where the winning bidders are required to acquire the customer and take all inherent risks (although customers can opt out, return to the utility service or choose an alternative supplier). Ohio has used an auction method to benchmark First Energy's fixed rate plan and Illinois has recently approved an auction for procurement of supply beginning in January 2007. (Authors' research.)

V. Status of Regulation of Electric Utilities in Wisconsin

Public utilities in Wisconsin, like many of its neighboring states have been operating in what amounts to a schizophrenic environment. As described above, regulators employ a static equilibrium

[53] Although in many such plans the level of profit is capped at some level that is higher than normally approved in a rate case.

[54] Pfeifenberger *et al.* (2004) discuss procurement methods for retail access states.

model of regulation to evaluate costs and set rates through the traditional ratemaking process utilizing cost-of-service information on a retrospective or prospective test year snapshot. Yet at the same time, the utility finds itself operating in a dynamic disequilibrium environment where costs are subject to shocks and demands for service fluctuate and grow in erratic patterns. As a result of this mismatch between the form of economic regulation and the economic environment, both regulators and utilities struggle to overcome one problem after another.

In the immediate post-World War II era, for the most part, interest rate, cost and demand fluctuations did not result in a crisis of major proportions. This outcome may have been due to the stability in electric usage growth and consequently the minimal size of any resultant disequilibrium. In effect, the dynamic world approximated the static world embodied by the regulatory process.

By the 1960s, however, the regulatory world came under increasing stress. The regulatory response was to attempt to fix the specific problem and not to reexamine the environment faced by utilities and the nature of regulation itself. This piecemeal approach to policy making resulted in a patchwork quilt of incentives that were at times diametrically opposed. What regulators have ignored—or refused to believe—is that every policy or rule passed by that body creates an incentive. Any regulatory decision that alters the marginal benefits or costs to utility decision makers is, in fact, an incentive.

In this section, we review the regulatory environment that has existed in Wisconsin over the past three decades, focusing on how the Commission has dealt with major issues arising in the electricity industry. The common thread binding together the regulatory policy regarding electricity over the years connects the objectives of reliability, efficiency and protection of the environment, as stated by the Commission:

> The task facing the Commission is to maintain system reliability so that Wisconsin residents can have the electricity they need, at reasonable prices, and at the same time encourage conservation and protect the environment. (Public Service Commission of Wisconsin, Biennial Report, 1977)

Wisconsin strived to accomplish this through a combination of innovative pricing programs for customers and highly centralized planning for utility providers.

A. Efficient Pricing

In the late 1970s regulatory policymakers began focusing on the importance of pricing in achieving efficient outcomes in the utility industry. This was a particularly prominent feature in the passage of PURPA. This rekindled the debate over the use of price as an incentive to control the growth of electric load by signaling the true marginal costs of its use to customers. But even before PURPA, the Wisconsin commission blazed a path to eliminate uneconomic pricing by adopting long-run incremental cost as a basis. The now famous ***Madison Gas*** Case[55] pioneered the movement to rational economic pricing. In 1975 Wisconsin directed this rational pricing emphasis to electric utilities by focusing on growth relative to promotional rates and cross subsidized rate structure. Rates were ordered into effect that reflected marginal costing principles, given the limits at that time on metering capabilities. In November 1976 specific time-of-day electric rates for large industrial customers were first authorized to Wisconsin Power and Light Company and Madison Gas & Electric. This put Wisconsin into the forefront

[55] ***Re: Madison Gas and Electric Co.***, Wisconsin Pub. Serv. Comm'n, Docket 2-U-7423, Aug. 8, 1974. ***See*** Cudahy and Malko (1976) for a complete analysis of this case.

of not just thinking but application of what was referred to at that time as “innovative electricity pricing,” where emphasis is put on setting marginal price signals to accurately reflect marginal costs. This approach had (and still has) a strong economic efficiency rationale leading to the most efficient use of the energy resources.[56]

On November 11, 1976, the Commission authorized the Wisconsin Power & Light Company to implement the first comprehensive application of mandatory time-of-day tariffs in Wisconsin. The tariff was applied to 130 commercial and industrial customers having monthly demands greater than 500 kW. At this time Madison Gas & Electric was authorized to place its two largest customers on time-of-day tariffs. By early 1979 it was also allowed to add customers with demands over 300 kW to the time-differentiated rate. In total, by 1980 about 25 percent of Wisconsin’s coincident peak load was being billed under some form of time-differentiated rate.

Also by 1980 industrial customers were offered interruptible and curtailable power service where the utility has the opportunity to shed load during times of peak demand and system constraints. Absent a market where demand response would occur through price rationing we grafted on these types of services to imitate demand response. Today, WEPCo has a shared savings program where saved energy is sold back into market we might want to note that success.

Efficient pricing programs are designed to reflect the price signals consumers would see in a market. These same signals, and the demand response exhibited by consumers as a result, provide signals to suppliers to build more or conserve; therefore, efficient pricing is one way to balance supply and demand. A second approach is through rational commercial planning, being a monopoly regulators step in and create a plan for all utilities in the state to follow. At the same time it was at the forefront in the efficient pricing of electricity Wisconsin was also at the forefront in central planning of capacity additions.

B. Electric Planning

For the most part, Wisconsin has addressed the need to balance supply and demand in the state through a centralized planning process. The Power Plant Siting Law, Chapter 68, Laws of 1975 (principally §196.491, Wis. Stats.) and the subsequent Commission rules (Chapter PSC 111, Wis. Adm. Code) required each electric utility to submit an Advance Plan detailing the following items.

1. Anticipated energy and demand requirements over the next 20 years.
2. Proposed construction of generating plants over the next 15 years.
3. Proposed construction of transmission facilities over the next 10 years.
4. Alternatives to the proposed generation and transmission facilities.

The intention of the siting law was to standardize the procedures for review and evaluation of proposed power plant construction and to eliminate expensive delays in processing specific construction application. The plans viewed in aggregate provided the Commission with a 20-year outlook on the

[56] Setting price at marginal cost assures that consumers will purchase at the level that equates their value with the cost incurred to produce the resource. S*ee e.g.*, Cicchetti (1975) or Cudahy and Malko, (1976).

demands for electricity and the supply portfolio to meet these demands. After examination of the plans and opportunity for public comment, the Commission issued orders approving or modifying each utility's plan.

In 1997, after the Advance Plan 7 was approved, the Commission made changes to streamline the process and add more flexibility for resource planning. Among other things it changed the planning horizon from 20 to 10 years to "ensure that the current and near-term assessments closely match the resources necessary to ensure reliability of the state's electric system."

The last Advance Plan was approved in 1998. In its place, the Wisconsin Legislature directed the Commission to conduct a Strategic Energy Assessment (SEA) to evaluate the adequacy and reliability of the state's current and future electrical supply (Wisconsin Act 204).

C. Fuel Adjustment Clauses

The problem of price inflation (particularly with regards to fuel costs) constitutes the most direct assault on the static form of regulation. As inflation increases, the historic test year no longer resembles the near term future under which the rates will be effective. The first effects were felt in the area of operating expenses with the problem eventually spilling over to plant construction costs.

In 1981 the PSCW opened proceedings to determine if it was appropriate to adopt the PURPA automatic adjustment clause standard, requiring incentives for efficient use of resources, including incentives for economical purchase and use of fuel and electric energy. The legislature mandated the elimination of the automatic fuel adjustment clause in 1984. In its place the PSCW approved an alternative method where fuel cost ranges are developed within which each utility must operate without rate action. If the costs vary by more than 10 percent in one month or 3 percent in one year, the utility may apply for rate review. The PSCW may also review the costs to determine if refunds are due the customers. This, in essence, creates a band around a targeted fuel cost, a band within which the utility operates without any regulatory changes. This creates an incentive mechanism for the utility to (1) forecast accurately and (2) achieve cost minimization, particularly if the utility is allowed to keep some of the gains it realizes by beating the forecast. After several years of experience with this approach the Commission was satisfied with its effectiveness.

D. Performance Indicator Project

In 1985 the Commission directed the development and implementation of a system called the Performance Indicator Project, designed to measure and monitor the overall performance of major gas and electric utilities. A broad range of operating ratios were evaluated, in relation to state averages to spot trends that may signal problems. "In the future, the Commission may be able to use these analyses in rate cases to gauge the utility's productivity against the rates it charges customers."

In 1989 the Commission determined that utilities are facing disincentives from the traditional ratemaking process to carrying out least cost plans. The Commission determined to begin a rulemaking investigation during the next two years to determine the extent of such disincentives and to consider alternative mechanisms which will reduce any disincentive which is found to be a deterrent to the utilities adopting a least-cost implementation strategy.

E. Corporate Structure

During an October 1985 special session on economic development, the Wisconsin Legislature passed into law conditions under which utilities could form holding companies in order to diversify into non-utility businesses (§196.795, the *Wisconsin Utility Holding Company Act* or "WUHCA"). This statute limits outside ventures to 25 percent of total assets and requires periodic review of diversification activities by the Commission. On May 28, 1986 the Commission approved Wisconsin Electric Power Company's application to form a holding company. This was followed by approval of a holding company formed by Wisconsin Power & Light on May 1, 1987. Alliant Energy filed a lawsuit in 2000 contesting the constitutionality of the WUHCA. In 2003, a Federal court upheld WUHCA and affirmed the ability of the PSCW to put limits on the utility. (US Court of Appeals for the Seventh Circuit, Case No. 02-2618.)

The legislature provided a statutory framework (through 1999 Wisconsin Act 9) for the formation of an independent, single purpose, transmission company whose sole responsibility is the planning, construction, operation, and maintenance of a transmission system in Wisconsin. The new company became operational on January 1, 2001 with a number of utilities contributing transmission facilities or cash contributions.

F. Post Planning Environment

1. Electric Industry Restructuring

During 1995 the Commission began an investigation into the appropriateness of competitive restructuring in Wisconsin, which included the formation of an Advisory Committee, issuance of an Environmental Impact Statement and public hearings across the state. In February 1996 the Commission submitted a report to the Wisconsin Legislature on its intended policy direction, which included a 32-Step Workplan and timeline to accomplish the Commission's objectives of implementing competition into the utility structure when it was deemed to be in the public interest. Key steps in the Workplan included an analysis of market power potential in the state, assurances of high customer service quality, and protection of the environment.[57]

2. Return to Traditional Regulation

In the late 1990s the regulatory climate in Wisconsin shifted from embracing changes to the traditional utility structure through industry restructuring, toward a greater concern over reliability, and in turn, a greater reliance on administrative oversight. In 1997, and again in 1998, the Midwest wholesale power markets experienced several periods of high prices. While the Federal Energy Regulatory Commission's staff reviewed these pricing anomalies and found them to be explained by events outside of the control of market participants (e.g., power plants going down at the same time, weather effects, etc.), none-the-less, many regulatory bodies and policymakers began to pull back from promoting decentralized markets as a solution to the concern over reliability. ***See e.g.,*** McDermott and Peterson (2002a, 2005) or Joskow (2003). Wisconsin followed this approach and abandoned the 32-step work plan for restructuring. However, the least cost planning apparatus, at one time cited by the PSCW as a model

[57] The Commission was not the only entity in Wisconsin advocating change. Wisconsin Electric presented its proposal for industry restructuring in Abdoo (1995).

for the nation, was abandoned in favor of a more traditional approach to utility investment. (PSCW (1997))

In response to the concern over reliability and the risk associated with utilities building power plants, the Wisconsin legislature authorized leased generation contracts between public utilities and their affiliates and authorizes the transfer of land or facilities from a public utility to a non-utility affiliate of the public utility for the purpose of implementing a leased generation contract. The Act specifies conditions under which the Commission may approve leased generation contracts and prohibits the Commission from considering, in setting the utility rates, any income, gains or losses that are received or incurred by the affiliate as a result of its ownership of a power plant under a leased generation contract. Wisconsin Energy Corporation's (n/k/a We Energies) Power the Future (PTF) construction program, filed with the PSCW in 2002, was the first generation expansion program where this unique contracting arrangement was proposed.[58]

While the explicit planning framework of the Advanced Plans was removed, the legislature did create a general planning framework through the so-called Energy Priorities Law.[59] The goals of this law were clearly articulated by the legislature:

> (a) It is the goal of the state to reduce the ratio of energy consumption to economic activity in the state. … (b) It is the goal of the state that, to the extent that it is cost–effective and technically feasible, all new installed capacity for electric generation in the state be based on renewable energy resources, including hydroelectric, wood, wind, solar, refuse, agricultural and biomass energy resources. (§ 1.12 (3)(a) (Energy Efficiency) and (b) (Renewable Energy Resources) of Wisconsin Statues.)

In order to implement these goals the legislature created a set of priorities for future resource deployment.

> (4) PRIORITIES. In meeting energy demands, the policy of the state is that, to the extent cost–effective and technically feasible, options be considered based on the following priorities, in the order listed:
>
> (a) Energy conservation and efficiency.
> (b) Noncombustible renewable energy resources.
> (c) Combustible renewable energy resources.
> (d) Nonrenewable combustible energy resources, in the order listed:
> 1. Natural gas.
> 2. Oil or coal with a sulphur content of less than 1%.
> 3. All other carbon–based fuels.
>
> (§ 1.12(4) of Wisconsin Statutes)

The first case to fall under the Energy Priorities Law was the PTF proposal by WE Energies. PTF proposed two 545 MW natural gas fired units at Port Washington and three coal fired units at Oak

[58] *See* Orders in PSCW Docket Nos. 05-AE-109, 05-CE-117 and 137-CE-104 ("Port Washington Order") and Docket Nos. 05-CE-130 and 05-AE-118 ("Oak Creek Order").

[59] This refers to § 1.12 (3), (4) and § 196.025 of the Wisconsin Statues.

Creek.[60] As a result of the application of the Priorities Law, the PSCW found that the coal and gas plants were necessary and could not be replaced by any resources higher on the priority list. However, the Commission did find that some level of energy conservation and efficiency was necessary and ordered We Energies to file a plan to procure these resources. (Order Point 19 in PSCW Docket Nos. 05-CE-130 and 05-AE-118) Other utilities have since filed similar, albeit smaller, construction programs with the Commission making similar findings.

The interesting twist in the application of the Priorities law by the Commission was the change in the interpretation of the law between the first gas plants proposed by We Energies in the PTF program and the coal proposal.[61] In Part I of the PTF filing for the construction of gas-fired generation at Port Washington, the PSCW stated that:

> Given the scale and timing of the energy capacity needs of Wisconsin Electric's customers…the Commission is not convinced that conservation programs and renewable generation could serve the energy capacity needs…more reliably or cost-effectively than the [PTF] proposal. (Port Washington Order at 16)

The Commission interpreted the law, arguably, in its pure form, in the sense the priorities were to be ranked and chosen based on the ability to meet "energy demands." However, in the Oak Creek case, the PSCW expanded this interpretation to include any cost-effective and technically feasible conservation and energy efficiency, despite its ability to substitute for or even delay the need for more traditional sources of power.[62] Therefore, the PSCW has moved in the direction of using the Energy Priorities Law as a general planning guide.

3. Wisconsin Regulation Going Forward

In setting electric utility rates Wisconsin continues to employ a fully-forecasted test year with "semi-automatic" fuel cost adjustments (which require a hearing prior to implementation). In the latest Strategic Energy Assessment the Commission focuses on balancing the objectives of increased reliability of electricity service in Wisconsin, increased employment of renewable resources, and minimization of rate impacts for customers. (SEA Report, 2004) The Commission recognizes that Wisconsin faces significant upward pressure in electricity rates as a result of the recent building programs in generation and transmission. Over the past few years operating expenses related to purchased power and transmission system operations have increased significantly (20 percent during the years 1997-2002). They state:

> Minimizing potential rate effects will require innovative ways to control costs, developing effective rate structures and achieving the best possible balance of fuel type, transmission and energy efficiency.

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[60] The PSCW denied We Energies' third proposed coal plant that would have incorporated a gasification technology. Therefore, the final PTF program included only two current technology coal units.

[61] While PTF was one overall construction proposal, the Commission addressed the proposed Port Washington (i.e., Part I) and Oak Creek (i.e., Part II) plants separately.

[62] While the PSCW relied on the language from the Port Washington order in its Oak Creek order to suggest that the evidence did not show are sufficiently large or achievable to replace traditional sources of power, it never-the-less ordered that a level of energy efficiency that was produced from the modeling provided by We Energies should be obtained. (Oak Creek Order at 17-18)

The Commission provides recommendations for future regulatory policy changes in SEA 2010 as follows:

- Improve coordination of transmission and generation planning;
- Maintain reasonable rates for Wisconsin consumers;
- Lead the way in energy efficiency and renewable resources.

To improve the coordination of planning the Commission discusses the return of utility generation plans. More scrutiny in the areas of interclass cost-of-service allocation and rate design will be pursued to assure reasonable rates for customers. And, consideration of the state adopting a 10 percent renewable portfolio standard is being recommended in order to demonstrate Wisconsin's environmental leadership.

VI. Identification and Classification of Regulatory Models

A. Analyzing Regulatory Models

While regulatory models have changed over time, the objectives have not. These objectives are multifaceted, however, using a pedagogical tool, which was the founding paradigm for study of industrial economics, will help better illustrate the focus of regulatory models.[63] This tool separates the study of markets into three basic areas: market structure, conduct of the firms and performance of the market. This is so-called Structure-Conduct-Performance (S-C-P) paradigm; while it is no longer explicitly used to create a frame of causality it is useful as a tool to help define the regulatory models under review in this section.[64] To understand the formation of regulatory models it worth looking at the three areas separately.

- Market ***structure*** is the generally thought of as the key factor influencing the choice of a regulatory model. Utilities have been traditionally considered ***natural monopolies***[65] and therefore the market is highly concentrated (i.e., one firm), as barriers to the entry of other firms into the market exist.
- *Conduct* of the firms in the industry relates to the behavioral aspects of the firms. For regulated utilities, behavior is explicitly regulated in an attempt to make it conform with both economic and social policy of the jurisdiction in question. Conduct includes concerns over pricing and production policies, levels of non-price competition such as advertising, research and development as well as legal and regulatory tactics.
- *Performance* is the result of the actions within the industry. For example, efficiency with which the firms produce output, the application of technological advancements and productivity gains, as well as the concern over "fair" outcomes are all areas of performance. Performance has always been the key metric in looking at an industry,

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[63] Scherer (1970) provides an overview of the structure-conduct-performance paradigm.

[64] Appendix 2 provides a graphical depiction of the S-C-P pedagogy as well as a model of the feedback loops between the various areas under study. Appendix 2 also adds the fundamental conditions of both supply and demand as well as public policy.

[65] A natural monopoly is so-called as it is a function of the technical features of production. Briefly, a firm has a natural monopoly if it is cheaper to produce the market output in one firm than in more than one firm. *See* Baumol et al. (1982).

especially in the electric utility business where changes have occurred, as noted above, precisely because of the general conclusion that performance of the industry could be improved using different regulatory mechanisms or ownership structures.

To place regulatory models in context, it may be useful to categorize different models according to the S-C-P methodology. Table 6 provides a very high-level characterization of regulatory models. In the first column of Table 6 the structure of the market identifies the level of competition and ranges from natural monopoly to complete competition. Reading across Table 6, the aspects of the other two areas are: conduct and performance of the industry. From the top of Table 6 indicates more of a ***command and control*** regime to the bottom of the table which is reflective of a more liberalized regime. Table 6 provides a backdrop for categorizing regulatory models. All of these models must address the fundamental question of the allocation of risk. Risk can manifest itself in multiple ways. For example, investors face not only business risk, such as changes in economic conditions, fluctuations in weather, etc., but also risks associated with the regulatory model itself (i.e., the probability of cost recovery). Customers also face risks associated with volatility of prices and the level of prices. In a sense, each model is providing some level of price insurance combined with cost recovery for the utility. The traditional regulation model prices insurance in one way (i.e., customers pay for a revenue requirement that is based on long-lived assets in addition to the short-term costs of production). On the other end of the scale, i.e., competition, customers pay only for the level of insurance they choose. This is purchased through several methods. For example, customers can choose to reduce consumption through investment (i.e., purchasing energy efficient equipment) or to purchase fixed-price contracts from the market. Customers could also choose to self-insure and pay only the short-term price of energy. In between these two extremes, risk allocation is slightly adjusted one way or the other.

Table 6: Characterizing Regulatory Models

Structure	Conduct	Performance
Natural Monopoly	Closely Regulated	Restricted Profit Administrative Pricing
Mixed Market	Incentive and Performance Regulation	Profit restrictions loosened Market-like Pricing
Competition	Restrained by Market	Un-restrained Profit Market pricing

Adapted from Table 2 in McDermott and Peterson (2005, p. 84)

B. Exploring Regulatory Models in the US and Europe

In summary, the models used in the United States and Europe can be categorized in four major categories:

- Traditional Regulation;
- Performance-based of Incentive Regulation;
- Markets; and
- Hybrid Models.

1. Traditional Regulation and its Different Incarnations

Traditional regulation has the following basic characteristics (simplifying greatly):

- *Profit* is controlled through direct price regulation and entry is limited.

- *Risk* is allocated through the prices that are based on total revenue requirement.

Once the revenue requirement is set, the utility has a reasonable expectation of recovery of its costs, subject to prudent management. As noted above, this approach has been criticized largely because of the lack of dynamic incentives for efficient behavior over time (as opposed to static incentives for current operational efficiency). Traditional regulation has also been criticized, more recently, with the inability to provide regulatory commitment and therefore provides a disincentive for investment.[66] These concerns have lead regulators to modify traditional regulation. Table 7 provides a listing of the modifications that have been applied to the traditional regulatory framework in order to address these and other issues.

From the discussion above, it should be noted that most of these modifications are policies that ***violate*** a principle of traditional regulation. For example, passing fuel or other costs through to customers, outside of a rate case, violates the ban on single-issue ratemaking. Providing higher profits on one part of the business, such as a targeted incentive, may violate the "fair" return concept, at least as that concept is conceptualized in traditional regulation. However, these policies were put in place to specifically address some of the shortcomings of traditional regulation in order to either provide investors with more assurance of cost recovery or to increase the efficiency of the utility through the strategic use of profits. In the United States, most states continue to use some form of traditional regulation. Even in states that have restructured markets, traditional regulation is used to price the services that are not provided competitively (i.e., transmission and distribution). In Europe, traditional regulation has fallen out of favor, or was never implemented in the first place. Although, even countries that have moved away from traditional regulation often retain some form of the revenue requirement concept as the starting point for pricing.

[66] The disincentive for investment results from the sovereignty of legislatures and regulators. Both bodies cannot bind future decision makers. Therefore, policy makers could make changes to the regulatory environment, such as allowing entry that may make cost recovery more difficult. During the restructuring debates in the United States in the 1990s, this was a key factor in the so-called "stranded cost" debate. *See e.g.,* Sidak and Spulber (1997). An alternative result suggests that, when the judiciary (i.e., a third body) enforces a requirement of a "fair" return, traditional regulation may provide a better commitment mechanism, relative to an alternative form of regulation, and therefore produces more efficient investment over time relative to alternative regulation. *See e.g.,* Gilbert and Newbery (1994).

Table 7: Modifications to Traditional Regulation

Issue	Modification to Regulatory Model	Examples
Fuel Price Inflation	Power Cost Adjustment (PCA)	30 US States currently use a form of a PCA for some or all utilities in the state*
Regulatory Lag	Cost Trackers	Mississippi Power PEP Plan
Efficiency Concerns	Targeted Incentive Plans	Minnesota: Incentives for Energy Efficiency Spending Florida P&L: Generation incentive and a profit sharing on off-system sales
Regulatory Uncertainty	Leased Generation Pre-approval of Regulatory Treatment	Wisconsin: We Energies PTF Iowa: MidAmerican Generation Investment
Volatile or Uncertain Costs	Cost Tracker	Environmental cost recovery: many utilities
Service Quality	Penalties	Illinois: Certain large utilities can be required to compensate customers for damages related to outages NJ: JCPL's ROE reduced 25 bps for summer 2003 outages**

* Only two states (Utah and Vermont) that have IOUs, and are not restructured, do not use some form of a PCA (Authors' Research)

** JCPL would have 25 bps added or another 25 bps reduced after a PUC review of steps to address issues.

2. Incentive Regulation

Incentive regulation (IR) or what is also called performance-based regulation (PBR), provides a slightly different allocation of risks and attempts to place the utility in an environment that more closely mimics the competitive market place or that removes certain disincentives that are inherent in traditional regulation (e.g., the connection between revenue and sales that tends to promote sales).[67] While incentive regulation can be practiced in a variety of ways and each program tends to have its own idiosyncrasies, for the purposes of this report, three common forms of IR, namely price caps, sliding scale regulation and revenue caps are discussed.[68] Earning sharing mechanisms will also be discussed as an ESM can be used alone (as a version of a sliding scale) or be added to the other forms of PBR discussed in this report. Table 8 provides examples of IR from both the US and Europe.[69]

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[67] PBR and IR will be used interchangeably in this report.

[68] These are not the only types of performance based regulation that may be applied. However, these provide a cross section that illustrates the reasons why regulators might move toward incentive regulation. A review of IR programs can be found in Sappington et al. (2001) and in McDemrott (2003). McDermott and Peterson (2004) provide an overview of IR programs for natural gas distribution in the US. Bell (2002) provides a review of IR in Europe.

[69] A short history of incentive regulation can be found in Schmidt (2000, Chapter 2)

Table 8: Selected Examples of Incentive Regulation for Electric Utilities

Jurisdiction and Company	Time Frame	Plan
CA -SoCalEdison	1998 – 2001	Price Cap with ESM (distribution)
CA - SDG&E	1994-1997 1999 – 2002	Revenue cap (integrated utility) Price Cap with ESM (distribution)
IL- All electrics* IA – MidAm DC- PEPCO (dist.) NY – RG&E Ohio- All electrics PA – PECO (dist.)	1997 – 2007 Through 2010 Through 2007 Through 2008 2000 through end of MDP** Through 2006	Rate Case Moratorium/Rate Freeze
AL – APC CT- CP&L GA- GPC LA – Entergy (NO)	Ongoing 2003- Through 2007 2003-	ESM
UK: All distcos Transmission	 2004-2010 2001-2006	Price caps (ESM for CapEx and service quality targets, costs are benchmarked) Price Cap
Finland: all distcos	2005-2007	RoRR with efficiency benchmark
Norway: all distcos	2002-2006	Revenue cap (ESM with quality of service penalties)
Sweden: all distcos	On-going	Yardstick based on hypothetical network[70]
Spain: transmission	2003-2006	Price cap

Sources: Sappington (2001), Viljainen *et al.* (2004) and Authors' research.
* Includes ESM and benchmark for residential rates.
** Different utilities had different market development periods (MDP)

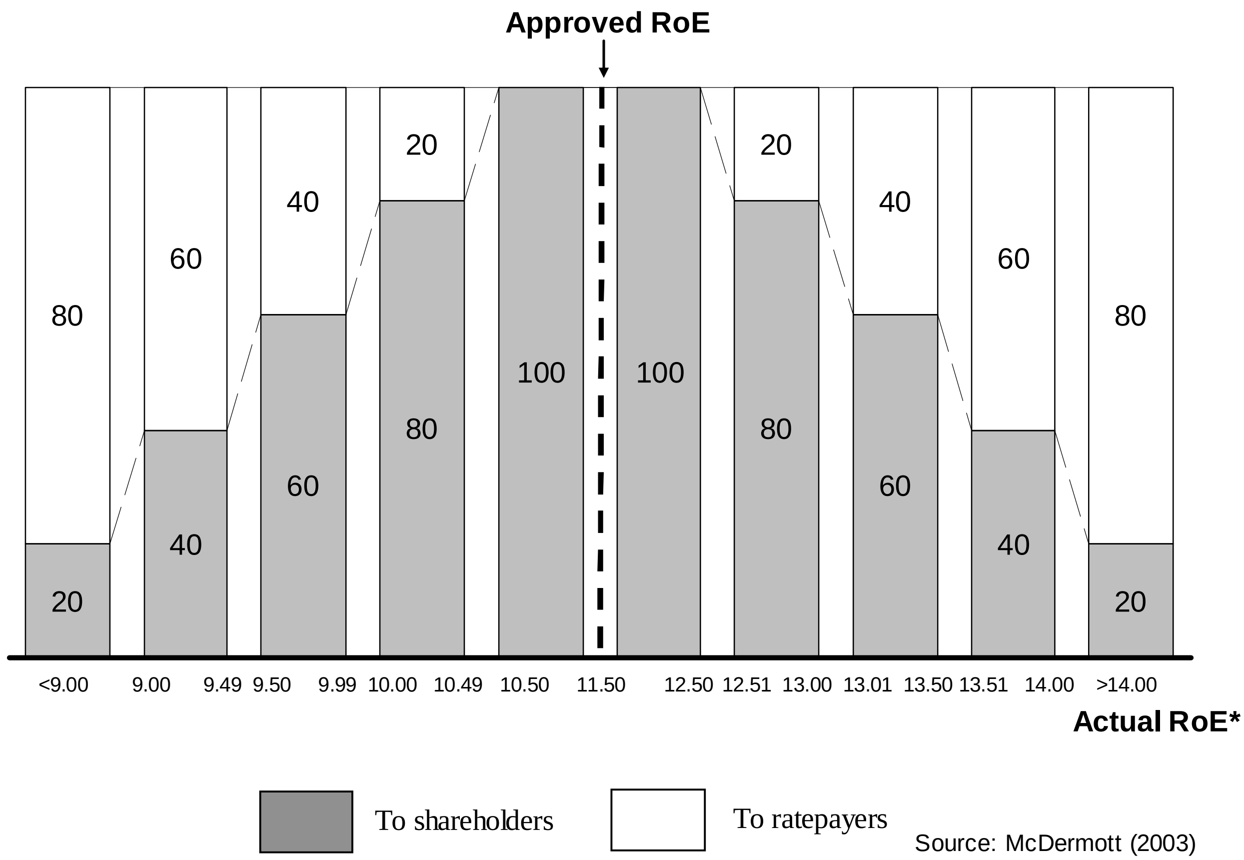
a. Earnings Sharing Mechanisms

Perhaps the simplest method of incentive regulation is the earning sharing mechanism (ESM). In its most reduced form, the ESM tracks the actual earnings of the utility and shares a certain percentage of the earnings over a target level with ratepayers. For example, Figure 6 provides an example of a simple earnings sharing mechanism. This figure illustrates the use of a deadband in which the utility absorbs or retains all earnings within 100 basis points of the approved ROE. This figure also illustrates a *symmetric* ESM in which shareholders and ratepayers share in earnings above the approved ROE and below the

[70] Yardstick regulation is a form of benchmarking. For example, a generic yardstick price is set as follows: $P_{i,t} = a_i C_{i,t} + (1 - a_i)\sum_{j=1}^{n} f_j C_{i,t}$ where $P_{i,t}$ ≡ overall price cap for the utility (i.e., firm *i*), a_i ≡ share of the utility's own costs in the price cap ($a_i = 1$ is RoRR, $a_i = 0$ is pure yardstick), f_j ≡ weight for each firm in the peer group that is the benchmark and $C_{i,t}$ ≡ unit cost of each peer group firm. (Note that prices could be substituted for costs on the right-hand side of the yardstick equation.)

approved ROE in the same fashion. An asymmetric ESM provide for sharing of profits with ratepayers but the utility must follow standard procedure and file a rate case to increase prices[71]

Figure 6: Earning Sharing Mechanism



Source: McDermott (2003)

The sharing rate is a key parameter of any ESM. If regulators are concerned with the traditional issues of monopoly profits, a sharing scheme where the utility retains less of the profits as the return increases may be used. If the regulator is concerned that there are “low hanging fruit” to be picked, the reverse could be employed where ratepayers share larger percentages closer to the allowed ROE, but as returns increase the utility retains a larger share.

More complex forms of ESM may be used with other forms of PBR such as those discussed below. In addition, as with most forms of PBR, there is a general concern over the incentive to cut costs related to non-price characteristics of service such as quality of service, customer service, and safety for employees, etc. This concern arises because under traditional regulation the firm is offered a single fixed ROE, if the firm earns above the ROE the regulator can reduce its prices, if it earns below its allowed ROE, the utility can request a rate increase. Therefore, whatever level of non-price service is included in the revenue requirement is recovered through prices. However, under PBR, cost cutting can lead to greater on-going profits for the firm.[72] Therefore, most IR programs also include metrics that measure the

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[71] McDermott (2003, Exhibit KAM-2) provides a review of sharing mechanisms adopted by state regulators in the US.

[72] In general the difference between traditional regulation and PBR is regulatory lag. Under traditional regulation, firms could earn higher than the allowed ROE but only until the regulator resets prices in the next rate case (the

non-price characteristics of utility service. For example, the Mississippi Power Performance Evaluation Plan or PEP includes a Company Performance Rating or CPR. The CPR is an index of three metrics: prices (based on comparison to other utilities in the southeast); customer satisfaction (based on customer opinion survey) and reliability (based on a 36-month average time customers are without power. The CPR is then used to adjust the deadband under which the utility can earn. That is, the better the utility performs under these metrics the larger deadband and a greater opportunity to earn profit above the allowed ROE.[73] Another example comes from North Dakota. In 2000, the regulator approved a price cap plan for Otter Tail Power.[74] Under the terms of the price cap, four metrics were used to measure performance: reliability (measured by standard utility interruption indices); customer satisfaction (measured through customer survey); prices (measured relative to other upper Midwest states); and employee safety (measured relative to OSHA standards).

b. Price Caps

Price caps are generally aimed at setting a benchmark for changes in utility prices overtime.[75] That benchmark is usually designed to represent the change in overall inflation of costs for the utility. A simple price cap would set the new price, P_t, where *t* represents the time period under consideration and P represents the price, as a function of the previous periods price, multiplied by an escalation factor or

$$P_t = P_{t-1} \bullet (1 + RPI - X) \qquad (2)^{76}$$

Equation (2) says that the new price is equal to the old price multiplied by 1 plus a measure of inflation minus a productivity factor (X). This is sometimes referred to as the "RPI-X" approach (i.e., retail price inflation minus productivity). RPI-X was adopted for British Telecom after privatization in the early 1980s and was later adopted in the US telecom industry for long-distance, by the Federal Communications Commission, and then broadly adopted in the local telecom industry, by state regulators, in the United States in the years following the Telecommunications Act of 1996.[77] The telecom industry

same is true for losses). Under PBR regulatory lag is removed and firms earn (or lose) money based on the, most often, annual results of operations, Therefore, the incentive to reduce costs on all non-revenue sources is stronger under PBR.

[73] The latest revision of the MS Power PEP plan was approved by the Mississippi regulator in 2004. *See* Mississippi Public Service Commission Order in Docket No. 2003-UN-0898.

[74] *See* North Dakota Public Service Commission order in Case No. PU-401-00-36. A similar plan was approved for Northern States Power in North Dakota.

[75] Price caps were introduced for utilities by Littlechild (1983) as a method to regulate British Telecom. Professor Littlechild later became the Director General of the electricity regulatory body in the UK. Armstrong *et al.* (1994, p. 166) report that the first use of price-cap regulation was recommended by the British Monopoly and Mergers Commission in 1982 for the dominant firm that supplied contraceptive sheaths. At about the same time rates for non-competitive railroad services in the US were placed under price caps and adjusted quarterly by a Rail Cost Adjustment Factor. Price-cap proposals can be traced to Baumol (1967), Sudit (1979), Crew et al. (1979) and Vogelsang and Finsinger (1979).

[76] Equation (2) may be modified by several other factors. The Z-factor account for costs that are beyond the control of the regulated firm (e.g., new government regulations, or supply costs for distribution companies), the so-called stretch factor can be applied to the X-factor (the stretch factor is generally an arbitrary adjustment to the X-factor) and a K-factor can be included to include new capital additions.

[77] Ai and Sappington (2002, Table 1) report that in the US telecommunications industry in 1985 all US states utilized RoRR, but by 2002 only 6 states used RoRR and 41 states used price cap regulation (the balance was

tends to have large productivity increases over time and regulators were convinced that traditional regulation could not keep up with the effects on the cost structure of the utility as technology changed. In addition, the Telecommunications Act of 1996 ushered in, what was thought to be a more competitive environment in local telecom business.[78] RPI-X has more recently been adopted in the United Kingdom for setting electricity distribution rates and has only slowly entered the US electric and natural gas industries.[79] Hemphill *et al.* (2003) summarize the reasons for IR's apparent slow adoption in electricity and gas regulation:

> Among the factors contributing to differences in the adoption of incentive regulation plans across the U.S. telecom, electricity, and gas distribution industries are differences in regulatory commitment and support (including commitment to existing regulation), technological change and productivity growth, industry concentration, service quality concerns, and industry externalities.

At its essence, RPI-X creates a benchmark price for firms that represent the likely outcome in a competitive market, or at a minimum, the changes in prices that a firm would see in the competitive market.[80] The idea is to provide incentives for innovation, e.g., through organizational and management changes, and provide the firm with a set of incentives that are likely to produce efficient outcomes (lower prices or more services, higher quality, etc.).[81] RPI-X regulation has been experimented within the US electric industry, generally as a result of restructuring (i.e., applied to distribution companies), but there are examples of this model applied in non-restructured states. While the theoretic case for price-cap regulation is fairly strong, the practical applications of this theory have been mixed due to many real-world complications that are often ignored or deemed unimportant by theory, or what may be more accurate is that real-world implementation deemed the theoretical assumption unimportant. Ironically, Joskow (2005, p.2) notes that implementation of incentive regulation is more complicated than first imagined and depends critically on "information gathering, auditing, and accounting institutions that are commonly associated with traditional cost of service…regulation."

The longest price cap regime in the electric industry is in the UK electricity distribution sector.[82] There are 14 electric distribution companies in the UK referred to as Regional Electricity Companies or RECs. The RECs provide franchised delivery (i.e., "wires") service and are regulated by the UK Office of Gas and Electricity Markets (OFGEM). The UK price cap sets a starting price and allows that price to escalate based on the RPI-X formula addressed above. The starting price is based on an evaluation of the capital assets, additions to capital, and operating costs, including target levels of reliability. This starting

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made up of other non-RoRR forms of regulation). The evidence is clear that price cap regulation has been adopted for telecom in the US and RoRR has been largely abandoned.

[78] One of many good references on telecom incentive regulation is Sappington and Weisman (1996).

[79] McDermott and Peterson (2004) provide some evidence that incentive regulation may be gaining ground in the US natural gas distribution business.

[80] In a competitive industry a firm must earn a normal return, therefore $\%\Delta \text{Price}_{industry} = \%\Delta \text{Unit Cost}_{industry}$ where the $\%\Delta \text{Unit Cost}_{industry} = \%\Delta \text{Input Price}_{\text{industry}} - \%\Delta \text{Productivity}_{inudstry}$. These equations say that the change in price has to reflect the change in costs and the change in costs is reflective of the change in the prices of the inputs used to produce the output minus any productivity gains.

[81] Price caps in the telecom industry are aimed also at inducing optimal prices. However, in the electric business, where firms typically have less control over price structures, price caps are more directed at providing better incentives. *See e.g.,* Joskow (2005).

[82] This discussion relies heavily on Joskow (2005)

price is reviewed every five years and adjusted accordingly. The initial price and the productivity factor are set such that the present discounted value of the revenues over the five years is equal to the present discounted value of the expected costs. The most recent review of prices in 2004 set the X-factor in Equation (2) at zero such that prices change on a going forward basis at the rate of inflation. For the operating costs portion of the revenue requirement the firms are full claimants on all residual profits that exist as a result of the difference between actual and projected costs. However, for the capital costs portion of the revenue requirement an innovative sliding scale has been adopted (see sliding scale discussion below) that essentially provides options for the RECs to choose a larger capital expenditure allowance and a lower level of profit sharing or the reverse. (OFGEM (2004a)). While there is some evidence that the UK style price cap plans have been beneficial,[83] Joskow (2005, pp.36-39) identifies several key issues that remain outstanding.

- Differential incentives depending on how close the firm is to the five year review.
- Asymmetries in the treatment of operating and capital costs as a result of the sliding scale for capital but not for operating costs and the blurry line between capital and operating expenses.
- Deterioration of service quality in future periods due to incentives to create profit opportunities with the current price period.[84]

c. Sliding Scale

Generically, a sliding scale[85] operates as follows:

$$r_t = r_{t-1} - l\left(r_{t-1} - r*\right) \qquad (3)$$

Equation (3) says that the allowed return in the current period is equal to the actual return in the previous period minus a fraction (i.e., l) of the difference between the actual return in the previous period and the benchmark return (i.e., the allowed return on equity (ROE) set by the regulator). Note that if the sharing parameter, l , is equal to 1, then Equation (3) reverts to traditional regulation (i.e., r=r*). If l is zero then the program is a price freeze (i.e., return is what it is, and prices do not change). Under sliding scale regulation prices are adjusted to keep the return within a range. For example, in Equation (3) if the earned return in the previous period (*t-1*) is above the allowed return (r*) then prices would be reduced such that the return for the current period (*t*) is reduced. The sliding scale was, in some sense, a precursor to modern IR. In 1855 in England a sliding-scale approach was adopted in the Sheffield Gas Act of 1855. *See e.g.,* Evetts (1922) The Sheffield sliding scale approach permitted dividends to rise or fall depending on the price of gas delivered to customers. The sliding scale was later applied to the British electricity supply and distribution system near the turn of the twentieth century. (***See e.g.,*** Hammond ***et al.*** (2002)). Sliding scale regulation may have similar drawbacks as rate of return regulation.

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[83] For example, Littleshild (2000) provides a review of the 1998-2000 price cap results and finds that regulatory model provided price reductions without sacrificing reliability.

[84] One concern is with ability of the regulator to "claw back" capital cost savings if found to not to result from efficiencies. Joskow (2005, p.38) suggests that such a policy is akin to prudence reviews found in US regulation.

[85] Sliding scale, as defined in Equation (3), is a form of ESM. However, sliding scale regulation can also refer to IR plan parameters other than return. For example, parameters such as the X-factor and sharing parameters could be linked by a sliding scale.

d. Revenue Caps

Revenue Caps set the level of revenue allowed for the test period (generally one year). This may be done by capping an overall level of revenue or a level of revenue per customer. Revenue caps also operate on a formula basis. The generic formula is:

$$\frac{\text{Total Regulated Revenue}_t}{\text{Unit Sales}_t} \leq \text{Maximum Average Charge}_t \quad (4)$$

where

$$\text{Maximum Average Charge}_t = (1 + RPI_t - X)P_{t-1} - K_t \quad (4')$$

Equation (4) sets the total unit revenue allowed in the test period (i.e., period ***t***) and caps that revenue at the maximum unit charge for that period. Equation (4') says that the maximum unit revenue is equal to an inflation rate (RPI) minus a productivity factor (X), plus the expected effect on costs of growth (K). Therefore, revenue caps are similar to price cap plans in that price changes are pegged to an inflation rate minus productivity (note that exogenous factors can also be taken into account in equation (4')). The difference between price and revenue caps comes in the K-factor which is used to determine the level of expected cost increase due to sales increases. If K is set at a positive level (i.e., K>0), then a revenue cap can operate in a similar manner to a price cap, if K is set at zero then the utility, in effect, has a penalty on all incremental sales. In addition, some revenue cap plans also include a balancing account treatment of the difference between actual revenues and those allowed under the cap. The so-called electric rate adjustment mechanism[86] or ERAM, or also called decoupling as it targets revenues to something other than sales, operates on a revenue cap basis, but includes a balancing account that true-ups the actual and allowed revenues.

Revenue caps have been criticized on several grounds. For example Costello (1996), in addition to identifying several other concerns, identifies two major problems that are of import to this discussion. First, utilities are discouraged from making incremental sales, even if those sales are economically beneficial. Second, due to the incentive effects of revenue caps, the industry may actually operate at a higher unit cost (i.e., prices increase). This last effect may actually cause prices to diverge from marginal cost (i.e., the efficient price) by even greater amounts because as consumption falls, prices will actually increase (to maintain the constant revenue), even though marginal cost may be falling or staying constant. In addition, as with other forms of PBR quality of service may suffer as the incentive to cut costs affects operation and maintenance spending. To address these issues regulators have developed certain service quality metrics, (examples are given above), that either target certain levels of quality or provide incentives to meet quality of service goals.

e. Conclusions on Incentive Regulation

In summary, IR was introduced as a response to the concerns over incentives inherent in traditional regulation. By harnessing incentives, IR programs have the potential to provide utilities and customers with benefits. Under rate of return regulation (RORR) total revenue is set to equal total cost and therefore provides lower power incentives to cut costs as revenues will be set at cost. Pure price caps

[86] The ERAM mechanism become popular in the early 1990s as a method to divorce the utility's perceived incentive to increase sales. It was often used as a method to encourage utilities to increase energy efficiency and other programs that reduced sales over time. *See e.g.,* Graniere and Cooley (1994, p. iii).

set a level of revenue and the utility must maintain (or reduce) its costs in order to maintain (or increase) its profit level. This is a higher powered incentive. Programs with profit sharing will provide incentives for cost reduction in between these two programs.

While the economic research is still not complete with respect to the impact of incentive regulation on the electric industry in the United States, Table 9 provides a summary of conclusions concerning the US telecommunications industry and the UK electric industry under incentive regulation. Sappington (2003, p. 6) provides a few key assessments of the economic literature on incentive regulation that should be kept in mind. First, many studies cannot or do not control for the effects of greater levels of competition. The expectation is that competition, regardless of the method of regulation, should induce utilities to operate more efficiently.[87] Second, there is evidence that competition combined with incentive regulation provides impetus for cost and price reduction, but the affect of incentive regulation alone may be limited.[88] Third, some effects on price reductions and network modernization are the result of government mandate rather then the form of regulation.

Several other observations concerning IR are also important. First, it is instructive to note that in the US and UK telecom industries and in the UK electric industry, regulators have generally been convinced that incentive regulation has provided sufficient benefits and have renewed these programs. Second, as noted elsewhere, in the US gas and electric industry, incentive regulation plans, while not nearly as prevalent as in the telecommunications industry, are beginning to penetrate the industry. Third, incentive regulation is generally seen as a best practice for network industries. For example, the OECD[89] published a set of guiding principles that were designed to promote regulatory quality and performance and included price caps as one of the methods to promote efficiency in regulated industries. (OECD (2005, p. 6)) Fourth, incentive regulation is designed to provide utilities with incentives to move toward more efficient production; in doing so, however, it is likely that the utility will be seen as more risky by investors and therefore equity returns will need to increase. ***See e.g.,*** Alexander and Irwin (1996). This does not mean that incentive regulation is undesirable; it simply means that regulators must recognize that returns earned by firms under IR are designed to reward investors for taking additional risks. What regulators need to focus on is that incentive regulation can result in a lower ***total average cost***, even if the utility earns slightly more profit as a reward for taking the risks. By appropriating incremental returns in the interest of benefiting customers, regulators will, in the end, harm customers through the utility's inability to attract future capital. (***Id.)*** Finally, after a thorough review of British privatization and regulation in the network industries, Newberry (1999, p. 333) concludes:

> …price caps seem not only to be the most efficient method of regulating…monopoly parts [of network industries] but the only viable form of regulation able to deal with the transition to a competitive…market.

[87] For example, Markiewicz ***et al.*** (2004) find that utility-owned electric generation plants in states that restructured the electric industry obtained the largest productivity gains and those plants that were largely unaffected by restructuring, e.g., municipally-owned generation, experienced the smallest gains. Steiner (2000) finds a similar correlation between generation efficiency and liberalization of the electricity market in European countries.

[88] For example, McDermott and Peterson (2001), in a limited study of the US electric industry, found that electric industry restructuring is by far the most important variable in explaining electric utility efficiency.

[89] The Organization of Economic Co-operation and Development (OECD) is an organization of 30 member countries, including the United States, whose goal is to foster good governance in both public and private sectors and provide policymakers analysis of emerging issues that affect economic growth and performance.

Table 9: Empirical Evidence on Incentive Regulation

Issue	Industry	Results	Source
Network Modernization	US Telecom UK Electric: Distribution (all companies)	More pronounced under IR Faster under IR More pronounced under IR £5.7 billion ($9.95 billion) in new distribution investment (2004-2010)	Ai and Sappington (2002) Taylor *et al.* (1992) Greenstein *et al.* (1995) OFGEM (2005)
Operating Costs	US Telecom UK Electric: Transmission Distribution	Lower under IR (where there is competition) Slightly high under IR Lower in non-review years Reduced operating cost by 50 percent (1990-2000) Reduced operating costs by 25 percent (1994-1998)	Ai and Sappington (2002) Shin and Ying (1993) Di Tella and Dyck (2002) National Audit Office (2002) National Audit Office (2002)
Profit	UK Telecom US Telecom	Higher after privatization Little Change	Armstrong *et al.* (1994) Ai and Sappington (2002)
Basic Rates	US Telecom UK Electric: Transmission Distribution	4 % Lower for business customers 10% Lower 17% lower “Significantly” lower Prices down 1.5 percent annually (2003-06) Price fell 24 percent in real terms (during first price cap period)	Ai and Sappington (2002) Crandall and Waverman (1995) Magura (1998) Braeutigam *et al.* (1997) National Audit Office (2002) National Audit Office (2002)
Service Quality	US Telecom UK Telecom UK Electric: Transmission Distribution	Little Change Little Change Limited decline (absent competition) Initial decline, later improvement Reduced outages (1990-9) Reduced outages (1990-9) Reduced outages and duration of outages (2002-2003)	Tardiff and Taylor (1993) Banerjee (2003) Clements (2001) Armstrong *et al.* (1994) National Audit Office (2002) National Audit Office (2002) OFGEM (2004b)
Productivity Growth	US Telecom	2.8% higher under IR Slightly higher under IR No change	Tardiff and Taylor (1993) Majumdar (1997) Resende (1999)

* Table is based on Sappington (2003) and augmented by authors’ research.

3. Markets

In both the US and European electric industries the use of markets to take some of the burden of regulation off the government has increased over the past twenty years. Markets address the regulatory issues as follows:

Generation investment è	Market driven, unregulated
Energy pricing è	Market-based or unregulated
Distribution pricing è	IR or, at a minimum, unbundled from energy rates
Transmission pricing è	Regulated access price (IR or RoRR), market based congestion prices, separate from G&D[90]
Obligation to serve è	Assigned to one entity or removed[91]

Implementation of restructuring in the EU has not been uniform. (Appendix 1 provides a review of the overall EU policy toward restructuring.) In January 2005, the European Commission identified only the Scandinavian countries (Sweden, Finland, Norway and Denmark) and the UK as having no major issues in implementing competition. The other EU countries were identified as having unbundling/regulation, lack of market integration or long-term power contracts and regulated end-use prices as key roadblocks to the implementation of competition. (European Commission, 2005a) Table 10 presents the switching rates for the EU member countries as of 2005 and Table 11 presents the concentration level of the generation market in the EU member states as of 2005. These patterns are roughly similar to the United States, large use customers in countries with more advanced markets are more likely to switch. More advanced markets are also more likely to have lower concentration levels. Small use customers, with a few notable exceptions, have not taken advantage of switching (although some low switch rates for small use customers are explained by the recent opening of markets in some member states). Of the 26 member nations reporting, only 14 provide a regulated tariff for large industrial customers and 5 countries (Austria, Germany, Denmark, Netherlands, Sweden and UK) do not provide a (price) regulated (supply) tariff for residential customers (or for any customers). (Corrigendum to Technical Appendix to European Commission (2005b), p. 5)

[90] In many countries (including some in Europe) the transmission function is nationalized in order to promote non-discrimination in the use of the transmission grid by (privately owned) competitive generation and supply companies. This concept is analogous to allowing private trucking firms to compete using publicly-owned inter- and intra-state highways or privately-held airlines competing using publicly-owned and operated (e.g., air tariff control and airport security) airports. In parts of the US, as in other nations where the grid operator is privately owned, transmission is either functionally separated from the other parts of the business and run by as independent entity or the transmission company is a separate company.

[91] For example, customers may be offered a "default" service from the local utility, or another entity, that is regulated. Although after a transition period, the price can be set through a market-based process. Pfeifenberger *et al.* (2004) provides a review of these processes.

Table 10: Customer Switching Rates in the EU Member States

Cumulative Switching Rates	Large Use	Medium Use	Small use and Residential
> 50%	DK, FI, IE, SE, UK, NO, IT	FI, UK, NO	NO
20 – 50%	AT, FR, DE, BE, LU, HU, NL	AT, IT, HU, NL	FI, UK, SE,
5-20%	ES, LT, PL, PT, CZ, SI	IE, DK, DE, PT, BE	IE, NL, DE, DK, BE
<5%	GR, EE, LV, SK	All Others	All Others

Source: Technical Appendix to European Commission (2005b), p. 16.

Table 11: Generation Concentration in the EU Member States

Concentration	Member State
Very Highly Concentrated (HHI > 5000)[92]	BE, FR, GR, IE, PT, EE, LV, SK,SI
Highly Concentrated (1800<HHI<5000	DE, IT, ES, LT, CZ,
Moderately Concentrated (750<HHI<1800)	AT, NORDIC, NL, UK, PL, HU

Source: Technical Appendix to European Commission (2005b), p. 20.

In summary, the European Commission (2005b) found that:

- Market integration is still insufficient, with the exception of the Nordic countries, to create real alternatives to domestic suppliers;
- The industry remains concentrated and consolidated with most national companies retaining over 75 percent of the market;
- Several member states have not implemented, been late in implementing or implementing the directive in a "minimalist" fashion;[93]
- Small use customers have been slow to exercise the right to choose (although the large use customer switching rates have been on the rise).

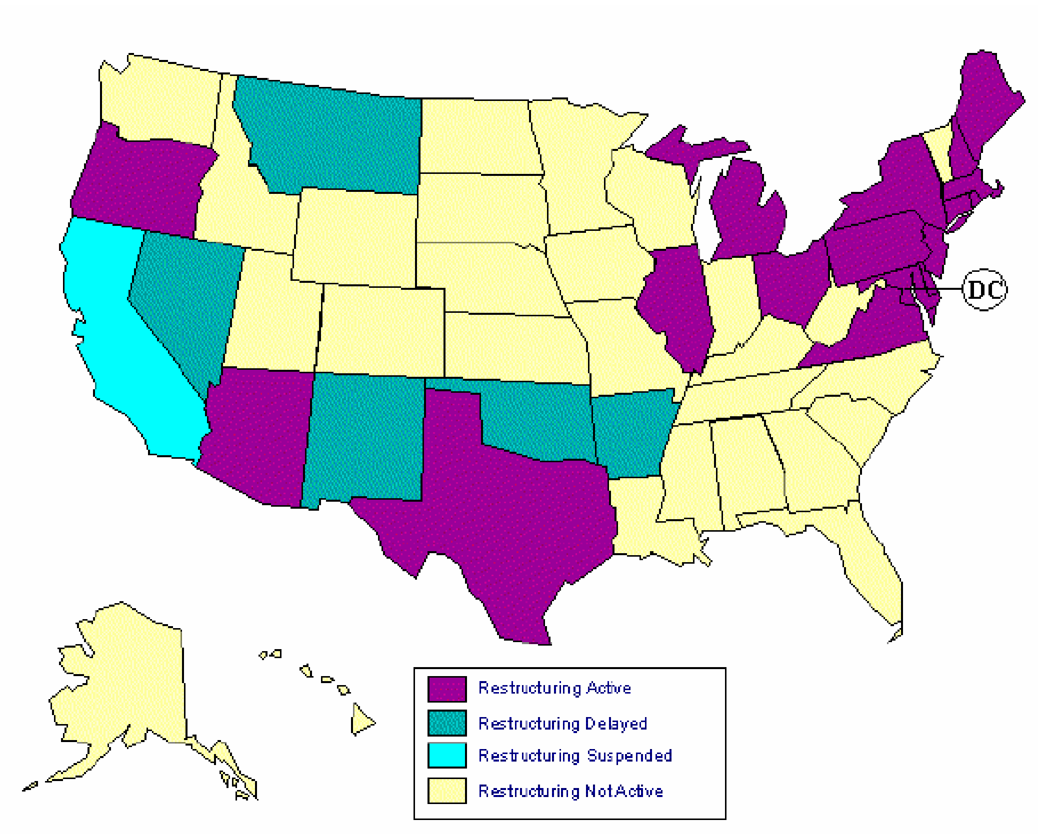
[92] The HHI or the Herfindahl-Hirschman Index is a measure of concentration that is calculated by summing the squares of the individual markets shares of each firm in the industry. The HHI's maximum number is 10,000 (=100^2). The US Department of Justice *Horizontal Merger Guidelines*, broadly defines a market as un-concentrated with an HHI below 1000, moderately concentrated with an HHI between 1000 and 1800, and highly concentrated with an HHI over 1800.

[93] In the case of those countries that have not implemented the directive they are currently in court over the breech of the Electricity Directive.

In the United States the implementation of competition is less uniform. While wholesale markets have been transformed by federal policy, the approach to competition on the retail side has been fragmented and uneven.[94] Figure 7 shows the current state of restructuring by state.[95] In summary:

- Seventeen states and DC have full retail access for all customers (generally Northeast, upper Midwest and Texas); 8 other states have instituted some form of retail access or restructuring;[96]
- Of those 25 states, only 21 are currently supporting retail access. Four states that originally decided to restructure have delayed, postponed or repealed open access (OK,WV,AK,NM); and
- State restructuring activity has ground to a halt. No new laws have been passed since 2000 and currently there are no states with restructuring under consideration

Figure 7: Status of Retail Competition in the US



[94] Joskow (2003) provides an appraisal of the implementation of competition in the US.

[95] Figure 7 is from the EIA and is based on the latest update as of February 2003. Pfeifenberger *et al.* (2004, Table 1) provide more detail on retail access in the US.

[96] For example, California suspended retail access in 2001, but grandfathered existing customers. Montana extended the transition period for small customers to 2027, effectively assigning these customers to the default supplier. Oregon allows direct access for very large customers only. Oregon also allows customers to choose a "market-based" rate provided by the utility.

VII. Future Direction for Electric Utility Regulation in Wisconsin

A. Lessons Learned

This section summarizes the key factors regarding the evolution of the electric industry and its regulation over the past few decades. Specifically, the following can be concluded from the above discussion.

- **Wholesale markets will continue to evolve:** Federal and certain state policies toward competition are not likely to be overturned. Regional transmission organizations will continue to grow and expand their roles in supporting regional markets. External economic forces in the energy market will continue to provide the impetus for markets to solve the resource allocation problem. The implications for Wisconsin are that market prices will continue to play a role in setting benchmarks for both customers (searching for lower prices) and utilities (seeking profitable markets for surplus supply).

- **Demand-side of market will be of growing importance:** Market price signals and growing recognition of the need for an active demand-side will provide incentives for demand response from customers (including energy efficiency, conservation and load control). These programs will help the wholesale markets to evolve toward a more competitive state. For Wisconsin this implies developing new utility services that will enhance reliability of the supply system and improved efficiency in the development of future supply additions.

- **Unbundling of products and services will continue:** The forces of competition and the attention of policymakers will continue to promote unbundled products and services to address competitive pressures at the margin. New technologies that are implemented as a result of evolution of the energy marketplace will put pressure on traditionally bundled cost recovery. This will make traditional rate structures less sustainable over time. Wisconsin will need to continue exploring the rationale for the functional unbundling of distribution and generation services in preparation for the developments in the wholesale market.

- **Input prices for electric generation will continue rise, at least in the near term:** Prices of fossil fuels and in turn rates for consumers are likely to continue to rise in the near term. Given the role of natural gas in serving peak demands Wisconsin will need to consider expanding its mix of demand response services in order to mitigate potential price shocks.

- **The current Wisconsin regulatory model has provided certain benefits to consumers:** This report concludes that traditional regulation, as practiced in Wisconsin, has provided consumers with the basic services and certainty of future service that is part of the regulatory bargain. However, given the uncertainty that characterizes the future energy markets and the rapid nature of changes that do arise, certain observations are warranted. Specifically:

    - Investment in Wisconsin, in generation, distribution and transmission has been forthcoming from the utilities.

    - While prices have been increasing steadily in Wisconsin, this has also occurred across the nation as a whole and will likely continue for the near-term as price inflation continues in energy markets.

- o Wisconsin was at one time a leader in promoting efficient price signals for customers. However, the state has not continued that leadership.

- o Wisconsin consumers will have safe and reliable service for the near and intermediate term.

§ **Incentive regulation can be a valuable policy in both providing better price signals as well as efficiency incentives:** Incentive regulation can be superior to traditional regulation in that it provides both efficiency incentives and incentives to price in an economic manner.

§ **Incentive regulation is becoming more prevalent in the regulation of public utilities:** Beginning with the telecom industry, incentive regulation has been introduced to the electric industry in both the United States and in Europe. While European energy utilities are more likely to be under some form of incentive regulation, but this approach is being adopted for US energy utilities, albeit at a much slower pace.

B. Evolution of the Regulatory Model in Wisconsin

Throughout this report, and indeed throughout the last few decades, the incentive structure inherent in the regulatory model has taken center stage in reviewing and understanding the costs and benefits of different regulatory models. While concern over proper incentives may seem common sense in today's world, the introduction of incentive-based structures has actually been very slow and sporadic in the United States in the electric industry.[97] While regulators recognized the importance and role that incentives could play as early as the 1920s, plans adopted by utilities would often be short lived. However, in the past decade or so, incentives have become recognized as critical to the proper functioning of the industry. With that understanding, changes have been made to the regulatory model. Some of these changes constitute very radical departures from past practice (e.g., restructuring and promotion of competition) while others have been less dramatic such as incorporation of incentive-based regulation (into at least some aspects of economic regulation) and the implementation of efficient pricing programs for retail customers.

Any changes to the future regulatory model in Wisconsin should capitalize on the lessons and experience of other states. Incentive structures do matter and are crucial to producing the benefits from this critical infrastructure industry. Wisconsin has, in the past, recognized that incentives are important component of regulation through the PSCW's early use of marginal cost pricing, efficiency incentives employed during the use of longer range planning and more recently in the latest "regulation by contract" approach taken in the PTF cases. These innovations have brought both benefits and costs with the overarching objective to provide customers with reliable service at reasonable prices. However, the industry continues to evolve. Wholesale markets for power are now beginning to mature in parts of the European Union and in most of the east and mid Atlantic regions as well as parts of the Midwest in the United States. Markets are the ultimate signal to consumers and producers and provide incentives for guiding both investment and consumption. **Markets will continue to evolve in the United States, regardless of the policies of individual state regulators and policymakers**. Therefore, the question for Wisconsin policymakers is how to coherently capture the benefits of this evolving market structure for customers while maintaining reliability and reasonable prices.

[97] Even economists may have been late to understand the importance of incentives. Laffont and Martimort (2002, p.1) cite the fact that the renowned mid-twentieth century economist Joseph Schumpeter's tome ***History of*** *Economic Analysis* does not even mention the word "incentives."

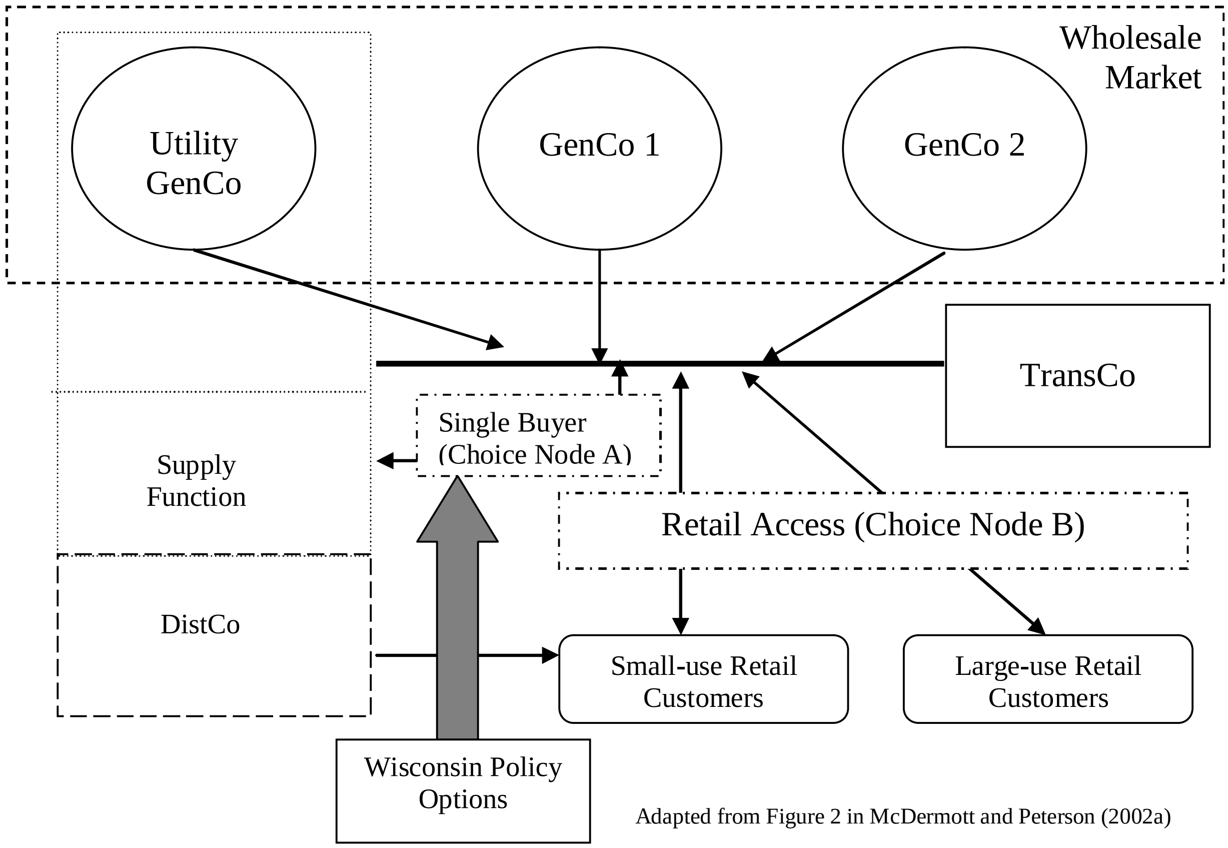
To fully understand the importance of this question, one must fully understand what aspects of markets are important. McDermott and Peterson (2002a) provide a discussion of the initial reforms in the electric industry and why these reforms failed to live up to expectations and what policymakers can do to avoid the mistakes, while taking advantage of the benefits of competition. The basic idea is that markets work based on an interaction of supply and demand. One of the key problems with the initial move toward retail markets in the United States was the misunderstanding of the role prices play in guiding the demand-side of the market. While it is understandable why policymakers would want to capture initial benefits for consumers through fixed prices or rate reductions, often these policies were at odds with the promotion of competition, and in turn the capturing of the benefits of competition. Deregulation of the supply-side of the market, which was the focus of many of the initial reforms, was only half the story. It is the disconnect between the wholesale (supply-side) markets and retail (demand-side) markets that led to many of the problems seen in California and in some eastern states as well.

Policymakers in Wisconsin will have to contend with the fact that markets are evolving and are becoming more important to the functioning of the statewide electric industry. Therefore, how do state regulators recognize the evolving market and incorporate the demand side into the new evolving structure?

Figure 8 provides a generalized version of the electric market. The top of the figure represents the wholesale market. In this figure we have simplified the market for illustrative purposes to only include three generation companies (GenCos) including the utility's generation arm. The wholesale market also includes the transmission company (TransCo), which is the provided of the transmission services such that buyers and sellers can transact with one another.[98] The wholesale market is generally under the jurisdiction of the Federal Energy Regulatory Commission. At the bottom right of the figure types of customers are illustrated: large-use and small-use. In between the supply side of the market (the top) and the demand side (the bottom) multiple configurations are possible. Currently Wisconsin does not require utilities to provide access to the wires network such that customers can directly access the wholesale market. Such a configuration is modeled as Choice Node B or what is referred to as Retail Access. Wisconsin's current approach provides choice only through Choice Node A which is referred to as the Single Buyer (i.e., utility buys or produces power and resells to customers).

[98] In the case of Wisconsin the transmission company, however, the Midwest ISO provides locational marginal prices and firm transmission rights for use of the interconnected systems.

Figure 8: Choice Options



1. Understanding Wisconsin's Policy Options

Wisconsin's policy options are varied, but we can categorize them under four general headings.

Option 1: No Change. Option 1 is the "stay the course" option. Wisconsin utilities have been through a construction phase and will be expected to follow traditional biannual rate cases in order to introduce this new investment into the rate base. Option 1 may be attractive to the casual observer of the industry as there does not appear to be any obvious problems. Option 1, however, does not address the fundamental issues of efficient pricing or incentives. Option 1 is probably not feasible over the next few years as markets begin to evolve. Pressure will occur, either from the demand or supply side.

Option 2: Incremental Change. Incremental change engenders the recognition that the role of incentives may need to change along with the introduction of efficient pricing strategies. In this option, however, these changes are accomplished more slowly and incrementally. This option should be adopted if the policymakers feel that the effects of markets will occur only slowly and have a smaller or more distant effect on the industry in Wisconsin. This approach can be viewed as a mechanism to prepare the state for future changes and the continual evolution of the market.

Option 3: Moderate Change. This option takes Option 2 somewhat further. There is an explicit recognition that markets will be impacting the state over the next decade and incentive mechanisms and pricing needs to be consistent with market forces. A more concerted effort will be needed to establish appropriate incentive and structural changes to ensure that utilities and customers are making decisions today that will effectively position the state to address the more rapid evolution of markets.

Option 4: (Legal) Restructuring. Restructuring is the most radical change and would only be undertaken if policymakers felt that markets will affect the Wisconsin electric industry to a degree that the traditional institutions, or even Option 2 and 3 reforms, could not sustain the changes.

After reviewing the Wisconsin regulatory model as well as the changes that have occurred in the industry we are of the opinion that Option 1 is unlikely to be sustainable for long and Option 4 would not be beneficial or feasible at this time. There are several reasons for this. First, it is clear that markets are evolving and will have an effect on Wisconsin; however, it is not clear that (full) retail competition is required to take advantage of those changes. Second, Wisconsin, in step with other jurisdictions, is experiencing a time of increasing prices. Doing nothing to address this issue would not be wise, but complete deregulation might risk large price increases. Third, market restructuring would likely take significant changes in Wisconsin law—as has been the case in other states—this process can take several years to go from the identification of the need for change to the implementation of those changes. Other options exist that can be implemented much faster and are likely to bring similar benefits. Therefore, either Option 2 or Option 3 is the best choice for Wisconsin at this time.

2. Evaluation of Policy Options

In the above discussion of regulatory models we identified three basic models, traditional regulation, performance-based regulation and markets. Under our S-C-P pedagogy, we discussed the performance of the industry as critical to the understanding of the regulatory models. In this section, we identify seven qualitative performance metrics and rank each of the policies under the basic models for its appropriateness in the context of the Wisconsin electric market.

Performance Metrics:

1. ***Investment for reliability***: This metric measures the ability of the policy to induce enough investment to maintain safe and reliable service.

2. ***Cost Efficiency:*** This covers general production efficiency, but not investment efficiency.

3. ***Efficient Investment:*** Efficient investment refers to the proper level and timing of investment as opposed to simply enough investment for reliability purposes. This also includes the incentive for non-utility investment in generation.

4. ***Price levels:*** Price levels refer to the overall level of prices. Under various regulatory models different customers may be charged different levels relative to the current model of regulation (due to implicit subsidies currently embedded in rates).

5. ***Pricing Efficiency:*** Pricing efficiency refers to the ability of the policy to create and enforce efficient prices.

6. ***Customer Options:*** Customer options may include multiple types of pricing arrangements, different services, differentiated customer service, etc.

7. ***Ease of Implementation*:** This metric is a "catch-all" measure that attempts to measure both the ease of regulatory implementation (i.e., is legislation necessary, can PSCW do without legislation, etc.), and practical implementation (i.e., is there a learning process for the new model that both customers and utilities will have to go through, etc.)

Next different policy options are ranked under the three basic models based on the following scale: 1.0(=poor), 2.0(=unsatisfactory), 3.0(=neutral), 4.0(=good) and 5.0(=excellent).[99] However, it must be understood that these rankings were determined based on the evidence provided in this report and the authors' judgment concerning the viability of each model in Wisconsin in the short-term and its viability in the long term recognizing the long-term uncertainty in the industry. A more thorough analysis of the various options would require significant effort and is beyond the scope of this document. The following policies will be ranked based on the above metrics:

1. **Traditional Regulation (RoRR):** This policy is defined as the revenue requirement approach to setting annual allowed revenue along with a used and useful and prudence review of investment.
   a. **Leased Generation**: Is an approach to address the regulatory risk associated with generation investment in an evolving market. Leases are pre-approved by the regulator and put into rates over the length of the lease.
   b. **Pre-approval of Regulatory Parameters:** This approach approves the return on investment and equity for the life of a project prior to construction. This is to address the ability of a future regulator to change the financial parameters.
   c. **Competitive Bidding for Generation:** In this approach generation would be bid out but the utility would be the single buyer of that generation. This could be done through an RFP for relatively short time frames or through contractual arrangements (through bidding) for longer.
2. **Performance-Based Regulation:** PBR is aimed at providing incentives for efficiency in production and investment as well as pricing efficiency. Two forms of PBR will be reviewed here:
   a. **Sliding-Scale Regulation:** This provides utilities incentives through allowing profits to rise and fall with utility effectiveness.
   b. **Price-Cap Regulation:** Price cap regulation sets a formula by which prices can change over time. This assumes that a set of quality of service targets are included in the plan. Price-cap regulation may included a sliding-scale as well.
   c. **Revenue-Cap Regulation**: Similar to price caps, but instead caps the level of revenue that is allowed to be recovered in any time period. This assumes that qualities of service targets are included in the plan. Revenue caps may include a sliding-scale as well.

4. **Restructuring:** This policy refers to providing retail access to consumers (either all consumers or some subset.) Restructuring would include a transition period in which the utility would be required to provide supply services, after the transition period a decision would be made as to how long the utility's obligation to provide supply services would remain and how those services would be procured. Distribution and transmission would be regulated, and distribution may or may not be unbundled

[99] Note that the hybrid model has not been defined under this analysis.

a. Investment for Reliability

- **Traditional Regulation**: Traditional RoRR regulation provides incentives for reliability investment through the regulatory commitment provided by the revenue requirement equation (i.e., used and useful regulation) backed up by the judicial requirement that a "fair" return be provided. Investment has occurred in Wisconsin under this approach. Score = 4.0
  - **Leased Generation:** This approach has worked to provide incentives for investment in Wisconsin (e.g., PTF). Investment has occurred in Wisconsin under this approach. Score = 5.0
  - **Pre-approval of Regulatory Parameters**: Likely to provide similar incentives to leased generation. Score = 4.0
  - **Competitive bidding for Generation:** Likely to provide similar incentives to leased generation. Score = 4.0
- **PBR:** PBR programs are likely to provide similar investment incentives as traditional regulation, although less likely to provide incentives for over-investment.
  - **Sliding Scale:** Score =4.0
  - **Price Cap:** Score = 4.0
  - **Revenue Cap:** Score = 4.0
- **Restructuring:** Restructuring would move the reliability (for supply) issue from the state level to the regional level. Suppliers would buy and sell in the wholesale market and load-serving entities would be required to obtain the amount of capacity needed to serve load from internal resources or by purchasing on the market. There remains an outstanding issue as to how quickly the demand side of the market can be incorporated and therefore some uncertainty remains concerning investment for reliability purposes. Reliability on the T&D system under this policy approach would not be affected. Score = 3.5

b. Cost Efficiency

- **Traditional Regulation**: Traditional RoRR has been criticized by economists and others for the poor incentives for cost efficiency. Cost-plus regulation provides a weak incentive for efficiency through regulatory lag. Score = 1.0
  - **Leased Generation:** If the leased generation approach is implemented through a traditional RoRR mechanism then the same poor incentives will exists. Score = 1.0
  - **Pre-approval of Regulatory Parameters**: Similar to above. Score = 1.0
  - **Competitive bidding for Generation:** May increase cost efficiencies if contracts are fixed price. Score = 1.0
- **PBR:** PBR programs are designed to provide incentives for cost efficiency.
  - **Sliding Scale:** This program provides mid-level incentives for cost efficiency through the sharing of profit. Score =3.5
  - **Price Cap:** Pure price caps, i.e., without a sliding scale, provide high level incentives. Score = 4.5 (with a sliding scale Score =4.0)

- **Revenue Cap:** There is some evidence that revenue caps may cause firms to focus on total cost reductions, rather than average cost reductions. Score = 3.0, (with sliding scale Score = 2.5)

§ **Restructuring:** Competition provides the highest level incentives for efficiency. This should appear through more efficient generation production and, because distribution would be unbundled from generation, more attention by the distribution company to that business. Score = 5.0

c. Investment Efficiency

§ **Traditional Regulation**: Traditional RoRR regulation provides incentives for investment through the regulatory commitment provided by the revenue requirement equation (i.e., used and useful regulation) backed up by the judicial requirement that a "fair" return be provided. Assuming appropriate planning has been followed; investments should be timed and optimized across technologies. May discourage non-utility investment. Score = 3.0

- **Leased Generation:** This approach has worked to provide incentives for investment in Wisconsin (e.g., PTF). Score = 3.5
- **Pre-approval of Regulatory Parameters**: Likely to provide similar incentives to leased generation. Score = 3.5
- **Competitive bidding for Generation:** Likely to provide similar incentives to leased generation. Score = 3.5

§ **PBR:** PBR programs are likely to provide similar investment incentives as traditional regulation, although less likely to provide incentives for over-investment.

- **Sliding Scale:** Score =4.0
- **Price Cap:** Score = 4.0
- **Revenue Cap:** Score = 4.0

§ **Restructuring:** Suppliers would buy and sell in the wholesale market and load-serving entities would be required to obtain the amount of capacity needed to serve load from internal resources or by purchasing on the market. Under conditions of full integration of demand side into the market, investment should be efficiently provided by generation companies. Reliability on the T&D system under this policy approach would not be affected. Score = 4.5.

d. Price Levels

§ **Traditional Regulation**: Traditional RoRR has been criticized by economists and others for the poor incentives for efficiency. Price levels are likely to be higher with lower levels of incentives. Score = 1.5 – 2.0

- **Leased Generation:** May increase price levels relative to traditional RoRR Score = 1.0- 2.0
- **Pre-approval of Regulatory Parameters**: Similar to leased generation, but may prove to provide lower levels of revenue requirement. Score = 1.5 - 2.5
- **Competitive bidding for Generation:** Similar to Traditional Regulation. Score = 1.5 - 2.0

- **PBR:** PBR programs are generally designed to provide better efficiency incentives. If unbundling is part of the PBR program pricing efficiency improves.
  - **Sliding Scale:** Score =3.0
  - **Price Cap:** Score = 3.5 – 4.0.
  - **Revenue Cap:** Revenue caps can lead to higher prices over time and may provide the incentive for utilities to increase price. Score=1.5 – 2.0
- **Restructuring:** In theory, restructuring provides incentives, through competition, to reduce prices, over time, to their lowest feasible level. However, depending on the specifics of a given utility that may be higher or lower than current rates. Therefore, it is unknown exactly how restructuring would impact rates for any given Wisconsin utility in the long run. However, it is clear that in times of shortages and increasing fuel prices, markets will produce increasing prices. Therefore, in the short-term markets are likely to have increasing prices, yet this is probably what will occur under continued regulation. Score = 1.0 – 3.0.

e. Pricing Efficiency

- **Traditional Regulation**: Traditional RoRR has been criticized by economists and others for the poor pricing efficiency when based on average costs. Marginal cost pricing improves efficiency. Generally under RoRR prices remain bundled and therefore do not send accurate signals to customers. Score = 1.5 – 2
  - **Leased Generation:** If it sets a fixed price over time, can distort prices away from efficient levels. Score = 1- 2
  - **Pre-approval of Regulatory Parameters**: Similar to above. Score = 1 - 2.
  - **Competitive bidding for Generation:** Similar to above. Score = 1 - 2.
- **PBR:** PBR programs are generally designed to provide for better pricing efficiency. If unbundling is part of the PBR program pricing efficiency improves.
  - **Sliding Scale:** Score =3
  - **Price Cap:** Score = 3.5 - 4
  - **Revenue Caps:** May provide incentive for prices to diverge from efficient levels. Score = 1.0 – 1.5.
- **Restructuring:** Under this policy pricing will eventually move to the efficient level for supply. T&D would be priced as above. Score = 5

f. Customer Options

- **Traditional Regulation**: Traditional RoRR generally provides very little customer choices. Score = 1.0
  - **Leased Generation:** Score = 1.0
  - **Pre-approval of Regulatory Parameters**: Score = 1.0
  - **Competitive bidding for Generation:** Score = 1.0
- **PBR:** PBR programs are generally designed to provide for better pricing efficiency and can include multiple options for customers.

- **Sliding Scale:** Score = 1.0 – 3.0
- **Price Cap:** Score = 3.0 – 4.5, Price caps are generally designed to allow some pricing flexibly and the incentives tend to move utility toward more commercial operations which provides customers with more options.
- **Revenue Caps:** Score = 1.0 – 3.0

§ **Restructuring:** Under this policy customer options, in the long-run, should improve. Score = 5.0

g. Ease of Implementation

§ **Traditional Regulation**: Is currently in place in Wisconsin and would not require additional legislation or implementation costs. Score = 5.0

- **Leased Generation:** Same as above. Score **=** 5.0
- **Pre-approval of Regulatory Parameters**: Would require changes in the law and implementation before the PSCW. Score =1.5
- **Competitive bidding for Generation:** Currently in place. Score = 5.0

§ **PBR:**

- **Sliding Scale:** Would have to be implemented before the PSCW in a rate case. Score = 4.5
- **Price Cap:** May need legislation, but could be implemented in a rate case. Score = 4.0
- **Revenue Cap:** Same as price cap. Score = 4.0

§ **Restructuring:** Requires massive overhaul of legislation and significant implementation at the PSCW. Score = 1.0

Table 12: Ranking Policy Options

Model (Total Points)	Investment for Reliability	Cost Efficiency	Investment Efficiency	Price Levels	Pricing Efficiency	Customer Options	Ease of Implementation
Traditional RORR (17.0 -18.0)	4.0	1.0	3.0	1.5 – 2.0	1.5 - 2.0	1.0	5.0
Leased Generation (17.5 – 19.5)	5.0	1.0	3.5	1.0 – 2.0	1.0 – 2.0	1.0	5.0
Pre-Approval (16.0 – 18.5)	4.0	1.0	3.5	1.5 – 2.5	1.0 – 2.0	1.0	4.0
Competitive Bidding (17.0 – 19.0)	4.0	1.0	3.5	1.5 – 2.5	1.0 – 2.0	1.0	5.0
IR- Sliding Scale (23.0 – 25.0)	4.0	3.5	4.0	3.0	3.0	1.0 – 3.0	4.5
IR- Price Caps (26.0 – 29.0)	4.0	4.5 (4.0)*	4.0	3.5 – 4.0	3.5 – 4.0	3.0 – 4.5	4.0
IR –Revenue Caps* (18.0 – 21.5)	4.0	3.0 (2.5)*	4.0	1.5 – 2.0	1.0 – 1.5	1.0 – 3.0	4.0
Restructuring (24.5 – 26.5)	3.0	5.0	4.5	1.0 – 3.0	5.0	5.0	1.0

* Score without ESM (With ESM)

h. Summary of Policy Rankings

Table 12 provides a summary of the policy rankings with the total points from each of the regulatory models summed and stated under the model name in the first column. Before reviewing the results, it must be understood that these rankings were determined based on the evidence provided in this report and the authors' judgment concerning the viability of each model in Wisconsin in the short-term. Further, we have equally weighted each performance metric to obtain the final scores. There is some evidence provided in this report that Wisconsin policymakers would weight certain of these factors higher than others. For example, as noted above, reliability has been a major factor in Wisconsin policy toward electric utilities since the late 1990s. Therefore, it is reasonable to assume that policymakers in Wisconsin may weight reliability investment higher than other factors. In addition, we have assumed that changes to Wisconsin legislation in the case of restructuring, based on the experience in other states, would be very difficult, but that changes that might be useful or needed to implement IR programs effectively would be far easier to implement. Again, this is based on experiences in other states, as well as the recognition that Wisconsin has made changes to its telecommunications law to allow and implement incentive regulation. Finally, it should be noted that the total possible points is 35.0 (7 metrics multiplied by 5 points). No model received a score above 29.0. This indicates the difficulty, as noted above, in implementing regulatory models for network industries. No model is perfect, nor will any model perfectly address every possible need or desire for the performance of the industry simultaneously.

Table 12 does provide one clear message. Traditional rate of return regulation, while very good at inducing investment for reliability purposes, scores very low in economic performance measures such as level and efficiency of prices. With the expectation that markets will play a larger role in the industry in future years, failure to induce efficiency in both production and consumption is a major drawback of traditional regulation. Incentive regulation, provides similar incentives for reliability investments, but provides better incentives for economic efficiency. One conclusion that can be drawn from this analysis is that incentive regulation will provide sufficient incentives for reliability investment while moving the industry toward a more economically efficient production frontier. Therefore, Wisconsin could benefit from harnessing the value that has been left on the table by utilizing RoRR, by moving utilities toward some form of incentive regulation.

3. Recommendations for Reforms that Could Benefit Wisconsin

The choice of whether Wisconsin needs incremental change or moderate change, no change or more radical change, is up to the policymakers. However, a vision for the kind of changes that could be useful will be outlined here. These changes are predicated on two facts. First, market evolution cannot be held off forever. Markets will continue to evolve and will continue to affect Wisconsin. Second, there are policies that can help Wisconsin move to a more efficient electric industry that are compatible with future market changes, but are also appropriate if the market does not evolve in the manner posited here. Therefore these changes can be made, without attempting to forecast the outcomes of future events.

Recommendation 1: Explore Implementation of Incentive Regulation

Incentive regulation of some form should be explored. We have described three forms of incentive regulation in this report. Any of these, or a combination of these, could be implemented effectively in Wisconsin Price caps could be very useful to address both capital additions and pricing efficiency. As noted above, capital additions over the next ten years will increase utility rates by a substantial figure. Providing utilities with better incentives to control costs and to price efficiently will provide benefits to consumers. Utilities should be encouraged to develop incentive rate plans to file with the PSCW.

Recommendation 2: Provide Utilities Option of Unbundling Prices

In addition to pricing efficiently, price unbundling may be an approach to provide better price signals to consumers. Price unbundling (i.e., separately pricing distribution services and generation services) would facilitate the ability to utilize a separate incentive program for generation and distribution. Furthermore, to the extent that retail markets evolve, utilities will be in a better position to respond to these changes.

Recommendation 3: Modify Legislation to Allow Incentive Regulation to Operate More Effectively

While we believe that the PSCW has sufficient authority to implement some form of incentive regulation, we believe that certain modification to the legislation would allow incentive regulation to perform more effectively. A useful modification would be to allow utilities to use formula rates if in the context of a PSCW-approved alternative regulation plan. Currently Wisconsin law requires rate hearings for rate increases. While this is appropriate under in the traditional model, it is less important under an alternative regulation plan. In essence, the IR plan would *pre-approve* rate increases based on a formula that the PSCW finds is just and reasonable. *Pre-approval* is not an unusual concept in public utility regulation, nor are formula rates. One example of pre-approval is the Commission's endorsement of "fixed financial parameters" for generation investment (this is the same as the "pre-approval" model analyzed above). (2004 SEA Report, pp. 138-139) Formula rates are used or have been used by many regulatory bodies including the US FERC, UK OFGEM, Illinois Commerce Commission, New Jersey Board of Public Utilities, California Public Utilities Commission and many others both in the US and in the EU.

Recommendation 4: Promote the Expansion of Utility Service Options

In the 1990s many proponents of restructuring pointed to the varied products and choices that markets can provide. Such options are likely to be beneficial to customers and will educate customers concerning energy choices. While we are not providing a recommendation of the exact products that should be provided, many different options and combinations of options are possible such as:

- § Green products;
- § Real-time pricing;
- § Market-based demand response programs;
- § Energy efficiency products and programs;
- § Multiple pricing options with various levels of price certainty.
- § Reliability pricing;

Customers could be given this menu of products that would simulate the competitive market place and provide customers with additional service options.

Recommendation 5: Promote the Expansion of Demand Response Programs

Demand response programs are designed to "motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized." (USDOE, 2006) Demand response programs are critical to the efficient operation of competitive markets. ***See e.g.,*** Caramanis ***et al.*** (1982), Fraser (2001), McDermott and Peterson (2002b) and USDOE (2006). Further, these programs are beneficial to utilities, customers and society through improved grid reliability, lowering peak prices through removing demand during high-price periods and providing customers benefits through compensation for changing consumption behavior. The programs come in two forms. First, price-based programs include real-time price, critical peak pricing and other forms of time-varying pricing. [100] Second, incentive-based programs pay customers to drop off or reduce usage based on a pre-defined trigger (e.g., high prices or grid reliability issues) and are generally implemented by the local utility. In the short-run price-based programs will be difficult to implement due to the need for more sophisticated metering that currently is not provided to most customers. However, incentive programs, such as those currently offered by most utilities in Wisconsin, could be promoted (as the PSCW did as part of We Energies demand-side management plan filed in response to the Oak Creek Order.) The PSCW should therefore explore ways to improve and expand incentive based programs, while determining the feasibility and desirability of expanding price-based programs through additional investment in the distribution system (e.g., meters, metering capabilities, etc.).

[100] The Energy Policy Act of 2005 suggests that states should aggressively implement price-based programs. ***See e.g.,*** USDOE (2006)

Appendix 1: Summary of Key Issues Addressed by the First EU Electricity Directive and Modifications Made by the Second EU Electricity Directive

The first EU Electricity Directive (First Directive) was passed by the European Council and Parliament 19 December 1996 (Directive 96/92/EC), it was later amended and superseded by the second EU Electricity Directive (Second Directive) passed 26 June 2003 (Directive 2003/54/EC). Modifications to the First Directive are shown in bold.

§ **Market Liberalization**. The provision for market opening was set in three steps: 1st step on 19 February 1999, 2nd step on 19 February 2000 and 3rd step 19 February 2003. **(Last step was extended to 1 July 2004 by Second Directive)**

- The minimum market opening corresponding to the 1st step is calculated as the share of the total consumption which is consumed by final consumers with an annual consumption exceeding 40 GWh. Following the latest calculation this implies that about 26.48% of each national market shall be opened for competition. In the 2nd step the threshold is reduced to a level of 20 GWh. This increases the minimum market opening to about 28%. In the 3rd step the threshold is further reduced to 9 GWh, which equals a market opening of about 33%.
- Eligible customers are defined by each state to participate in the market opening. End-users over 100 GWh, and distributors responsible for the volume of electricity consumed through their distribution network by other final eligible customers must be included in the definition of eligible customers. The criteria for the definition of the eligible customers will be published.
- All customers are eligible by 1 July 2007 (**Modified by Second Directive, Article 21)**

§ **Generation Competition**. The Directive allows two options for opening up the construction of new generation.

- *Authorizing*. Any entity can request authorization to build a plant at any time and criteria for review of the authorization should be made a matter of public record. The criteria may relate to safety and security of the electricity system installation and associated equipment, protection of the environment, land use and siting, use of public ground, energy efficiency, the nature of primary sources, characteristics particular to the applicant such as technical, economic and financial capabilities and public service obligations. No requirement of "need" is listed in the Directive.
- *Tendering.* The transmission operator (or other competent authority) decides when new (including replacement) generation is needed and puts that new generation out for bid. The bidding procedure is required to be objective, transparent and non-discriminatory. The specifications are to be published and must contain a detailed description of the contract specifications and a complete list of criteria governing the selection of bids. [**Tendering can be used if authorizing does not provide the needed resources to meet supply security. This was modified by Article 6 of the Second Directive**]

§ **Transmission.** Transmission is defined as the transport of electricity on the high-voltage interconnected systems.

- *System Operator*. A transmission system operator (TSO) must be designated with the responsibilities for operating, ensuring the maintenance and developing the transmission system in a given area and its interconnections with other systems in order to guarantee security of supply.

→ TSO is responsible for dispatching the generating installations in its area and for determining the use of interconnections with other systems. Dispatching must be objective, public and applied in a non-discriminatory manner.[101]

→ Dispatching is to be based on a constrained economic merit order that is applied indiscriminately to both in system and out of system generation.

→ The TSO may be, however, be required to give priority in the dispatching based on the environmentally favorable characteristics of the generation (e.g., renewables, waste and combined heat and power).

→ Dispatching priority can be given to the use of indigenous fuels for the production of electricity up to 15 percent of the annual (calendar) overall primary energy necessary to produce the electricity consumed in each country.

→ The TSO must protect confidentiality of commercially sensitive information.

→ **TSO shall procure energy to cover losses and reserve capacity according to transparent, market based procedures, if they have this function. (Second Directive, Article 11)**

→ **Rules must be transparent for balancing of the system. Terms and conditions must be published. (Second Directive Article 11)**

– *Network Access*

→ *Regulated Third-Party Access (RTPA*). Rules, regulations and prices for access to the network are approved by regulator and publicly published. Eligible customers have a right of access on the basis of these tariffs. **(Second Directive only allows for RTPA, Article 20)**

§ **Unbundling.** Unbundling is suggested as a method to promote transparency and avoid discrimination, cross-subsidization and the distortion of competition.

– *Unbundling of management of transmission system*. Unless already physically separate from generation and retailing functions, the transmission system operator must have separate management. **(Second Electric Directive calls for only legal unbundling. Article 10)**

§ **Distribution.** Distribution is defined as the transport of electricity on the medium-voltage and low-voltage interconnected systems.

– *System Operator*. The distribution system operator is responsible for maintaining a secure, reliable and efficient electricity distribution system in its area with due regard to the environment. The operator must not discriminate between the system users and in particular not favor its subsidiaries or shareholders.

– *Obligation to Serve*. Distribution companies may be vested with an obligation to supply customers located in its area via regulated tariffs.

§ **Reciprocity** Access for some customers can be denied when a country opens a larger part (possibly to meet minimum eligible criteria) of the market than the other states (e.g. if a customer is eligible in Member State A but not in Member State B). **(The Second Directive provides the European**

[101] This implies that the TSO is not allowed to favor generating facilities belonging to the same company or shareholders of the company in case the TSO is not totally separated from production.

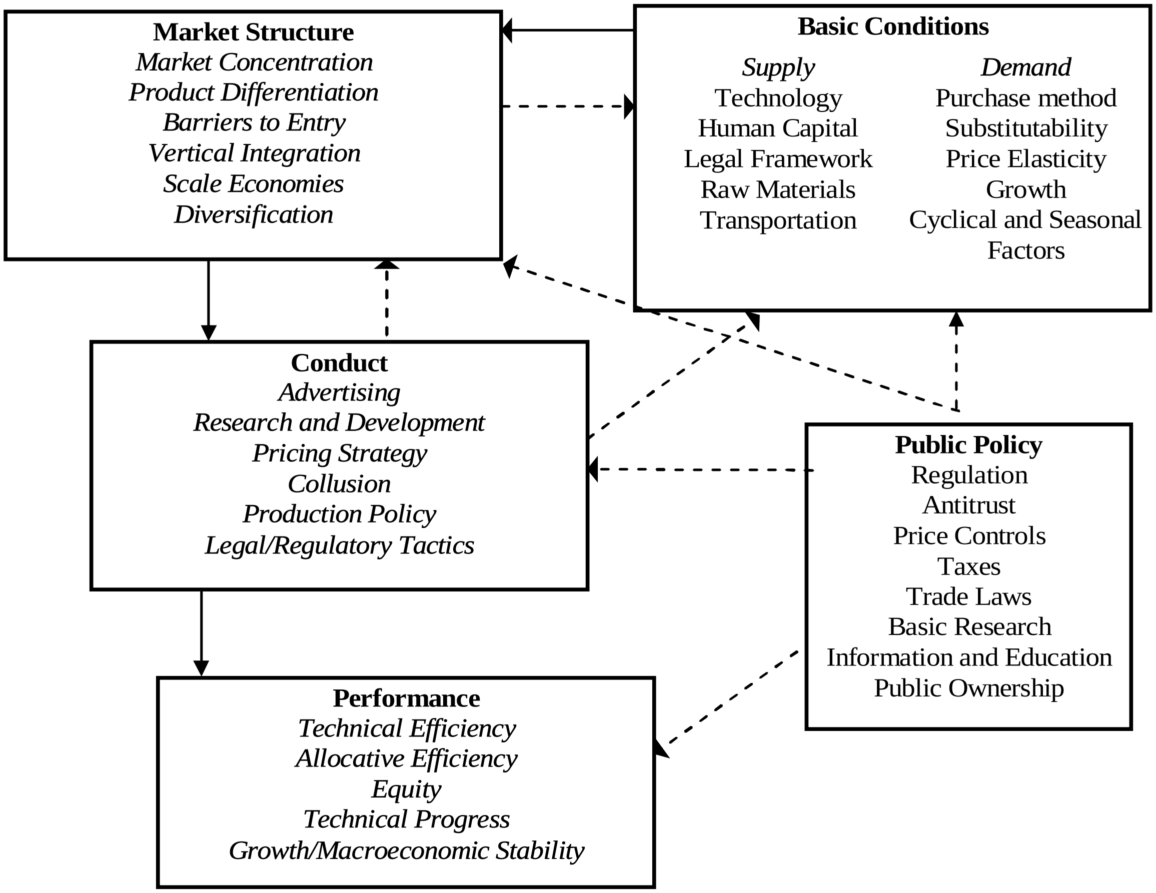
Commission the ability to allow these transactions, taking into account market conditions and the common interest. Article 21)

§ **Public Service Obligations.** Member states are allowed to define public service obligation in five categories—environmental considerations, security, regularity, quality of supply and pricing policy. While there is no common definition of public service obligation the following are common in the EU.

- *Universal Service and Consumer Protection.* These regulations set forth which services will be regulated or subsidized and the obligations to connect customers to the network.
- *Environmental Protection.* Specific rules and regulations may be applied to address, for example, environmentally friendly generation sources, internalizing external environmental costs or to encourage demand-side management.
- *Security of Supply.* These rules may address items such as connection and use of the gird, maintaining reserve capacity, availability of capacity, fuel sources and maintenance of a reliable system.

– **Regulatory Authorities.** Each member state must designate one or more competent authorities to oversee compliance with the Directive. **(Modified by Article 23 of the Second Directive.)**

Appendix 2: The Structure-Conduct-Performance Pedagogy



Adapted from Scherer (1970) and Bonanno and Brandolini (1990).

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About the Authors

Karl A. McDermott is a Vice-President in NERA's Chicago office where he specializes in public utility regulation. His projects have included advising the members of the Southern Companies, Wisconsin Electric Power Co., and Bell Atlantic on issues regarding electric restructuring and performance-based regulation. He has also assisted the country of Poland with efforts to privatize and restructure the electric supply industry. Prior to joining NERA, he served as Commissioner on the Illinois Commerce Commission during the negotiation of the Illinois restructuring law. Dr. McDermott initiated the Commission's investigation into the alternative restructuring options and has lectured on numerous occasions on restructuring and utility pricing issues in the United States. Dr. McDermott is currently on the faculty of the Institute for Public Utilities at Michigan State University where he lectures at the Institute's Annual and Advanced Regulatory Studies programs. Dr. McDermott has also lectured extensively in Eastern Europe and South America on regulatory reform and restructuring and has published articles in *The Electricity Journal, Natural Gas and Electricity,* and has contributed to numerous book chapters and authored or co-authored reports for the Illinois Commerce Commission, the Edison Electric Institute, the US Department of Energy, the National Regulatory Research Institute as well as the governments of several eastern European countries. Dr. McDermott earned his Ph.D. in economics from the University of Illinois at Urbana-Champaign, an M.S. in public utility economics from the University of Wyoming and a B.A. in economics from Indiana University of Pennsylvania.

Carl R. Peterson is a Consultant in NERA's Chicago office where he specializes in energy and public utility regulation. His work involves both policy and analytical issues in the electric and natural gas industries. In particular, his work has focused on performance-based regulation for gas and electric utilities, rate design, and electric restructuring both in the US and internationally. Recently, Mr. Peterson has been advising electric utility clients on issues related to post-restructuring power procurement and the design of unbundled rate structures. Prior to joining NERA, Mr. Peterson held senior positions with the Illinois Commerce Commission, where he advised the Commission on specific energy issues, including electric restructuring and performance-based regulation. Mr. Peterson has also served as a staff economist at the Center for Regulatory Studies housed at Illinois State University where he was the author or co-author of several reports pertaining to electric least-cost planning, electric restructuring and the price elasticity of electricity demand. Mr. Peterson has also taught economics at Illinois Central College and Eureka College. He is currently on the faculty of the Institute for Public Utilities at Michigan State University where he lectures at the Institute's Annual and Advanced Regulatory Studies programs. He has written on energy pricing, performance-based regulation, access pricing, and electric restructuring and has published in *The Electricity Journal, Natural Gas and Electricity,* as well as contributing chapters to several books and has been an author or co-author of reports for the Illinois Department of Energy and Natural Resources, the Illinois Commerce Commission, the United States Agency for International Development, governments of several eastern European countries and numerous other clients. Mr. Peterson holds a B.S. and M.S. in economics from Illinois State University and is currently completing his dissertation entitled "Efficiency in the US Electric Industry: Transaction Costs, Deregulation and Governance Structures," as a final requirement for a Ph.D. in economics from the University of Illinois at Chicago.

Ross C. Hemphill is a Vice-President in NERA's Chicago office where he specializes in pricing design, cost of service analyses, and regulatory strategies for electricity and natural gas utilities. With over twenty-five years' experience in these areas, he has testified on behalf of utilities, state jurisdictions, and customers in regulatory proceedings and legal disputes. Throughout his varied career, Dr. Hemphill has successfully undertaken a wide range of analytical and strategic challenges, demonstrating his ability to guide clients with critical policy-making decisions while also providing valuable technical leadership in evaluating issues commonly addressed by the industry. Prior to joining NERA, Dr. Hemphill was a Vice President at Laurits R. Christensen Associates. He has also performed valuation studies for GTE, served as an economist for the Illinois Commerce Commission, performed research for the National Regulatory Research Institute, and conducted rate design and cost of service analyses for the American Electric Power Service Corporation. While Manager of Economics & Law at Argonne National Laboratory, he led the economic analysis regarding changes to the Power Marketing Programs of the Western Area Power Administration. As Director of Electric Pricing at Niagara Mohawk Power Corporation, he was closely involved in the planning stages of the state's restructuring effort and was the central architect in the company's unbundled service design. Dr. Hemphill also developed one of the first applications of the flexible pricing rule for electric utilities through the creation of the individually negotiated contract tariff, which was used to avoid millions of dollars of customer bypass. Dr. Hemphill has published articles on pricing design in *Public Utilities Fortnightly* and *Resources and Energy* as well as reports for the Edison Electric Institute and the National Regulatory Research Institute. Dr. Hemphill is currently on the faculty of the Institute for Public Utilities at Michigan State University where he lectures at the Institute's Annual and Advanced Regulatory Studies programs. Dr. Hemphill obtained his Ph.D. in resource economics from The Ohio State University, and his M.S. and B.A. in economics from Indiana State University and Lewis University, respectively.

About the Institute

The **Wisconsin Policy Research Institute** is a not-for-profit institute established to study public-policy issues affecting the state of Wisconsin.

Under the new federalism, government policy increasingly is made at the state and local levels. These public-policy decisions affect the life of every citizen in the state. Our goal is to provide nonpartisan research on key issues affecting Wisconsinites, so that their elected representatives can make informed decisions to improve the quality of life and future of the state.

Our major priority is to increase the accountability of Wisconsin's government. State and local governments must be responsive to the citizenry, both in terms of the programs they devise and the tax money they spend. Accountability should apply in every area to which the state devotes the public's funds.

The Institute's agenda encompasses the following issues: education, welfare and social services, criminal justice, taxes and spending, and economic development.

We believe that the views of the citizens of Wisconsin should guide the decisions of government officials. To help accomplish this, we also conduct regular public-opinion polls that are designed to inform public officials about how the citizenry views major statewide issues. These polls are disseminated through the media and are made available to the general public and the legislative and executive branches of state government. It is essential that elected officials remember that all of the programs they create and all of the money they spend comes from the citizens of Wisconsin and is made available through their taxes. Public policy should reflect the real needs and concerns of all of the citizens of the state and not those of specific special-interest groups.