UNIVERSITY OF CALGARY

THE EVOLUTION OF COMPETITIVE ENERGY MARKETS IN NORTH AMERICA

PROJECT: COMPETITION IN ENERGY MARKETS

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HELIOS

Energy research for a sustainable future

THE EVOLUTION OF COMPETITIVE ENERGY MARKETS IN NORTH AMERICA

Final Report

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1 Introduction

1.1 The University of Calgary/OLADE Sustainable Energy Project

Beginning with the restructuring of the electricity industry in Chile in 1982, the Latin American energy sector has undergone profound transformation. Market reforms are far advanced in most of South America and in process in most of the countries of Central America. At the same time, the pace of change in the English-speaking Caribbean has been dramatically slower.

During this time, foreign investment in generating capacity in the region has certainly increased, but the implications for energy consumers remain mixed. Residential electricity prices declined in some countries in the 1990s, but in others — notably in Peru, Columbia and El Salvador — they increased dramatically.

The crisis of the California electric industry in 2000-01 demonstrated poignantly the extent to which generation market power and its abuse can have catastrophic consequences in competitive energy markets. Even without the spectacular abuses observed in California, market power resulting from concentration in the generation sector can subtly undermine the expected benefits from competitive markets. As the models already applied in many Latin America countries continue to evolve, and as other countries of the region explore potential avenues for reform, it is essential to examine the experiences to date throughout the Americas, in order to develop appropriate strategies to ensure that competition contributes to meeting consumers' needs for accessible and affordable energy resources.

In this context, the Latin American Energy Organization (Organisación Latinoamericana de Energía, or OLADE has undertaken a five-year Sustainable Energy Project, in collaboration with the University of Calgary and the Canadian International Development Agency. The primary objective of this Sustainable Energy Project is to strengthen public-sector reform, and to support the sustainable management of the environment and natural resources in Latin America and the Caribbean in a manner that contributes to the alleviation of poverty.

The Sustainable Energy Project has three main components. Component 1 will provide training to Latin American and Caribbean professionals at the postgraduate level. Component 2 will assist decision-makers in the LAC region in defining more effective strategies and policies aimed at meeting sustainable development goals in three specific areas: rural energy, competition in energy markets and climate change issues. Component 3 aims to support OLADE member countries in developing sustainable energy policies and initiatives that address selected social issues that are pertinent to the energy sector.

The "competition in energy markets" section of Component 2 begins with the present report on energy sector restructuring in North America and its impact on energy consumers. It will continue with case studies of energy sector restructuring in Chile, Brazil, Peru and the Dominican Republic, and will conclude with the development of policy recommendations for the region, based on these experiences.

1.2 The structure of this report

The report begins with an overview of electricity restructuring in the United States and Canada. This section presents in broad terms the evolution of the energy sector in the two countries over the past century, and their different responses to the competitive restructuring movement. It points out the jurisdictional differences between the two countries and the differing roles of federal and sub-federal regulatory agencies.

Section 3 presents an overview of traditional electricity regulation. It reviews the basic principles of cost-of-service regulation and performance-based regulation and describes the evolution of resource planning processes in the regulated environment.

Section 4 addresses the transition to competitive electricity markets in the United States. It examines in detail the evolution the nationwide competitive wholesale market, under the jurisdiction of the Federal Energy Regulatory Commission (FERC). It also addresses the evolution of competitive retail markets by looking at several key states. Finally, it looks at the role of planning processes in the restructured environment.

Section 5 looks at electricity restructuring in four Canadian provinces: British Columbia and Quebec (almost exclusively hydroelectric), Alberta (almost exclusively thermal) and Ontario (hydro, thermal and nuclear).

Section 6 addresses the regulation of wholesale natural gas markets in the two countries and their evolution toward competitive markets.

Section 7 summarizes the key issues related to enhancing the public voice in the decision-making process.

Finally, section 8 presents some concluding comments.

2 Overview of electricity regulation and restructuring

The restructuring movement has played out differently in the United States and Canada. The United States experience is described in the following section; Canada's is described in section 2.2.

2.1 United States

2.1.1 The four restructurings

U.S. electric markets have evolved for more than a century, during which four distinct restructurings have occurred. Many other nations are seeking to compress a similar institutional evolution into a time frame of a decade or less, though of course their electric systems themselves are already mature. To show the magnitude of this task, the evolution of the key elements of the U.S. system must first be summarized.

The first major restructuring occurred early in the twentieth century. It was characterized by the development of utility regulatory commissions for most U.S. states. These commissions came into being as a result of a consensus between leaders in government and in the utility industry that the system of private monopoly regulated only by municipal councils and state legislatures was too abusive of the public, too corrupt and too unpredictable to suit a growing industry with a large and increasing need for capital. The choices seemed to be between outright government ownership and private ownership constrained by regulation. Regulation was the choice followed by most of the U.S., so regulatory commissions spread quickly and existed in most states by 1920.

From the outset, one of the clear missions of the regulators was to prevent the monopoly abuses that were then common. Thus, for the most part, U.S. regulatory commissions (unlike those in many countries) came into being with a popular mandate, thereby assuring them a more favourable public reception than has awaited regulators in other countries, where such commissions were often imposed from without by international lending institutions. Their mandates have often required them to raise rates and disconnect customers before the commissions had gained any real credibility in the eyes of the public, creating a challenge to their legitimacy that U.S. regulators have never had to face.

Because the U.S. had evolved a set of Constitutional protections for private property, for the regulation of business and for the enforcement of contracts in the 19th century, utility regulation was implemented within a framework quite strictly overseen by independent state and federal courts, some of them suspicious of monopoly power, others suspicious of the power of the new commissions. All U.S. courts operated under the ultimate review of the U.S. Supreme Court, which set forth and enforced principles for setting rates and protecting investors.[1]

The evolution of these commissions had several noteworthy characteristics. First, regulators experimented with various tariff-setting methodologies (all within the aforementioned constitutional framework) before settling on what has come to be called "cost-of-service regulation". Second, after experimenting with regulation through license conditions and finding it too inflexible, U.S. states turned instead to the promulgation of generic rules applicable to all licensees. (The same constitutional protections and judicial oversight that applied to tariff setting also applied to such rulemakings.) The licenses themselves (called "franchises" in the U.S.) came to have little practical importance. Third, regulation took place largely through trial-type proceedings in which the commissions functioned as specialized courts. Though time consuming, this method assured a high degree of sharing of information and of transparency.

The second major restructuring involved the assertion of a major federal role in the electric industry, which led to the basic industry and regulatory structures that were to serve the U.S. for the rest of the twentieth century. This restructuring was precipitated in substantial part by the collapse of several multi-state utility holding companies in the late 1920s. These organizations, which adopted a number of unsound financial practices, were beyond the power of any one state to oversee. Their collapse wiped out the holdings of millions of investors.

In the 1930s, the U.S. Congress responded by empowering the Federal Power Commission (now the Federal Energy Regulatory Commission, or FERC) to regulate wholesale power and gas markets. Another law passed at this time required the breaking up of the holding companies and the regulation of future utility corporate affiliate relationships in the gas and electric sector by the

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[1] The history of U.S. utility rate regulation is reviewed in Charles Phillips, *The Regulation of Public Utilities,* 3rd edition, (Public Utility Reports, Arlington, Va., 1993); James Bonbright, Albert K. Danielson, David R. Kamerschen, *Principles of Public Utility Rates* (Public Utility Reports, Arlington,Va., 1988); Alfred Kahn, *The Economics of Regulation* (MIT Press, Cambridge Massachusetts, 1988); Leonard Hyman, *America's Electric Utilities, Past, Present and Future* 146 (6th Ed. 1997); and Richard Hirsch, *Power Loss: The Origins of Deregulation & Restructuring in the American Electric Utility System* (The MIT Press, Cambridge, Massachusetts, 1999). By 1940, the Supreme Court had stopped trying to set formulas for utility ratemaking and had come instead to insist that fair procedures be followed and that the ultimate result of regulatory decisions not confiscate investors' capital.

U.S. Securities and Exchange Commission.[2] Other federal initiatives included the undertaking of major hydroelectric development in selected river basins[3] and the extending of electric service into areas which privately owned power companies had not been willing to undertake the expense of serving.[4]

As a result of these events, the federal government claimed jurisdiction over wholesale markets, while state commissions retained jurisdiction over retail gas and electric service. Despite constant skirmishes over the precise placement of this frontier, this overall concept of shared jurisdiction has remained for the most part stable since the 1930s.[5] The complexities for electricity and gas regulation resulting from this shared jurisdiction are a constant and unavoidable feature of the U.S. regulatory environment.

The third restructuring occurred in the late 1970s, in reaction to widespread public dissatisfaction resulting from a number of developments, including electric price increases resulting in part from rising oil prices caused by OPEC's emergence and in part from the high costs of nuclear power plant construction. In addition, substantial controversy over the safety of nuclear power and over the air and water pollution impacts of electric power generation precipitated increased interest in energy efficiency.

This public dissatisfaction had several consequences. The first was the passage of a law requiring that electric utilities buy power from independent generators at a price equal to what it would have cost the utility to generate the power itself.[6] At the same time, many states

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[2] This legislation, known as the Public Utility Holding Company Act (PUHCA), represented the first major recognition that utility regulation might also have a responsibility to protect investors. Most state commissions have also been given some responsibilities (such as approval of the issuance of stocks or bonds) in this area.

[3] Congress created the Tennessee Valley Authority and the Bonneville Power Administration to build major hydroelectric facilities in the southeastern and northwestern U.S. respectively. These were followed by the creation of federal "power marketing administrations" to sell the power generated from other large federal water management projects.

[4] The U.S. Rural Electrification Administration was empowered to make low interest loans available to cooperatives established for the purpose of bringing power to rural areas.

[5] A Supreme Court decision in 1964 (*City of Colton* v. *SoCal Edison*) made clear that federal jurisdiction included wholesale sales that were between two entities in the same state. A separate line of cases requires states to include federally allowed power prices in retail rates.

[6] The *Public Utilities Regulatory Policies Act (PURPA*), adopted in 1978, is described in detail in section 4.1. The Federal Energy Regulatory Commission's 1980 guidance document on PURPA indicated that states could require payment of prices above the utilities projected costs to stimulate particular technologies. This guidance was revoked in 1995.

empowered regulators to require that utilities seek to avoid the need for new generation by investing in energy efficiency. Finally, many state regulatory commissions became involved in the utility planning process, primarily through a process known as integrated resource planning (IRP). The IRP process entailed comparing the costs and environmental impacts potential investments in power generation, energy efficiency and transmission and distribution expansion in order to determine the combinations with the lowest costs to customers and to society as a whole.

The fourth restructuring (the one that came in the mid-1990s actually to carry the name "electric restructuring") sought to substitute competition for regulation as the driver of efficiency in the energy utilities. In so doing it built upon the competitive forces first unleashed by PURPA while deemphasizing such regulator-dependent solutions as energy efficiency and IRP. Instead, the fourth restructuring included federal legislation and FERC rulemakings opening access to the transmission system to assure that all generators had access on equal terms to all potential buyers of their electricity. At the same time, many of the states where electricity was most expensive opened access to their distribution systems, in order to provide for customer choice among suppliers of electricity. This fourth electric restructuring mirrored policies adopted as to natural gas during the 1980s and 90s.

The fourth restructuring also included separation of transmission grid operations (and in some cases ownership) from power generation, in order to assure that the operators of the transmission system would not favour affiliated generators. While open transmission access is now U.S. national policy, retail customer choice has only been adopted in about half the states and has been successful only for larger industrial and commercial customers. Few suppliers to date have made serious efforts to market to small customers. In the wake of the California crisis of 2000-01, the collapse of Enron and the blackout of August 2003, these policies are subject to ongoing re-evaluation. Largely as a result of these events, retail customer choice has not advanced at the state or federal level in several years.

The result of these four restructurings is a U.S. electric system that is institutionally complex. About half of the electricity generated in the U.S. comes from vertically integrated investor-owned utilities; another 35% comes from independent power producers; the rest comes from government-owned generators. About three-quarters of all U.S. customers are served by investor-owned utilities. The rest are split between government-owned distribution companies and customer-owned electric cooperatives. As noted earlier, most sales to end-use customers are regulated by the state commissions, while the regulation of wholesale transactions and of most aspects of transmission are the responsibility of FERC.

As we shall see below, the decision to replace traditional regulation in the U.S. with customer choice has not gone according to plan, and the U.S. Congress seems unlikely to give definitive guidance on the topic in the near future. Unpleasant surprises and the general failure of suppliers to be able to offer attractive choices to smaller customers have led to renewed interest in applying regulatory techniques in place of competition policy, at least for residential and small commercial customers.

2.1.2 Jurisdictional issues in the U.S.

The search for wise allocations of jurisdiction between national and provincial bodies goes on continuously in all countries large enough to have significant governmental functions lodged below the national level. Different countries reach different conclusions, and any one country will change its allocation of powers and responsibilities from time to time.

The allocation of jurisdiction over the electric sector is often complicated by the fact that one or more levels of government own different components of the electric power system, and these government-owned components are usually regulated differently from privately-owned systems, if they are regulated at all. Finally, jurisdiction is likely to be different for different subjects, such as pricing, service and reliability standards, license issuance, market design, antimonopoly enforcement, facility siting, air emissions, water emissions, radiation safety, transmission and distribution access or the funding of research and development.

Jurisdiction over electricity derives, of course, from the principles for jurisdiction over all economic activity. The United States Constitution gives the national government power to regulate all commerce with foreign governments and between the states. The federal government may defer to the states explicitly or may choose not to act, in which case the power to regulate remains with the individual states. Because most U.S. states are now electrically interconnected with each other, most electricity sales could be considered subject to federal jurisdiction if Congress so chose. However, the U.S. Congress has not given such extensive power to the Federal Energy Regulatory Commission (FERC), so a great deal of regulatory jurisdiction remains with U.S. state governments, and some jurisdiction remains with local governments such as cities and counties.

While history and politics have played a considerable role in these jurisdictional allocations, certain principles are also important.

1. When the matter in question crosses state lines (electric transmission, the design of wholesale markets or pollution), national interests require that primary jurisdiction be at the federal level.

2. Allowing decisions to be made as close to their point of impact as possible assures that decisionmakers are aware of the impacts of their decisions and that the public has reasonable access to those making the decisions. Because ordinary citizens and businesses are not well represented in Washington, decisionmaking at the headquarters of national agencies is less likely to be well-informed as to local consequences, although the availability of the internet improves the ability of central decisionmakers to be alert to local circumstances, within limits.

3. In cases where specialized knowledge is essential to the decision being made, the case for a federal jurisdiction is stronger. This was the basis for giving the Nuclear Regulatory Commission (NRC) exclusive jurisdiction over radiation health and safety back in the 1950s, even though all other forms of pollution regulation involve some sharing of responsibility. However, such specialized knowledge may no longer justify exclusive jurisdiction. The sharing of knowledge on an advisory basis is far easier now than in the past, whether between levels of government or through the use of consultants.

4. The U.S. system allows different states to experiment with different approaches and to learn from each other's mistakes. This has been an important source of innovation, particularly with regard to power purchase programs and energy efficiency.

5. The U.S. system of energy regulation has not yet been successful in creating effective regional regulatory systems for making decisions involving more than one state but not the nation as a whole (transmission siting, for example). FERC's initiatives to further the voluntary formation of regional entities such as Independent System Operators and Regional Transmission Organizations (discussed in detail in section 4.1.1) have met with only partial success. An approach whereby FERC would give a time deadline and general decision guidelines to the affected states, reserving the power to make the decision itself if these are not followed, has never been tried.

6. Nor have most U.S. states or the federal government been notably successful in coordinating energy and environmental regulatory goals. There is some experience at the state level with energy plans developed jointly by energy and environmental regulators – such as the New York State Energy Master Plans of the late 1980s and early 1990s - but this is the exception, not the rule.

The U.S. system of regulation developed over many years, largely as a response to the need for expert decisionmaking removed from the day-to-day political process. It was intended to protect citizens from abuse by monopolies and utility investors from abuse by politicians. It puts a high value on the right of the public and of those affected by regulatory decisions to have a voice in those decisions, both as a source of information and as process to convey legitimacy. It is also a process that depends heavily on a stable and predictable legal system and on the enforceability of contracts and license conditions. It was not designed as an instrument for the rapid implementation of national energy policies or for rapid creation of regional systems or markets.

The U.S. has developed a number of successful methods of blending national and state concerns in ways that allow for considerable innovation while still providing for the enforcement of essential policies. This structure is being tested strenuously by the challenges of restructuring. This evolution is currently being defined in the Congress, in FERC proceedings, in many states and in the courts. This process has some significant shortcomings but also offers many useful lessons to other countries embarking upon energy sector regulation and reform programs.

The following sections briefly summarize the allocation of jurisdiction in the U.S. between the federal, state and local levels.

2.1.2.1 Federal jurisdiction

The U.S. Federal Energy Regulatory Commission has exclusive jurisdiction over the pricing of transmission services and sales of electricity in the "wholesale market", i.e. sales of electricity not to be consumed by the buyer ("sales for resale"). FERC also has jurisdiction over sales by all but the largest of the major federal wholesale power authorities, but not over sales by municipally owned utilities. While FERC's jurisdiction has grown considerably in recent years, less than half of the kilowatt-hours generated in the U.S. are sold in transactions under its jurisdiction.

FERC has jurisdiction over the arrangements governing wholesale markets, such as power pools, contracts for the operation of transmission systems and other wholesale market control matters. This jurisdiction includes the terms and conditions under which transmission is operated, such as the requirement of equal access for all sellers and buyers in a given market.

As a result of scandals in electric utility financing in the 1920s, the federal Securities and Exchange Commission – the agency with responsibility for protecting the integrity of U.S. securities markets generally – was given the power to prevent electric utility corporate structures that involved more that two layers of companies or that joined companies whose territories were not contiguous. For several years, the U.S. Congress has been considering repeal of this legislation (the Public Utilities Holding Corporations Act, or PUHCA), leaving the remaining responsibilities with FERC and the states.

In addition to regulation, several special purpose federal authorities (e.g. the Bonneville Power Administration and the Tennessee Valley Authority) own very substantial amounts of electric generation and transmission. These authorities are self-regulating in economic matters, not subject to direct FERC or state jurisdiction.

2.1.2.2 State and local jurisdiction

Each of the 50 U.S. states has its own utility regulatory commission, and some states have their own energy research and energy policy offices. These state commissions have jurisdiction over electricity sold to the customers who will actually use it, often called retail customers. Most of the state regulatory commissions are older than the FERC. Their powers and duties are created by their state laws and constitutions. They vary somewhat from state to state. However, most of them have the powers necessary to issue licenses and describe territories for distribution utilities, to set tariffs for those utilities, to set service standards, to enforce each of these measures and to resolve disputes between customers and utilities.

The states also have exclusive jurisdiction:

- over power supply planning, i.e. decisions as to what mixture of resources will be used to generate the electricity sold by the regulated utilities,
- over the energy efficiency programs of the distribution companies,
- over whether to allow retail customer access to choose among power suppliers,
- over the siting of power plants as well as transmission and distribution lines, and
- over public safety issues associated with electric delivery.

Local governments have jurisdiction over the work done under their streets and can regulate many aspects of the timing and standards that control such activity. Local governments rarely have jurisdiction over pricing and licensing except when the utility is owned by the city itself, such as Los Angeles or Sacramento (California), Seattle (Washington), Austin (Texas) and many smaller cities serving about 15% of the customers in the U.S. In addition, not-for-profit customer-owned electric cooperatives serve another 12% of U.S. customers. These systems are often self-regulating or, in the case of municipal systems, regulated by the city government on the theory that – since the citizens and customers are electing the directors – the protections of state and federal regulation are not needed.

Mergers between utility companies are subject to shared jurisdiction, as both federal and state governments have power to approve, disapprove or attach conditions to them. Each jurisdiction may also enforce its own laws as to antimonopoly activity or unfair trade practices.

2.1.2.3 The role of the courts

Generally, decisions of the federal agencies (FERC, EPA, NRC and SEC) can be appealed to the second highest federal court, the U.S. Court of Appeals. From there some decisions can be appealed to the U.S. Supreme Court. The appeals process in the states varies, but the most common route of appeal of state utility regulatory commission decisions is directly to the highest court in the state. From there, decisions that raise federal questions can sometimes be appealed to the U.S. Supreme Court.

2.1.3 Four features of effective regulation

While the U.S. system may fairly be criticized for a number of shortcomings, it also has developed a number of features that are of potential interest to other countries. These include the following:

1. Ability to attract capital on reasonable terms,
2. Transparency,
3. Customer representation in the regulatory process, and
4. Advanced techniques for regulatory involvement in facility planning and authorization.

2.1.3.1 Ability to attract capital on reasonable terms

A key accomplishment of the U.S. regulatory system has been its ability to ensure that capital is available for needed power plant investments on reasonable terms.

From the collapse of the holding companies in the late 1920s to the collapse of Enron in 2002, the U.S. utility industry remained free of generic scandal. Investors in individual utilities certainly lost money, most notably during the nuclear power plant construction disappointments of the 1970s and 1980s, and investors are never shy about decrying perceived arbitrariness by regulators and the public. Nevertheless, investors have continued to advance funds to regulated utilities under a general understanding that investments deemed prudent by regulators would be recovered in rates from customers, and investors in U.S. utilities have – decade in and decade out – fared at least as well as investors in other large industries.[7] U.S. courts have shied away from reading any requirement for recovery of prudent investment into the Constitution,[8] but regulators have enabled recovery of prudent investment in practice.

However, the collapse of Enron and the ongoing inquiries into its behaviour and that of other generators and marketers in the California crisis of 2000-01 and beyond have, for the first time since the U.S. regulatory system took its modern form in the 1930s, resulted in a crisis of confidence in the electric industry that is affecting its ability to attract capital on reasonable terms, especially (but not exclusively) the generation sector. As will be discussed in further detail in section 4.1.5, many market participants have expressed concern that this crisis of confidence may undermine the industry's ability to maintain reliability and stable prices in future years.

As competitive power generation markets have evolved since the 1978 passage of PURPA, regulators and the courts have been firm in upholding the sanctity of signed contracts, even when they produced prices that turned out to be much higher than actual market prices a few years after they were signed. Both FERC and the state commissions have not hesitated to change course as to future contract policies, bidding requirements and pricing policies, but they have generally not upset the expectations of investors as embodied in signed contracts.

Here too, the events surrounding the California crisis have called into question this pillar of industry stability. Refund claims for billions of dollars were filed by the State of California, based on allegations of market manipulation by Enron and other suppliers, were upheld only in small part by FERC. However, the question is far from closed, both retrospectively (as these

[7] Michael Foley and Ann Thompson, *Electric and Telephone Utility Stockholder Returns: 1972-1992* (National Association of Regulatory Utility Commissioners, 1993).

[8] Most recently in *Duquesne Light & Power Company* v. *Barasch*, 488 U.S. 299 (1989). In the context of electric restructuring, utilities repeatedly urged regulators and courts to find that reimbursement of prudent investment was mandatory. In this they failed, but – as a practical matter – the design of each state that chose to restructure included an opportunity for such recovery. Only in California did it not occur.

claims work their way through the courts) and prospectively, as FERC struggles with mechanisms to mitigate, control and ultimately punish market power abuse.

Among the important issues are the finality of spot market transactions and the tension between contractual certainty and market power mitigation in competitive markets. Generators argue that allowing regulators to modify market prices after the fact will ultimately undermine the sanctity of the contract implicit in hourly spot market auctions.

Finally, U.S. regulatory practice affords extensive procedural safeguards to investors and to customers alike. These include the right of notice of any proceeding involving their interests, the right to participate in all decisions affecting their interests, the right to an impartial regulatory decisionmaker and the right to appeal an adverse decision to the highest levels of an independent judiciary system. In addition, investors and customers are entitled to all of the information known to the regulators. Because of the extensive reporting and disclosure requirements imposed at both the federal and the state levels, this information should include everything an investor would need to know in order to be satisfied as to the integrity of a regulated company. Of course, as the scandals at Enron, WorldCom and others have shown, this system remains dependent on the integrity of the systems designed to verify and attest to the accuracy of the information that is provided.

2.1.3.2 Transparency

Due to the origins of U.S. regulation in populist political traditions, the right of the public to participate in regulatory processes has been accepted from the beginning.[9] Not only does this right apply to commission proceedings, it also applies to the shaping of the regulatory laws and to the process by which commissioners are selected. This right to participate is – as noted above – an important safeguard in itself. In addition, it carries with it several rights related to the transparency of regulatory decisionmaking. These include notice of matters under consideration, the right to review all information in the possession of the regulatory agency and to demand additional information pertinent to the pending decision, the right to participate in public hearings, the right to a written decision explaining the commission's conclusions as to the facts and the law, and the right to appeal that decision to a competent court.

[9] In addition, regulation in the U.S. is generally understood to be a delegation of a legislative power to the commissions. Because the U.S. legislative process is open to widespread public participation, the commissions who exercise legislative power are expected to be similarly accessible.

Information is the lifeblood of the regulatory process. U.S. regulators require that information be gathered, kept according to prescribed accounting systems, and reported regularly and in a standard format. This information is available to customers, to the media and to investors as part of the routine regulatory process. In addition, the U.S. and most states have freedom-of-information laws that grant every citizen access to all but a limited category of government records. Finally, most states and the federal government also have so-called "Sunshine Laws", which require that commissions make their decisions in public rather than behind closed doors.

2.1.3.3 Customer representation

During the early decades of U.S. regulation, the general assumption was that the utility commissions themselves existed to protect the public and not just to function as neutral arbiters. As Governor Franklin Roosevelt of New York said in 1930,

> The Public Service Commission is not a mere judicial body, acting solely as an umpire between complaining consumers or complaining investors on the one hand and the great utility systems on the other. The regulatory commission....must be a tribune of the people, putting its engineering, accounting and legal resources into the breach for the purpose of getting the facts and doing justice to both consumers and investors in public utilities...[10]

However, following the extraordinary rate increases and nuclear construction mishaps of the 1970s, many states lost faith in the ability of the commissions to represent the public effectively. Consequently new institutional structures designed to represent the public evolved. Foremost among these were divisions within the commissions separated from the rest of the agency and charged solely with representing the public, government agencies charged solely with representing the public, consumer funded "public interest organizations", and consumer representatives funded by the utilities themselves under "intervener funding" programs. Intervener funding costs are generally charged to the utilities on the rationale that since the customers pay for the utility presentations through the inclusion of those costs in their rates, it is only fair that they also pay for the costs of responsible interveners who presented a different perspective in an effective way.

The government agencies — with titles like "Public Advocate" or "Consumers' Counsel" — were established by the legislature, usually with a director appointed by the governor. While these offices usually had a perspective different from the commissions, the fact that they were

[10] Quoted in Richard Rudolph and Scott Ridley, *Power Struggle: The Hundred Year War over Electricity* (New York, Harper & Row, 1986), p. 40.

appointed by the same executive and confirmed by the same legislature as the commissioners themselves raised concerns in some cases as to their independence.

Independent groups funded through customers indicating a willingness to pay a $1 surcharge on their monthly utility bills ("citizens utilities boards," as championed by Ralph Nader) were more independent of the centralized government view, as were intervener groups funded by utilities under programs supervised by the commission, sometimes called intervener funding. However, these programs were strongly resisted by the utilities, and only a few states – California, New York, Vermont, Oregon, Wisconsin and Maine among others — ever made use these mechanisms.

The most common mechanisms now in use are those where consumer interests are defended either by a division of the regulatory staff or by a separate government agency. While neither approach is ideal, without an entity whose mission is to represent consumer interests, the regulatory process will almost inevitably tilt toward the utilities, the generators and the large customers – those with resources to assure that their concerns are effectively presented to the regulators.

2.1.3.4 Influencing the future instead of allocating the past

One shortcoming of traditional utility regulation has been its tendency to seek to make pricing decisions whose greatest importance should be the efficient allocation of future resources by intensively reviewing past investments, a form of governance through the rear view mirror. The setting of rates on the basis of past expenditure patterns gives weak and ambiguous signals for efficient future resource allocation. For many years, the only serious efforts to deal with this problem took the form of prior regulatory reviews of specific utility actions, such as issuances of common stock, sales of assets, mergers or construction of large power plants or transmission lines. In the 1980s, utility demand side management programs were added to this list in many states.

During the late 1980s, three different methods of applying more generic mechanisms for stimulating improved efficiency emerged in U.S. regulation. The first of these was marginal cost pricing. The second was performance-based ratesetting or PBR. The third was integrated resource planning.

The central tenet of marginal cost pricing for electric utilities is that prices should reflect the cost either of producing additional energy from existing facilities (short-run marginal costs) or of producing energy from additional facilities (long-run marginal costs). Since such pricing may produce either too much or too little revenue to allow a fair return on past investment, actual prices are adjusted upward or downward to produce the necessary revenues.

Marginal costs have rarely, if ever, been used as the sole basis for electric utility pricing, but such innovations as time-of-day pricing and seasonal pricing represented efforts to introduce marginal cost considerations into traditional ratesetting.

Under performance-based ratesetting, regulators set rates or revenue-per-customer levels for extended periods, with automatic adjustments for inflation and productivity as well as for other factors. Utility earnings, whether high or low, would not trigger a rate adjustment unless they fell outside of predetermined limits. Because a utility could earn more (or less) under this system than under methodologies designed to limit their recovery to an assured approximation of their costs, PBR was thought to provide stronger incentives to contain costs and improve management. While PBR rates have been tried extensively in relatively few U.S. jurisdictions, they have now been in use for long enough to make clear that they are a viable alternative to cost-of-service regulation. However, they are not a panacea. U.S. (and British) experience also show that they can produce excessive earnings if regulators are not sufficiently vigilant in setting them up and monitoring them. Moreover, PBR methodologies that focus on price alone give a powerful incentive to avoid energy efficiency programs which often produce savings by lowering bills even though they may slightly raise prices. PBR is discussed in greater detail in section 3.1.2, below.

PBR proposals operate by freeing the utility from pervasive regulatory oversight, relying instead on economic incentives intended to replicate competitive market pricing. By contrast, integrated resource planning or IRP, seeks instead to assure more efficient and societally beneficial decisions through regulatory oversight designed to assure that major investment decisions are made on the basis of careful advance consideration of the costs and societal impacts of all of the alternatives, including energy efficiency. Under this approach, utilities are required to submit their investment and power supply plans for regulatory review at regular intervals (usually two years). With commission approval of the overall plan, a utility might proceed to seek bids to supply the services reflected in the plan and to weight its choices among the bidders to reflect commission-approved factors such as reliability, fuel security and environmental impacts. IRP is discussed further in section 3.2.

2.2 *Canada*

2.2.1 Jurisdictional issues

Like the United States, Canada is a federal system, but the roles of the federal government and the provinces with respect to energy regulation are very different than those that we have seen in the U.S. Compared to the U.S., the Canadian government plays a much smaller role, with the provinces occupying the vast majority of the responsibilities borne in the U.S. by the Federal Energy Regulatory Commission.

This division of powers flows from directly from the Canadian constitution which — like that of Great Britain, from which it evolved, and unlike that of the U.S. — derives from a number of sources, both written and unwritten.[11] The *Constitution Act of 1867*, Canada's first written constitutional document, set out the respective powers of the federal and provincial governments in sections 91 and 92, respectively. While the federal union as defined by the *Constitution Act* was in many ways more centralized than that in the U.S., in practice it has evolved over the years into a far more decentralized one.

To take one important example, while the Tenth Amendment to the U.S. Constitution reserves to the states (or to the people) all powers not delegated to the federal government by the Constitution, the *Constitution Act* reserves residual plenary powers for the federal government, through its general power of "peace, order and good government." In the U.S., however, the federal government can extend its reach simply by adopting legislation that preempts state regulation of a particular subject matter; this is not the case in Canada. As a result, the powers exercised by Washington have increased greatly over time, while in Canada, the balance of power has shifted toward the provinces.

Thus, because article 92 grants the provinces jurisdiction over natural resources, virtually all aspects of energy development have been left to the provinces.[12] Any remaining ambiguity in this matter was resolved in favour of the provinces by the adoption of Article 92A as one of the

[11] A useful summary of Canada's constitutional history can be found at http://www.pco-bcp.gc.ca/aia/default.asp?Language=E&Page=consfile&Sub=TheHistoryofConstitution.

[12] For similar reasons, health care and education are matters of exclusively provincial jurisdiction. As the environment was not mentioned in the *Constitution Act of 1867*, it is considered a jurisdiction shared between the federal government and the provinces.

constitutional amendments associated with the patriation of the Canadian constitution in 1982.[13] Article 92A is commonly referred to as the "resource amendment," and it bears the heading "Non-Renewable Natural Resources, Forestry Resources and Electrical Energy." It explicitly empowers the provinces to make laws in these three areas, and in particular permits provincial legislatures to "make laws in relation to the export from the province to another part of Canada of ... the production from facilities in the province for the generation of electrical energy," as long as they do not provide for discrimination in prices or in supplies exported to another part of Canada. This further entrenched the primacy of the provincial role in energy regulation.

As a result, most of the powers exercised in the U.S. by FERC are exercised in Canada by the provinces. On the positive side, this has spared the Canadian energy sector much of the complexity and conflict that flows from the division of regulatory powers between FERC and state regulators. On the negative side, however, it has led to a policy vacuum at the federal level in Canada. This, combined with the geographical fact that Canadian population centres are closer to their U.S. neighbours than they are to each other, and the fact that the U.S. population and economy are almost ten times larger, has created a situation where the evolution of the continental electricity market has been designed almost exclusively in the U.S., with little or no Canadian involvement. With respect to electricity restructuring, Canadian policy has consisted almost exclusively of reactions to developments in the U.S. For this reason, much of this paper will be focused on developments in the United States.

2.2.2 Crown corporations and the role of regulation

As we have seen, despite the presence of significant quantities of government- and consumer-owned generation, the U.S. electric industry is largely characterized by the presence of investor-owned utilities (IOUs) and the regulatory mechanisms that have evolved to circumscribe them. In Canada, however, the industry has historically been dominated by Crown corporations — entities owned by the provincial governments. Crown corporations still enjoy full or quasi monopolies in Quebec, Manitoba, British Columbia and most of the smaller provinces.[14] Only in Ontario has a Crown utility actually been (partially) dismantled to promote competition.

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[13] Since the *Constitution Act of 1867* was an act of the British Parliament, it could only be modified by the British government. It was "patriated" in 1982. While Queen Elizabeth II remains the Queen of Canada, there are no structural links between the Canadian government and that of the United Kingdom.

[14] Crown corporations have played a particularly important role in those provinces with substantial hydro power resources (Quebec, British Columbia, Manitoba, Ontario, Newfoundland and Labrador, and, to a lesser extent, other provinces and territories). Ontario Hydro was formed by the nationalization of three private electric companies in 1916. Hydro-Québec was created in 1945, but attained its current status with the nationalization of 11 electric

As these Crown corporations grew dramatically in the later decades of the twentieth century, they were generally not subject to any form of regulation other than control by their sole shareholder, the provincial government. However, due in part to the inability of governments to adequately oversee such a complicated industry and, in several cases, to growing public opposition to large-scale hydro projects, each of these Crown utilities was eventually made subject (to varying degrees) to a provincial regulator, largely based on the U.S. regulatory model.

Ontario Hydro, for example, was not subject to any independent regulation until 1973, when the mandate of the Ontario Energy Board, which had been established in 1960 to regulate oil and gas pipelines and natural gas sales, was enlarged to allow it to review the utility's rates. However, the OEB was never actually empowered set Ontario Hydro's rates or to approve its expansion plans. [15] Following the dismantling of Ontario Hydro (discussed below in section 5.2), the OEB's primary role is to regulate transmission and distribution, though it also has a role in ensuring that market power is not abused.

The British Columbia Utilities Commission (BCUC) is an independent regulatory agency of the provincial government, set up under the *Utilities Commission Act.* Since 1980, the Utilities Commission has regulated the rates of virtually all gas and electric utilities in B.C., including B.C. Hydro. Starting in 1992, as a means of judging the prudence of investments and hence the justification of rates, the Utilities Commission required regulated utilities to carry out least-cost integrated resource planning. In 1995, the Utilities Commission issued IRP guidelines to ensure that capital expenditures, and hence rates, are fully justified.[16]

In Quebec, the provincial Cabinet was solely responsible for approval of Hydro-Québec's rates and development plans until 1997. In 1995, following the embarrassing failure of the Great Whale project — a 3,000 MW hydro project blocked by concerted opposition from Native

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companies in 1963. Similarly, B.C. Hydro grew out of the state-owned B.C. Power Commission created in 1945, primarily for purposes of rural electrification, which was fused with the recently nationalized B.C. Electric Company in 1962. The Manitoba Hydroelectric Board was created in 1949. In the 1950s, it absorbed most other power companies and in 1961, it was fused with the Manitoba Power Corporation to become Manitoba Hydro, a Crown corporation.

[15] http://www.oeb.gov.on.ca/html/en/abouttheoeb/history.htm

[16] While the *Utilities Act,* under the authority of which the Commission operates, does not specifically mention IRP, it does "outline the Commission's responsibility to make certain that utilities undertake comprehensive planning to ensure that generation, transmission and distribution assets are installed by utilities so that the customer needs are fully satisfied and that rates are fully justified." (B. C. Utilities Commission, *In the Matter of British Columbia Hydro and Power Authority, 1994/95 Revenue Requirements Application: Decision,* November 24, 1994, p. 64.) However, the limits of this jurisdiction were tested, successfully, in B.C. Hydro's appeal to the B.C. Court of Appeal, described below in note 139.

peoples and environmentalists in Canada and the U.S. — the provincial government launched a high-profile “Public Debate on Energy” to set the terms of a new energy policy. The resulting policy called for the creation of a new regulator (the “Régie de l’énergie”) which would have decision-making power over Hydro-Québec’s rates, expansion plans and exports. Legislation putting this policy into effect (known as “Bill 50”) was adopted at the same time. However, new legislation adopted in 2000 substantially reduced the Régie’s jurisdiction. (These changes are discussed further in section 5.3.)

Only two Canadian provinces — Alberta and Ontario — have undertaken thoroughgoing restructuring of their electricity markets. Others, led by Quebec and British Columbia, have taken cautious steps in this direction, driven primarily by concern about maintaining access to export markets in the U.S. These developments are described in detail in section 5.

2.2.3 The National Energy Board

The National Energy Board (NEB), created in 1959, is the energy regulatory agency of the Government of Canada. As such, it is in some ways homologous to FERC. However, due to the differences described in the previous section, there is virtually no resemblance between FERC’s role in electricity restructuring and that of the NEB. In natural gas, however, the roles played by the two regulators are far more similar, as we shall see in section 6.

The NEB’s regulatory mandate for electricity and gas includes the following areas:

- construction, operation, tolls and tariffs for interprovincial and international pipelines,
- construction and operation of international and designated interprovincial power lines,
- export of electricity, natural gas and other fuels (and import of natural gas).

Unlike FERC, the NEB has no regulatory role with respect to Canadian power markets nor does it regulate transmission, where its role is for the most part limited to the approval of the construction of international lines.

The NEB does have statutory jurisdiction over the export of electricity and gas. Under its enabling legislation, the Board’s decisions regarding electricity exports must take into consideration the effects on other provinces and on the environment and whether the applicant has taken steps to ensure that Canadian buyers have been offered the opportunity to purchase the power on similar terms. In practice, however, the Board in recent years has been issuing 20- or 30-year umbrella permits that make these questions largely academic. Given the often fragile nature of the Canadian federation and in particular the strained relations between the federal government and the two largest energy-exporting provinces, Alberta[17] and Quebec[18], it is not surprising that the NEB exercises this jurisdiction with such a light hand.

[17] The National Energy Program (NEP), adopted by the federal government under Prime Minister Pierre Elliott Trudeau in 1980, imposed federal authority over energy resources and established new price and revenue sharing schemes without consent of Alberta, which holds the vast majority of Canadian oil and gas reserves. See http://www.ucalgary.ca/applied_history/tutor/calgary/ energycrisis.html.

[18] Efforts by the sovereignist movement in Quebec to secede from Canada led to hotly contested referendums in 1980 and 1995. Any attempt by the federal government to restrict electricity exports by the provincially owned Crown corporation Hydro-Québec could lend additional support to separatist arguments.

3 Traditional electricity regulation

An essential characteristic of the regulatory approach used throughout the United States is a detailed knowledge of the costs of the existing electric system. U.S. regulation as it evolved over the last century almost invariably involved the allowance of a reasonable rate of return on the undepreciated prudent investment in plant coupled with full recovery of reasonable operating expenses.

To support regulation of this type, a substantial and precise system for the regular reporting of costs and investments has been in place for many years. As a result of this system, regulators become aware quite quickly of significant changes in utility costs and can respond appropriately to them.

This system worked reasonably well for decades. However, the strains of the nuclear construction experience coupled with the oil price run-ups and environmental controversies of the 1970s resulted in considerable disillusionment and reform.

This reform has led in two directions simultaneously: to improve regulation and to seek to establish competitive markets to obviate the need for regulation.

The first reaction to the regulatory shortcomings revealed by the problems of the late 1970s was to enhance the attention paid by U.S. regulators to monitoring and controlling costs under the conventional cost of service framework. Thus many states strengthened their commissions and required regular management and operational audits of problem utilities and problem areas. Furthermore, they mandated regulatory attention to energy efficiency, in an effort to ensure that cost-effective energy savings would be carried out, and integrated resource planning (IRP) processes, to ensure that resource strategies considered all alternatives. Some also established public advocates and/or provided intervener funding to allow public interest groups to participate fully in the regulatory process. In all cases, these approaches included cost-based regulation of rates.

At the same time, the belief grew that competitive markets in electricity would replace cost-of-service regulation in some parts of the industry. Interest in retail electric competition was spurred partly by gas and telephone experience in the U.S. and partly by the British electricity restructuring of 1990. The key federal milestones were the *Energy Policy Act* of 1992 – which empowered Federal Energy Regulatory Commission (FERC) to establish a competitive wholesale market for electricity while leaving retail competition to the states – and FERC's orders requiring open access to transmission services.

The trend toward competition also renewed interest in performance-based regulation (PBR), which simulates competitive pricing. PBR, described in detail in 3.1.2, can be used as a transitional approach while competitive markets are being established or as a regulatory regime in lieu of competition in situations where cost-based regulation will not be replaced by competition.

Among the states that decided to restructure, a small minority made a clear commitment to adopt price cap regulation in the long term. Restructuring has often begun with rate decreases on the order of 10-20%, with a commitment to review desirable types of regulation in the period during which the reduced rates are to remain frozen. In all PBR regulation in the United States, the starting point has been based on careful consideration of the utility's costs.[19]

In the following sections, we look in some detail at rate regulation and resource planning.

3.1 Rate regulation

3.1.1 Cost-of-service regulation

The principal reasons for rate regulation are to protect consumers from monopoly pricing and to protect utilities and their investors from opportunistic and confiscatory behaviour by government. Thus, the regulator is called upon to set prices that are "just and reasonable," both for the regulated monopoly and for its captive customers. At the same time, the regulator must not create conditions or incentives for inefficient practices that will increase the overall cost of providing service. This tension between equity and efficiency is at the source of many of the great debates about ratemaking.

Regulation in the U.S started with a detailed awareness of the costs of service, though an unfortunate Supreme Court decision at the beginning of the 20th century required that "fair value", generally interpreted as replacement cost, be the dominant measure of cost.[20] Early experiments in long term price cap plans foundered in times of high inflation (when the public would not tolerate automatic increases) or in the face of excessive earnings. The fundamental purposes of this regulation have been protection of customers (from monopoly abuse) and of

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[19] The sole exception has been a few merger approvals that have included rate freezes without a review of the costs of the combined companies. Of course, the costs of the two merging companies were well known at the time.

[20] Smyth v. Ames, 169 U.S. 466 (1898).

investors/lenders (from fraud and political interference). Both goals require a reasonable relationship between costs and prices..

To regulate effectively in a cost-of-service framework, the regulator must know the operating costs and the levels of investment, as well as the justification for management decisions. State laws in the U.S. explicitly establish the power of regulators to get such information.[21] There can be no question of the regulator's entitlement to this information or of the right to other parties to have access to it. When such information has a competitive significance that outweighs the right of the general public to be aware of the basis for monopoly rates, the fashioning of appropriate protective orders is not difficult. Even in U.S. states where decisions in favour of retail competition have been made, a great deal of information about the costs of utility operations is routinely available in annual reports (including the FERC Form 1, which must be filed by all but the smallest electric utilities) and through processes of discovery.

The regulator must exercise judgment as to a reasonable return on the investment as well as many other determinants of cost (such as reasonable depreciation rates). After an overall revenue requirement has been determined, it must be allocated to the various classes of customers. This too requires detailed knowledge of the costs of all phases of the business and leaves room for considerable judgment as to which costs are fairly borne by each class of customer.

Although cost-of-service regulation has been called into question by the nuclear construction experience and by theoretical arguments that it does not provide sufficient incentives to efficiency, it remains the most common approach in the U.S. in those areas that do not permit retail customer choice or that are in transition toward competition. Even in California and the U.S. Northeast, where retail choice has been initiated, cost-of-service regulation is often applied to the remaining monopoly areas, such as transmission and distribution, as well as to generation, until such time as retail markets are fully competitive.

In most of the states that have opted for retail competition, the price of generation to most customers is determined by a “standard offer,” or default service. Default service represents an approximation of the current market price of the generation sector, with the remaining embedded costs designed to be recovered through a separate stranded investment charge. Furthermore, the relationship between the default service and actual costs is sometimes skewed by political imperatives to secure substantial rate reductions for all customers in the early years of restructuring.

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[21] Indeed, Maine law gives each individual commissioner full access to information, including the right to be admitted to utility property to obtain it.

Proponents of cost of service regulation argue that it better enables capable regulators to prevent excessive earnings as well as to avoid subsidies to particular customer classes or among the different divisions or subsidiaries within a company. It also provides a superior ability to track cost trends within a company and thereby gives regulators early warnings of potential trouble spots. In addition, it provides assurance of cost recovery of governmentally mandated expenses (such as taxes, environmental compliance, low-income assistance, economic development, and energy efficiency) in ways that may minimize resistance to such initiatives.

3.1.2 Performance based regulation

3.1.2.1 Description, rationale and context

Performance-based regulation (PBR) has received increasing attention as an alternative to cost-of-service regulation. PBR is specifically designed to encourage utilities to reduce costs or otherwise improve operational efficiency. Instead of determining all prudent costs plus a reasonable profit, PBR mechanisms provide utilities with a fixed price or a fixed level of revenues. As a result, utility profits depend in large part on how efficiently they plan and operate their systems. Regulation based on price more nearly approximates market conditions than does cost-of-service regulation. Therefore it may better prepare a utility for increasing competition and may better govern prices for entities such as nuclear generators that function in a competitive environment while themselves remaining price regulated.

The most commonly applied PBR mechanism is the price cap. Regulators set a utility's prices under both PBR and cost-of-service regulation, but price caps differ from cost-of-service regulation in two fundamental ways. First, price caps tend to be put in place for longer periods of time (e.g., four to six years). The fixed prices over longer periods are intended to provide incentives to reduce costs. Second, utilities are allowed to lower their prices to customers that might otherwise leave the system, as long as all prices stay within the cap. Thus, price caps largely remove the cost-price linkage that is at the heart of cost-based regulation, and tend to shift risk from consumers to the utility. This practice has mixed implications for emerging competition.

Most price caps include adjustments for inflation, as well as for increased productivity over time. PBR mechanisms also frequently include profit/loss sharing mechanisms that are intended to protect both the company and customers from the risk of excessive earnings or losses. In addition, some PBR mechanisms include "off-ramps" or triggers that require a modification or abandonment of the PBR if conditions warrant.

A well-designed price cap scheme begins by setting the initial rates for each customer class fairly, based upon a detailed cost-of service study and an appropriate allocation of costs.[22] The cap is then allowed to increase from year to year to allow for inflation, but is also required to decline over time to reflect increased productivity. The generic price cap formula is:

$$\text{Price}_{(t)} \leq \text{Price}_{(t-1)} * (1 + I - X) + Z$$

where $\text{Price}_{(t)}$ is the maximum price that can be charged to a customer class or classes for the period of the cap, $\text{Price}_{(t-1)}$ is the average price charged to the same class or classes during the previous period, "I" is the inflation factor, "X" the productivity factor, and "Z" represents any incremental costs per kWh that are not subject to the cap.

The inflation factor is meant to track changes in economy-wide output prices or industry-wide input prices. The X factor, on the other hand, can be described as follows:

> The X-factor in a price-cap plan is the mechanism by which customers receive the benefit of the regulated firm's expected productivity growth over and above the average productivity growth of firms in the … economy. Its purpose is to limit the firm's average price changes to a reasonable rate and hence allow a price-cap plan the time needed to provide its efficiency incentives to the regulated firm.[23]

PBR mechanisms can also be designed using "revenue caps" instead of price caps. Revenue caps are based on the same principle as price caps – the cap in one year is based on the previous year with adjustments for inflation and productivity – and can achieve many of the same objectives as price caps. However, revenue caps provide utilities with significantly different incentives regarding energy efficiency and increased sales. (This point is discussed in more detail in the next section.)

PBR mechanisms can be designed in many ways, and can be tailored to achieve many different regulatory objectives. Efficient operations and low costs are not the only objectives of utilities or their regulators, and too much emphasis on these goals may cause unintended and undesirable consequences. For example, quality of customer service may deteriorate under price cap regulation, because utilities may be inclined to cut corners or even eliminate certain services. To prevent such deterioration, regulators frequently define service quality performance standards and impose penalties if the standards are not met.

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[22] In countries in which reliable cost data is lacking a PBR plan may start with an estimate of the costs of an idealized company serving the area in question.

[23] Wayne P. Olson and Caroline Richards, "It's All in the Incentives: Lessons learned in Implementing Incentive Ratemaking," *Electricity Journal,* December 2003, p. 21.

It is frequently argued that PBR mechanisms are more appropriate for an increasingly competitive industry, because they reduce regulatory oversight However, designing and implementing PBR mechanisms requires substantial regulatory analysis and oversight, because (a) the specific PBR design will have significant financial implications for the utility, (b) the mechanism may need to be designed to meet a number of regulatory objectives, (c) it is important to prevent any one aspect of the mechanism from creating unintended and undesirable consequences, (d) PBR mechanisms sometimes need to be monitored over time to ensure that they are effectively achieving their original goals, and (e) upon expiration of the period the formula will need to be reset in a way that reflects current costs of service. Consequently, it is not clear how much less regulatory oversight PBR mechanisms require relative to cost-of-service regulation.

Furthermore, the lines between cost-of-service regulation and performance-based regulation are not clear. Cost-of-service regimes can be designed with benchmarks based on comparisons to performance of other utilities. These benchmarks serve much the same purpose as a PBR plan.

3.1.2.2 Regulatory options for removing the financial barriers to energy efficiency

One of the primary lessons learned from the U.S. experience in the 1980s and 90s is that utilities must be provided with appropriate financial incentives if they are to design and implement successful energy efficiency resources. If energy efficiency programs do not contribute to a utility's profitability, then they will not receive the level of corporate priority and support necessary to make them work. Furthermore, if energy efficiency programs threaten a utility's profits as a result of lost sales, then utility management is likely to be hostile to them and to ensure that they are not successful.

Under traditional cost-of-service regulation utilities have a financial incentive to promote electricity sales between rate cases. Whenever a utility's marginal cost of production is lower than its electricity price, it will be able to increase profits through increased sales. This incentive to increase electricity sales creates a significant financial barrier to utility demand-side management (DSM) programs. This barrier exists even when a DSM program is cost-effective from the utility's perspective and society’s perspective.

Price caps or freezes exacerbate these financial barriers to DSM, for two reasons. First, price caps are designed to be applied for longer time periods than those that occur between cost-of-service rate cases. The longer period increases the “regulatory lag” which allows utilities to profit from increased sales even if customer bills remain higher than necessary because of inefficient and unnecessary use. Second, price cap plans by definition focus on prices. They will reward a utility that maintains price targets. However, successful energy efficiency programs are likely to lower customer bills but not necessarily prices, which may even rise slightly.[24]

In the U.S. it is now widely accepted that utilities are unlikely to undertake aggressive DSM programs unless the financial barriers to DSM are removed. In 1988, the National Association of Regulatory Utility Commissioners (NARUC) urged state regulatory commissions to adopt ratemaking policies that would make cost effective DSM at least as profitable as supply-side investments. Regulatory commissions in many states have established various mechanisms to allow utilities to recover lost revenues from DSM. In the 1992 Energy Policy Act, the U.S. federal government also recognized the need to remove financial barriers to DSM and encouraged state regulators to design electric utility rates in such a way that cost effective utility DSM investments are "at least as profitable, giving appropriate consideration to income lost from reduced sales," as investments in supply-side equipment.[25] In several states, stalemates that had developed between the utility and the regulators around DSM programs declined once these reforms were implemented.

In order to remove the financial barriers to a regulated utility's energy efficiency programs, it is necessary to (a) allow the utility to recover net lost revenues, and (b) remove or reduce the financial incentive to increase electricity sales. Under cost-of-service regulation, utilities can be allowed to recover their lost revenues through periodic adjustments to rates. Under performance-based regulation, revenue caps (sometimes designed as caps to revenue per customer to avoid the need to adjust for population changes) can be used to both allow the recovery of lost revenues and remove the financial incentive to increase electricity sales. This method has been implemented by a number of utilities, including the Consolidated Edison Company of New York and, more recently, PacifiCorp in Oregon.

Revenue caps are based on the same general approach as price caps, but focus on allowed revenues rather than allowed prices. The regulatory commission begins by setting an allowed level of revenues based on actual costs for a test year. Over time, the allowed level of revenues can be adjusted to account for inflation and productivity, similar to price cap mechanisms. The fundamental difference between revenue caps and price caps is that the allowed level of revenues may change to reflect changes to sales levels. If revenues collected deviate significantly from

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[24] For example, consider the case of a customer using 500 kWh per month at a price of 10¢ per kWh, for a monthly bill of $50. If the utility undertakes energy efficiency programs that reduce the customer's use to 450 kWh but have a cost that raises the price to 10.1¢, the next bill will be for $45.45. Thus the customer is better off, but a utility operating under a price cap of 10¢ will not want to undertake such programs. PBR programs that cap revenues per customer instead of prices avoid this problem.

[25] U.S. Congress, *Energy Policy Act of 1992*, Subtitle B, Sec. 111(a)(8).

those allowed, the difference will be returned to, or recovered from, customers through periodic reconciliation adjustments.

Because of this reconciliation process, revenue caps remove the financial disincentives to utility-run energy efficiency programs. If a utility were to reduce its sales through DSM programs, its revenues would not suffer a corresponding reduction. In other words, there would be no lost profits from successful DSM programs. Conversely, if a utility were to increase its sales through load building, then it would not be able to keep the extra revenues and related profits. In this way, revenue caps ensure that DSM and load promotion programs are profit neutral.

Put another way, programs that decrease customers' bills by decreasing usage will be implemented even if they increase prices slightly. This would not be the case under a price cap plan.

Furthermore, revenue caps ensure that utility's profits will not be jeopardized by energy efficiency initiatives undertaken by other entities. As the energy services market matures, energy efficiency initiatives may be pursued by a number of different entities, such as distribution companies, energy service companies, and the customers themselves.

3.1.2.3 Recent experience of U.S. electric utilities with PBR

Regulatory commissions in the U.S. have recently focused increasing attention on PBR mechanisms as an alternative to traditional cost-of-service regulation. While targeted performance incentive experiments were tried in the U.S. electricity industry for most of the 20th century, the recent interest has resulted in more extensive and diverse experimentation.

In general, the interest in PBR mechanisms in the U.S. has developed in two phases. In the early 1990’s several state regulatory commissions begin investigating PBR to improve the regulation of the monopoly electric enterprises. PBR mechanisms were considered as a means of providing utilities with market-like incentives, without necessarily establishing a competitive electricity market. Regulatory commissions in Maine, California and New York implemented a variety of types of PBR mechanisms at this time, and currently have the greatest amount of experience with this regulatory approach.

However, even these states have only had a few years of experience with PBR, it is too early to draw many long-term implications from their experiences. A 1997 review of the PBR practices in these states found that:

- The experience with four PBR mechanisms in New York is considered mixed, with concerns including the administrative burden of reviewing accounting procedures for cost allocation, the implications of flowing through "uncontrollable" costs, and unintended consequences resulting from the focus on particular topics.

- The experience with Central Maine Power's PBR is generally thought to be positive, although the situation is dominated by an extended nuclear plant outage.
- San Diego Gas & Electric's PBR is considered successful toward: (1) reducing operating costs and capital expenditures, (2) reducing regulatory costs, and (3) continuing demand-side management activities. However, this PBR is generally viewed as being overly generous to shareholders with little of the savings going to customers. [26]

This same study pointed out, however, that it is difficult to determine how much of any productivity improvement by these utilities has been due to the PBR mechanism, as opposed to the pressures of operating in the more competitive context of the mid-1990s.

The second phase of interest in PBR has occurred in those states that have taken measures to restructure their electricity industries (e.g. Maine, Massachusetts, New Jersey, New York, Pennsylvania, and Vermont). In this phase, PBR is no longer considered an interim step towards restructuring or as a proxy for competitive markets, but rather as one of options for regulating utilities in a fully competitive electricity market.

It is also important to recall that a number of states adopted price freezes as part of their restructuring plans. These freezes function very much like price caps in the incentives that they convey, though they aren't normally adjusted for inflation and productivity.

In general, generation services in these states are provided on a competitive basis, while transmission and distribution services continue to be provided by monopoly utilities. As transmission is regulated primarily by the U.S. Federal Energy Regulatory Commission, state regulatory commissions have not focused much attention on applying PBR to transmission services. Most of the interest in PBR, therefore, has focused on the regulation of the monopoly distribution company. PBR is frequently considered as one option for providing regulatory incentives to improve the efficiency of distribution services, while reducing regulatory oversight of the remaining monopoly utility. However, given that the role of PBR is limited to the distribution services in this context, regulators have not given it a high priority among the many other issues being discussed in the contentious restructuring debate.

[26] Synapse Energy Economics, Peter Bradford, Resource Insight and Jerrold Oppenheim, *Performance-Based Regulation in a Restructured Electricity Industry*, prepared for the National Association of Regulatory Utility Commissioners, November 1997.

A recent survey of price-cap plans in six countries demonstrates the variety of approaches used in fixing both the initial price and the X-factor.[27] The authors conclude that it is essential to base the initial price on the utility's real cost of service, and not on a benchmark derived from other utilities. The X-factor, on the other hand, should be based on benchmarks rigorously derived through a total factor productivity (TFP) study, which is based on historical indices for the most important inputs (labour, capital, fuel, etc.).

3.2 Resource planning

As we have seen, for most of the twentieth century, the North American electric industry was dominated by vertically integrated utilities.[28] In order to meet their obligation to serve, these vertically integrated utilities had to forecast future energy needs and plan both their generation systems (or their power purchases) and their transmission systems to meet these needs. The economics of electricity generation reflected considerable economies of scale, meaning that it was far less costly, on average, to build a single large power plant than many small ones.

Until the 1970s, utilities generally used historical growth rates for their planning processes. Later, they began to use a range of forecasts of future load growth, comparing the costs of the various ways it could go about meeting those energy needs. The resulting plan would be the one that minimized the cost of meeting energy needs.

As the sophistication of energy planning increased, due in part to increasing public involvement in regulatory proceedings, least-cost planning evolved as well. One important change concerned utility expenditures to reduce energy consumption ("demand-side management," or DSM). Since marginal costs had reversed their historic pattern of decline and risen rapidly in the 1970s, future increases in electricity demand seemed likely eventually to translate into rate increases for all. In such a context, it was in everyone's interest to restrain future load growth.

When a utility spends money to convince its customers to use less energy, or to use it more efficiently, these additional costs must be recovered through rates. In many cases, the DSM-induced rate increases will be lower than they would have been if new power plants had been built to meet the increased demand. In other cases, per-kWh rates might be higher than they

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[27] Olson and Richards, see note 23.

[28] "Vertical integration" refers to the integration of generation, transmission and distribution functions in a single company. Traditionally, most utilities had a legal monopoly in each of these domains, as well as the obligation to serve all customers within their monopoly "service territories."

would have been without DSM, but due to reduced consumption, the average customer's bill would go down. In putting the emphasis on minimizing customers' bills rather than their rates, this new planning approach sought to ensure that new power plants would not be built if cost-effective energy efficiency investments could be undertaken instead.

Together with other innovations, these methods gradually coalesced into an approach known as Integrated Resource Planning (IRP), which was defined in the U.S. *Energy Policy Act* of 1992 as follows:

> [A] planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost. The process shall take into account necessary features for system operation, such as diversity, reliability, dispatchability, and other factors of risk; shall take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and shall treat demand and supply resources on a consistent and integrated basis.[29]

While this definition fails to include reference to the environmental costs of power production, most state IRP rules do so. Indeed, planners and regulators agreed that minimizing dollar costs at the expense of environmental costs was not necessarily in society's best interest. Rather, they concluded that the public interest is best served if electric power needs are met at "least societal cost," taking into account non-monetary costs as well.

Thus, IRP can be thought of as a process that starts with an estimation of the utility's future loads and assesses the options to meet those loads, choosing the one that best serves society's long-term interests. Since electricity demand evolves gradually over time, the least social cost solution will rarely consist of a single power plant; rather, it will usually consist of a sequence of actions that can be thought of as a "portfolio" of energy resources. The goal of IRP is to optimize this portfolio, to meet future needs, taking into account the economic, environmental and reliability characteristics of each resource as well as the many uncertainties involved.

Conducting this type of planning is extremely complex. First, there is the peculiar nature of electricity itself, which, unlike any other commodity, must be produced at the same moment it is consumed. Second, there is the highly uncertain nature of load forecasts combined with the

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[29] United States Government, Energy Policy Act of 1992, s. 111(d). This section of the Act, which required state regulators to consider using IRP in state energy planning, has in many ways been overshadowed by Title VII, which paved the way for competitive restructuring.

relatively long periods of time required to plan, site and build power plants (and, to a lesser extent, to design and implement energy efficiency programs). A third factor is the uncertainty in predicting actual energy savings from energy efficiency programs. Finally, it is complex because of the very different types of non-monetary costs (externalities) associated with the different options that must be compared.

Whatever the methodology used to account for externalities, the integrated planning process must inevitably address the following issues:

- the range of forecasts of future needs,
- the feasibility, projected cost and environmental impacts of available generating alternatives, such as nuclear, coal, oil, natural gas, hydropower, wind, geothermal or solar power. For most of these resources, the costs and impacts are for the most part generic. For hydropower, however (and to a lesser extent for wind and geothermal power), both the costs and the impacts are highly site-specific. As a result, relatively detailed information regarding the proposed projects is essential for the resource planning process,
- the economic and environmental costs of new transmission lines needed for each of these possible resources,
- the availability, cost and environmental and social impacts attributable to power imports, and
- the feasibility, cost and potential energy and capacity savings of a range of energy efficiency and conservation measures.

Optimizing these choices on a strictly economic basis is already a difficult undertaking, but taking environmental and social impacts into account compounds the problem, especially when hydropower is one of the options. However, the modern regulatory process — with expert testimony, cross-examination, and full participation by all interested parties, supported by intervener funding or cost awards for public-interest participants — at least provides a venue in which such complex issues can be addressed. Furthermore, widespread use of "collaboratives"[30] and other approaches to early stakeholder involvement often help ensure that no valid concerns are neglected. For all its flaws, a system whereby an independent regulator must approve each utility's integrated resource plan after full public hearings is well suited to assessing the complex

[30] Collaboratives give stakeholder representatives a direct role in consensus decision making. An over-reliance on collaboratives can be problematic, however, as they only represent the interests of those present.

trade-offs between economic and environmental costs and benefits involved in long-term energy planning.

The many jurisdictions that have required utilities to practice IRP have developed different approaches to integrating environmental externalities into the decision-making process. These approaches can be separated into those that express environmental costs in monetary terms ("monetization") and those that do not. In most jurisdictions, monetization has involved the determination of "adders" — dollar values representing environmental costs which are to be added to the financial cost of each generating option before they are compared on a "least cost" basis. These adders can either be based on "damage costs" (estimates of the actual monetary value of the damage caused by different environmental stressors) or on "control costs" (estimates of the cost of controlling or avoiding the environmental harm).

In each case, the estimation process is difficult and subject to large uncertainties, which, in a public process, translates into controversy. Some impacts, such as sulphate emissions from a thermal power plant, can be easily quantified (tons SOx per GWh) — though these levels may change over time, as fuel quality changes and the plant itself ages. Since damage costs (e.g., the harm sulphates cause to human health, to urban infrastructure and to natural ecosystems) are very hard to evaluate, many jurisdictions base their evaluations on control costs (the cost of adding scrubbers, or the cost differential compared to a cleaner natural gas plant) instead.[31]

However, other types of impacts, and in particular those associated with hydropower, such as changes in landscapes, reduction in biodiversity or harm to traditional livelihoods are virtually impossible to quantify, much less to monetize. Putting a dollar value on damage to a commercial or even a recreational fishery with methodologies such as contingent valuation (which estimate values based on people's preferences, on the amounts they say they would be willing to pay to avoid a given impact, or on the amounts they actually spend on recreational pursuits), provides results that are far from satisfactory, as are attempts to quantify non-power benefits such as recreation. Assessment of cumulative impacts also remains exceedingly problematic.

These difficulties led some jurisdictions to turn instead to qualitative techniques in order to integrate diverse types of externalities into the decision-making process. There are many variants of these methods, known by such names generally as multi-criteria decision making, multiple accounts evaluation and multiple-attribute trade-off analysis. For example, the approach adopted by the B.C. Utilities Commission in the late 1990s was based on multiple accounts evaluation.

[31] To avoid lengthy technical debates over these values, some jurisdictions have selected adder values without trying to determine actual damage or control costs.

Rather than reducing all impacts to a single common denominator (money), multiple accounts evaluation keeps tallies of the various types of costs as several distinct "accounts." Thus, each supply-side (generating) or demand-side (conservation, efficiency or load management) option could be characterized by its score on a variety of accounts such as financial cost, air pollution, greenhouse gas emissions, ecosystem damage and disruption to Native societies. No explicit weighting is given to the different accounts, as would be necessary if they were all to be "collapsed" into a single score. However, scores can be summed within an account, to compare different portfolios of resource options that the utility could use to respond to its evolving energy needs. Multiple account evaluation thus provides a way to summarize the financial and environmental costs of a complex range of options, enabling subjective evaluation by a stakeholder group or a decision-maker.

More sophisticated procedures have also been developed to integrate quantitative analysis with stakeholder values. Perhaps the best example is the "multiple-attribute trade-off analysis" developed by the Analysis Group for Regional Electricity Alternatives (AGREA) at the Massachusetts Institute of Technology in the early 1990s. This approach uses sophisticated computer modeling to explore the economic and environmental implications of different resource strategies under a variety of possible futures. The results are provided to a stakeholder group in an iterative process that seeks consensus around a set of strategies that will meet energy needs at the lowest social cost, taking the many uncertainties into account.[32]

[32] For a detailed description of this approach, see AGREA, *Final Report for Phase One: The Commonwealth Electric Open Planning Project*, Commonwealth Electric and M.I.T. Energy Laboratory (1991); C.J. Andrews, "Spurring Inventiveness by Analyzing Tradeoffs: A Public Look at New England's Energy Alternatives," *Environmental Impact Assessment Review* (1992).

4 The transition toward competitive electricity markets in the U.S.

In this section, we look in greater detail at the recent evolution of power markets in the United States. In section 4.1, we look at the restructuring of wholesale electricity markets in the U.S. While many aspects of the functioning of these markets are set at a state or regional level, they are ultimately subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). We therefore focus on FERC and its policies.

Next, we look at the evolution of competition in retail markets in the U.S. As retail electric service is subject to state jurisdiction in the U.S., retail markets have evolved differently in each of the states. In section 4.2, we look in detail at a few of these jurisdictions, and attempt to describe the diverse experiences in others.

Finally, in section 7.11 we discuss the increasing attention given to planning in recent years.

4.1 Restructuring wholesale electricity markets

By the mid 1990s, just as IRP had become standard practice in a large number of North American jurisdictions, a massive change began to sweep across the electric power industry: the shift toward competitive markets.

The industry structure built around vertically integrated monopolies was based on the notion that the electric power industry is a natural monopoly. For transmission and distribution, this logic remains for the most part unchallenged. Since it would be enormously wasteful for competing companies to build their own set of wires and poles, one company normally holds an exclusive franchise to perform these services. As a general rule, transmission and distribution prices are therefore fixed by a regulator, who is mandated to ensure that they are just and reasonable.[33]

In fact, the move toward competitive power markets has its roots in legislative and regulatory changes in the late 1970s designed to promote non-utility generation. The most important was the *Public Utilities Regulatory Policies Act* of 1978 (PURPA), adopted under the Carter

[33] The Federal Energy Regulatory Commission (FERC), which regulates most high-voltage transmission in the U.S., has recently begun to authorize “merchant” transmission lines, which charge market rates and are not part of any utility’s ratebase. A vigorous debate is currently underway as to the role of markets in transmission rates and expansion.

administration.[34] PURPA required utilities to purchase power from so-called "qualifying facilities" at rates based on the utility's avoided costs (the cost the utility would otherwise have to pay to generate or purchase power).[35] It led to the rapid development of large amounts of non-utility generation, without which the move to competition might never have occurred.

With PURPA, Congress hoped to reduce the demand for fossil fuels and to overcome utilities' traditional reluctance to purchase power from, and to sell power to, the nontraditional facilities. PURPA sought to overcome this utility "reluctance" through its "must-buy" provisions. Specifically, it required FERC to "prescribe . . . such rules as it determines necessary to encourage cogeneration and small power production." The statute requires that the rates set by the Commission for the purchase shall (a) be just and reasonable to the electric consumers of the electric utility and in the public interest, and (b) not discriminate against qualifying cogenerators or qualifying small power producers. The statute states that the maximum rate is the incremental cost to the electric utility of alternative electric energy, known as the utility's "avoided cost".[36]

At the same time, as we have seen, another driving force gained significance in the U.S., this time regulatory and political. In the 1970s and 80s, many U.S. utilities had embraced nuclear power, but the dreams of power "too cheap to meter" quickly disappeared. Instead, faced with dedicated grassroots political opposition and wave after wave of technical difficulties, the cost of nuclear power spiralled ever higher.

While bankruptcies were rare, regulated electricity rates climbed rapidly as the high costs of the nuclear plants entered the rate base. Within a decade inexpensive, small-scale gas turbines became commercially available. Before long, industrial consumers began to clamour for the right to buy power directly from new, independent power producers, to import power from neighbouring regions or to install their own on-site power plants in order to avoid the high rates of their local utilities.

The confluence of these two historical developments led to the adoption by Congress of the Energy Policy Act of 1992 (EPAct). This landmark legislation mandated FERC to create conditions which would allow a competitive market in electricity generation to flourish while

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[34] Even before PURPA, the State of California in 1976 had enacted legislation promoting the development of non-utility sources of electricity.

[35] Qualifying facilities included renewables and high-efficiency thermal generation, including cogeneration.

[36] PURPA s. 210(b), 16 U. S. C. s. 824a-3(b).

leaving to the states all decisions as to whether to allow or require customer choice at the retail level. At the same time, the new law recognized that drastic changes to the way the transmission system is managed would be fundamental to the establishment of such a market.

Under the mandate created by the EPAct, FERC has issued a number of important rulings to further the development of competitive wholesale energy markets in the U.S. These can be broadly divided into two major spheres of action: open access to the bulk transmission system and access to deregulated wholesale power market.

4.1.1 Transmission access

4.1.1.1 Orders 888 and 2000

At the heart of FERC's efforts to create a competitive wholesale power market in the U.S. is Order 888, issued in 1995. Until then, the "essential facilities doctrine" of U.S. antimonopoly law comprised the legal avenue by which nonutility generators obtained transmission access to reach customers. The essential facilities doctrine provides that the owner of a nonreplicable facility essential to the functioning of a market must provide non-discriminatory access to other potential users. The doctrine has been applied by courts and regulators to require transmission-owning utilities to provide customers and competitors access to alternative supplies via their transmission systems.

Order 888 was predicated on the understanding that the primary impediment to the development of a fully competitive market in electric energy was the ability of vertically integrated utilities to use their control over their transmission systems to hinder transactions that were not in their interests (or not in the interests of their marketing subsidiaries or affiliates). It required utilities to offer open access to their transmission systems, at non-discriminatory rates and conditions, and called for "functional separation" between their transmission and energy marketing functions.

FERC judged that such functional unbundling would be adequate to create confidence on the part of other users of the transmission system that they were being treated fairly, and that the transmission operator would not unduly favour its own marketing affiliates at the expense of other users. At the same time, it favoured, but did not require, the creation of Independent System Operators (ISO). An ISO is a non-profit organization that controls and operates, but does not own, a transmission system.

In rejecting demands that vertically integrated utilities be broken up, FERC took a calculated risk — that these halfway measures would be good enough to allow competition to take root. Order

888 did in fact result in an explosion of restructuring activity, but it gradually became clear that vertically integrated utilities were still able to use their control over transmission lines to their own advantage. In response, FERC began the process which led to the issuance of Order 2000 in December 1999.

In Order 2000, FERC acknowledged that Order 888 was not entirely successful, and that there remain significant barriers and impediments to fully competitive electricity markets. The Order strongly favours the creation of "regional transmission organizations" (RTOs), regional bodies that would control and operate the transmission systems of the utilities located within their territories, while remaining independent of control by any company that generates or sells power. The intent is to ensure that the transmission system — the most critical element to a truly competitive market — cannot be used to favour the interests of its owners and their affiliates.

In summary, the Energy Policy Act thus initiated a shift away from the historic regime whereby prices for electrical energy were fixed by a regulator based on the generator's costs toward a new regime where energy prices would be determined by market forces (supply and demand). With a competitive market slowly taking form, private companies began to build power plants without any long-term commitment for the purchase of their output. Instead, power from these "merchant" plants would be sold on the open market, at the best price that could be obtained.

While FERC stopped well short of requiring integrated utilities to divest themselves of their generation assets, many state restructuring settlements have required precisely that. Thus, in several regions, most generating assets have been sold off, either to independent companies or to unregulated affiliates of the parent utilities. As noted above, about one-third of the U.S. power supply is now provided by generators independent of transmission owners.

4.1.1.2 Proposal for a Standard Market Design

In summer 2002 FERC issued its proposed Standard Market Design (SMD) rules. The rulemaking proceeding was intended to address the "differences in the sets of rules that apply to users of the transmission system." In FERC's words:

> The current system allows a vertically integrated utility to discriminate in favour of their own retail customers (bundled retail load) at the expense of other retail customers who are served by the utility's wholesale customers. This occurs because transmission service for bundled retail customers is subject to different rules and rates than service for wholesale customers.[37]

[37] Docket RM01-12-000, Notice of Proposed Rulemaking and Wholesale Power Market Platform White Paper issued on April 28, 2003.

FERC's proposed solution would create a new service, Network Access Service. This service would be made available through a single open access transmission tariff that applies to all transmission customers: wholesale, unbundled retail and bundled retail. The new service would replace the existing Point-to-Point and Network Integration Transmission services. Network service is used by distribution companies and other load-serving entities to connect multiple generating sources to multiple loads, whereas point-to-point service is used to obtain transmission service out of or through a control area for off-system sales or other wholesale transactions.

Originally, FERC proposed that transmission service in each region would be provided by an Independent Transmission Provider, by September 30, 2004. However, the proposal has encountered significant opposition from state governments and regulators, especially in low-cost regions, based largely on the fear that creation of a nationwide market will cause them to lose their price advantage. Opposition has also come from vertically integrated utilities in the south, where these utilities have enjoyed exceptionally close relationships with state regulators such that they are reluctant to see an expansion of federal jurisdiction.

Furthermore, the SMD proposal constitutes another important skirmish on the border between state and federal jurisdiction in that, until now, transmission service to a utility's retail customers (native load, or "bundled retail load") was the exclusive province of state regulators. In particular, low-cost states fear that the costs of new transmission infrastructure built to facilitate transfers between adjoining regions will be borne by their own regulated customers. In this regard, the difficult question of how to distinguish reliability-related transmission expansions from those that are built for economic purposes has taken on great importance.[38]

FERC's SMD proposal has been blocked by state and utility opposition. The SMD approach is unlikely to progress further without federal legislation, such as that which has been proposed but not adopted for each of the last three years.

4.1.1.3 Interconnection Standards (Order 2003)

Another essential and controversial element of FERC's efforts to create a level playing field for utilities and non-utility generators concerns interconnection standards. Transmission systems are still owned and/or controlled by utilities with generation interests in many regions. Their ability

[38] Edward N. Krapels, "The Angle of Repose in Electricity Restructuring: The 2003 Energy Act, FERC, and the Outlook for Transmission Investment," *Electricity Journal*¸ January/February 2004, pp. 16-20.

to prevent independent generators from interconnecting with the grid efficiently and economically represents a significant obstacle for independent generation.

On July 23, 2003, FERC issued standard procedures and a standard agreement for the interconnection of generators larger than 20 megawatts. FERC said its Order is “designed to facilitate development of needed infrastructure for the nation's electric system.” On the same day, the Commission proposed expedited procedures for small generators. The Commission said that its new rule would “reduce interconnection time and cost, help preserve reliability, increase energy supply, and lower wholesale prices for the nation's customers by increasing the number and variety of independent generators that can compete in the wholesale electricity markets.”

Regarding the critical issue of the allocation of the costs of interconnection, FERC's new rule required the generator to pay for all facilities on its side of the point of interconnection. Beyond the point of interconnection, however, *all* costs were allocated to the utilities’ customers. The costs of these upgrades would initially be funded by the generator and would be reimbursed as credits for transmission service over a five-year period. This constitutes a significant departure from FERC’s traditional approach, whereby the generator had to pay for all upgrades that could not be shown to directly benefit the network as a whole. These pricing rules would benefit generators by ensuring that all system upgrades are ultimately paid for by all customers rather than the generator.

These rules were modified by Order 2003-A, issued in March 2004, in order to ensure that native load does not subsidize interconnection facilities built to serve the competitive market.[39] The new order emphasizes its continuity with FERC’s underlying transmission pricing policy, whereby a transmission provider can charge an interconnection customer the “higher of” an average embedded (“rolled-in”) rate or an incremental rate that covers the cost of any needed network upgrades, but not both. However, it makes an important distinction between independent transmission providers and those that are affiliated with generators. The former may require interconnecting generators to absorb the cost of network upgrades, when doing so will help protect native load from bearing costs related to merchant generation. Transmission providers that are affiliated with generators are not allowed this option, as it could be used to discriminate against independent generation.

In so doing, FERC provides yet another incentive for independent transmission providers, consistent with its policy of encouraging separation of transmission and generation ownership.

[39] *Foster Electric Report No. 437*, March 10, 2004.

4.1.2 Competitive energy markets

As we have seen, the ongoing efforts to remove transmission obstacles in order to create a level playing field between utility and non-utility generators are far from over. While significant achievements have been made, obstacles still remain.

The primary concern is market power. If a generator is in a position to manipulate market prices to his own benefit, unregulated market prices will neither send efficient price signals nor be just and reasonable. Before describing efforts to control market power, we briefly summarize the operation of spot markets as implemented in North America.

4.1.2.1 Spot markets

The centerpiece of the restructured electricity market is the spot market, or power exchange. Electricity spot markets were in past a necessary but minor part of the industry structure. Under restructuring, however, the spot market plays the central role of both ensuring balance of supply and demand and determining the ever changing price (and value) of electricity. The amount of energy transacted in these markets is increasing rapidly, as is its influence on all power sales.

A typical power exchange holds a daily auction for every hour of the following day.[40] By 11am of each day, every generator in the area must advise the PX of the amount of power it is willing and able to provide for each hour of the next day, and the minimum price at which it is willing to do so. At the same time, buyers (large consumers and distribution companies) must also indicate their expected hourly power needs. For each hour, the PX stacks the bids in order of price (the merit order) and determines which generators will operate during that hour (the hourly dispatch). The price of the most expensive generator dispatched for that hour becomes the system price (the market clearing price), paid by all buyers to all sellers during that hour.

The market price will thus depend on the demand in any given hour. The higher the demand, the more the dispatcher will have to call upon plants higher up in the merit order, and the higher the market clearing price for that hour.

This market clearing price system, whereby all producers receive the hourly clearing price for all the power they provide during that hour and all wholesale purchasers pay that same price for all the power they receive, is meant to eliminate incentives for “gaming.” If each generator were

[40] In practice, there are many variations on the simple model presented here.

instead paid the price that it bid, the average price for the hour would indeed be lower (since only the "marginal generator" — the most expensive one included in the dispatch — would receive the cut-off price), but generators would inevitably bid strategically, based on their estimates of what the market would bear. The market clearing price system is meant to eliminate this incentive for strategic bidding, since a generator's revenues are not determined by its bid (as long as it does not bid so high as to be cut out of the dispatch). The idea is to give generators an incentive to bid each plant's output at its variable operating cost. As we shall see, however, the market crisis in California has raised doubts about the effectiveness of these incentives, and hence about the adequacy of the market clearing price system.

During periods when the supply of low-variable-cost power exceeds demand, the market clearing price will be equal to the typical generator's variable costs, and thus far below its "full" costs. Thus, during periods of surplus, power prices will be well below the rates that would have been charged under traditional regulation, where rates were designed to ensure that utilities recovered their full costs (including a reasonable return on equity).

However, during periods of shortage, when even the plants with the highest variable costs are needed to meet demand, the market clearing price will be high, and even the generators with low fixed and variable costs will obtain that same high price. During those periods, power prices under restructuring will be considerably higher than they would have been under traditional regulation — even without strategic bidding or market manipulation.

In theory, those high price periods should provide the incentive for generators to build new power plants, which in turn will drive prices back down. While these prospects of low-cost power have driven the restructuring movement, high-price periods are an essential part of the dynamic the market clearing-price system creates. Indeed, price volatility is an essential part of all commodity markets.

4.1.2.2 Location-based marginal prices

The simple model described above assumes that all generation and loads are present at a single point. In a real electrical system, however, generation and load are almost always spread across a large or small area, connected by transmission lines. Depending on the configuration of generation and load, these lines may at times become congested, preventing the least-cost generator from providing power to certain loads. Furthermore, the transmission system produces line losses, which increase with the degree of loading (congestion). It is not possible to calculate the market clearing price for an electric system without taking these factors into consideration.

To permit the rigorous integration of these factors, a system known as locational-based marginal pricing (LBMP) or locational marginal pricing (LMP) was developed by William Hogan of Harvard University. First implemented in the PJM (Pennsylvania-New Jersey-Maryland) Interconnection in 1998 and by the New York ISO shortly thereafter, LMP is used by an increasing number of regions, despite its great complexity.

According to PJM, "LMP is the marginal cost of supplying the next increment of electric energy at a specific location (node) on the Electric Power Network, taking into account both generation marginal cost and the physical aspects of the transmission system." More specifically, instead of a single market clearing price, a locational price is determined each hour for each node on the system. These prices are determined taking into account the load at each node as well as quantity and price of generation available there, as well as the transmission capacities and loss rates connecting the nodes. They are set so as to minimize the total cost of power generation needed to meet system load at that hour.

When load is low and the transmission system is unconstrained, the LMP differences from one node to another are very small. However, as loads and congestion increase, the differences can become quite significant. If all transmission paths into a load centre are filled to capacity, the LMP will be based on the lowest cost generation available within that "load pocket," even if much lower-cost generation is available elsewhere.

For this reason, transmission conditions can have an enormous influence on market prices in high-load areas.

4.1.3 Controlling market power

Market power is the ability of a company profitably to raise prices above competitive levels for a significant period of time. Market power exists where a supplier can raise prices without suffering a loss of market share as a consequence. A supplier with market power can also lower prices below competitive levels in order to drive out competitors, and then raise prices to supra-competitive levels.

Market power threatens the development of effective competition in the retail market for electricity:

> The market power issue is of particular interest to policymakers and legislators as they consider electric power industry restructuring, because the exploitation of market power

> can significantly erode the consumer benefits that would be expected to result from the transition from regulated to competitive markets for electricity generation.[41]

Section 205 of the Federal Power Act requires FERC to establish "just and reasonable" rates for the sale or transmission of electric energy. The premise of the statutory requirement for just and reasonable rates is the need to control monopoly power and political interference through price regulation. However, the courts have found that, "when there is a competitive market the FERC may rely upon market-based prices in lieu of cost-based regulation to assure a 'just and reasonable' result."[42]

As early as 1989, FERC began to recognize that, under certain conditions, it could loosen its regulatory control over prices for wholesale electricity sales without opening the door to monopoly power. Thus, FERC granted certain companies the right to buy and sell "bulk" electricity without obtaining prior regulatory approval — in other words, to engage in transactions at market-based rates — once it was convinced that they couldn't exercise monopoly power.

At first, this so-called "energy marketer status" was granted only to independent marketers that did not own generation or transmission facilities, had no monopoly service territory and were not affiliated with any such company.[43] In 1993, FERC decided to grant similar status to marketers affiliated with independent power producers (IPPs), as long as they had neither transmission nor a monopoly service territory.[44] More broadly, it would allow such marketers to transact at market-based rates, as long as neither the marketer nor its IPP affiliate had the ability to exercise monopoly control or market power.

For FERC to grant market-based rate authority, it must find specific evidence that a competitive market will produce just and reasonable rates. The specific evidence must demonstrate that "neither buyer nor seller has significant market power."[45] When neither buyer nor seller can exercise significant market power, the Commission may infer "that the [market] price is close to

[41] "Horizontal Market Power in Restructuring Electricity Markets," U.S. Department of Energy (March 2000), p. v.

[42] *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 870 (D.C. Cir. 1993).

[43] FERC, Citizens Power & Light Corp., 48 FERC 61,120 (1989).

[44] FERC, Enron Power Marketing, Inc., 65 FERC 61,305 (1993).

[45] Tejas Power Corp. v. FERC, 908 F.2d 998, 1004 (D.C. Cir. 1990).

marginal cost, such that the seller makes only a normal return on its investment" rather than monopoly profits.[46]

4.1.3.1 The Hub-and-Spoke Test

Until 2001, the test used by FERC to assess the generation market power of a generator or marketer was the "hub-and-spoke" test, which:

> identifies the affected customers as those that are directly interconnected.... It then identifies potential suppliers as:
>
> (1) those suppliers that are directly interconnected with the customer (the "first-tier" suppliers); and
>
> (2) those suppliers that are directly interconnected with the merging parties and that the customer thus can reach through the merging parties' open access transmission tariff (the "second-tier" suppliers).[47]

The analysis calculates market shares for total resources and surplus capacity in the first- and second-tier markets as defined above. Market share is therefore calculated based on the simple fact that the customer and potential supplier are somehow interconnected.

Hub-and-spoke analysis was widely criticized. In 1996, FERC itself identified numerous deficiencies with it:

> A drawback of this method of defining geographic markets is that it does not account for the range of parameters that affect the scope of trade: relative generation prices, transmission prices, losses, and transmission constraints. Taking these factors into account, markets could be broader or narrower than the first- or second-tier entities identified under the hub-and-spoke analysis. … In other words, mere proximity is not always indicative of whether a supplier is an economic alternative.
>
> Another concern with the approach we have used in the past is its *analytic inconsistency.* ... Now that virtually all public utilities have open access transmission tariffs on file, it is

[46] Ibid.

[47] *Merger Policy Statement*, 61 Fed. Reg. at 68,599.

> no longer appropriate to recognize only the effect of certain entities' tariffs on the size of the market."[48]

Nevertheless, the test continued to be used. By 2000, even FERC commissioner William L. Massey referred to it as an "anachronism,"[49] yet it remained in use. It was only when market power was identified as a critical causative agent in the crisis that brought the California electric system to its knees that FERC finally moved to replace this outmoded tool.

4.1.3.2 The Supply Margin Assessment test

In November 2001, FERC finally concluded that the hub-and-spoke analysis should no longer apply to market-based rate applications. "[B]ecause of significant structural changes and corporate realignments that have occurred and continue to occur in the electric industry, our hub-and-spoke analysis no longer adequately protects customers against generation market power in all circumstances," FERC stated.[50]

FERC then adopted the "supply margin assessment" (SMA), which will apply on an interim basis until a permanent replacement is adopted. SMA distinguishes between physical and economic withholding. The Commission's has defined these as follows:

> **Physical withholding** occurs when a supplier fails to offer its output to the market during periods when the market price exceeds the supplier's full incremental costs. For example, physical withholding would occur when a generator declares a forced outage when its unit is not, in fact, experiencing mechanical problems, and when the market price is above the unit's full incremental costs.
>
> **Economic withholding** occurs when a supplier offers output to the market at a price that is above both its full incremental costs and the market price (and thus, the output is not sold). For example, we would expect that, during periods of high demand and high market prices, all generation capacity whose full incremental costs do not exceed the

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[48] Ibid.

[49] William L. Massey, "Three Messages from Volatile Electric Markets," EBA Mid-Year 2000 Program, Washington, D.C., Nov. 17, 2000.

[50] *AEP Power Marketing, Inc.*, 97 FERC. 61,219 (Nov. 20, 2001) (order on triennial market power updates and announcing new, interim generation market power screen and mitigation policy).

> market price would be either producing energy or supplying operating reserves. Failing to do so would be an example of economic withholding. [51]

Under the SMA, the supply margin for each market is defined as the excess of supply over peak demand, taking into account transmission constraints. Where FERC finds that a seller controls supply resources greater than the supply margin, it will conclude that the applicant seller is in a position to exercise market power. When that is the case, it may limit the buyer to a regulated ("split savings") price rather than a market price.

FERC's order described how it will address the mitigation of market power when an applicant for market rates fails market power the screening test.

> To prevent physical withholding, we will require that an applicant who fails the SMA screen offer uncommitted capacity (i.e., generation in excess of each hourly projected peak load and minimum required operating reserves) for spot market sales in the relevant market. **To prevent economic withholding, this uncommitted capacity will be priced under a form of cost-based rates. We will require a split the-savings formula, which was the traditional cost-based ratemaking model used for spot market energy sales.** This historical costing approach was a way of establishing an economic value for spot energy exchanges by dividing the trade benefits equally between the buyer and the seller. Eliminating an applicant's ability to negotiate trade benefits is an effective means of mitigating the applicant's market power in the spot market. (emphasis added)

Thus, the SMA in effect removes the authorization to transact at market rates whenever a supplier is in a position to affect market prices by withholding during peak periods. Not surprisingly, this approach has provoked substantial opposition, notably by generators affected by it. However, the order exempts from the SMA analysis all sales, including bilateral sales, into an ISO or RTO with a commission-approved monitoring and mitigation plan. This creates another powerful incentive for utilities to participate in ISOs or RTOs. However, it presumes, but does not demonstrate, that the market monitoring process in each ISO and RTO is sufficiently rigorous to make the SMA unnecessary. In 2000 and 2001, the California ISO operated with a commission-approved monitoring and mitigation plan.

[51] *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 97 FERC. 61,220 (Nov. 20, 2001) (order establishing refund effective date and proposing to revise market-based rate tariffs and authorizations).

4.1.4 Market power abuses and remedies

4.1.4.1 Market power abuse in California

California set out to restructure its electricity sector in 1994, expecting that consumers' direct access to the wholesale electricity market would provide relief from high retail rates charged by the incumbent utilities, based on cost-of-service pricing. At the same time, wholesale prices were expected to diminish, due to increased efficiencies resulting from competitive forces.

When California's restructuring legislation AB1890 was enacted in 1996, an unusual combination of circumstances permitted rates to be reduced and frozen for five years at rates above those that would have been set by pure cost of service methods. It was thought that the excess collection could pay down stranded costs while the freeze would protect consumers against the exercise of market power by the utilities which then controlled the vast majority of generation in the California market. Because the restructuring legislation emerged from discussions among the existing stakeholders, it paid little attention to guarding against market abuse, which was beyond the expertise of those charged with protecting consumers through conventional regulation. Antimonopoly experts had no seat at the table.

As the utilities divested their fossil fuel power plants, these plants were bought up by independent generating companies (many of which were affiliated with utilities in other states, just as the non-regulated affiliates of the California utilities were buying up power plants in other regions). As wholesale prices rose sharply in the summer of 2000, the rate freeze began to have an effect very different from what was intended, preventing those same utilities from recovering from consumers the cost of power purchased on their behalf while also preventing consumers from receiving price signals indicating a need to conserve in light of the expense of buying power. This effect was exacerbated by the fact that the distribution companies were required to buy all of their power through the spot market and could not therefore obtain a measure of price stability through long-term contracts.

The utilities were thus caught in a vice largely of their own making, for they had been enthusiastic proponents of the legislation requiring the freeze at what seemed to be high retail prices. Not surprisingly, California customers and regulators were extremely reticent about allowing rate increases that would break the informal compact represented by the legislation.

What led to those astronomical wholesale prices in the first place? At first, in the summer of 2000, the price spikes were blamed on supply shortages resulting from hot weather, plant outages, transmission constraints and low water conditions in the Pacific Northwest (from which California imports a substantial portion of its summer energy supply). In addition, California had

– in anticipation of restructuring – sharply reduced the energy efficiency programs that had been among the most effective in the nation.[52] The elimination of these programs has been estimated to have cost California the equivalent of some 1300 MW of generating capacity, enough to have avoided all of the blackouts and many of the price spikes.

To make matters worse, the new markets had been designed with no mechanism to allow for purchases on the demand side as the crisis approached. As a result, power was being purchased for hundreds of dollars per MWh when large customers would have been glad to cut back for a fraction of that price.

Finally, careful analysis demonstrated that only the exercise of significant market power by generators —both through bidding behaviour and by withholding capacity from the market — could fully explain the chaos precipitated by this combination of events. As Robert McCullough wrote:

> The bottom line is straightforward — the California market was characterized by large, enduring deviations from traditional utility practice. Generators did not generate. Peakers did not peak. Emergencies appeared to lack solid justification. All of the evidence is consistent with a major, sustained exercise of market power.
>
> … The ISO's [Independent System Operator's] complex and secretive operations have provided a petri dish for collusive behavior.[53]

These comments, made in 2001, have for the most part been confirmed by ongoing investigations into the California crisis. In its 2003 staff report, FERC found that:

- the California market was indeed subject to significant market manipulation in 2000 and 2001,
- market prices were affected by economic withholding and inflated price bidding, in violation of anti-gaming provisions of the tariff, and

[52] In a particularly ill-timed maneuver, California's two largest electric utilities persuaded FERC to void the purchase of 1400 MW of renewable energy in a 1995 ruling reversing FERC's position of 15 years to the effect that the state could require payments in excess of avoided cost to further renewable energy. As soon as FERC issued the ruling, the utilities sharply cut back the energy efficiency programs on which the findings that the renewables were unnecessary had been based.

[53] Robert McCullough, "Price Spike Tsunami: How Market Power Soaked California," *Public Utilities Fortnightly* (1 January 2001), p. 22.

- this manipulation would not have been possible but for flawed market design and inconsistent rules.[54]

To a certain extent, price spikes are an indication that the market is doing its job. The purpose of a spot market is to create price signals whereby prices increase when demand increases relative to supply, and vice versa. According to theory, shortage leads to high prices, which leads to new entrants, which leads to lower prices. Thus, it is argued, any attempt to cap or otherwise prevent price spikes will only prevent the market from self-correcting by providing new supply.[55] However, this mechanism can only function properly when no firm is capable of manipulating markets to its own advantage.[56] There can be little doubt that "gaming" of the market process by generators contributed substantially to the amplitude of the price spikes in California. In the words of one wag, "the invisible hand [of the market] was in the cookie jar."

Just how deep in the cookie jar that hand was has gradually been revealed as the details of manipulation of the California spot market by Enron and other energy suppliers have emerged. Internal memos have been released by FERC that describe in detail the mechanisms used to increase market prices within the state.[57] These included tactics such as artificially creating congestion and then collecting payments to relieve it, buying power in California at capped prices and then reselling it out-of-state at a profit, and buying non-firm energy and reselling it as firm.[58]

In summary, then, it appears that three intertwining causes contributed to the California crisis:

1. declining reserve margins due to:

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[54] FERC, Staff Report, Price Manipulation in Western Markets, docket PA02-2-000.

[55] A more sophisticated market design with a separate capacity market, such as that used in the Pennsylvania-New Jersey- Maryland (PJM) region, is meant to provide price signals to induce new generation supply without price spikes. Steven Stoft, *PJM's* Capacity Market in a Price-Spike World, U.C. Berkeley, Program on Workable Energy Regulation, PWP-077 (7 May 2000). Others, however, have argued that capacity markets only provide additional revenues to existing revenues during periods of scarcity, without creating an effective incentive to build new generation. See, for example, Alexander Galatic, Director of Market Development, Strategic Energy, comments at FERC technical conference on California Market Monitoring (23 January 2001).

[56] The larger a firm's share of the market, the greater the likelihood that it can exercise market power.

[57] The results of FERC's investigation can be found at http://www.ferc.gov/industries/electric/indus-act/wem/pa02-2/info-release.asp. The Enron memos are at http://www.ferc.gov/industries/electric/indus-act/wem/pa02-2/12-06-00.pdf.

[58] Richard Sanders, Memorandum re Traders' Strategies in the California Wholesale Power Markets/ISO Sanctions, December 6, 2000.

- gradually increasing loads and the absence of new generating capacity over the last decade, resulting in large part from the uncertainty surrounding restructuring,
- reduced availability of imported hydropower from the Northwest, due to climatic conditions,
- manipulation by generating companies, including non-forced plant outages and artificial transmission congestion;
- cutbacks in DSM and renewable energy purchase programs

2. extraordinary increases in market prices, due to:
   - declining reserve margins,
   - market manipulation,
   - high natural gas prices, also due in part to market manipulation;
3. insolvency of two of the states three distribution utilities, due to the above conditions and their obligation under AB 1890 to purchase all their power through the California Power Exchange and their inability to pass on those costs due to the legislated rate freeze. The threat of insolvency further contributed to the power shortage and price increases, as suppliers were increasingly unwilling to sell power to the utilities.

The messy jurisdictional divide in the U.S. with respect to electricity regulation means that both state and federal institutions bear some of the responsibility. On a day-to-day basis, it was the California ISO, created under FERC's jurisdiction, that was charged with monitoring the market to ensure that it remained free of abuse. In its November 2000 analysis of the California situation, FERC found that the "seriously flawed" market structure and rules of the Cal-ISO enabled sellers to exercise market power when supply was tight, which in turn resulted in "unjust and unreasonable rates."[59]

To remedy the situation, it recommended, first of all, eliminating the requirement, designed to mitigate the market power of the three California utilities, that they sell all their power into and

[59] FERC, Market Order Proposing Remedies for California's Wholesale Electrics, Docket EL00-95-000 (1 November 2000), p. 3.

buy all their power from the power exchange. This requirement was itself imposed in order to prevent the exercise of market power by the utilities. In their efforts to ensure that the retail market could not be manipulated by the utilities, the architects of California's restructuring inadvertently left the *wholesale* market open to precisely such manipulation on the part of the generators. And, thanks to the inadequate market power test used by FERC, there was no other mechanism to prevent the rampant abuse of that market power by unscrupulous generators and marketers.

In further efforts to restore flexibility to the California power supply, the state emphasized energy efficiency, which in the short run brought the crisis to an end and in the longer run has been restored to its prominent place in California's power supply strategy. In addition, California committed itself to obtaining 20% of its power supply from renewable energy by 2017.

4.1.4.2 Price spikes in Texas

While no other jurisdiction has suffered a systemic collapse such as occurred in California, short-term price spikes have occurred periodically in most spot markets. For example, at 1 pm on May 8, 2000, the spot price in New England shot up to $6,000 / MWh. Within a few hours, it had fallen back to its usual range of $30 - $150. A FERC investigation revealed that, during these hours, there was a 736-MW shortfall in reserves, and the ISO accepted a $6,000 bid from outside the region.[60]

While price spikes have indeed occurred at moments when supplies were tightest, that fact alone is insufficient to explain their size. It is quite clear that $6,000/MWh is not the actual marginal cost for any generator. According to many analysts, this alone is proof that generators are exercising market power. Others argue, however, that generators should be free to charge what the market will bear. In either case, it means that generators are not all following the logic described above, with each bidding its marginal cost of generation.

Another example of this problem emerged following a series of price spikes that occurred in Texas in February 2003. For three days, wholesale prices frequently reached $990/MWh, just under the price cap of $1000. In a preliminary analysis, the Texas PUC staff found that, while there were many circumstances leading to high prices during those days, related primarily to cold temperatures and scarce gas supplies, the scale of the price spikes was due to the bidding behaviour of a single supplier:

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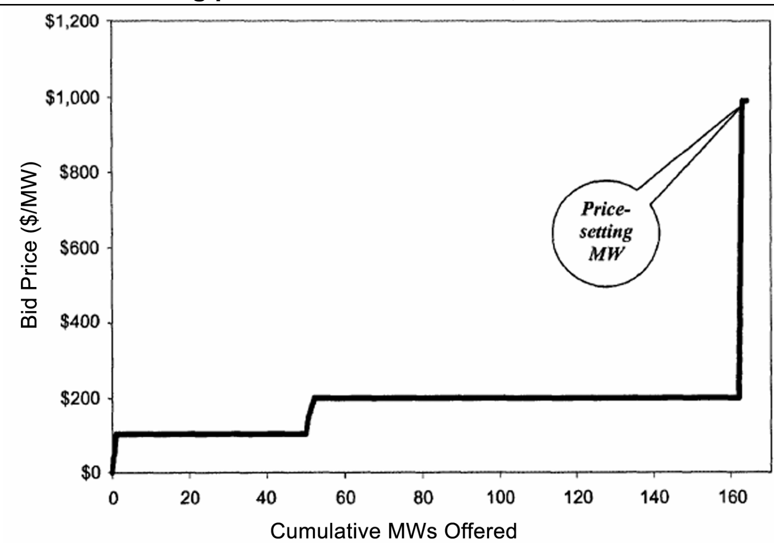
[60] FERC, *Investigation of Bulk Power Market, Northeast Region* (1 November 2000), pp. 53-54.

> In the case of UBES [Up Balancing Energy Service, the spot price], a market participant had bid a single megawatt hour at $990, while all other quantities in its bid curve were priced at $200 or lower. The second most expensive megawatt hour from all other bidders … was $500. Consequently, the last megawatt-hour out of the some 4,100 MWh … caused the MCPE to double or triple. **MOD [Market Oversight Division] estimates that the additional cost of this last megawatt- hour of UBES during the price spike intervals of February 24 and 25 was approximately $17 million.** The price-setting market participant will realize this additional revenue, along with all other UBES bidders, since the market-clearing price is paid uniformly for all MWhs procured by ERCOT.[61] (bold in original)

This supplier's bidding strategy, known as "hockey-stick bidding", is illustrated in the following graph, which shows that it bid 50 MW at $100, 110 MW at $200, and 1 MW at $990:

Bid curve that set the clearing price of $990 on Feb. 25, 2003 at 10 am[62]



Further study by the PUC staff found that two bidders had routinely been submitting such "hockey stick" bids, though one had ceased to do so before the February event.

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[61] Public Utilities Commission of Texas, *Analysis of Balancing Energy Price Spikes during the Extreme Weather Event of February 24-26*, Market Oversight Division Staff Report, March 3, 2003, p. 2.

[62] Ibid., p. 5.

> In both cases, the high bids exhibited the classic hockey stick pattern: a small quantity (one or two megawatts) bid at or near the maximum allowable price, with the rest of the bid curve priced near marginal cost. When asked to explain their high bids, both pointed out that hockey stick bidding is not prohibited by either ERCOT or the commission. <u>They acknowledged that the extreme bids did not reflect production costs during the weather event, but claimed that the sporadic windfall revenues were intended to improve the long-term profitability of a plant.</u>[63] (emphasis added)

The Texas PUC is now addressing the question of hockey stick bidding in the context of a larger proceeding. It is noteworthy however that, years after the California meltdown, a jurisdiction as sophisticated as Texas saw no need to restrict this clearly abusive strategy.

4.1.4.3 Remedies and penalties for competitive pricing abuses

This section examines the remedies available to consumers and competitors harmed by market manipulation. Since the California power market crisis of 2000-01, the refund issue has dominated the press and the agendas of federal and state regulators in the western states.

A key legal hurdle FERC faces in addressing past conduct is the principle that ratemaking is prospective in nature. A federal Court of Appeal has ruled that "It is ... a cardinal principal of ratemaking that a utility may not set rates to recoup past losses, nor may the Commission prescribe rates on that principal".[64] Under traditional ratemaking, prospective rates are based on a prediction of the utility's future costs and revenues. A prediction that later proves incorrect cannot be altered to affect rates that already have been charged. Thus, additional recovery for costs beyond those anticipated in the rate-case test year is generally impermissible.

In 2001 FERC announced a change in policy to facilitate its ability to require refunds for anticompetitive conduct. The policy required changes to all the market-based rate tariffs on file with the agency to provide for refunds when sellers act anticompetitively. Thus, FERC intends to remedy anticompetitive conduct without violating the prohibition against retroactive ratemaking. The Commission stated:

> We believe that our proposal ... is necessary to ensure that rates which are market-based remain just and reasonable, and to ensure that the Commission can adequately remedy any anticompetitive behaviour or the exercise of market power that might subsequently

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[63] Public Utilities Commission of Texas, *Market and Reliability Issues Related to the Extreme Weather Event on February 24-26, 2003*, Market Oversight Division Staff Report, May 19, 2003, p. 21.
[64] *Nader v. FCC*, 520 F.2d 182, 202 (D.C. Cir. 1975).

> be brought to the Commission's attention, and protect customers through refunds or other remedies where appropriate.[65]

FERC's proceedings to obtain refunds for market manipulation in California in 2000-01 are still ongoing and may not be completed before 2005. An administrative law judge in late 2002 recommended refunds totalling about $1.8 billion, but FERC has since modified the methodology used to determine that amount. In the meantime, FERC staff has negotiated a number of settlement agreements with power generators and marketers, which have been attacked as insufficient. For instance, Dynegy agreed to pay $3 million to settle charges it gamed the market, without admitting or denying guilt. California Senator Diane Feinstein denounced the settlement, pointing out that Dynegy's net income rose by almost $40 million in the first quarter of 2001 compared to the previous year.[66]

As FERC struggles with these problems, an entirely different solution may be offered by the Commodity Futures Trading Commission (CFTC), the agency responsible for overseeing the operations of futures markets in agricultural and other commodities. Where FERC's jurisdiction is structured to regulate prices, the CFTC's, like that of the Securities and Exchange Commission (SEC), is designed to regulate markets.

> FERC has elected to address the California energy market malfunctions in a manner which is basically disconnected from and significantly different from, the way in which all other markets in this country are regulated. Thus FERC is currently going through an exercise of figuring out what parties should have bid (given the assumption that all sellers should bid their opportunity costs, usually their short run marginal costs), given what they should have paid for natural gas, and concluding that the level at which such reconstructed bids should have cleared was the just and reasonable rate, and that all sales in excess of that reconstructed price were at unjust and unreasonable rates.[67]

This approach means, on the one hand, that market manipulators are not subject to punitive damages or restitution.

> [A]t least in principle, the CAISO and PX actually could have had contractual terms for dealing in those markets which could be used to force malefactors to disgorge profits, and perhaps to force malefactors to make all other participants whole. That, at least, would

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[65] *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 97 FERC. 61,220 (Nov. 20, 2001) (order establishing refund effective date and proposing to revise market-based rate tariffs and authorizations).

[66] FERC chair Pat Wood quoted in *Electric Utility Week,* Feb. 2, 2004, p. 14.

[67] Robert C. Diarmid, "Oversight over Electricity and Gas: FERC/CFTC or Unless Electricity is Onions", APPA Legal Seminar, October 27, 2003, p. 10.

> have given some of the participants in the California market malaise some disincentive to manipulation of the market, rather than a rule — especially a jurisdictionally dubious one — which simply forces them to disgorge profits, a solution which always encourages profit-making participants to game the market, since there is a chance of high profits, less than 100% chance of getting caught, and no more risk than paying back down to the price level that would have been in effect without manipulation.[68]

It also means that even innocent sellers in a manipulated market may be forced to pay refunds. In financial and commodities markets, on the other hand, only those shown to have manipulated the market are at risk, and they may be held liable for the actual losses they caused, not just for their own excessive profits.

It is far from clear where FERC's jurisdiction stops and the CFTC's begins. In recent years, however, the CFTC has begun actively investigating and prosecuting energy companies for market manipulation. Recent examples include:

- Reliant Resources Inc. and CMS Energy Corp. agreed to pay $34 million to resolve allegations of unfair energy trading.
- Six marketers including subsidiaries of Duke, Williams, El Paso and Dynegy agreed to settlements totalling $96 million penalty after the CFTC charged them with reporting inflated prices for natural-gas trading in an attempt to manipulate the market.
- Similar charges are outstanding with respect to American Electric Power (AEP), with fines potentially exceeding $300 million.[69]

It remains to be seen what role the CFTC will eventually play in the regulation of U.S. electricity markets.

4.1.5 Power markets in crisis

The consequences of the market manipulation scandals in California and elsewhere are only one of the problems facing the merchant generation sector. The period since 2001 has also been marked by the following events, many of which are inter-dependent:

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[68] Ibid., page 13.

[69] Ibid., pp. 16-17.

- the stock market collapse that followed the "tech bubble" of the late 90s,
- the accounting and corporate management scandals,
- the economic slowdown that began in 2001,
- the economic consequences of the attacks on the World Trade Center in September 2001, and
- the decline in electricity demand and the glut in supply in many regions, due to the building boom of prior years, resulting in depressed market prices for electricity.

For all these reasons, the financial situation of highly leveraged generators has been and remains grim. In the last two years, over $100 billion of energy merchant market capitalization has disappeared and several major companies have sought bankruptcy protection. In the words of the director of utility and energy project finance at Standard & Poor's, "it is difficult at this point to construct a credible optimistic forecast."[70]

In part, the problem is due to the boom-and-bust cyclical nature of the industry: when reserve margins are low, prices are high and many new projects are launched. When they all come on line at the same time, however, the surplus capacity drives prices down, creating severe financial pressures for all.

Thus, some 200,000 MW of new capacity have been developed in the U.S. since 1999. At the same time, despite assumptions that they would soon be retired, the older coal plants have continued to operate. The resulting surplus has driven prices for capacity in installed-capacity markets to near zero values.[71]

Furthermore, because of the high debt levels of most generating companies, refinancing has become a major hurdle. Twelve leading merchant generators had to refinance $25 billion in debt that matured in 2003 alone. While most of this debt was successfully refinanced, in the process these companies' credit ratings fell precipitously. They now owe $125 billion in debt, half of which comes due by 2010, and most of that by 2007.[72]

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[70] Peter Rigby, "Energy Merchant Dept Prospects: When "Worst-case" Scenarios Become the "Base Case," *Electricity Journal,* January/February 2004, p. 38.

[71] Paul D. Tonko, *New York's Perfect Storm: An Industry in Crisis: The Financial Condition of Electric Generating Companies in New York State,* Oct. 17, 2002.

[72] Rigby, p. 39.

With high debt and negative returns, new equity investment is largely unavailable. Write-offs have been substantial, due largely to the fact that market values for new combined-cycle gas plants are far less than their installed costs, and many companies are selling off assets in order to remain out of bankruptcy.

4.1.6 Reliability

The responsibility of U.S. regulators to preserve reliability and other service quality standards is as old as regulation itself. Together with the establishment of franchise boundaries and the setting of prices, it is among the most fundamental duties of a regulatory commission. However, with customer choice and deregulation, the regulator loses jurisdiction over some of the entities essential to the provision of reliable service.

In the U.S., the system reliability problem manifested itself dramatically in the Northeastern blackout of August 2003. This blackout, which began just after 16:00 on August 14, 2003, affected an area with an estimated 50 million people and 61,800 MW of load in 8 U.S. states and in Ontario. Power remained out for up to four days in parts of the U.S., and for up to a week in Ontario, due to difficulties in restarting the province's nuclear plants. Estimates of economic losses related to the blackout range up to $10 billion (U.S.) or more.[73]

The blackout began with a series of unconnected transmission problems in Ohio, primarily within the control area of FirstEnergy. The 138-kV transmission system of Northern Ohio collapsed between 15:39 and 16:08, and in the next few minutes, the 345-kV system went down as well. Then, between 16:10 and 16:12, the cascading blackout struck the region. The growth of the blackout from 16:05 to 16:13 is shown on the following page.

The causes of its initiation are now widely understood to be a series of errors by FirstEnergy, starting with its failure to properly manage tree growth in its transmission rights-of-way. It also failed to operate its system with appropriate voltage criteria, and to recognize the deteriorating condition of its system once the chain of events began.[74]

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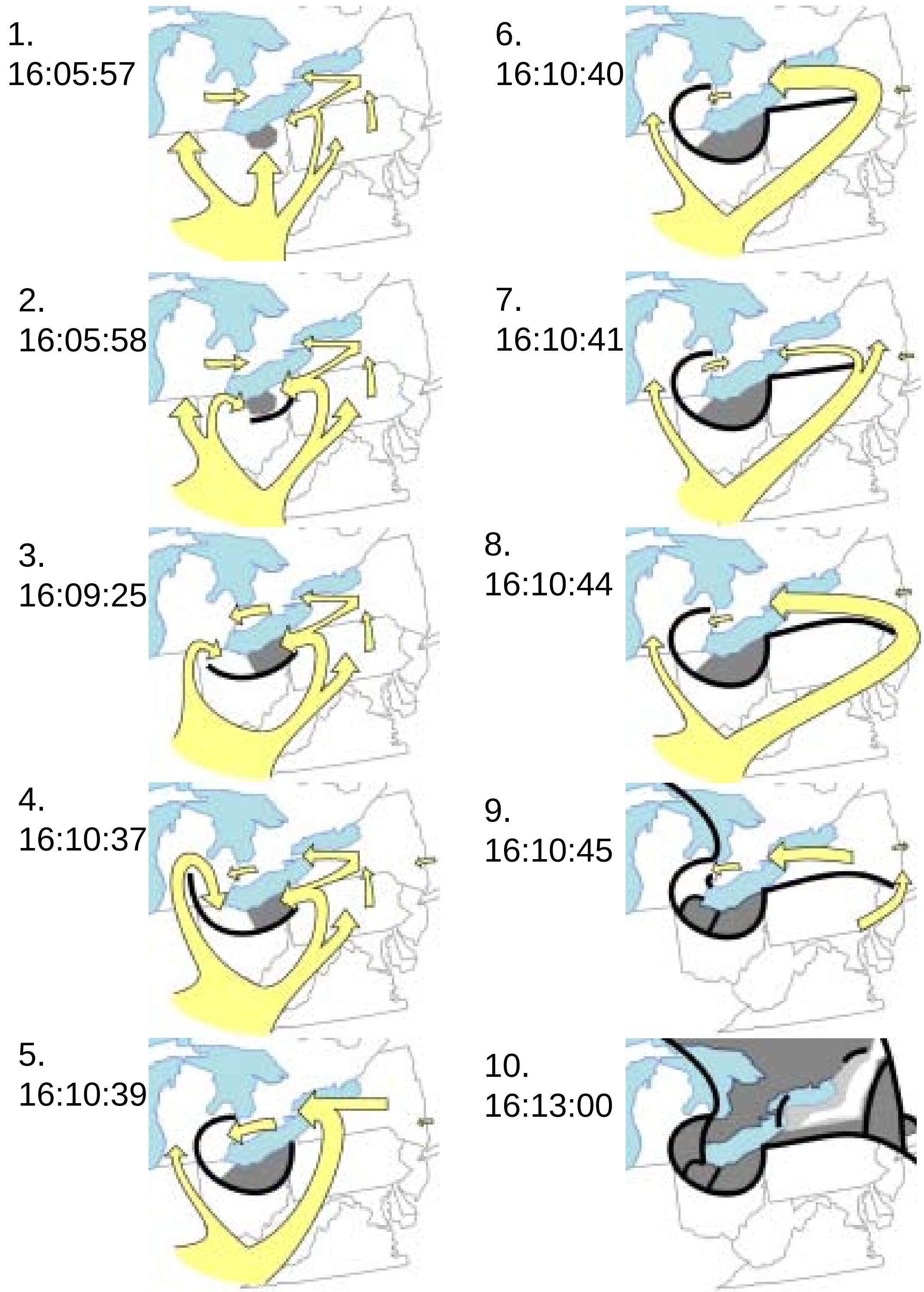
[73] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* April 2004.

[74] Ibid., p. 18.

Figure 6.30. Cascade Sequence



Legend: Yellow arrows represent the overall pattern of electricity flows. Black lines represent approximate points of separation between areas within the Eastern Interconnect. Gray shading represents areas affected by the blackout.

Cascading outages are an inherent risk of high-voltage transmission systems. A cascade is a dynamic phenomenon that occurs when there is a sequential tripping of numerous transmission lines and generators in a widening geographic area. This occurs when power swings and voltage fluctuations caused by the triggering events are incorrectly interpreted as faults by protection equipment on neighbouring lines. Generators, in turn, are tripped off automatically to protect them from damage.

These protective relay systems work well to protect lines and generators from damage by isolating from the system when faults occur, but when power system operating criteria are violated because several outages occur simultaneously, these relays can trip unnecessarily. This leads to more and more lines and generators being tripped, widening the blackout area.[75]

In the August blackout,

> many of the key lines which tripped … responded to overloads rather than true faults on the grid. The speed at which they tripped spread the reach and accelerated the spread of the cascade…. [T]he evidence collected indicates that the relay protection settings for the transmission lines, generators and under-frequency load-shedding in the northeast may not be entirely appropriate and are certainly not coordinated and integrated to reduce the likelihood and consequences of a cascade—nor were they intended to do so.[76]

More broadly, it appears that electricity restructuring contributed to these events in a number of ways. First, the combination of cost-cutting pressure and divestiture of generation, which reduced the degree of coordination in operating the electrical system, clearly contributed to the fragility of the system.[77] Second, the increasing use of the transmission system for long-distance baseload power transfers has tended to increase loading problems at unexpected locations on the grid, and the fragmented and constantly shifting institutional arrangements that manage these flows are not all up to the task. Finally, questions have been raised as to whether some vertically integrated utilities have used congestion as an excuse to avoid transmitting power for their competitors. This concern is particularly acute in the Midwest, which has accounted for almost

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[75] Ibid., pp. 73-74.

[76] Ibid., p. 73.

[77] Between 1999 and 2002, about 19% of total generation capacity in the U.S. was divested, totally almost 95,000 MW (Edison Electric Institute, *2002 Financial Review,* p. 19).

half the utility mergers in recent years, which in some cases have exempted key transmission interfaces from open access regulations.[78]

As to reliability at the transmission level, well before the 2003 blackout, the North American Electric Reliability Council (NERC) repeatedly expressed extraordinary concern to Congress as to the impact of restructuring on reliability and the need for federal legislation. As long ago as December 1999, NERC told House Commerce Committee Chairman Thomas Bliley, "Without the ability to enforce compliance with mandatory reliability rules, fairly applied to all participants, we may not be able much longer to keep the interstate electric grids operating reliably."

In reference to violations of NERC regional reliability rules, the letter went on:

> This past summer, the actions of certain control areas in the Eastern Interconnection clearly demonstrated that we are facing a real and immediate crisis.
>
> The users and operators of the system, who used to cooperate voluntarily under the regulated model, are now competitors without the same incentives to cooperate with each other or comply with voluntary reliability rules.
>
> …
>
> The bottom line is that not a single bulk power system reliability standard can be enforced effectively today, by NERC or the Commission. The rules must be made mandatory and enforceable, and fairly applied to all participants in the electricity market.[79]

Since that time, NERC has been instrumental in efforts to establish a North American Electric Reliability Organization (NAERO), an impartial and technically competent body with a mandate to develop, promote and endorse standards for a reliable bulk electric system. However, in the United States, federal legislation would be required in order to give enforcement powers to such an organization. For instance, FERC could be given authority to certify an independent electric reliability organization (i.e. NAERO) to develop and enforce reliability standards. Provisions of this nature have been included in several of the energy bills presented to Congress over the last several years, but none has yet been adopted.

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[78] Diana L. Moss, "Competition or Reliability in Electricity? What the Coming Policy Shift Means for Restructuring," *Electricity Journal,* March 2004, pp. 11-28.

[79] www.nerc.com/pub/sys/all_updl/docs/legislation/Bliley_letter_122099.pdf.

At the distribution level also, several pre-blackout summers saw lapses from accustomed levels of service quality in California, Chicago and New York City. Of course, a state commission's duty and ability to set service standards for the distribution network is not fundamentally changed by restructuring. The state legislation that has passed to date is either silent on this topic or contains a mandate that service quality must not decline. However, such mandates do little to address the difficult issues of changing institutional responsibility presented by restructuring in the U.S. or elsewhere.

Some commissions have sought to deal with these impacts by adopting enforceable service quality standards. In order to be sure that utilities under cost pressure do not defer necessary maintenance, some commissions have linked service standards to ratesetting in a way that rarely existed under traditional ratesetting.[80] This linkage is characterized by substantial penalties - much larger than ordinary fines - in the event of failure by the utility to meet its customer service obligations in such areas as service restoration times, complaints to the commission or response times to customer requests. The penalties may also include direct payments to aggrieved customers for such offences as failure to appear for service connection appointments.

4.1.7 Regulatory outlook

In recent years, FERC's efforts to promote competition have come under consistent attack by utilities, anxious to protect their markets, sometimes with the support of their state regulatory commissions concerned about the expansion of federal jurisdiction into areas until now regulated by the states. The attacks accelerated when FERC issued its Standard Market Design proposal in July 2002. That proposal would have mandated utility participation in regional transmission organizations, which some state regulators fear will benefit higher cost states to the detriment of lower cost states. Other state commissions have supported the FERC efforts.

In 2003, FERC’s opponents took their challenges to the U.S. Congress. In late 2003, Congress nearly passed an energy bill that would have:

- slowed and possibly halted FERC’s effort to require transmission providers to join regional transmission organizations;

- modified the Commission policies for the interconnection of new generation by shifting FERC's allocation of costs from utility customers to the interconnecting generator.

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[80] Barbara Alexander, *How to Construct a Service Quality Index in Performance-based Ratemaking*, Electricity Journal, April 1996, p. 46.

The energy bill would have affected electricity regulation in other meaningful ways. It would have repealed the Public Utility Holding Company Act of 1935, and it would have established a framework for FERC regulation of electric reliability, an authority which FERC presently lacks.

It appears that FERC responded to the state criticism and congressional efforts in 2003 by putting on a hold on its standard market design proposal. The Commission also has not issued final orders in several interconnection pricing disputes, despite issuing initial decisions favourable to new generators.

4.2 Retail competition

As noted earlier, the approach to retail competition has varied dramatically from state to state.

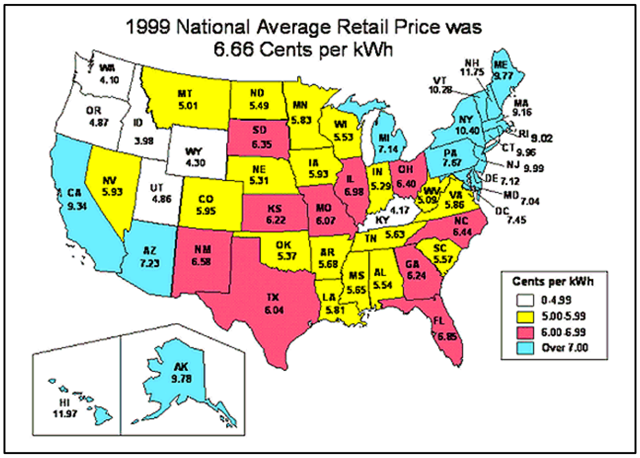
The restructuring movement began and moved fastest in the regions where electricity costs are highest — specifically, in those regions where the marginal cost of new electric generation (usually natural gas combined cycle) was lower than the embedded cost of the pre-restructuring electric system, as expressed in regulated rates. Industrial consumers in these regions realized that it would cost less to buy from new power plants than to pay the regulated rates of the local utility. To do so, however, they and their potential suppliers needed access to the transmission grid. It was this logic that led to the Energy Policy Act of 1992 and FERC's subsequent efforts described in the previous section.

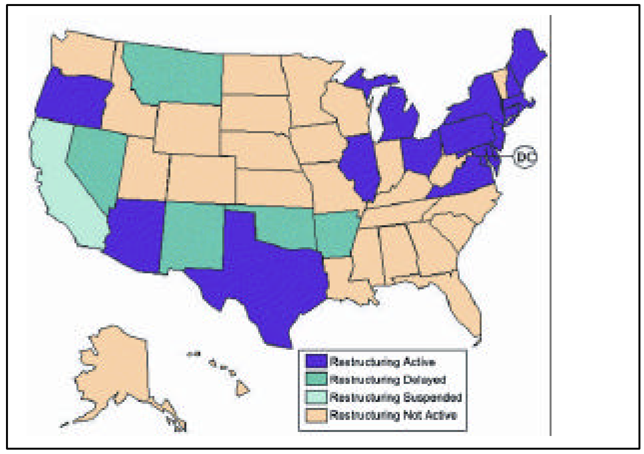
To achieve the ultimate aim of freeing themselves from the burden of regulated rates, which in high-cost regions often reflected the costs of past oil dependence, forecasting errors and nuclear cost overruns, these customers needed action at the state level as well, to allow them to transact directly with suppliers. Thus, the same drivers that led to wholesale restructuring on the national level also led the drive to allow retail competition in the high-cost states.

The first map below shows the average retail price in 1999 for each state.[81] The second map shows the status of restructuring in each one.[82] Not surprisingly, restructuring activity is concentrated in the higher-priced states.

[81] U.S. Energy Information Administration, http://www.eia.doe.gov/cneaf/electricity/epav1/fig12.html.

[82] U.S. Energy Information Administration, http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf.





In those high-priced states, the evolution toward retail access often followed a similar pattern. First, industrial users, using their political and economic clout and the implicit threat of self-generation, won the right to retail access over the opposition of groups representing residential and other smaller consumers. Having lost this battle, however, these groups realize that, if industrials had privileged or unique access to lower-priced independent generation, rates would go up for the consumer classes that remain captive. Thus, those who initially opposed retail access become proponents of rate freezes and of simultaneous access for all customer classes.

At the same time, residential and commercial consumers are clearly reluctant to switch providers, whether due to lack of interest on the part of marketers in serving small customers, a lack of understanding and enthusiasm for restructuring in general, lack of confidence in alternate providers, difficulty of comparing alternate offers, or the minimal economic benefit from switching.

The terms offered to small consumers who do not switch ("default service" or the "standard offer") thus became a major battleground. Realizing that a large majority of consumers would not in fact switch, many consumer advocates lobbied for advantageous terms. Thus, in many states, rate cuts and extended freezes for default service became the political price for adopting retail access. However, the more advantageous the terms for default service, the harder it was for alternate providers to gain a foothold.

To date, no U.S. jurisdiction has adopted retail access without ensuring that default service is offered. In Canada, however, two provinces did so, exposing all consumers directly to the volatility of the wholesale market. As we shall see in section 5, this approach is fraught with difficulties.

While this broad pattern is common to many states, the way it has played out varies greatly from one state to another, depending both on the choice of market structures and when they are implemented.

Furthermore, the political fallout from the California energy crisis and the Enron debacle has dampened state efforts to bring competition to retail markets. During the late 1990s, the trend was toward retail competition. At its height, twenty-four states and the District of Columbia had either enacted legislation enabling competition or issued a regulatory order to implement retail access.

No new states have enacted retail access legislation in the last few years. Several states have delayed or suspended retail access programs by legislative or administrative decision. For example, Arkansas enacted legislation in early 2003 repealing its customer choice law, replacing the comprehensive competition statute with a simple directive to the state commission to "study the feasibility of a large user access program for electric service choice." In repealing the law, the state legislature stated that "the environment in the electric utility industry has changed, and it is in the public interest to continue regulating electric rates for the foreseeable future."[83]

In Arizona, the state Supreme Court recently ruled that the state commission exceeded its authority under the Arizona Constitution when it adopted retail access rules. Oklahoma and New Mexico effectively have eliminated retail competition plans altogether.

Other states continue in their efforts to promote retail competition. Retail access is either currently available to all or some customers or will be available in the following states: Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, and Virginia. In some states, such as Nevada and Oregon, only identified customer groups (such as customers exceeding a certain demand) are eligible to participate in the State's retail access program.

[83] Arkansas House Bill 1114, Act 204 of 2003, The Electric Utility Regulatory Reform Act of 2003.

5 Restructuring in Canada

As noted above, only two Canadian provinces — Alberta and Ontario — have undertaken thoroughgoing restructuring of their electricity markets. Others, led by Quebec and British Columbia, have taken cautious steps in this direction, driven primarily by concern about maintaining access to export markets in the U.S. These steps are limited primarily to opening the transmission to third-party access and a certain degree of functional separation.

These developments are described in the following sections.

5.1 Alberta

Prior to restructuring, the Alberta electric industry was made up of three vertically integrated utilities, one of which was municipally owned (by the City of Edmonton) and the other two investor-owned (Trans Alta and Alberta Power). Under the *Electric Utilities Act (EUA)* of 1995, on Jan. 1, 1996 Alberta became the first jurisdiction in North America with a mandatory power exchange (spot market), through which all power generated in and imported into the province had to be sold. At the same time, a complex system of legislated hedges ensured that customers continued to benefit from the low-cost existing generation, with the result that some 85% of generation in the province was effectively removed from the market.

As originally implemented, these hedges required Alberta's distributors to pay the capital and fixed operating costs of the existing generation, and the producers were required to return to the distributors the difference between their market revenues and their actual variable operating costs. Producers were thus guaranteed cost recovery (plus a reasonable return) on their old plants, and consumers were guaranteed prices no higher than they would have been under regulation. New plants, however, would be unaffected by these hedges.

For a variety of reasons, however, independent producers were reluctant to build new capacity for the new Alberta market. As a result, capacity margins declined, and a sense of crisis arose:

> At the beginning of 1998, two years after the Power Pool of Alberta had been established, restructuring of Alberta's electric industry was stalled in the no man's land between the regulated world and the competitive world, while the regulated world's link between demand and supply had been broken. The EUA provided a framework for a competitive market, but failed to create that market. While generation reserve margins shrank to dangerously low levels, stakeholders were gridlocked, and the government delayed taking action to move the process forward to remove existing generation from regulation, and to

> introduce customer choice. The key obstacle was lack of agreement on how to mitigate the potential for market power abuse if the legislated hedges were removed.[84]

In 1998, faced with a growing threat of power supply disruptions, the Alberta government amended the EUA to eliminate the legislated hedges, mitigate market power and allow full retail competition, all to begin on Jan. 1, 2001. The hedges were to be replaced by Power Purchase Arrangements (PPAs) which granted the holder the right to buy the output of the formerly regulated plants for up to 20 years. These PPAs were to be auctioned off and the proceeds used to compensate consumers for the higher cost of deregulated power, via a "balancing pool, " returning to consumers the value of existing low-cost generation for which they had assumed the capital costs and the risk through past regulation. This cumbersome mechanism was an innovative and controversial attempt to tackle the critical issues of market power and the question of who should capture the stranded benefits associated with the low-cost regulated generation in the province – shareholders or consumers. At the same time, it allowed the government to avoid the political and legal problems that might accompany a policy of obligatory divestiture.

2000 was a turbulent year for the power industry in Alberta. Due to a huge run-up in natural gas prices, combined with declining reserve margins, an uncertain regulatory environment and an upcoming provincial election, power prices skyrocketed, peaking in November 2000 with an average monthly price of over CAN$250/MWh.[85] It was during that period that he PPA auction took place, in August 2000. Despite the very high market prices, the auction produced far less revenue than anticipated, and four of the PPAs remained unsold. The unsold PPAs were transferred to the Balancing Pool, creating new problems of credibility and conflict of interest.

Fear of voter backlash drove the Conservative government, a strong proponent of free-market energy policies, to cap market prices in November 2000 and announce substantial consumer rebates. While this did help calm public outrage, it also created a significant degree of uncertainty as to the extent to which the government would intervene in the new electricity market, which helped to chill investor interest in building new generation.[86]

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[84] INTENCO Energy Consultants Ltd., *Electric Restructuring in Canada: A Report Prepared for CIDA,* March 2002, p. 27.

[85] Kevin Wellenius and Seabron Adamson, "Is the Restructuring of Alberta's Power Market on the Right Track? Evaluating Alberta's First Two Years of Deregulation," Tabors and Caramanlis Associates, for the Independent Power Producers Society of Alberta, http://www.tca-us.com/publications/Alberta2003.pdf.

[86] Terry Daniel, Joseph Doucet and André Plourde, "Electricity Industry Restructuring: The Alberta Experience," School of Business University of Alberta, October 2001 (revised June 2002).

Prices returned to more normal levels shortly after the full market opening in 2001, though they again doubled in the winter of 2003. New legislation was adopted in 2003 that:

- established a regulated default rate for consumers who continue to be served by the three distributors, based on the flow-through of spot market prices. To avoid the fluctuations of the default rate, consumers can contract with independent retailers;
- established an Independent System Operator, to run the transmission system and the power pool;
- established a Market Surveillance Administrator, appointed by the regulator (the Alberta Energy and Utilities Board), to monitor the exercise of market power and ensure that retail functions are competitive.

As of 2004, the Alberta wholesale market is increasingly competitive and liquid, and reserve margins have improved. The problems created by the unsold PPAs are being dealt with gradually. The retail market remains very weak for smaller consumers, and issues related to electricity exports and Alberta's relationship with RTO West (including the western states and B.C.) remain controversial.[87]

5.2 Ontario

When the Ontario Conservative Party led by Premier Mike Harris took power following the 1995 elections, Ontario Hydro was plagued by high rates and an enormous debt burden due in large part to mismanagement of its nuclear program. In 1996, an advisory committee recommended the breakup of Ontario Hydro and the establishment of a competitive market for wholesale and retail electricity. This eventually led to the Energy Competition Act of 1998, which:

- split Ontario Hydro into a generating company (Ontario Power Generation) and a wires company (later renamed Hydro One). OPG was required reduce its market share to 35% within ten years, through a combination of divestiture and "de-control";
- established an Independent Market Operator (IMO) to operate the spot market and maintain grid reliability;

[87] INTENCO Energy Consultants Ltd., "Understanding The Alberta Power Pool And The Restructured Electric Industry," March 2004.

- gave the Ontario Energy Board (OEB) full regulatory control over transmission and distribution monopolies (both Hydro One and the 276 municipal utilities) which, like natural gas distribution, would be subject to performance-based regulation (PBR). The OEB would also be responsible for licensing transmitters, distributors, purchasers and retailers of bulk power; and

- provided for simultaneous opening of wholesale and retail markets.

Market opening was delayed several times and, in December 2001, was finally announced for May 1, 2002. The next week, the government also announced the privatization of Hydro One. That spring, Premier Mike Harris announced his retirement and was replaced by his former Finance Minister Ernie Eves who, it turned out, was a far less committed proponent of electricity markets than his predecessor.

The Ontario market did indeed open as planned on May 1, 2002. By that time, OPG had sold a coal-fired plant, an oil-gas fired one, and four hydroelectric stations totalling 490 MW. It also had entered into a long-term lease for the operation of the 6,000 MW Bruce nuclear facility. Prices remained at normal levels ($25-35/MWh) for the first two months. Then, however, things began to go awry.

- In May, the restart of the Pickering A nuclear station, out of service since 1997, was delayed for another nine months, with costs increasing proportionately.

- In July and August, with record high temperatures and ever declining reserve margins, weekly average prices rose to levels two to three times higher (up to $97/MWh), with price spikes up to $1,000.

- The privatization of Hydro One, already blocked by a provincial court, was withdrawn. Instead, a minority partner would be sought. At the same time, the company's entire board was replaced by the government, the new board fired Hydro One's CEO, who promptly sued.

- The British company that had leased the Bruce nuclear station was facing bankruptcy.

- The chair of the OEB resigned following comments from the Premier questioning the Board's judgement.

- In October, the IMO warned of serious shortages of generating capacity. Later that month, Sithe Energies announced it was shelving plans to build two new power plants in the province.

Finally, in November 2002, Premier Eves announced a series of steps that in effect halted Ontario's restructuring experiment, fixing an electricity rate of 4.3 ¢/kWh for residential and small business consumers and refunding the entire difference between this rate and the amount actually paid for power, retroactive to market opening on May 1, 2002. These decisions, apparently taken without consultation with the IMO, the OEB, Hydro One or OPG,[88] were part of an ultimately unsuccessful attempt to stave off defeat in the upcoming provincial election.[89] While they were applauded by customer advocates, they were denounced by virtually all other participants in the electric industry — "central planning without a plan," in the words of one competition advocate.

As a result, the entire electricity sector in Ontario has been cast into disarray. The spot market continues to operate, with the government picking up the tab — close to $1 billion by now[90] — for distributors' rebates to consumers. Credit ratings for market participants have been downgraded, due to the increasing uncertainty.

Insofar as the profits from high market prices flow back to the government via OPG, it can be argued that the rebate policy is sustainable. However, moneys paid by distributors to third-party generators of course cannot be so recovered. In March 2004, the newly elected Liberal government adopted legislation modifying the price cap. For the first year, the price for small consumers for the first 750 kWh/month increases by 10%, and the price for additional consumption is increased by 28%. After May 2005, the commodity rate will be set by the OEB, based on regulations that have not yet been drawn up.[91]

Meanwhile, the supply-demand balance continues to be dangerously thin. A report on OPG's future, released in March 2004 by a commission headed by John Manley, former Deputy Premier of Canada, warns that the province may face energy shortages by 2007 unless drastic measures are taken. The report favours the controversial refurbishment of the Pickering nuclear reactors as the only way out of its supply problems.

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[88] Intenco Energy Consultants Ltd., *Electric Restructuring in Canada: A Report Prepared for CIDA,* March 2003, p. 50.

[89] Eves' government was soundly trounced by the Liberal Party in October 2003.

[90] Intenco, p. 67.

[91] *Energy Analects,* March 29, 2004, p. 2.

5.3 Quebec

As described above on page 19, legislation establishing regulatory control over Hydro-Québec, a Crown corporation, was only enacted in 1996. The new Régie de l'énergie (Quebec Energy Board) was given full regulatory authority over the Crown utility, including rates, new investments, integrated resource planning, energy efficiency and exports. In 2000, however, the Régie's jurisdiction was substantially reduced by Bill 116, which excludes generation from any regulatory oversight.

Bill 116 is based on the principle of functional separation. While Hydro-Québec remains a vertically integrated utility with a single board of directors, for the purposes of regulation its primary business units — HQ Generation, HQ Transmission (known as TransÉnergie) and HQ Distribution — are treated as separate entities.[92] Only transmission and distribution are subject to the jurisdiction of the Régie de l'énergie.

At the heart of the new arrangement is the so-called "heritage contract," whereby HQ Production must provide HQ Distribution with up to 165 TWh per year to meet domestic needs at a price fixed by the legislation (2.79 ¢/kWh). This is meant to ensure that domestic customers retain the benefit of the existing low-cost hydropower system, paid for out of past rates and for which they bore the long-term risk. For its additional needs, HQ Distribution must proceed by public tender; HQ Production may participate in these tenders, with power from either new or existing stations, but is under no obligation to do so.

The heritage contract is a firm obligation for HQ Production, but it is not related to any specific generating facilities. Thus, HQP is free to manage its generating system as it sees fit, and can meet its obligation to HQD at any given moment with power from any of its generating stations or with imported power.

HQD carries out a triennial long-term planning process under the supervision of the Régie to determine its long-term acquisition needs. HQP is free to buy and sell power, on a short- and long-term basis, without regulatory oversight. It can develop new generating projects with government approval, and has a legislative monopoly on all hydropower development over 50 MW.

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[92] Codes of conduct restrict the sharing of certain types of information between these entities.

Rates charged by HQD to its captive customers are based on its own cost of service, which includes flowing through the amounts paid to TransÉnergie for transmission service (determined by the Régie in a transmission rate case) and those paid to HQP for generation.

The transfer price of 2.79¢/kWh is actually considerably greater than the average production cost of the existing system. Thus, upon separation, the Production division was estimated to earn an annual return on equity of around 18%, while the return on equity of the Distribution division was initially around minus 11%. In 2004, HQD requested and obtained a significant rate increase in order to allow it a "reasonable return on equity."

Unlike restructuring in the U.S., Bill 116 was not adopted in response to pressure from industrial consumers. Indeed, these consumers, together with residential and environmental groups joined together in a "Rainbow Coalition" in 1999 and 2000 in an unsuccessful attempt to block this legislation. While the law does allow Hydro-Québec to implement a retail access pilot program for industrial users, it has shown no interest in doing so.

Thus, while Bill 116 does require competitive acquisition of HQD's additional needs, it appears not to have been conceived as a steppingstone toward either retail access or even a fully competitive wholesale market in Quebec. Its primary effect is to ensure that Quebec consumers pay more for generation, both by paying HQP a handsome ROE on its existing generation and by ensuring that it will pay the international price (based on the cost of combined cycle gas generation) for its additional needs.[93] A secondary benefit (from the point of view of HQP and its shareholder the Quebec government) was to eliminate the need for messy public debates about large hydropower projects and about exports.

Despite the broad opposition to Bill 116, there was until recently little activity with respect to energy policy in the legislative or political arena since its adoption in June 2000. That changed when a broad coalition organized rapidly to oppose construction of a merchant gas plant by Hydro-Québec Production. Public pressure — including massive demonstrations in -20ºC winter weather — led the government to ask the Régie to hold hearings and advise it as to the need for the plant. Thus, for the first time since its jurisdiction over generation was first called into question, a very public debate was held before the Régie concerning the activities of HQ Production.

[93] To date, even when HQP has bid existing hydropower into HQD's auctions, its bids have been based not on its own production costs but on those of its competitors, i.e. combined cycle gas turbines.

While the Régie's recommendation was inconclusive regarding the gas plant,[94] it was surprisingly direct in recommending changes to the legislative framework within which it operates, pointing out that participants in the hearing were virtually unanimous with respect to its deficiencies. It points out that:

- the public has not understood and does not accept Hydro-Québec's new commercial orientation, which has led to a crisis of public confidence with respect to the Crown utility;
- the current system is predicated on the existence of a competitive market for the acquisition of power under long-term contracts which in fact does not now exist, and the situation is unlikely to change; and
- the current situation is not neutral with respect to generation choices, as it will lead inevitably to the choice of gas-fired or large hydro generation to meet future needs; and
- there is currently no neutral and independent forum in which generation choices can be debated.

It thus recommends a serious rethinking of the existing regulatory framework with respect to Hydro-Québec, in order to promote greater transparency and to favour the emergence of an efficient and transparent market for the acquisition of long-term supplies.

5.4 British Columbia

As noted above in section 2.2.2, the British Columbia Utilities Commission has regulated the rates of B.C. Hydro since 1980. In 1998, however, the provincial government greatly restricted the scope of these regulatory activities through the issuance of an executive order (Special Direction Number 8).

In November 2002, the new Liberal government issued a new energy policy which called, among other things, for changing the structure of B.C. Hydro. According to the energy minister, the proposed approach was meant to avoid the failures seen in California, Alberta and Ontario. "All

[94] It found it to be not "indispensable" but nevertheless desirable to reduce future risks.

[of them] had to do with deregulation and market rates and private ownership of utility assets. We are doing exactly the opposite," he said.[95]

The policy proposed removing the transmission system from B.C. Hydro and placing it under the control of a separate Crown corporation. B.C. Hydro's generation and distribution arms would remain in a single corporate entity, but functionally separated. Distribution would be expected to obtain all new generation from the private sector, based on a resource acquisition process overseen by the BCUC, using the principles of IRP. Rates would be regulated, with new stepped and time-of-use pricing for industrial and large commercial customers. These customers would be free to self-generate or to buy directly from independent producers. BCH Generation would continue to supply Distribution with power and energy equivalent to the average output of its existing generation system, under a Heritage Contract modelled in some ways on that used in Quebec.

The B.C. government asked the BCUC to hold hearings concerning B.C. Hydro's proposed implementation of these orientations. In its recommendation, the BCUC rejected the approach used in Quebec in favour of one designed to ensure that all the benefits of the existing generating system are returned to consumers.

One intervener had proposed establishing a Heritage Contract like that created by Bill 116 in Quebec ("The Fixed Price/Fixed Quantity model"). Under this approach, no generating resources are identified as "heritage resources." Thus, the quantity of energy covered under the contract is not directly tied to the output of any particular plants, and the price is not tied to their actual costs. The BCUC rejected this approach in favour of the "Revenue Requirements model" proposed by B.C. Hydro, which is based on the revenue required by Generation to meet the embedded cost of supplying the energy of Heritage Resources to Distribution.

> A salient feature of the Revenue Requirement model is that Generation remains subject to traditional regulatory oversight, with the opportunity for performance-based ratemaking ("PBR"). BC Hydro believes that the Revenue Requirements model ensures the appropriate alignment of interests of BC Hydro Distribution, BC Hydro Generation, and Powerex, and that such alignment is necessary for the efficient dispatch of the Heritage Resources and effective planning for new resources.[96]

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[95] Intenco Energy Consultants Ltd., *Electric Restructuring in Canada: A Report Prepared for CIDA,* March 2002, p. 21.

[96] BCUC, *An inquiry into a heritage contract for B.C. Hydro's existing generation resources and regarding stepped rates and transmission access: Report and recommendations*, October 17, 2003, pp. i-ii. http://www.bcuc.com/Documents/Decisions/2003Dec/Heritage%20LGIC%20Rpt-Recommend.pdf

The Commission rejected the argument that the Fixed Price/Fixed Quantity model would afford greater certainty for consumers, pointing out that it would also impose greater risk on BC Hydro, requiring a risk premium to be borne by consumers.

> Customer advocates believe that the Revenue Requirements model ensures continuing congruence of risks and rewards, that is, it ensures risks and rewards are borne by customers. The Fixed Price/Fixed Quantity contract requires the problematic determination of fair compensation for the risks, and it does not ensure that full heritage benefits will remain with customers. For these reasons, together with strong support for ongoing regulation of BC Hydro Generation, customers unanimously support the Revenue Requirements model.
>
> This Report endorses the preference of the customers and BC Hydro, and makes recommendations for the implementation of a Revenue Requirements model for the Heritage Contract.[97]

Unlike the Quebec model, the Revenue Requirements approach requires continued regulation of BC Hydro Generation. Unlike Hydro-Québec, B.C. Hydro seems in no hurry to extract itself from the regulator's purview. This is no doubt due to the very different commercial orientations of the two Crown utilities.

In Quebec, the desire to eliminate regulatory oversight of HQ's generation was due in large part to the utility's ambitions to develop major new hydro sites for export, becoming in essence a merchant generator in the deregulated U.S. market. In B.C., on the other hand, there has long been a social and political consensus to the effect that B.C. Hydro should not develop new generating facilities.[98] Nevertheless, the ongoing public opposition to Hydro-Québec's generation projects — both the Suroît gas plant discussed above and the large hydro projects on the horizon — demonstrate the problems associated with the approach embodied in Bill 116, which provides no regulatory or political forum in which to debate the economic, social and environmental merits of major new generating projects.

5.5 Outlook

As noted earlier, the fact that natural resources are under provincial jurisdiction in Canada means that, except for certain areas, the federal government only a small role to play in defining

[97] Ibid.

[98] British Columbia Energy Council, *Planning Today for Tomorrow's Energy,* 1992.

Canadian energy policies. Instead, the provincial governments will continue their separate evolutions.

Thus, even if agreements are negotiated between FERC and the NEB, they will not be of great significance, compared to the policy choices made by provincial legislatures and regulators.

That said, it is clear that the restructuring movement is in a period of retrenchment. Even at its zenith, only Alberta and Ontario took the plunge to competitive markets, while B.C. and Québec have taken limited steps to protect their access to U.S. markets.

Each of these jurisdictions will thus continue to evolve, responding both to events in the U.S. and to their own evolving political perspectives.

6 The regulation of wholesale natural gas markets in North America

6.1 United States (FERC)

6.1.1 Historical overview

The role of the U.S. federal government in the regulation of interstate commerce in natural gas began with the adoption of the Natural Gas Act in 1938. This act gave the Federal Power Commission (predecessor to FERC) power to set the rates charged for gas sold by interstate pipelines, and to authorize any new pipeline construction. It explicitly forbade the construction of any new pipelines to deliver gas into a market already served by an existing pipeline.

Sales from producers to pipeline owners ("wellhead" prices) were not addressed in the Act. In the 1940s, however, the Supreme Court found that such prices were subject to federal oversight if the sale was between affiliated companies. Further, in 1954 the Act was interpreted by the Court to require that natural gas producers be subject to federal regulation.[99] Thus began the era of wellhead price regulation in the U.S., which did not fully disappear until the adoption of the *Natural Gas Wellhead Decontrol Act* of 1989.

Throughout the 1950s, the FPC set wellhead prices through cost-of-service regulation, as described above. However, the large number of individual producers led to a lengthening backlog, which led the Commission in 1960 to begin setting wellhead prices for each of five producing regions based on an assumption that the cost of service for producers within a region would be essentially similar. This system also proved unworkable, leading to the adoption of national price ceilings in 1974.

As a result of this regulatory regime and the low price ceilings in effect, which were ultimately based on the average production cost of existing wells rather than on the marginal cost of exploring for and developing new ones, the interstate gas market was characterized in the mid 1970s by low prices and low supply. Within the gas-producing states, however, where prices were not subject to federal regulation, supplies were generally plentiful. In large part to resolve these problems, Congress in 1978 adopted the *Natural Gas Policy Act,* which sought to create a single nationwide gas market in which wellhead prices would eventually be determined by competitive forces. While it continued to regulate wellhead prices, the price ceilings for new wells would be gradually phased out. This, together with other factors, led to much higher prices and much greater supply, which resulted in turn in reduced demand. Because most pipelines had

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[99] Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954).

made inflexible forward purchases (under "take-or-pay"contacts which obliged them to make payments even if they couldn't take delivery), the resulting oversupply situation created serious difficulties for the pipeline companies.

In its Order 436 (known as the Open Access Order) in 1985, FERC for the first time allowed pipeline companies to sell transportation services only, as opposed to the bundled product (delivered gas) that until then accounted for virtually all their sales. Within two years, some 75% of all gas carried by interstate pipelines was transported rather than resold.[100]

After several court tests and additional rulings, the process begun by Order 436 was brought to its completion in 1992 by Order 636, known as the Final Restructuring Rule. Transportation services by pipeline companies became obligatory: henceforth, pipelines could no longer engage in merchant gas sales or sell any product as a bundled service. Thus, the production and marketing arms of interstate pipeline companies had to be restructured as arms-length affiliates, which could be given no advantage over their competitors in price, volume or timing of gas transportation.[101]

In addition, Order 636 required pipelines to offer all their customers:

- "no notice" transportation services, allowing local distribution companies (LDC's) or utilities to meet their customers' peak service needs without penalty,
- access to storage facilities,
- flexibility in receipt and delivery points, and
- "capacity release" programs, allowing them to resell excess capacity on a secondary market.

Order 636 also required that gas transportation rates be based on the "straight fixed-variable" method which puts all fixed costs in the capacity charge and all variable costs in the transport charge. This method tends to eliminate cross-subsidization, in particular with respect to residential heating loads and their suppliers, who must bear the full cost of the capacity they use during peak periods.

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[100] Michaels, Robert J., "The New Age of Natural Gas: How the Regulators Brought Competition," in *Regulation,* The Cato Review of Business and Government, http://www.cato.org/pubs/regulation/reg16n1e.html (1999).

[101] Natural Gas Supply Association, Natural Gas: The History of Regulation, http://www.naturalgas.org/regulation/history.asp.

6.1.2 The current regulatory environment

As described in the previous section, natural gas producers and wholesale marketers are not subject to any price regulation. Gas transport, storage and related services provided by pipeline companies are regulated by FERC; at the same time, retail service by local distribution companies (LDCs) are regulated by the states.

6.1.2.1 Pipeline regulation (FERC)

As noted earlier, pipelines can no longer take ownership of the gas they transport nor can they offer bundled products to purchasers. FERC regulates the rates they charge, the access to their services and the siting and construction of new pipelines.

Pipeline rates are set on the basis of cost-of-service regulation using a projected test year. Since 1994, FERC has set rates using the Straight Fixed Variable (SFV) approach, as mandated by Order 636. Before, it used the Modified Fixed Variable (MFV) approach, under which equity return and income taxes were recovered in the commodity charge instead of the demand charge. The use of SFV greatly reduces the commodity charge, which now consists only of variable O&M costs (usually just a few percent of the overall cost of service).[102] The result is to almost completely dissociate pipeline profits from the volume of gas moved, and thus from external drivers such as weather.

6.1.2.2 Regulated local distribution companies

As is the case for electricity, natural gas local distribution companies (LDCs) are regulated by the states. Many states have undertaken to unbundle the sale of gas from the services related to its transport, allowing customers to purchase gas from suppliers other than their LDC. The status of these retail access (unbundling) initiatives in the U.S. is shown in the following map.[103]

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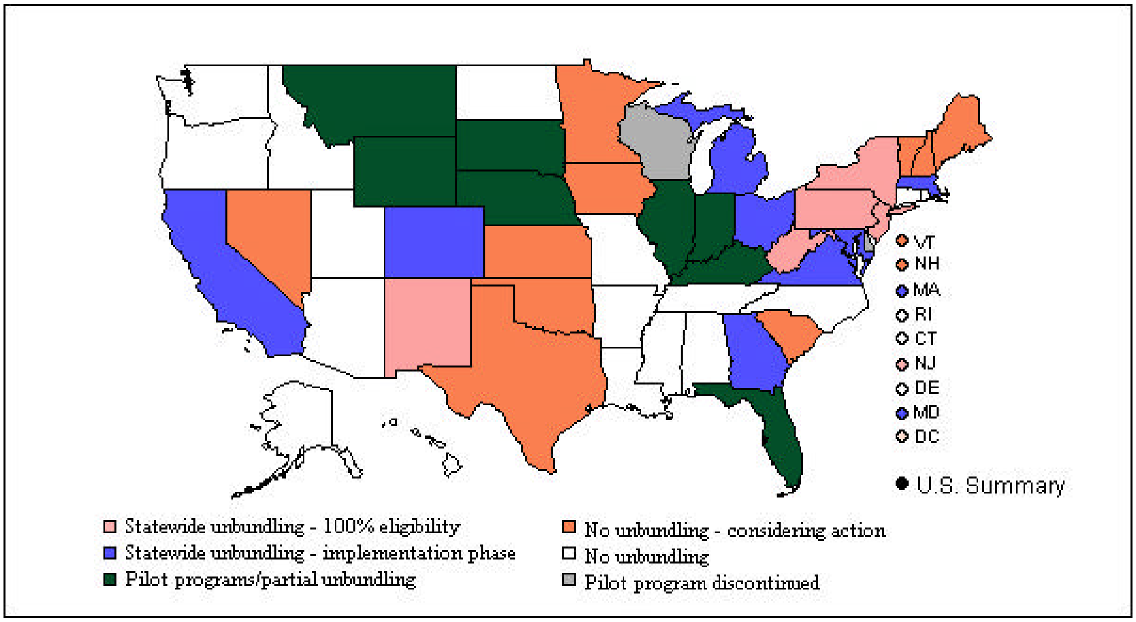
[102] Steven P. Schneider, *Natural Gas Pipeline Regulation and its Impact on Value,* http://law.honigman.com/db30/cgi-bin/pubs/SchneiderA67602.pdf (1997).

[103] U.S. Energy Information Administration, http://www.eia.doe.gov/oil_gas/natural_gas/restructure/restructure.html.



Most of the large gas consumers in the U.S. can take unbundled service, and about half of the 60 million residential gas customers in the U.S. have access to retail choice programs. Some 13% of those eligible to choose alternate providers actually did so in 2003, equivalent to 6.8% of all residential gas customers.[104]

6.2 Canada

6.2.1 The National Energy Board

As noted earlier, the National Energy Board (the NEB) has regulatory control over the construction and operation of interprovincial and international pipelines, as well as over the export and import of natural gas.

The NEB's approval is needed prior to construction of any interprovincial or international oil and gas pipelines, or of any additions to existing pipeline systems. Public hearings are held for all proposed additions of 40 kilometres or more. Pipelines which lie completely within the borders of a single province, however, are regulated by that province's regulatory body. The NEB is also

[104] http://www.eia.doe.gov/oil_gas/natural_gas/restructure/state/us.html.

responsible for ensuring environmental protection during the planning, construction, operation and abandonment of energy projects within its jurisdiction.

The NEB also regulates pipeline tolls and tariffs under its jurisdiction to ensure they are just and reasonable and that there is no undue discrimination in tariffs or services. Until 1995, all pipelines were regulated on a cost-of-service basis, with annual rate cases. Since then, the Board has favoured negotiated multi-year settlements, based on the principles of performance-based regulation (PBR). The Board does not participate in the negotiations but must either approve or reject the resulting settlement package, in its entirety.

These pipelines are divided into two groups: Group 1 consists of ten major oil and gas pipeline companies and Group 2 encompasses about 60 smaller pipeline companies. The Group 1 companies are regulated on a cost-of-service basis, using the Straight Fixed Variable approach described above.

In 1994, the Board conducted a generic proceeding regarding the cost of capital. The proceeding resulted in the establishment of an adjustment mechanism that is used by some of the Group 1 companies to determine their capital structure and rate of return on common equity.

The Group 2 companies are instead regulated on what is known as a "complaint" basis.[105] Under this approach, the Board does not examine a tariff filing unless a complaint is filed. In the absence of a complaint, it may presume that the filed tolls are just and reasonable. Thus, insofar as the regulated company and its customers negotiate these issues to their mutual satisfaction, there is no regulatory involvement at all.

The Board requires that pipeline companies provide all parties with access to transportation on a non-discriminatory basis. In addition, tolls for services provided under similar circumstances and conditions with respect to all traffic of the same description, carried over the same route, must be the same for all customers.

Generally speaking, the Board sets tolls on a postage-stamp basis within large geographical zones. The tolls for each zone are based on the average distance over which gas is transported within the zone.[106] For gas exports, each export point is treated as a distinct zone, since each

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[105] Several Group 1 companies now also use the complaint approach for their tariff filings, with the general support of their stakeholders. National Energy Board, Information Bulletin No. 7, *Traffic, Tolls and Tariffs,* June 1997, p. 3.

[106] Evidence of Roland Priddle, Hydro-Québec Transmission Tariff Application R-3401, p. 12.

export point serves a particular market or market area of the United States and each of these markets is dissimilar to the adjacent Canadian market.[107]

6.2.2 Deregulation and unbundling

Until 1985, commodity prices for natural gas in Canada were set by agreement between the federal government and that of Alberta. Commodity prices for the interprovincial market were based on the international price of oil; LDC's in the gas-producing provinces of Alberta, British Columbia and Saskatchewan were regulated by the provincial boards.

Two agreements reached in 1985 dramatically changed this situation. The Western Accord on Energy Pricing and Taxation, signed in March 1985 by the governments of Canada and of the three gas-producing provinces. This Accord, which established the need for a more flexible and market-oriented environment, led to the October 31 Agreement on National Gas markets and Pricing, known as the "Halloween Agreement", which set up a market system and eliminated regulation of gas commodity prices.

Until the Halloween Agreement, LDC's in Eastern Canada purchased gas from TransCanada Pipelines (TCPL) under long-term contracts covering both supply and transportation of gas. Following the Agreement, gas customers were able to displace the LDC's volumes by purchasing supplies directly. At first, the LDC's were subjected to substantial shortfall charges (known as unabsorbed demand charges, or UDC's) when they failed to take the gas volumes committed to under their long-term contracts. However, these charges were eventually eliminated by the NEB and the provincial boards.[108]

Since then, two types of direct purchase have evolved: Transportation Service (T-Service) and buy-sell agreements. Under buy-sell agreements, customers or their agents arrange commodity purchases corresponding to their needs and sell the gas to the LDC at its average cost of gas. While these customers continue to pay the LDC's regular rates, their costs are offset by the difference between their direct purchase price and the LDC's weighted average cost of gas (WACOG).

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[107] Ibid., p. 16.

[108] Holly Reid, "The Deregulation of the Canadian Natural Gas Market: A Consumer Progress Report," Public Interest Advocacy Centre (1999), p. 3.

Buy-sell arrangements are simpler to execute that T-Service, and so are used by smaller industrial and commercial customers. This approach has also been offered by aggregators to residential and small commercial customers. However, there have been considerable problems and abuses related to these arrangements, due among other things to misleading marketing.[109]

Transportation Service can be obtained either for the long-distance TCPL pipeline only, or bundled with LDC services. Furthermore, since 1997, Ontario has permitted Agent Billing and Collecting (ABC) T-Service, whereby LDC's bill on behalf of agents, brokers and marketers that have arranged commodity purchases for small customers. Such customers therefore receive a single bill, instead of being billed directly for the commodity portion.

In the ten years following the Halloween Agreement, average gas prices for homeowners in Toronto have fallen by 36%, after adjusting for inflation.[110]

[109] Ibid., p. 4.

[110] Tom Adams, *Utility Reform, Regulation & Consumer Protection - Natural Gas Utility Regulation and Commodity Deregulation*, Energy Probe, February 19, 1996. www.energyprobe.org/energyprobe/index.cfm?DSP =content&ContentID=134.

7 Enhancing the public voice

Energy sector reform in the U.S. and in Canada has required decisions unpopular with large blocs of voters or with politically powerful factions. It is likely to continue to do so in Latin America as well. This is because one of the goals of energy sector reform is the greater efficiencies that flow from prices based on costs of service. In the U.S. and Canada, this has generally meant allowing competition to move prices toward marginal costs. In much of the developing world it has meant trying to establish prices that recover the money spent to provide service.

Where prices diverge greatly from costs of service, efforts to remedy this situation bring about widespread perceptions of injustice from those whose rates must increase. These perceptions of injustice may not be based on concepts of economic justice that U.S. or Canadian policymakers would endorse.[111] They may nevertheless precipitate widespread resistance to the reforms, if the perceptions are widely shared, as in many cases they have been.

Studies of energy sector reform around the world are replete with examples of well-intentioned reforms undone by popular resistance expressed through democratic processes, some themselves of recent origin and some decades old. In some cases, the reforms were either unwise or poorly timed. In others they were necessary for the development of a well-functioning energy sector, and the sector has continued to languish in their absence. Necessary financial and technical measures are often much easier to see than are the means of accomplishing them in an enduring way. Too much attention gets paid to devising a theoretical reform framework, work done by economists, engineers, accountants and lawyers; too little gets paid to implementation, which is more likely to be a job for those with political, community action or labour union experience.

In the U.S. and in Canada, regulatory commissions have offered some potential as a buffer against popular backlash. To accomplish this function, however, they must fulfill several conditions: They must have the expertise to devise and administer the necessary reforms with fairness. They must have the legal mandate and the financial resources necessary to do this job. They must have a measure of independence both from the rest of government and from the utility

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[111] Edward Zajac's "injustice propositions" include the following; "The beneficial retention of a status quo is considered a right whose removal is considered unjust" (Proposition 3); "Society is expected to insure individuals against economic loss because of economic changes" (Proposition 4); but also "The existence of numerous and significant economic inefficiencies is considered unjust, especially if their existence is seen as conferring benefits on special interest groups who oppose their removal (Proposition 5). "Perceived Economic Injustice: The Example of Public Utility Regulation" in *Cost Allocation: Methods, Principles, Allocation,* H. Peyton Young, ed. (Elsevier Science Publishers, 1985), p. 129.

industry. They must operate transparently. And they must engage with the public in a constructive, ongoing dialogue.

Seen in these terms, regulation falls into the category that Fareed Zakaria labels "delegated democracy".[112] He refers to such institutions as the U.S. Federal Reserve System and the European Union as examples of institutions positioned to take an independent and expert view over a variety of specialized subjects. However, in developing nations the institutions of delegated democracy are likely to lack legitimacy in the eyes of the general public, especially if they have been created in response to the demands of multinational donors or lenders, rather than – as in the U.S. and Canada – as a result of a domestic political consensus.

Such institutions exist in substantial part to circumscribe the tendency of democracy toward short-term gratification of the electorate, even against its longer term interests. Effective public interaction can perform a legitimizing function for the controversial decisions of such institutions. The distinction between forms of public participation that achieve this result meaningfully and those that seek to do so through propaganda and public relations techniques makes all the difference in the world.

Of course, regulation itself has rarely represented an injection of democratic decision making into the energy sector. Regulatory institutions were charged with energy sector responsibility in the U.S. a century ago in part to displace more democratic forms, namely public ownership of utilities and the awarding of franchises and setting of tariffs by city councils and by state legislatures. Indeed, regulation emerged as a compromise solution, championed in large part by utility executives seeking a solution that would on one hand stall the movement toward government-owned power systems while on the other ending the corruption and uncertainty inherent in rates and franchise decisions made by directly-elected bodies. To this day, the power of state regulatory commissions in the U.S. is routinely described by courts and treatises as a "delegated" legislative power, even though it exercised by appointees of the executive branch.[113]

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[112] Fareed Zakaria, *The future of Freedom: Illiberal Democracy at Home and Abroad*, W.W. Norton & Company, 2003, pp. 241ff.

[113] However, some ten U.S. states provide for the popular election of utility regulators, a blend of democracy with regulatory institutions not followed in other nations. In two other U.S. states the regulators are selected by the legislature rather than the governor. The regulators in those states tend to be former legislators. Elected regulators are far more likely to have aspirations toward higher elective office. Studies over the years have not shown any clear differences in the overall quality of regulation attributable to the method of commissioner selection, though the courts have been unusually active in setting utility rates in some of the elected jurisdictions.

Against this background, public participation emerges as a means for improving the quality and the legitimacy of regulatory decisions by involving the public. However, such public interaction should not be confused with democracy itself. Matters are not being decided by popular vote. Indeed, there is no reason in principle why a program of public interaction would not be as beneficial (and as workable) for a regulatory institution in a totalitarian regime as in a democratic one.

7.1 Designing restructuring with effective public involvement

Effective regulation is a chain with many links. Each of those links provides an opportunity and a need for public interaction. How those opportunities are used will do much to determine the eventual success or failure of the regulatory process.

The links include 1) a comprehensive energy law that conveys the necessary powers and responsibilities, 2) the appointment of people who are honest, qualified and dedicated, 3) adequate financial resources devoted to regulation from sources that do not compromise the commission's integrity, 4) decisionmaking processes that obtain all necessary information and are responsive to the public, to the licensees and to investors, 5) vigorous monitoring and enforcement and 6) written, publicly available decisions that explain the Commission's reasons for its conclusions and that are reviewable by a court or other independent entity. Weakness or failure in any one of these links cannot adequately be offset by strengthening one of the others. All require continuous attention.

Public interaction is important at every stage of the regulatory process, from the shaping of the law and the appointment of the commissioners to the making of decisions to the protection of individual customers. Such interaction can take many forms, ranging from concerns by individuals about their utility service to participation in commission proceedings to participation in regular sessions with the commission staff and/or the utility. For the interaction to be effective, the public must have adequate information about the commission's workings and the decisions being made and must feel that its concerns have received a fair hearing and a reasoned decision.

In many countries, one often hears such phrases as "But we don't have the time (or the money or the people) for such procedures yet" or "We don't really need to have public meetings to know that the public cannot afford higher tariffs and doesn't want to pay them," or "Such practices do not fit the culture of our country". Of course, there is some truth to each of these statements.

Nevertheless, the credibility of a regulatory agency is always fragile. A demonstrated willingness to listen can be important in itself. Furthermore, the public may have views about ways to implement or to mitigate necessary but unpopular decisions that can be very useful even when the decisions themselves cannot be avoided. The most effective public education programs have been those that understood that the commissions and energy companies needed to learn from the public as urgently as the public needed to learn from them.[114]

Finally, carefully conceived public education can be a method of informing customers about the need to take unpopular steps, about actions (such as more efficient use of energy) that can mitigate the impact of rising prices and about the rights of customers and citizens in energy sector decisionmaking.

No regulatory agency in a democracy has the option of not interacting with the public. The question is what kind of a relationship will exist. Failure to pay close attention to the soundness of the ongoing public interaction is like a failure to exercise. It does no particular damage on any given day, and other matters will seem to have a higher priority. But if it goes on for too long, the effects are very hard to reverse, and the necessary credibility and familiarity will not be available when a real crisis arrives.

7.1.1 Effective public involvement in the regulatory process itself

Public interaction involves all aspects of a regulatory commission's work. However, the following are the most significant:

- Public involvement in the appointment of regulators whose past performance shows them to be capable of honest and creative resolution of economically complex matters in ways responsive to public concerns;
- Meaningful participation in proceedings having broad public impact, particularly tariff setting and the conditions included in licenses;
- The handling of individual or widespread customer concerns in such areas as reliability of supply, billing, disconnection and service quality; and

[114] See for example, Brenda Dervin and Peter Shields, “Some Guidelines for a Philosophy of Communicating with Citizens in a New Regulatory Environment”, in “Compendium of Resources on Consumer Education”, (National Regulatory Research Institute, Columbus, Ohio, 1998, pp. 69-86).

- Participation in setting the Commission's overall priorities.

The criteria by which to judge effective public participation might include:

1. Availability of information to the public.

   a. Does the public receive meaningful notice of commission proceedings at the earliest possible moment? Does that notice specify what topics are being considered, what the schedule will be and what the public must do in order to participate in the proceeding?

   b. Does the public have easy access to information on the functioning of the commission, through – for example – printed materials, an accessible web page, public service announcements or frequent public appearances by commissioners and commission employees?

   c. Are the rights of utility customers clearly set forth in a single document, also available in brochure form, on a web page and in the form of public service announcements?

   d. Do customers have access to all information in the possession of the commission regarding utilities, including the utilities' periodic reports of financial and technical data?

   e. Does the commission explain its decisions in a clear and publicly available fashion that discusses the law, the facts, the positions of the participants and the commission's reasoning in sufficient detail to give the reader a clear sense of how the commission will treat similar matters that may come before it in the future.

2. The effectiveness of the means by which the public may participate in the decisionmaking of the Commission.

   a. Can individuals or companies become participants or otherwise be represented in proceedings affecting their interests and thereby gain prompt access to the information filed by the utility? In particular, does a mechanism exist by which small customer interests are assured of representation, from the Commission staff, a consumer advocate or an adequately funded NGO?

b. Can participants or their representatives ask questions of the utility and the commission staff about tariff or other proposals during the proceedings in which they are being considered?

c. Can participants or their representatives present views to the Commission during such proceedings at a time before the commission has reached its decision?

d. Can participants or their representatives be present at all meetings between the commission staff and the utility after a proceeding has begun?

e. Are participants in regulatory proceedings protected through procedural rules from sudden changes in fundamental theory and basic data presented by the utility or commission staff late in a proceeding?

f. Do participants have a right to appeal a commission decision to a capable and honest court for review of whether the commission decision and procedures are consistent with applicable laws and constitutional requirements?

3. The extent to which the Commission seeks interaction with the public

   a. Do the Commission and staff meet regularly with groups representing all customer classes affected by forthcoming commission decisions?

   b. When undertaking major tariff or other major regulatory decisions, does the commission develop a strategy for seeking input from and interaction with the public on the best ways to proceed?

   c. Does the Commission have a strategy for public education regarding matters of long term importance to the energy sector, such as improvements in service, availability of low income assistance, reduction of theft, need for metering and disconnection policies?

   d. Does the commission meet regularly with the media to answer questions and explain commission decisions?

Any Latin American reform program seeking to meet these criteria might consider the following steps.

First, wherever possible, steps that are likely to be unpopular should come at the same time as (or after) clear benefits. The public in many reforming countries indicates a willingness to pay more in return for a reliable power supply. What is not acceptable is a series of substantial tariff increases and disconnections accompanied by little or no service improvement. In some cases, phasing in increases so that they apply only to neighbourhoods that have received upgraded service (as has been done in some countries with telephone and water service) may make the increases more acceptable. Another alternative would be to provide for tariff reductions if electricity availability fails to meet expected standards.

Second, a new regulatory agency cannot be expected to succeed if all of its early actions must be unpopular. The creation — especially upon the demand of an external lender or donor — of an agency whose primary initial purpose is to increase tariffs and approve disconnections is designed to fail.[115] Care must be taken to assure that the early results of regulatory action include some results that the public will see as a benefit – such as improved service reliability and quality, reduction of privileged treatment or reestablishment of gas service in areas which have lost it.

Third, if the privatization documents purport to bind the regulatory commission to specified results or methodologies, then they themselves should go through a process of regulatory review informed by public involvement. A regulator approving tariff increases without allowing any public comment because such increases have been agreed to by the government will not have much public credibility — especially if the regulator has itself signed documents committing to the rate increases.

Fourth, corruption and the existence of special privileges are particularly destructive of public confidence in reform. A regulatory commission must have enforcement powers consistent with its mission.

Fifth, a regulatory agency needs effective channels for public involvement from the beginning. Hindsight in country after country has shown ways in which early public involvement would have revealed pitfalls and suggested alternative courses of action that might have averted or mitigated the backlash against energy sector reforms.

In addition to these five general lessons, there are a number of specific measures that can be taken to increase the effectiveness of public involvement in the regulatory process. These include:

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[115] U.S. regulatory commissions came into being in substantial part as a result of public outcry over monopolistic abuse in several different industries. In most cases, they were able to deliver immediate public benefits, including rate reductions. Of course, the U.S. commissions also paved the way for a system in which investor ownership could compete with government ownership for public approval.

1) Preparation and distribution of written (and perhaps video) materials explaining what the regulatory body does, how it works, and what the rights of the customers are. Such materials should be available at commission offices and meetings. They could also be made available to customer groups, as could a periodic newsletter. In the U.S. such materials typically have titles like "The Answers to Frequent Questions Regarding Utility Service", or "The Rights of Utility Customers" or "Advice Regarding Energy Efficiency."

2) Requiring through license conditions or as a condition of tariff approvals that the utilities themselves undertake to improve their interaction with the public. Each distribution utility could be required to have a consumer advisory council.[116] Of course, such councils require individuals who have some stature as leaders of the groups that they represent if they are to be useful and not just a reflection of the views of the utility.

3) A commission could also have its own consumer advisory council, consisting of representatives who could attend several meetings per year on topics of particular interest. Such meetings would, of course, tend to have more structure and purpose than a meeting with the general public. The results of these meetings, including the main questions and answers, can be written up in brochure form for a wider distribution to the public.

4) A commission can also consider the use of advisory councils with technical or economic expertise to advise periodically on matters pending before the commission. Such councils might not only provide useful advice; their involvement would also enhance the credibility of commission decisions if the outside experts were in agreement with them. Regular consultations with individual outside experts — from academia, for example — are also worth considering.

5) It is particularly important that a commission prepare detailed explanations of the reasons for its decisions.[117] Such material would be helpful to entities with a particular interest in the decisions of the commission, such as the utilities, organized customer groups, potential

[116] In New York such utility consumer councils typically consist of some fifteen people who represent different types of customers (for example, large, small, commercial, people with different ethnic backgrounds, people living in apartments). They meet perhaps every two months with the senior management of the utility to discuss issues of customer concern. Perhaps once a year one or two of the commissioners meet with the council.

[117] The importance of a careful explanation of regulatory decisions goes beyond public interaction. As a basic U.S. administrative law summary states, "The aim is to urge the agency to give careful rather than cursory consideration, to keep it within statutory bounds, to assist judicial review of agency decisions and to develop a body of available precedent...Unexplained administrative actions may be inexplicable and unjustifiable. As Judge Frank once stated so well: '[A]dministrative agencies, when acting judicially, have an obligation to be as articulate as practically possible. For no aspect of a democratic government should be mysterious.'" Ernest Gellhorn, *Administrative Law*, West Publishing Company, 1972, pp. 236-37).

investors in the utilities, serious commentators in the media and staff and commissioners in future years. In the U.S. the absence of such a document would cause a court to reverse the decision, at least until it was explained well enough to permit judges to review it.

6) Donor agencies could consider assistance to create and train Public Advocate offices inside or separate from the regulators in techniques of responsible public representation. At least half of the U.S. states provide for representation of the public through an agency of government apart from the Commission, such as an Office of People's Counsel (Maryland), Division of the Ratepayer Advocate (New Jersey), Consumer Protection Board (New York), Attorney General's Office (Massachusetts), Department of Public Service (Vermont), or Public Advocate (Maine). And in almost all states, part of the staff of the regulatory agency is separated from the Commission and acts as an advocate for consumers or for "the public interest" in most major proceedings.

   Furthermore, some states (notably California) and provinces (notably British Columbia and Quebec) provide (or require utilities to provide) financial assistance to customer groups intervening in particular cases. Overall assistance is less common, but a good case for such institution-building expertise exists in countries in which the basic consumer movement institutional infrastructure is lacking. Undertakings as basic as the distribution of informational newsletters are beyond the means of many customer groups at this time. Obtaining expert advice on energy and regulatory matters seems completely out of reach. It is hard to see how public interaction can become a reality until an informed public exists to interact with.

7) Regulators need to make their principles known to the public outside of capital cities as well. In countries where travel can be difficult and the postal system is not reliable, regional offices primarily for interaction with utility customers could also be very useful. Public meetings in other parts of the country would be a possible starting point. However, such measures are unlikely to have much impact unless they are part of a coordinated strategy.

8) Surveys, perhaps in conjunction with "focus groups" could help to inform the Commission on the likely public response to certain types of decisions. The regulator cannot, of course, allow its basic tariff decisions to be made on the basis of public opinion, but that is quite different from seeking to understand the likely public response to types of decisions when success or failure of those decisions depends on changes in the public's behaviour.

9) Each utility could be required to have programs for customers with special needs (such as disabilities or the elderly). These programs can be developed through the consumer advisory councils or by special working groups set up by the utility.

10) Commission proceedings must provide an early opportunity for significant public input. This is not to say that the Commission needs to adopt the judicial model often associated with U.S. regulation. Even in that system, which is sometimes criticized for offering excessive public participation and procedural requirements, ample opportunity exists to choose procedures that are applicable to particular situations. Informal or hybrid procedures based on public notice, access to information and an opportunity for comment before the decision have long been available as an alternative to fully litigated cases. In recent years, many commissions have experimented with alternative dispute resolution, mediation, and negotiation formats. In these proceedings, such safeguards as cross-examination and prohibition of ex *parte* contact are often relaxed relative to their application when a matter is decided through formal litigation. Even with such less formal processes, the need for a reasoned decision remains.

7.1.2 Restructuring by collaboration

The "collaborative process" that many U.S. states have used to formulate their restructuring plans is a unique outgrowth of the long U.S. tradition of extensive public participation in the regulatory process. As many parties wearied of the sterile interactions that occurred during formal litigation, a number of states began in the late 1980s and early 1990s to experiment with alternative dispute resolution procedures, public outreach programs and mediated forums of several sorts.

With the onset of electric restructuring, with its myriad of issues and affected parties, these various techniques for enhanced public participation were applied to amalgams of "stakeholders" larger and more diverse than had previously taken part in utility proceedings. As a result of these processes, the potential claims of many affected parties were identified earlier and became part of the grand restructuring bazaar that displaced formal adjudication as the preferred means of assembling the restructuring package in most states.

These procedures tended to place more of a premium on successful coalition building than on building a case through formal litigation. Because electric restructuring touched so many interests, many state legislatures concluded that they — and not the regulators — should set the underlying policies. Indeed, in some states, courts held that existing law did not give the regulators the power needed to adopt retail competition. Consequently, the collaborative processes often ran ahead of, in parallel with or after the overtly political legislative process. As a result, solutions that could command broad political support had an inherent advantage, a factor that helps to account for the predominance of solutions based on paying off the claims of many stakeholders, usually through "non-bypassable" charges (i.e. systems benefits charges), as discussed below.

As a rule, these "collaboratives" were overseen by regulators and resulted in recommendations to the executive and legislative branches. The resulting legislation then provided the general restructuring framework, while leaving the specific implementation to the regulatory agency. In a few cases — notably New York — the collaborative process led directly to regulatory decisions implemented without separate action by the legislature.

In most of the world, on the other hand, restructuring proceeds without a systematic process through which the stakeholders have a meaningful opportunity to be heard and to work together to craft solutions that a majority of them would find acceptable. It should thus come as no surprise when such restructuring processes lead to political crisis.

7.1.3 Energy efficiency and renewables

7.1.3.1 Energy efficiency programs

Programs to educate the public regarding efficient use of energy and to promote such efficiency are a desirable part of a reform package in that they can reduce energy bills for both individuals and for the nation. In rapidly growing societies, applying current energy efficiency best practices to new buildings is likely to reduce future energy investment requirements substantially, with a large savings to the nation's future electric bill as well as to its environment.

As noted earlier, the choice of tariff methodologies is also critical to the furtherance of cost effective energy efficiency. Methodologies that reward utilities for selling energy but not for saving it will create a powerful political constituency opposed to energy efficiency.

Other steps necessary to advance cost-effective energy efficiency in a restructuring country include:

- *Make DSM a priority policy.* U.S. experience clearly demonstrates that DSM, including energy efficiency, will only happen with clear, strong, and consistent government and regulatory leadership. Energy efficiency must be affirmatively designed into restructuring programs. Otherwise, cost and other pressures will tend to undermine it.

- *Make DSM a distribution company service obligation*. The policy should require distribution companies to identify, design, and deliver DSM programs for customers in all customer classes subject to review and oversight by regulators.

- *Adopt energy efficiency programs to address power shortages*. Energy efficiency can be particularly important in jurisdictions facing power shortages, as recent experience in California and New York (as well as Brazil) has shown.

- *Market Structure.* Wholesale markets should be designed so that demand-side resources can participate, and short-term demand response (load management) should be allowed to compete in short-term wholesale markets for energy and ancillary services.

- *Environmental equality*. Generation markets and environmental rules should be designed to eliminate the competitive advantage highly polluting generating plants could have over clean plants.

The American Council for an Energy-Efficient Economy (ACEEE) reviewed the energy efficiency policies of 25 states that had pursued electricity restructuring. In twenty of these jurisdictions, funding for energy efficiency programs was set out in the restructuring legislation or agreements, all but two of which currently have such programs in operation.[118]

Twelve of these eighteen states rely on a small non-bypassable per-kilowatthour charge, known as a "public benefits charge" or a "system benefits charge" to fund these programs. In the remaining states, funding is either embedded in rates or provided via a flat monthly fee. Funding levels ranged from 0.03 to 3 mills/kWh, with a median value of just over 1.1 mills/kWh. In roughly half the states, programs are administered by utilities, while in the other half they are administered either by government agencies or by independent non-profit organizations.

The survey found annual energy efficiency spending in the 18 states of over $900 million, with energy savings of 2.8 TWh and 1,060 MW in the 12 states reporting. Estimated cost-benefit ratios range from 1.0 to 4.3, and the estimated cost of conserved energy range from just 2.3 to 4.4¢/kWh.

These results indicate that energy efficiency remains a viable and cost-effective option within a restructured environment.

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[118] Martin Kushler, Dan York and Patti White, *Five Years In: An examination of the First Half-Decade of Public Benefits Energy Efficiency Policies,* ACEEE, April 2004, 43 pp.

7.1.3.2 Price-responsive demand

One of the crucial benefits expected of restructuring is that it will allow demand to vary in response to market prices. With prices that reflect the constantly fluctuating costs of electric generation, consumers will have the opportunity to modulate their consumption of electricity in response to these price signals. In allowing consumers to become much more efficient economic actors, the overall cost of electric service should decline.

While progress has been made, demand responsiveness remains an elusive goal. Only a handful of jurisdictions established tariffs that allow small and medium-sized consumers to respond to price signals in the wholesale market. Demand response has been described as the "missing link" between the wholesale and retail electricity markets:

> The industry's history is littered with unfortunately experiences which could have been ameliorated by the insertion of this linkage. The industry will continue to be vulnerable and less efficient until demand response is pursued.[119]

Thus, it has been estimated that real-time pricing would allow a typical utility to reduce its peak load by 5%.[120]

On a theoretical level, much work has been done to develop a full range of options. A number of products have been developed that bridge the gap between time-of-use (TOU) pricing, where tariffs are fixed for peak and off-peak periods, and real-time pricing, where consumers are directly exposed to the wholesale price that fluctuates on an hourly basis. For example, under "day-type TOU pricing," there are separate schedules for high, low and medium-price days. The utility gives consumers one day's notice as to what "type" the next day will be, thereby allowing them to avoid consumption during the highest price periods.

While there has to date been considerably more talk than action in this regard, the Ontario government has indicated it will move quickly to make price-responsive demand a reality. Faced with the need to refurbish, rebuild, replace or conserve 25,000 MW of capacity over the next 15

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[119] Michael O'Sheasy, "Demand Response: Not Just Rhetoric, It Can Truly be the Silver Bullet," *Electricity Journal,* December 2003, p. 58.

[120] Ibid., p. 56.

years, the government has announced a plan to install “smart meters” in 800,000 Ontario homes by 2007.[121]

7.1.3.3 Promoting renewable resources

Because energy sector reforms tend to drive prices toward marginal costs and because renewable resources have higher marginal costs than fossil fuel fired power plants in most countries, renewables will normally be at a disadvantage under restructuring. Their claim to some special treatment to offset this disadvantage rests on the proposition that they offer environmental, economic and national security benefits that are not reflected in market prices but that are clear when these “externalities” are properly valued and taken into account. Jurisdictions that have accepted these claims (see the Integrated Resource Planning discussion above) have generally supported renewables through purchase prices, through their systems benefit charges, through requirements that each distribution utility purchase a percentage its total supply from renewables (often called a renewable portfolio standard, or RPS[122]) or through a production tax credit allowing a credit for each kilowatt hour produced.[123] Other forms of support include rebates by the government of a percentage of the purchase price and net metering, under which the customer is allowed to sell any excess power to the utility at the retail price, essentially by running their meter backward when their generation exceeds their need.

7.2 Dealing effectively with values and expectations woven into the existing industry structure

In many jurisdictions, “power sector reform” will strand certain expectations that have been built into many years of experience with the existing electric system. Those who have benefited from

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[121] Remarks of Dwight Duncan, Ontario Energy Minister, to the Ontario Energy Association Energy Management/DSM Management Forum and Trade Show, April 26, 2004.

[122] For a comprehensive discussion of the Texas renewable portfolio standard, see http://www-library.lbl.gov/docs/LBNL/491/07/PDF/LBNL-49107.pdf. For an overview of policy issues related to RPS design, see Scott Hempling and Nancy Rader, *The Renewables Portfolio Standard: A Practical Guide* (NARUC, 2001), http://www.naruc.org/goto.cfm?returnto=displayindustrynews.cfm&industrytopicnbr=380&page=www.naruc.affiniscape.com/associations/1773/files/rps.pdf.

[123] The U.S. has a 1.8¢/kWh production tax credit for wind energy. . In Canada, the Wind Power Production Incentive has provided incentives of up to CA 1.2¢/kWh since 2002. In 2005, the federal government quadrupled the WPPI target to 4,000 MW by 2010.

the inefficiencies of the existing system have a strong and understandable reason to claim that fairness requires that their accustomed benefits be protected during any transition, perhaps beyond. In this regard, the similarities between investors faced with stranded investment, municipalities faced with declining property taxes, workers faced with the prospect of job losses and customers faced with substantial rate increases and unprecedented disconnection for nonpayment are much greater than the differences.

The litigation threats of Wall Street investors in the face of potential stranded investment in the U.S. have been implausibly mirrored in the menace of gun-toting enforcers barring disconnections throughout the former Soviet Union and in street demonstrations half the world away by men in loincloths who spend most of their days tending their crops and partaking of the free electricity India allocated to farmers. Transitional strategies devised with the involvement of the public are an essential element of energy sector reform throughout the world.[124]

Every country has such impacts, such claimants.[125] To say that the U.S. experience with potential stranded investment is irrelevant to, for example, the Indian experience with

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[124] "The case studies offer good reasons to doubt the viability of a sequential view of reforms and public benefits— … fixing the financial position of the sector first and dealing with public benefits later". Navroz K. Dubash et al, "Power Politics: Equity and Environment in Electric Utility Reform", World Resources Institute, Washington, D.C., 2002, p. 166.

[125] Consider the applicability of the following, written about the U.S. experience, to restructuring in other countries:

> Any major change in regulatory policy... requires some market participants to incur stranded costs, i.e. one time changes in wealth attributable to the change in regulatory policy. Stranded costs are inevitable when a change in regulatory policy increases the efficiency of a previously regulated market. The prior regulatory system inevitably induced the firm to have to hire too many employees, to pay excessive wages, to make excessive investments in capital assets, to invest in the wrong mix of capital assets......Elimination or relaxation of regulatory constraints and introduction of competition forces many market participants to restructure their operations to eliminate excessive costs.
>
> Stranded costs can take the form of layoffs and salary reductions (the primary consequences of deregulation of air transportation and financial services); the bankruptcy of many firms (one of the primary consequences of deregulation of trucking); …
>
> No market participant willingly bears large stranded costs. Participants in a regulated market that expect to absorb large stranded costs as a result of a proposed regulatory reform engage in a series of actions designed to avoid incurrence of these costs or to reduce the magnitude the magnitude of the costs each must absorb. These actions include: attempts to block regulatory reform, attempts to delay regulatory reform, and attempts to convince legislatures, agencies and courts to reallocate stranded costs to other market participants. Proponents of regulatory reform often must devote more time and energy to disputes concerning allocation of stranded costs than to all other aspects of the process of regulatory reform. Richard Pierce, Jr., and Walter Gellhorn, *Regulated Industries*, (4th Ed, West Group, St. Paul, Minn., 1999), pp. 399-401.

discontinuing free electricity for farming is to misunderstand the fact that the investors and the farmers are asking for the same thing for the same reasons. Neither claim is supportable in the context of economic efficiency, but both are based on long reliance and other social considerations. Because most countries have long believed that considerations other than pure economic efficiency are important in this vital industry,[126] such claims must be carefully heard and wisely resolved.

Furthermore, those pressing these claims have in one way or another the potential to slow and stymie the restructuring process to such an extent that their societies may find it easier to buy them out than to insist that they accept the necessary changes regardless of the disadvantage to them. The techniques for identifying these impacts, for presenting and considering them and for resolving them are the subject of this chapter.

Restructuring in the U.S. — with its emphasis on retail customer choice — entails impacts quite different from those to be expected in Latin America. Nevertheless, there are techniques for identifying, negotiating and mitigating those impacts that may be useful in other countries as well. This section sets forth the impacts that U.S. states have sought in one way or another to mitigate. It also discusses the substantive and procedural mitigation techniques that have been employed and offers some observations on their possible applicability in Latin America.

7.3 Lifeline programs

Low income customers (usually defined in terms of eligibility for other assistance programs) have for many years benefited from assistance rolled into traditionally-set U.S. utility rates. These "lifeline rates" took the form of rates below the full imbedded cost (though usually above the marginal cost) of serving those customers. Other forms of assistance included targeted

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[126] For example, "The people we (public officials) serve are citizens as well as consumers, and they are entitled to public utility services that address their needs and concerns as citizens, not just their pocketbook concerns as ratepayers. As citizens, we share common concerns about the health of the environment, the well-being of our neighbors, the security of the nation, and the needs of future generations." Richard Cowart, *Restructuring and the Public Good, Electricity Journal*, April 1997, p. 53. See also Daniel Yergin and Joseph Stanislaw, *The Commanding Heights*, *The Battle between Government and the Marketplace that is Remaking the World*, Simon and Schuster, New York, 1998, "The economic tests are eminently measurable....The second set of tests cannot be expressed in figures, but it is no less powerful. It goes to the basic values by which people judge the world, the system in which they live, and their own lot....How widely shared is the success? Is the system fair and just? Or does it disproportionately benefit the rich and the avaricious at the expense of the hardworking of more modest circumstances? Does it treat people decently, and does it include the disenfranchised and the disadvantaged? Are there equity, fair play and opportunity?", p. 383.

energy efficiency measures (particularly weatherization, limitations on the utility right to disconnect for non-payment and outright financial assistance from the state and federal governments.[127]

To the extent that these measures require a regulated supplier to charge some customers prices higher than the costs of serving them, they are incompatible with retail competition because the customers paying the higher price can switch suppliers. However, a clear precedent for the allocating the cost of such programs across all suppliers was set in the U.S. federal Telecommunications Policy Act of 1996. This law required the use of a non-bypassable fee to create a universal service fund of several billion dollars, to be designed by the Federal Communications Commission).[128] This fund provides support for universal service, lifeline, rural areas, and handicapped users, as well as discounts for schools, hospitals and rural health facilities.

Most of the states that have enacted electric restructuring legislation have required that assistance available to low income customers not be diminished. They have also mandated that a supplier of last resort be available to serve customers who are unable to qualify for service in the unregulated market. Several state electric restructuring laws have included provisions similar to the federal telecommunications legislation for the protection of low-income electric service.[129] In short, the measures used deal with the historic commitment to electric service for low-income people have included:

a) Payment by other customers, both in the form of a non-bypassable charge and in the form of the voluntary contributions that some utilities provide through a checked box on the bill. In addition, subsidies (such as the general subsidy that once went to the basic

[127] Much of the information in this section is from Jerrold Oppenheim and Theo MacGregor, *Low Income Consumer Utility Issues*, a report to the Utah Low Income Task Force, October 1999. The authors observe that low income assistance programs are likely to be cost beneficial for all customers when full account is taken of the impact of uncollectibles on the utility bills of other customers as well as reduced collection costs and reduced taxpayer costs as a result of such impacts as homelessness.

[128] The Telecommunications Act sets forth a number of principles to guide the Commission and the states, including the requirement that "quality service should be available at just, reasonable and affordable rates." The Act also provides that the Commission and the states must devise methods to insure that consumers "in all regions of the Nation, including low-income consumers and those in rural, insular, and high cost areas ... have access to telecommunications and information services ... at rates that are reasonably comparable to rates charged for similar services in urban areas."

[129] California and Pennsylvania enacted such provisions. Maryland set up a $34 million annual low-income assistance program, mostly for direct assistance and with some 10% for weatherization.

monthly rate of all residential telephone users) have been retargeted to apply only to low income customers.[130]

b) Taxpayer funding in the form of direct grants from federal and state governments. However, the federal program reached its peak in 1986 at some $2.1 billion and before declining to about half of that amount in 1998 and rebounding to $1.9 billion in FY2004, an amount worth less than half of the 1986 peak when adjusted for inflation.[131]

c) Mitigation in the form of weatherization assistance. Special energy efficiency assistance has amounted to 10-15% of the assistance available to low income people. Especially when accompanied by a sufficient public education effort, such assistance produces benefits that can last for many years.

d) Another, more controversial mitigation undertaking in the electric sector has been the introduction of load-limiting or prepayment meters, devices that either limit the amount of energy that can be consumed in a month or require that a prepaid card like a telephone card be inserted in the meter before electricity will flow. These have met with considerable resistance in the U.S. Low income advocates have argued that they are discriminatory and are not cost-justified under the conditions that exist in the U.S. system, where widespread non-payment is neither an impediment to utility financial integrity nor a deterrent to extending service to unserved areas. This approach is unsuitable for the gas industry because of the need for service reestablishment to be done by professionals.

e) Customer education has been important to many aspects of electric restructuring, but particularly with regard to the impacts on low-income people. All the assistance programs mentioned above are enhanced by a significant public education effort. Energy efficiency achievements increase, disconnections and late payments decrease, and low-income customers are less vulnerable to unscrupulous marketing. Utilities have begun in recent years to recognize that disconnection — however necessary as an occasional tool to discourage non-payment — is not a collection success but a collection failure in that a disconnected customer is less likely to pay than one who is able to remain on the system under a restructured payment obligation.

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[130] Because the entitlement to such assistance has been based on enrollment in other assistance programs, use of the data bases from those programs has substantially reduced record-keeping and verification expense.

[131] http://www.acf.hhs.gov/programs/liheap/approp.htm.

f) Reducing the commitment — In at least one area (line extension tariffs), restructuring has had the effect of causing substantial price increases. Utility willingness to extend wires substantial distances in the name of universal service has come to an end, and line extension fees have risen dramatically. In the U.S., this has had significant impact on local land-use planning processes. In countries with substantial areas that do not yet have service, reducing the subsidy for extensions of service are certain to be more controversial. Adjusting the subsidy to reflect the real costs of extending service according to a least-cost plan will in any case be necessary to maintaining the financial integrity of the utility.

In light of the above, one can formulate some generic principles to assure that restructuring programs do not unduly disrupt the social welfare considerations woven into existing utility systems in Latin America. First, no program of tariff increases and customer disconnections should go forward under circumstances in which poor customers are likely to be disconnected because they cannot pay the cost of a reasonable amount of electricity and/or gas. Second, subsidy systems should be reformed to extend support primarily to those who need it. Often, the removal of subsidies from those who can afford to pay coupled with a firm collection policy will bring in enough money to offset the cost of such a program. Where such funds are not likely to be freed up promptly by reform measures, this is an especially promising area for donor assistance in order to eliminate a strong source of resistance to sectoral reform.

Third, any reform program that includes customer disconnections must be preceded by a careful program to assure that payment information is accurate. Disconnection of customers who have fully paid their bills is certain to undermine the credibility of the entire reform process and cannot be tolerated. Until metering and collection procedures have reduced the likelihood of mistaken disconnections to a level to which the regulatory agency can quickly respond, an aggressive disconnection program will be counterproductive.

7.4 Employment impacts

With the onset of competition, utility managements for the first time had to examine their payrolls aggressively. In theory, regulation should have assured that the staffing and salary levels in the U.S. utility industry were no higher than necessary. In fact, regulators rarely had the resources or the information to perform this task well. When they sought to do so, the political repercussions were likely to be formidable. Consequently, staffing and pay levels in all of the U.S. regulated monopoly industries came under intense pressure once competition displaced regulation.

The International Brotherhood of Electrical Workers estimates that jobs in the electric sector declined by 27% in the first five years after California announced its decision to establish retail choice. In the face of this pressure, utility workers and utility investors became allied in a formidable coalition opposed to retail choice unless their interests first were safeguarded.

Here again, the non-bypassable charge has been a favoured vehicle for financing the transition costs. The California Competitive Transition Charge, for example, includes the retraining and severance costs incurred in the first four years of retail competition. The Connecticut restructuring law also provides explicitly that such costs are to be included in the transition charge.

The collaborative nature of the restructuring process assisted consumer groups and labour unions in discovering their common interest in maintaining high service quality standards. For the customers, the reasons were self-evident; for the workers such standards were a safeguard against rapid downsizing with its potential for reduced reliability and increased customer complaints. This linkage was driven home to regulators when several telephone companies experienced substantial delays in key customer service indexes as a result of excessive workforce reductions in the mid-1990s.

7.5 Nuclear power and power plant safety

Those Latin American countries seeking to reconcile nuclear power with competitive markets may want to consider the fact that neither the U.S. nor Canada has seen any interest in building new nuclear units financed by private capital since power supply markets became competitive. Indeed, among democratic countries that generally choose their power supply through transparent and competitive processes only Finland has ordered a new nuclear unit in recent years, and that decision was made outside of competitive market mechanisms.

Although the operating costs of the existing nuclear units have fallen under restructuring, new nuclear plants are too expensive to prevail (or even to bid) in existing markets. All proposals for new units in the U.S. are heavily dependent on government subsidies of several sorts.[132]

Restructuring has also led to concerns that pressure to cut costs or to boost output could compromise safe operation at nuclear power plants. Indeed, the problems at the Millstone nuclear plants in Connecticut in the mid-1990s seem clearly to have originated in just such

[132] See generally John Deutch, Ernest Moniz et al, The Future of Nuclear Power, (MIT, 2003) and Peter A. Bradford, “Nuclear Power’s Prospects in the Power Markets of the 21st Century”, (Nonproliferation Policy Education Center, 2005).

pressure from top management.[133] Economic considerations also played a part in the Nuclear Regulatory Commission's 2001 decision to permit the Davis Besse nuclear station in Ohio to operate beyond a shutdown deadline, a decision that could have proven disastrous because the head of the pressure vessel was – unbeknownst to the plant owners or the NRC – dangerously corroded.[134]

At the same time, other nuclear plants have shown a high correlation between practices that improve safety and practices that increase plant output, and the U.S. Nuclear Regulatory Commission has sought to upgrade its own capability to function in an atmosphere of heightened economic pressure. The U.S. nuclear fleet has increased its output some 35% in the last 12 years without adding any new plants.

Nuclear safety is not a problem that can be solved through a transition charge or other protected revenue stream. As in the airline industry, the need to avoid unlikely but catastrophic accidents is universally accepted, and the safety margins are large. Whether economic pressure compromises them at some sites is unknowable in the short run, though one would eventually expect to see an increase in what the NRC terms "precursor" events like the Davis Besse problem if safety is being compromised.

7.6 Rate shock

As noted earlier, both legislatures and regulators implementing restructuring have generally sought to avoid rate increases to any class of customers and have tended to endorse equal distribution of the savings among customer classes. This concern has less to do with universal service than with public acceptance of restructuring. Because U.S. restructuring has come during a time of declining costs, most utilities have been able to commit to long-term freezes, often coupled with substantial reductions. The largest rate reductions have tended to go to large users, but this is less controversial when all customers are getting rate reductions.

Since most restructuring laws require that no class of customers receive an immediate rate increase, rate shock of the sort being experienced in other parts of the world has only been

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[133] The Millstone problems predated Connecticut's restructuring law. However, the reality of wholesale competition and the prospect of customer choice were already creating substantial pressure to cut costs.

[134] "The fact that (the licensee) sought and staff allowed Davis-Besse to operate past December 31, 2001, without performing these inspections was driven in large part by a desire to lessen the financial impact on (the licensee) that would result from an early shutdown", "NRC's Regulation of Davis Besse Regarding Damage to the Reactor Vessel Head", NRC Inspector General, December 30, 2002, p. 23.

experienced in California, Alberta and Ontario. Some cross-subsidies may have occurred in order to make the overall restructuring politically acceptable, but this effect is not large, if it exists at all.

The combination of the capped overall rate and substantial stranded cost recovery has created situations where what is called the "supply price" is really a regulated artefact – the difference between the cap and the charge for stranded cost recovery plus the cost of transmission and distribution. This number, which is not really a "price" at all, is often too low for a competitor (who must pay a real supply price) to be able to meet, especially to smaller customers.[135] Consequently, the decision to emphasize rate stability has meant a decision to defer customer choice, especially for residential customers, until the time when the cap is gone, stranded costs are paid off and prices can reflect the actual costs of acquiring a power supply.

7.7 Other social impacts

A number of other social impacts have accompanied the introduction of retail competition in the U.S. electric sector. They fit the general pattern of expenditures that competitive conditions will not support. As such, they have had to be supported or mandated in other ways. This section treats them together because they are less significant than the ones discussed above.

In dollar terms, the largest of these items by far is the impact on tax collections. Under restructuring, taxes are usually based on a plant's market value — which in turn is based on the market value of its output, rather than the amount spent to build it. This change can result in dramatic local revenue shifts. In one instance in New York, a 1000 MW nuclear plant built some time ago by a utility paid a property tax bill 1000 times higher than that of a 1000 MW gas-fired plant built recently by an independent power producer. Such a discrepancy between plants making equal quantities of the same product is not sustainable if the two plants are to compete. However, the impact on local schools and services of cutting the taxes of the nuclear plant by a factor of 1000 would be immense.

Here again the device of a non-bypassable charge has been used to create a fund to permit gradual transitions in some states. In other states, where no such provision was made, substantial

[135] Indeed, even a utility with a rate freeze can prosper if it has a regulatory promise that, when the rate freeze ends, it can collect any "losses" under the cap from its customers, with interest — as is the case in the vast majority of U.S. restructuring settlements. Of course, such freezes are not really freezes at all — if wholesale prices rise, they are deferred rate increases. Only California utilities had no such promise. Their losses were so large that a promise to defer recovery to a later date might not have meant much in any case.

litigation has arisen as costly plants, some of them already closed, demand that communities reduce their taxes to reflect market realities. Some communities with closed nuclear plants have negotiated phase downs of these taxes. Of course, in the case of inexpensive or fully depreciated plants, the property's value may be much higher in a competitive market than under regulation, producing a windfall for the local taxing jurisdiction.

Other social costs that have been counted as transition costs and been reimbursed from non-bypassable charges in some states (or from federal agencies) include gas industry research expenditures and, implausibly, future nuclear capital expenditures (in California and Michigan). Some utilities have announced that restructuring will compel them to re-evaluate their charitable donation policy, but overall charitable donations as a percentage of total revenue has not declined.

Most of the research done at the Electric Power Research Institute is not funded out of non-bypassable charges, and utility contributions to EPRI have declined. As a result, EPRI has had to become more market oriented in its research and in selling itself to potential donors. Direct federal and state research grants in the energy area remain a separate source of revenue.

7.8 Corruption

Nothing contributes more rapidly to public disillusion with reform than a sense that decisions are being influenced illegitimately, through the paying of bribes or by less direct methods.

Before the California energy crisis and the collapse of Enron, the U.S. prided itself on the relative absence of direct corruption in its regulatory processes and in its restructuring. Until those two events, it was possible to assert that the U.S. learned its lessons about the harm that can accompany corrupt and inadequate regulatory processes many years ago, in the utility holding company scandals of the 1920s. As a result of these lessons, reinforced by one or two distasteful episodes per year, usually at the state level, most U.S. regulatory jurisdictions employed a significant array of measures to prevent illegitimate influence. However, it now appears that these safeguards were insufficient to prevent immense harm to customers and investors as well as to public confidence in restructuring.

The extent to which laws were broken remains subject to litigation, but it is now clear that illegal conduct occurred and that other conduct took place that should have been illegal. That said, the U.S. record on regulated energy sector corruption nevertheless remains a relatively good one, reviewed over decades. Even with the recent scandals, its underpinnings are worth understanding, given the extent to which real and perceived corruption haunts restructuring in some nations.

These protections include not only the encouragement of public involvement but measures to assure transparency, measures to assure independence, rules against *ex parte* contact and codes of ethics. At times regulators and participants chafe at the delay and awkwardness imposed by these procedures and at times they violate them. Nevertheless, U.S. regulators have made decisions in the last five years reallocating the flow of tens of billions of dollars in annual revenues with only minor instances of scandal. To those who have worked on restructuring in many nations, this is not a small achievement.

7.9 Integrating national security considerations in the regulatory process

A recurring concern of governments considering the establishment of "independent" regulatory bodies is whether such bodies will follow the national security concerns of the central government in such matter as oil dependence or energy imports. The surest way to assure that they do so is to write such a mandate into the legislation creating a regulatory body. At the same time, experience shows that governments and private litigants have often invoked national security arguments in furtherance of private interests.

No regulatory commission can be expected to reject an unequivocal claim from the competent federal authority that national security requires a particular action as long as that claim is conveyed in a legitimate manner. However, national security claims made by other parties must meet the same challenges and standards of proof as any other claim of public benefit.

7.10 Balancing competition policy and regulatory policy to empower the customer

A fundamental cause of unnecessary restructuring costs and other disappointments in the U.S. and in Canada has been the failure to appreciate the differences between regulatory policy and competition policy. While California and other U.S. states paid substantial attention to the regulatory policies necessary to further restructuring, they paid very little attention to competition policy, i.e., to the detection and deterrence of anticompetitive conduct. To make matters worse, they entrusted the oversight of electric restructuring almost entirely to utility regulatory bodies with little or no experience in bringing competitive markets into being.

As a result, restructuring moved forward with extraordinarily little attention to the measures necessary to assure that effective customer choice would in fact come into being in the markets in which it could theoretically do so. Such measures as divestiture, Pennsylvania's high shopping credit or Maine's discouragement of distribution companies from providing retail services are examples of structural safeguards that were generally ignored in favour of the codes of conduct and after-the-fact policing that experienced antitrust officials warned would not be effective.[136]

Minimum conditions necessary for competitive markets are reasonably well understood. They include:

- At least five sellers, none able to set prices all able to increase output as conditions justify; [137]
- Ease of entry and exit;
- Easy access to necessary market information;
- Equal access across all bottleneck monopoly facilities;
- An effective regulatory presence capable of deterring, detecting and sanctioning anticompetitive conduct; and
- A statutory mandate, in the case of existing monopoly markets, that effective competition be created wherever possible

Such conditions will not arise easily or smoothly in markets that have been dominated by a single company with an exclusive government-granted franchise. Affirmative pro-competition

[136] Joel Klein, the U.S. Assistant Attorney General for Antitrust gave one such warning to the Federal Energy Regulatory Commission, "Finally, based on a century of experience, I would further emphasize that the Department is also highly skeptical of any relief that requires judges or regulators to take on the role of constantly policing the industry. Relief generally should eliminate the incentive or the opportunity to act anticompetitively rather than attempt to control conduct directly. We are institutionally skeptical about code-of-conduct remedies. The costs of enforcement are high and, in our experience, the regulatory agency often ends up playing catch-up, while the market forces move forward and the underlying competitive problems escape real detection and remediation", Making *the Transition from Regulation to Competition: Thinking about Merger Policy during the Transition to Electric Power Restructuring*, FERC Distinguished Speaker Series, January 21, 1998, p. 12.

[137] William Shepherd, *Monopoly and Antitrust Policies in Network-Based Markets such as Electricity*, RPI Symposium on the Virtual Utility (1996).

policies in areas unfamiliar to traditional pricesetting regulators are necessary if retail competition policies are to succeed, and even if viable wholesale markets are to be created.

One example of the need for regulators to become versed in competition policy is the subject of merger reviews. Regulated entities confronted by new requirements to compete invariably respond with a wave of mergers, in part to increase the efficiency of their operations and in part to reduce the number of potential competitors. Such mergers can produce anticompetitive combinations of vertical market power (i.e., ownership of essential transmission and distribution networks by companies also owning generation) or of horizontal market power (i.e. ownership of enough generation or marketing market share to be able to exert market power). Regulators have a tendency to respond to such mergers with detailed codes of conduct that depend on policing activity of a sort that they lack the resources to conduct. Experts in competition policy, by contrast, urge attention to steps that will create effectively competitive market structures that do not depend on extensive and regular policing by regulators.

7.11 The tension between planning and restructuring

As noted earlier, a marked decline in interest in long-term energy planning accompanied the rise of the restructuring movement. The philosophy (or ideology) underlying the move toward competitive markets — that resource decisions should be made not by regulators but by the market itself — was until recently widely believed to be incompatible with long-term governmental planning of any type, much less IRP.

The immediate consequence was that, as restructuring concepts swept the North American energy world in the late 1990s, IRP disappeared from the agendas of conferences and scholarly journals, to be replaced by esoteric discussions of market structure and mechanisms. However, IRP continued to be practiced in a number of U.S. jurisdictions that did not embrace retail competition, including Colorado, Arkansas, Idaho, Michigan, and Minnesota.

Even in some states that have opened their retail markets to competition, planning has remained a real concern. For instance, the state of Nevada continues to require each electric utility to submit a plan every three years concerning increasing supply or decreasing demand on its system. The plan must include load forecasts (three scenarios); plans for conservation, demand-side management and load management (load shaping); analyses of options for supply for twenty years into the future; financial information and assumptions and integration analysis.

The utility is required to establish priorities among its options for demand and supply so that it can determine the minimum costs of providing electricity to its customers. It must also determine its preferred option for resource supply based on lowest cost (present worth of future revenue requirements) but can also include risk avoidance factors in its analysis. If its preferred plan doesn't produce the lowest cost, the utility must set forth the criteria which influenced its chosen plan.

In Canada, British Columbia was the leader in implementing IRP. In the mid 1990s, the British Columbia Utilities Commission issued integrated resource planning guidelines based on a review of best practice in the U.S.[138] In 1996, however, the B.C. experience with IRP came to a sudden halt — though not because of restructuring. Rather, B.C. Hydro mounted a successful court challenge to an order requiring the utility to involve the public in its IRP process.[139]

In fact, the Utilities Commission had attempted to require IRP under legislation that had been adopted long before the concept had even been developed, and which simply did not provide the Commission with sufficient powers to see it through. This problem was avoided in Quebec, however, which adopted regulatory legislation in 1996 that explicitly authorized the new *Régie de l'énergie* to required that the Crown utility Hydro-Québec carry out integrated resource planning under its supervision.[140] However, these resource planning provisions were never applied. In 2000, new legislation removed generation and integrated resource planning from the regulator's jurisdiction.

In the aftermath of the crises that began with the rolling blackouts in California in 2000 and 2001 — and continued with the collapse of Enron, the ongoing investigations into its behaviour and that of other power marketers in California, the collapse of wholesale power prices, the blackout of 2003 and a deepening financing crisis for the entire sector — there is renewed interest in long-term planning.

In B.C., for instance, the Utilities Commission Act was amended in 2003 in order, among other objectives, to give the BCUC a clear mandate to implement to oversee utility planning. In its

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[138] B.C. Utilities Commission, *Integrated Resource Planning Guidelines.* See also P. Raphals. 1995. *Energy in British Colombia: Integrated resource planning and regulation,* Report prepared for the Quebec Natural Resources Department, 98 pp.

[139] When the Commission ordered it to establish a collaborative committee to participate in the planning process, B.C. Hydro challenged in court not only the order, but also the Commission's power to require the utility to submit a long-term plan for approval. The B.C. Court of Appeal decided in favour of the utility, finding that the statute creating the Commission did not authorise it to require integrated resource planning, much less to demand that the public be involved in it. (B.C. Hydro and Power Authority v. B. C. Utilities Commission *et al.,* Court of Appeal for British Columbia, 23 February 1996.)

[140] See section 5.3, above. The Quebec legislation was in large part based on the B.C. experience.

new Resource Planning Guidelines issued in December 2003, the Commission requires consideration of all known supply- and demand-side resources for meeting the utility's projected demand, concluding that:

> a resource planning process that assesses multiple objectives and the tradeoffs between alternative resource portfolios is key to the development of a cost-effective resource plan for meeting demand for a utility's service.[141]

Thus, the California debacle and other recent events have led many observers to think again about the need for planning, even in a market context. It is increasingly recognized that, as long as utilities have an obligation to serve, the need for careful planning remains. However, given the vastly different structure of the electric industry in many areas, risk-management tools are increasingly being called upon to supplement deterministic planning tools.

In this regard, there is increasing interest in the use of regulated portfolio management processes for utilities or default service providers. The National Association of Regulatory Utilities Commissioners (NARUC) describes this concept as follows:

> A utility or default service provider that actively participates in electricity markets and carefully chooses among the wide variety of different electricity products and resources will be able to provide better services to its customers over both the short- and long-term future.
>
> Portfolio management begins with the primary objectives of a utility or default service provider obtaining electricity resources for customers. Providing reliable electricity services at just and reasonable rates will continue to be a primary goal of electric utilities for the foreseeable future. Other objectives include mitigating risk; maintaining customer equity; improving the efficiency of the generation, transmission and distribution system; improving the efficiency of customer end-use consumption; and reduction of environmental impacts and risks. Portfolio management provides a process for utilities to determine and implement the mix of electricity resources that will achieve these objectives to the greatest extent possible.[142]

The Northwest Power and Conservation Council is a leader in this area. Its portfolio management model abandons the implicit assumption of perfect knowledge of the future that has so often led to bad outcomes in the past, offering instead a coherent picture of the tradeoffs between the expected costs of any specific portfolio and the risks it presents. The NWPCC's

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[141] British Columbia Utilities Commission, *Resource Planning Guidelines*, December 2003.

[142] www.naruc.org. A regularly updated list of portfolio management resources can be found at www.naruc.org/displaycommon.cfm?an=1&subarticlenbr=390.

fifth power plan, released in draft form January 2005, represents an important model that will be closely studied in coming years as other regions grapple with these issues.[143]

[143] http://nwppc.org/energy/powerplan/draftplan/Default.htm.

8 Conclusion

Compared to the future promised by restructuring advocates in the late 90s, the reality of the last few years has been decidedly sombre. The California debacle, the Enron bankruptcy, the financing crisis in the merchant generation sector and the 2003 blackout … Even enthusiastic restructuring proponents acknowledge that the real benefits to date have been small and the transition costs have been high.[144]

Some analysts attribute the current chaos in the U.S. electric industry to the jurisdictional split discussed in section 1:

> The basic problem is the split of regulation between the federal government and the states. It is a thoroughly interstate industry, but no one has overall authority to decide what needs to be done. This has resulted in a plethora of incompatible initiatives. What is required is to develop the conceptual framework, make a plan, and to implement the institutional changes necessary to make it happen.[145]

In fact, the ongoing debate over the rightful role of the state and federal governments in governing the gas and electric industries has been both a cause and a consequence of these difficulties in the U.S. Even in jurisdictionally simpler countries like Canada, where the federal government plays only a very limited role in energy regulation, the restructuring experiences of Alberta and Ontario have been fraught with difficulties.

8.1 Wholesale markets

Bringing competition to the real-time pricing of electricity, a commodity for which supply must match demand on an instantaneous basis, is no small challenge. Compared to other auction systems, such as those used for commodities and securities, the "clearing price" auction used in electricity markets has the advantage that, under normal circumstances, it disincents strategic bidding. Alas, normal circumstances do not always prevail.

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[144] Larry E. Ruff, "UnReDeregulating Electricity: Hard Times for a True Believer," Seminar on New Directions in Regulation, Kennedy School of Government, Harvard University, May 1, 2003.

[145] Sally Hunt, "The State of U.S. Electricity Restructuring," *Electricity Journal,* June 2002, p. 12.

The California experience has clearly shown that many forms of gaming can thrive in this environment.[146] Indeed, given the complexity of the rules and the large amounts of money at stake, it can be expected that producers and marketers will constantly seek and find loopholes. In the words of economist Severin Borenstein, "if firms of noticeable size are not exercising market power, they are doing so out of the goodness of their heart, and against the interest of their shareholders."[147]

Even if the market oversight "cats" ultimately prevail over the market manipulating "mice", other important problems remain. The experience of the last five years demonstrates the importance — and elusiveness — of price stability in a competitive market. Not only does the market mechanism need to balance supply and demand on a moment-to-moment basis, it also needs to ensure that prices do not become so high as to provoke a political crisis, and that prices do not fluctuate widely, either in the short or the medium term, as price volatility discourages investment both in power generation and in the rest of the economy.

Given the long lead times and large capital investments required for building generating facilities, it appears that the large cyclical fluctuations — in the supply/demand balance, and hence in price — that we have seen to date are the rule and not the exception. The consequences of this long-term instability for the rest of the economy are important. Ultimately, distributed generation may help to break this cycle.[148] In the meantime, however, it appears that this price instability is an unavoidable feature of competitive energy markets, as it is for most other commodities.

At the same time, it is important to realize that the first phase of the "demonopolization" of the electricity sector was a clear success. Described as the "third restructuring" in the overview to this report (page 6), the adoption of PURPA in the United States in 1979 made it possible for non-utility generators to obtain long-term contracts to serve utilities' loads. For all the differences of opinion that exist as to the way forward, one would be hard pressed to find a voice calling for a return to the world where only utilities could generate electricity.

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[146] The strategies implemented by Enron to inflate market prices during the California crisis are described in FERC, *Initial report on company-specific separate proceedings and generic reevaluations, published natural gas price data and Enron trading strategies,* Docket no. PA02-2-000, August 13, 2002, pp. 78-101. http://ferris.ferc.gov/idmws/common/opennat.asp?fileID=9548231.

[147] "Electricity Restructuring: Deregulation or Re-regulation?" (February 2000), p. 9, quoted in Michael Kahn, Chairman, California Electricity Oversight Board and Loretta Lynch, President, California Public Utilities Commission, California's Electricity Options and Challenges: Report to Governor Gray Davis (2 August 2000).

[148] If small-scale generation were eventually to represent a significant portion of new supply, the supply curve would be much less lumpy and these fluctuations would tend to flatten out.

These developments have conclusively demonstrated that the generation of electric power and the supply of natural gas are not natural monopolies, and that substantial economic benefits are available from introducing competition. Considerable care must be paid, however, to ensure that appropriate safeguards are in place before regulatory controls are lifted. Competition must precede or accompany deregulation, not bounce hopefully along in its wake. Furthermore, because of environmental and other externalities, continued regulation may still be justified, even when it is not necessary for economic purposes.

The impact of restructuring on energy efficiency and on renewable energy has been both worse and better than originally foreseen. Worse, because competition has not produced the anticipated expansion of load management and efficiency investments driven by enhanced customer awareness and competitive marketing. Better, because environmentalists have shown opportunistic astuteness in trading their blessing for restructuring settlements for commitments to invest in appreciable quantities of efficiency and renewables that would otherwise not have been built. Of course, these investments have nothing to do with emerging markets. Indeed, they were achieved by means of traditional regulatory tools, not through competition. However, the benefits to the utilities and the large customers in the restructuring settlements did expand the size of the opportunities available in the collaborative bazaars.

In the medium term, competitive wholesale markets, where they already exist, can be expected to continue to evolve and improve, with continued progress in transmission pricing and governance, market monitoring and the incorporation of demand response. However, expansion of these markets into states and provinces that have not embraced them seems certain to be much slower than proponents would have wished.

8.2 Retail markets

The other great challenge of the fourth restructuring — customer choice — remains highly problematic. Retail customer choice has clearly provided benefits to large customers — though much of this has involved shifting sunk costs to customers without choice, to utility stockholders or to taxpayers, and therefore cannot be said to have furthered economic efficiency. A number of other benefits, such as increased attention to cost containment, occurred more in contemplation of retail choice than as a response to the real thing.

But for smaller customers, choice among providers has been elusive. They confront a world of competition without competitors, markets without marketers, customer choice without alternatives. For them, franchise competition in the form of standard offers has been substituted for actual customer choice. Exercise of market power against customers and competitors — sometimes even suppliers — has been frequent. Outright abuse in California exceeded the darkest nightmares of restructuring opponents, while costing California alone more than the FERC estimates of nationwide benefits from its restructuring orders to date.[149]

As a result, retail competition is presently stymied in both the U.S. and in Canada. The further expansion of retail customer choice in electricity is not certain unless and until benefits for larger classes of customers can be shown.

In some measure, this slowing is healthy. But it also reflects a decisional process that did not secure the customer benefits of reform with the same vigour, detail and precision that it secured the benefits to the utilities, to the new power producers and to the larger customers. The triggering of such benefits as stranded cost recovery could have been contingent on the occurring of actual customer choice.[150] Had this been done, a much fairer and — in all likelihood — more expeditious process would have resulted.

This mistake is sufficiently clear in hindsight that no other nation need repeat it.

8.3 Looking ahead

For countries trying to decide the future course of their electric power industries, a number of lessons seems clear from the U.S. and the Canadian experience. Here we highlight the most important points from the history set forth above:

1) No one model is so obviously "correct" that all countries should adopt it. Supporters of government ownership, of vertical integration, of wholesale competition and of full retail customer choice can all find support for their preferences in the developments of the last decade.

2) Nevertheless, the case for maintaining vertically integrated monopoly seems weak. Experience in North America and throughout the world makes clear that competition in the building and operation of power plants (and the supply of natural gas) can produce

[149] Of course, most of California's flawed market design arose from choices made not by FERC but by the state — albeit under FERC's mandate and with its approval.

[150] Such a relationship was established in the U.S. Telecommunications Act of 1996, which established a checklist of competition policy findings that had to precede any entry into long distance markets by a major local telephone service provider.

efficiencies that have almost always eluded regulation and government ownership in those activities.

3) Markets, however, will not safeguard governmental priorities regarding the environment, the furtherance of competition, national security and assuring universal service will not be safeguarded by the free market. Governmental standards and oversight remain essential to furthering these ends. Such oversight will be most effective if it takes forms compatible with market mechanisms, for example the use of cap-and-trade pollution control approaches or renewable set-aside auctions rather than a governmental mandate or subsidy for a particular technology.

4) Markets and conventional regulatory tariff policy will also not assure that energy efficiency achieves its potential in assuring the lowest possible national energy bill. The reasons for this are set forth in Section 3.1.2.2. In developing countries, the importance of energy efficiency in reducing the future costs and environmental impacts of the energy sector is potentially very large, so governments should be alert to the necessary tariff and policy modifications necessary to assuring that all cost effective energy efficiency is implemented.

5) Where regulation is undertaken, there is no substitute for capable regulators with experience in relevant areas of technology, economics and law, as well as in involving the public in major decisions. Strong laws, adequate resources and effective enforcement are also essential, but mediocrity on the regulatory commissions guarantees that reform will be far more difficult and expensive than necessary, if it occurs at all.

6) In larger countries, a jurisdictional allocation that allows both for the imposition of national priorities and for decisions to be made as closely as possible to the areas and people on whom the impact will be greatest is desirable, as is the opportunity for different regions to experiment with different models. Ideally, jurisdiction will be divided between large regions and the nation as a whole, with the national regulator pre-empting regional decisionmaking only when a stalemate of some sort occurs or when a clear need for a uniform national policy exists.

7) Energy sector reform involves a great deal of trial-and-error, so flexibility and the ability to change direction are important. However, there is a tension between such flexibility and the stability of policy required by investors if they are to commit the capital necessary to developing needed energy infrastructure. This tension is best resolved by policies that assure the recovery of capital committed in good faith and spent prudently when it is endangered by changes in government policy. The allocation of different types

of risk between investors, customers and governments needs at all times to be clear and to be adhered to.

8) Where governments do seek to further competition, they need to be aware of the distinction between competition policy (called antitrust in the U.S.) and regulatory policy. Regulatory commissions in the U.S. have shown no particular expertise at furthering competition because competition was not part of their historic mission. If a country expects its regulators to further competition, it should make this mission clear in the law and should keep it in mind when choosing the regulators. It should also provide for an active role in the regulatory process for its antimonopoly agency. Areas of particular concern include merger review, transactions among corporate affiliates and review of market structures and market rules.

9) Effective involvement of the public at all stages of the energy sector reform process is essential to avoiding the collisions between energy sector reform and democratic governance that have often sidetracked energy sector reform throughout the world in the past. Whatever the shortcomings of the U.S. and the Canadian experiences, they do illustrate many of the mechanisms through which the public may have a voice in energy sector policymaking in ways that enhance transparency and reduce the opportunities for the corrosive alienation fostered by constant corruption in the electric and gas systems of most of the world.

BIOGRAPHICAL NOTES

Philip Raphals. Executive Director and cofounder of the Helios Centre, an independent, non-profit energy research group, Mr. Raphals has extensive experience in many aspects of sustainable energy policy, including least-cost energy planning, competitive market design, utility regulation, transmission ratemaking and green power certification. He is the author of numerous studies and reports and has provided expert testimony in numerous regulatory proceedings. Mr. Raphals has explored in detail the interaction between competition and regulation as well as the environmental implications of electricity trade. He is also an authority in the area of hydroelectricity and the environment, and has authored a major study on the issue entitled *Restructured Rivers: Hydropower in the Era of Competitive Energy Markets* (2001). He holds degrees from Yale University and from Boston University.

Peter Bradford has chaired the New York State Public Service Commission and the Maine Public Utilities Commission, has served as President of the National Association of Regulatory Utility Commissioners, and was a member of the U.S. Nuclear Regulatory Commission from 1977 until 1982. A graduate of Yale University and Yale Law School, Mr. Bradford has written many articles on utility regulation and nuclear power, and authored the book *Fragile Structures: a Story of Oil Refineries, National Security and the Coast of Maine*. He teaches Energy Policy and Environmental Protection as a Visiting Lecturer at Yale and advises and teaches on utility regulation, restructuring and energy policy in the U.S. and abroad. He was a member of an International Expert Panel advising the European Bank for Reconstruction & Development on least cost alternatives to continued operation of Chernobyl, and serves on the Policy Advisory Committee of the China Sustainable Energy Project of the Packard Foundation.