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LEARNING FROM THE STORM: LESSONS FOR ILLINOIS FOLLOWING CALIFORNIA'S EXPERIENCE WITH ELECTRICITY RESTRUCTURING

WILLIAM A. BORDERS*

INTRODUCTION

The transition of California's electric industry from a regulated structure to a market-based environment can be likened to *The Perfect Storm*, a popular book and motion picture about the confluence of three powerful storms off the coast of Nova Scotia in 1991.¹ California's restructuring storm was not based on the convergence of meteorological conditions, but instead on a confluence of shortsighted market design, poor timing, and limited supply. The storm lasted through the summer of 2000 and the spring of 2001, leaving in its path three multibillion dollar utilities on the brink of bankruptcy, state agencies scrambling to triage a state-wide energy crisis before the electrical demands of the California summer and, ultimately, a remarkable historical and educational milestone in the annals of deregulation.

California was not the first state to open its electricity markets to competition.² Nonetheless, with annual electricity expenditures approaching \$23 billion³ and the largest population in the country,⁴

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1. SEBASTIAN JUNGER, *THE PERFECT STORM* (1999); *THE PERFECT STORM* (Warner Bros. 2000). See E-mail from Kenneth Rose, Senior Institute Economist, National Regulatory Research Institute, Ohio State University, to William Borders (Feb. 5, 2001, 11:05 CST) (on file with author) (analogizing California's energy restructuring to *The Perfect Storm*).

2. New Hampshire was the first state to introduce electricity market restructuring. RICHARD F. HIRSH, *POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN UTILITY SYSTEM I* (1999).

3. CAL. PUB. UTIL. CODE § 330 (West Supp. 1997) as amended by stats. 1986, c. 854 (AB 1890, § 10).

4. See U.S. Census Bureau, *State and County QuickFacts: California*, at <http://quickfacts.census.gov/qfd/states/06000.html> (last modified July 3, 2001).

California's experience provides other states with a powerful example of what to avoid before and during the move to a dynamic electricity market.

The factors behind California's rocketing electricity price, from a low of thirty-five dollars per megawatt hour ("MWh") in the spring of 2000 to a high of \$1400 per MWh in December 2000, are many and complex: the inability to build sufficient supply to meet rapidly growing demand, unusually warm weather, high natural gas prices, reduced electricity imports, transmission constraints, limited demand response,⁵ and a lack of long-term contracting all contributed to tight market conditions and upwardly spiraling prices.⁶

Though replicating the convergence of so many factors would be virtually impossible, the lessons learned from this crisis can help any state in its restructuring efforts. As Illinois makes its comparably slow transition to open electricity markets, it should evaluate its goals and strategies for a new market structure in light of mistakes made by other states.⁷ Two obstacles that could create inefficient market operation in Illinois are: (1) the impact of transmission constraints and subsequent market power concerns, and (2) the need for consumer demand response measures and education programs.

Part I of this Note gives a brief history of electricity regulation and the move from monopoly to competition. Part II discusses the structural components of California's and Illinois's electricity markets since restructuring. Part III highlights some of the key developments in California's recent energy troubles, and briefly considers how expanded transmission and demand response measures may have lessened the impact of the crisis. Part IV considers the unique challenges for Illinois's electricity market and recommends new federal and state transmission policy to complement heightened demand response and consumer education programs.

The Note concludes that regulators should not protect customers from market volatility, but instead should ensure that the market is

5. Demand response refers to conservation measures that allow the consumer to save energy and money by tracking usage and cost of electricity at periods throughout the day. For a detailed description and analysis see *infra* Part IV.

6. See *infra* Part IV.

7. "[T]he failure of people to take this [California electricity restructuring issue] seriously and the public officials to really focus on this when they had the opportunity has brought us to this point. . . . [T]here's collective amnesia on the part of a lot of folks that there were problems last summer." *Electric Policy Committee Meeting: The California Energy Crisis and Its Relevance to Illinois: Hearings before the Illinois Commerce Commission* 31 (Feb. 8, 2001) [hereinafter *Hearings, February 8, 2001*] (testimony of Jerry Keenan).

able to send appropriate price signals and that customers have the necessary means to respond to market price information. Once provided with adequate transmission, pervasive demand response technologies, and a heightened understanding of the structure of electricity markets, consumers will have the tools necessary to purchase electricity from diverse suppliers, react quickly to market fluctuations, and stimulate a vibrant power market at both the wholesale and retail levels.

I. THE MOVE FROM MONOPOLY TO COMPETITION

The three primary components of electricity infrastructure systems—generation, transmission and distribution⁸—are being redefined in the United States. The role of generation, transmission, and distribution are becoming more dynamic and market-driven as regulated electric monopolies shed their vertically integrated structures and reinvent themselves for the competitive marketplace.

A. *Electricity: A Unique Commodity*

Though other industries, like airlines and telecommunications, have successfully made the transition from a regulated to market environment, electricity has certain characteristics that make handling it as a traditional commodity particularly challenging. First, electricity is very difficult and costly to store. This means that once generated, electricity must be used immediately or lost to waste. Just as an empty seat on a commercial airplane is pure waste once the plane is in the air, electricity produced and not used is unrecoverable.⁹ Second, the physics of electricity, combined with the difficulty in forecasting potential demand, make it critical that a surplus of power runs through the nation's transmission lines at all times. A simple break in power supply on one line can set off a chain of failures and black out an entire region if not controlled.

8. Generation involves the production of electricity and can take any number of forms using mechanical or solid state technology. Transmission involves the transportation of electricity at a high voltage to distribution facilities. Once the electricity has reached its destination, the voltage is reduced and the distribution process begins. Edison Elec. Inst., *How Does the System Work?*, at <http://www.eei.org/future/reliability/how.htm> (last visited Oct. 4, 2001).

9. See Severin Borenstein, *The Trouble with Electricity Markets and California's Electricity Restructuring Disaster*, 16 J. ECON. PERSP. (forthcoming Winter 2002) (manuscript at 5, available at <http://www.haas.berkeley.edu/~borenste> (last visited Oct. 5, 2001)).

Lastly, the cost of electricity does not generally fluctuate with demand.¹⁰ Though one of the common goals of electricity restructuring is to develop a market with a strong correlation or “elasticity”¹¹ between electricity supply and demand, most electricity prices in the United States are quite static, or inelastic.¹² Consumers typically pay a flat rate for electricity and therefore do not have an idea of the true cost of producing that power. Without price signals between supply and demand, operators of transmission and generation systems are forced to provide a significant amount of excess capacity “just in case.” Further, electricity’s integral role in our society creates a level of reliance unlike the reliance on airline or telephone service, for example. We do not call our congressperson when there is not a discount seat on a Friday afternoon flight,¹³ or when we get a busy signal. But when it comes to electric power, a “busy signal” takes the form of a blackout.¹⁴ Therein lies the challenge of exposing electric power, a vital community asset, to the forces of the marketplace.

B. Federal Legislative Development

The move to open electricity markets continues to be a gradual process. Over three decades, Congress has set the stage for today’s nationwide restructuring movement. This Section discusses the

10. Most consumers in the United States still pay a fixed price for electricity that has no relation to the amount of electricity actually used. In fact, the price for that electricity is typically determined months before any consumption occurs. Eric Hirst, *Price-Responsive Retail Demand: Key to Competitive Electricity Markets*, PUB. UTIL. FORT., Mar. 1, 2001, at 34.

11. “Elasticity is the ratio of the relative change in a dependent variable to the relative change in an independent variable.” Donald Watson, *Elasticity*, ENCYCLOPEDIA OF ECONOMICS 329 (Douglas Greenwald ed., 1982). Used here, elasticity refers to a customer’s flexibility in seeking alternative suppliers from which to purchase wholesale electricity. If the consumer needs to make the purchase and the market has few suppliers then the customer has limited choice. Without flexibility in price, the demand is inelastic. JAMES B. BUSHNELL & FRANK A. WOLAK, REGULATION AND THE LEVERAGE OF LOCAL MARKET POWER IN THE CALIFORNIA ELECTRICITY MARKET 3 (Program on Workable Energy Regulation, Working Paper No. PWP-070, 1999), available at <http://www.ucei.berkeley.edu/ucei/PDF/pwp070.pdf>.

12. One of the common gains expected to come from restructuring is an overall reduction in wholesale price by exposing consumers to the volatility of the market. If a person experiences high prices for electricity during peak periods then that person is likely to use less electricity during that period. Decreased electricity use during peak periods allows the generator to incur fewer expenses and therefore charge less for the electricity used. *Hearings, February 8, 2001, supra* note 7, at 53 (testimony of Charles Stalon).

13. Borenstein, *supra* note 9, at 5.

14. *Prepared Testimony for the Oversight Hearing: California’s Electricity Crisis and Implications for the West, Before the S. Comm. on Energy and Natural Res.* 3 (January 31, 2001) [hereinafter *CERA Senate hearing*] (testimony by Laurence J. Makovich, Senior Director, Cambridge Energy Research Associates).

relevant federal legislative provisions, their original intent, and how each helped further the progress of electricity restructuring.

1. Public Utility Regulatory Policy Act (PURPA)

The electric utility industry, historically staid in its design and operation, was first given a taste of competitive markets in 1978, with the passage of the Public Utility Regulatory Policy Act (“PURPA”).¹⁵ Drafted in the wake of the 1973 oil embargo,¹⁶ PURPA was designed to help minimize high energy prices, economic stagnation, and dependence on the foreign suppliers of petroleum that had dominated domestic energy concerns in the early 1970s.¹⁷ The act sought to promote domestic energy self-sufficiency and outlined requirements for energy conservation and efficiency.¹⁸

Though designed to stimulate the use of efficient and nontraditional power production within the regulated market system, three of PURPA’s provisions helped prepare the United States for electricity competition.¹⁹ First, PURPA encouraged the development of small power production plants and cogeneration²⁰ by requiring utilities to purchase power produced by small generators or qualifying facilities (“QFs”)²¹ and to pay them an “avoided cost”²² for that power. To encourage entry into the supply market, PURPA did not require most QFs to submit to the traditional ratemaking²³ process or to

15. Public Utility Regulatory Policy Act, Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended in scattered sections of 16 U.S.C.).

16. The members of the Organization of Petroleum Exporting Countries (OPEC) imposed the embargo for five months in response to Western nations’ support of Israel in the October 1973 war. HIRSH, *supra* note 2.

17. Richard F. Hirsh, *The Spur to Competition and Utility Restructuring*, ELEC. J., Aug. 1999, at 2.

18. *Id.*

19. HIRSH, *supra* note 2, at 71.

20. Cogeneration is the use of waste heat energy, both to heat adjoining buildings and run turbines to generate electric power. Edison Elec. Inst., *Fuel Diversity*, at http://www.eei.org/future/fuel_diversity/fuels.htm (last visited Oct. 5, 2001).

21. A qualifying facility is a small power producer or cogenerator that qualifies under PURPA to provide electricity to regulated utilities that are required to purchase that power at a state-approved price. Such generators include power producers that use renewable and alternative energy resources such as hydropower, wind, solar, geothermal energy, biomass, municipal solid waste, or landfill gas to generate power. Energy Info. Admin., *Glossary*, at http://www.eia.doe.gov/glossary/glossary_qr.htm (last visited Dec. 3, 2001).

22. Avoided cost is the incremental cost a utility would incur to produce power itself equivalent to an amount of power purchased from cogenerators or small power producers. Nat’l Ass’n of Regulatory Util. Comm’rs, *Glossary of Regulatory Terms*, at <http://www.naruc.org/resources/glossary.html> (last visited Dec. 3, 2001).

23. Under the traditional relationship, utility rates to customers are determined by way of a rate-making process overseen by a state’s Public Utility Commission. These regulatory agencies

federal and state regulations required for larger producers.²⁴ Utilities entered into long-term, fixed contracts with the QFs to hedge against an expected increase in electricity costs. These contract prices held for decades, and, to the disappointment of utilities, proved to be much higher than the steady decrease in energy costs that followed PURPA's enactment. Ultimately, the QF contracts would serve as a primary rallying point for the utilities' sponsorship of restructuring legislation.²⁵

Second, PURPA amended the Federal Power Act to require utilities to allow the transmission of power from other generators across their transmission and distribution lines.²⁶ Overseen by the Federal Energy Regulatory Commission ("FERC"), the mandate for wholesale interstate transportation of power would prove to be a significant step in the long road toward electric market competition. This "open access" provision signaled the potential for markets to move from a regional distribution structure to an electricity market run on a nationwide grid.²⁷

Lastly, PURPA incorporated progressive "load management" techniques that supported the implementation of "any technique . . . to reduce the maximum kilowatt demand on the electric utility."²⁸ More commonly known as demand-side management or demand responsiveness, these techniques found their first federal validation in PURPA and continue to be a key factor in regulatory policymaking and market activity today.

2. Energy Policy Act of 1992

Wholesale electric competition was given additional support through the Energy Policy Act of 1992 ("EPAAct").²⁹ The Act was intended to spur the domestic production of energy and encourage its more efficient use with the goal of lessening the country's dependence

use supply, demand, and operations data gathered from a previous year to gauge whether to adjust utility rates. FRED BOSSELMAN ET AL., *ENERGY ECONOMICS AND THE ENVIRONMENT* 718 (2000).

24. *Id.*

25. Bernard S. Black & Richard J. Pierce, *The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry*, 93 COLUM. L. REV. 1339, 1348 (1993).

26. 16 U.S.C. § 210 (1998).

27. "Grid" is a colloquial term for the electric system linking transmission lines both regionally and locally. Cal. Indep. Sys. Operator, *Glossary of Terms*, at <http://www.caiso.com/aboutus/glossary/index.html> (last visited Sept. 4, 2001).

28. 16 U.S.C. § 115(c) (1998).

29. HIRSH, *supra* note 2, at 239.

on foreign oil.³⁰ Emphasizing the use of the free-market to achieve its objectives, the EPAct allowed even independent electricity suppliers, which did not qualify under the terms of PURPA,³¹ to sell electricity.³² The EPAct also expanded FERC's authority regarding wholesale "wheeling"³³ and permitted generators to deliver electricity to retail customers.³⁴ With these delivery mechanisms in place, industry restructuring was easily within view.

3. FERC Order No. 888

The final legislative push toward competition in the electricity industry came by way of FERC Order No. 888, effective July 1996.³⁵ Simply, FERC's goal was "to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower-cost power to the Nation's electricity customers."³⁶ The order requires public utilities that own, operate or control interstate transmission facilities to file terms and conditions for providing service to power suppliers transporting electricity across their wires.³⁷ In other words, the federal government gave its blessing for electricity restructuring, but left the states to develop individual strategies for implementation. Though initially challenged, the order was upheld,³⁸ and has opened the way for restructuring legislation in twenty-five states.³⁹

30. *Id.* at 240.

31. Independent power producers that were too large to fit within the exemptions of PURPA were subject to Securities and Exchange Commission reporting regulations imposed by the Public Utilities Holding Company Act. The EPAct qualified these producers as exempt wholesale generators. BOSSELMAN, *supra* note 23, at 732.

32. HIRSH, *supra* note 2, at 243.

33. Wheeling is the process of sending electricity from one utility to another wholesale purchaser over the transmission lines of an intermediate utility. Nat'l Ass'n of Regulatory Utility Commissioners, *supra* note 22, at <http://www.naruc.org/resources/w.html> (last visited Dec. 3, 2001).

34. Hirsh, *supra* note 2, at 243.

35. 61 Fed. Reg. 21,540, F.E.R.C. Order No. 888.

36. *Id.*

37. *Id.*

38. Transmission Access Policy Study Group v. F.E.R.C., No. 97-1715, 2000 WL 762706 (D.C. Cir. June 30, 2000).

39. See Energy Info. Admin., *Status of State Electric Industry Restructuring Activity as of August 2001*, at http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html (last visited Sept. 4, 2001).

II. RESTRUCTURING IN CALIFORNIA AND ILLINOIS

This Section provides an overview of the structural components of California's and Illinois's restructuring efforts, including each state's transmission and trading organizations, rate structure and legislative restructuring acts.

A. *California's Restructuring Components*

The California state legislature began restructuring its electricity market in 1996, when it passed Assembly Bill 1890, commonly known as A.B. 1890. The intent of A.B. 1890 was to create a market structure that "provides competitive, low cost and reliable electric service."⁴⁰ From that point on, the once-monopolized state market for electricity began a move toward competition. Consumers large and small awaited the prospect of savings through competitive choice, and through the kind of technological advancements in products and services experienced in the deregulated telecommunications market.

Assembly Bill 1890 established two regulatory bodies: the Independent System Operator ("ISO") and the Power Exchange ("PX") that would control the daily transmission and purchasing of power, respectively.⁴¹ It also provided strong financial incentives for the divestment of generation within utilities that had previously been vertically integrated.⁴² So while utilities retained a stake in the transmission and distribution business, regulated by FERC and the California Public Utilities Commission, respectively, the generation side of the utility's business was fully deregulated and subject to market forces.

1. The Independent System Operator

The California Independent System Operator ("ISO") is a nonprofit corporation created under A.B. 1890 to serve as a traffic control center for California's long-distance, high-voltage power lines.⁴³ The primary purpose of the ISO is to ensure the reliable and safe delivery of electricity while guaranteeing that all generators,

40. CAL. PUB. UTIL. CODE § 330 (West Supp. 1997) as amended by stats. 1986, c. 854 (AB 1890, § 1(a)).

41. *Id.* § 1(c).

42. *Id.* § 390(c).

43. Cal. Indep. Sys. Operator, *Frequently Asked Questions*, at <http://www.caiso.com/aboutus/infokit/FAQ.html> (last visited Sept. 4, 2001).

utilities, and marketers have the opportunity to deliver electricity over the state's electric power grid.⁴⁴ The ISO's management of the electric grid includes managing day- and hour-ahead schedules, performing real-time balancing⁴⁵ of load and generation, settling real-time imbalances,⁴⁶ maintaining scheduled interchanges with other control areas, administering congestion management protocols, maintaining the frequency of the electric power system, and ensuring that sufficient levels of power are generated.⁴⁷

2. The Power Exchange

The California Power Exchange⁴⁸ was a nonprofit corporation that oversaw the operation of the California electricity market and ensured that all participants had equal access to sell and purchase within that arena.⁴⁹ Overseen by FERC, the now defunct PX facilitated transactions within the new market by determining the price of electricity in day-ahead⁵⁰ and hour-ahead⁵¹ markets according to the demand and supply bids of the PX market participants.⁵² Based on bids for generation and demand, the PX set a market-clearing price at which all the bids for the day were bought and sold.⁵³ Assembly Bill 1890 required the three largest vertically integrated

44. *Id.*

45. Real-time balancing requires that the ISO operator make adjustments to ensure that the amount of electricity being consumed within a certain area is equal to, or "balances" with, the amount of electricity being supplied to that area. RICHARD MATHIAS, ILL. COMMERCE COMM'N, REPORT OF CHAIRMAN'S ROUNDTABLE DISCUSSIONS RE: IMPLEMENTATION OF THE ELECTRIC SERVICE CUSTOMER CHOICE AND RATE RELIEF LAW OF 1997, at 22 (2000).

46. If an electricity supplier schedules more or less than is consumed in a particular area, then the supplier is charged for the difference, or "imbalance," and the costs are settled between the ISO and the supplier according to the utilities transmission tariff provisions. *Id.*

47. California Indep. Sys. Operator, *Frequently Asked Questions*, at <http://www.caiso.com/aboutus/infokit/FAQ.html> (last visited Oct. 5, 2001).

48. The California Power Exchange suspended all trading on January 30, 2001 in compliance with an order from the Federal Energy Regulatory Commission eliminating the requirement that utilities purchase their power needs through the PX. The nonprofit PX filed for Chapter 11 protection on March 9, 2001. See Energy Info. Admin., *Status of State Electric Industry Restructuring Activity as of September 2001*, at http://www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html#CA (last visited Oct. 5, 2001).

49. *Id.*

50. The day-ahead market is a forward market for the supply of electrical power at least twenty-four hours before delivery to buyers and end-use customers. Cal. Indep. Sys. Operator, *supra* note 27.

51. The hour-ahead market is an electric power futures market established one hour before delivery to end-use customers. *Id.*

52. *Id.*

53. *Id.*

utilities to divest of a significant portion of their generation business and to buy and sell all their electricity through the PX.⁵⁴

The required-purchase mandate was intended to provide market stability to the burgeoning PX. Ultimately, however, the requirement that utilities purchase all their power in the PX's short-term market left utilities at the mercy of electricity suppliers who could set virtually limitless prices.⁵⁵ The California ISO claims that generators used their knowledge of the utilities' electricity needs to manipulate the market by withholding supply from the day-ahead market, knowing that any shortage would have to be filled in the next day's volatile and lucrative spot market.⁵⁶

Hoping to stabilize California's turbulent power market, FERC ordered market reform in the state on December 15, 2000.⁵⁷ The order encouraged utilities to enter into long-term contracts for electricity and eliminated the requirement that California's three investor-owned utilities purchase all 40,000 MW of their power needs on the wholesale spot market.⁵⁸ Trade volume in the PX quickly diminished, and the PX shut down its operations on January 30, 2001.⁵⁹ The failure of the PX was a matter of market structure: the transparency that allowed the PX to provide power at equal cost to large and small buyers alike was the very component that allowed sellers to know the maximum price they could exact from a sale.⁶⁰ This factor, coupled with a limited electricity supply, assured that power purchases would always be near the market's cap.

54. These three are: Pacific Gas & Electric, Southern California Edison, and San Diego Gas and Electric.

55. "If you are a distribution company and you are required to satisfy the demands of your customers, and your customers are buying according to the established price, then it makes no difference what the market price is. You have to buy to satisfy that [demand], which means the bidding process, into the Power Exchange, the demand curves that were presented were perfectly vertical, no demand elasticity. . . . Something an economist can't imagine happening but in California they engineered it to happen, and it did." *Hearings, February 8, 2001, supra* note 7, at 49 (testimony of Charles Stalon).

56. Tim Reiterman & Nancy Rivera Brooks, *Energy Overcharge of \$5.5 Billion Is Alleged*, L.A. TIMES, March 22, 2001, at A1.

57. F.E.R.C. Docket No. EL00-95 (Dec. 15, 2000).

58. *Id.*; *FERC Issues Final Order on California's Market Problems: Response is Mixed*, FOSTER ELEC. REP., December 27, 2000, at 2.

59. Cal. Indep. Sys. Operator, *Power Central*, at <http://www.caiso.com/PowerCentral/> (last visited Oct. 5, 2001).

60. *California PX Prepares to End Operations*, FOSTER ELEC. REP., January 31, 2000, at 7.

3. California Rate Structure

California's restructuring legislation, A.B. 1890, was designed to give consumers choice within the electricity market while allowing utilities to recoup capital investments or "stranded costs."⁶¹

To assist utilities in recouping their costs, A.B. 1890 froze retail electricity rates.⁶² The freeze was intended to allow utilities to garner the difference between the frozen rate they collect and their actual costs as a means of paying down stranded asset debt.⁶³ There are several components to the frozen rate: a generation charge,⁶⁴ transmission and distribution charges,⁶⁵ "customer charges,"⁶⁶ and the Competitive Transition Charge⁶⁷ ("CTC"). When the cost of purchasing electricity (generation cost) is low, utilities have no trouble collecting their CTC and paying off debt. However, if the markets have established a higher than expected cost, as in the last half of 2000 and early 2001, then the utility is stripped of its ability to collect the CTC. In other words, if the price of electricity is higher than the frozen price, the utility is not permitted to charge its

61. Stranded costs are capital costs assumed by a utility for the development of infrastructure while regulated that, because of risk, political or other reasons are not be easily recouped within a market environment. BOSSELMAN, *supra* note 23, at 798.

62. CAL. PUB. UTIL. CODE § 330 (West Supp. 1997) as amended by stats. 1986, c. 854 (AB 1890, § 10).

63. Michael Kahn & Loretta Lynch, Cal. Pub. Util. Comm'n, *California's Electricity Options and Challenges: Report to Governor Gray Davis 15* (2000), at http://www.cpuc.ca.gov/published/report/GOV_REPORT.htm#TopOfPage (last visited Oct. 28, 2001).

64. The generation charge is a currently fixed price charged to customers for the purchase of electricity. Of the four billing components, this is the one with the greatest potential for volatility, rising and falling with the variables that typically influence electricity prices (i.e. fuel costs, weather fluctuations, supply and demand). Kenneth Rose, *Open Access Retail Models in Electricity*, Presentation at Camp NARUC 2000: NARUC Annual Regulatory Studies Program (Aug. 7, 2000).

65. The transmission and distribution component of the current pricing structure not only includes the costs of transporting electricity locally and regionally, but also includes the ancillary costs of billing, metering, and maintenance of the electricity infrastructure system. The transportation and distribution of electricity is often referred to as the "wires" business. Though it continues to be regulated by FERC and the California Public Utilities Commission, respectively, the billing and metering elements of the wires business are eventually expected to be open to competition. *Id.*

66. The "customer charges" component of the frozen rate most directly reflects the policy initiatives at the heart of electricity restructuring. Though the CTC may be included within this component, typical charges include costs for programs in conservation and renewable energy, low-income assistance, securitization and nuclear decommissioning. *Id.*

67. The CTC is a flat fee charged to every customer, aimed at recovering "stranded assets" (the capital cost of investments in nuclear plants and some fossil fuel plants that have a less appealing return on investment in a competitive market). This charge also compensates utilities for decommissioning of nuclear plants and the costs of long-term contracts under the Public Utility Regulatory Policy Act ("PURPA"). *Id.*

customers the additional cost. The utility *must* take a loss and cannot pass these added costs to its customers. In California, the consequences of multibillion dollar utilities operating at a significant loss, for even a short period, proved dire.⁶⁸ Compared with California's rush to the starting line, the gradual pace of Illinois's restructuring efforts coupled with its diverse rate structure should allow it to avoid California's pricing problems.

B. Illinois's Restructuring Components

The Illinois Electric Service Customer Choice and Rate Relief Law of 1997, commonly known as the Customer Choice Law, initiated Illinois's entrance into the world of electric competition by making several changes to Illinois's Public Utilities Act.⁶⁹ In October 1999, large industrial and commercial customers were allowed to choose their electric supplier.⁷⁰ Between June and October 2000, certain industrial and commercial customers of the state's largest utility, Commonwealth Edison ("Edison"), were phased in for choice of electric service.⁷¹ Edison has allowed industrial and commercial customers to choose new suppliers and has entered long-term contracts with customers who deem playing on an open market too risky. Next, as of December 31, 2000, all nonresidential customers were able to choose their electricity supplier.⁷² Lastly, the introduction of residential choice,⁷³ the transition that affects the greatest number of customers, will occur in May 2002. This gradual, overall shift to full competition in Illinois is proposed to result in a less traumatic transition with fewer economic casualties.

Unlike California, the Illinois legislature did not require utilities to fully divest of their generating capacity, but instead required a functional separation of electric generation entities from the transmission and distribution ("T&D") divisions of companies.⁷⁴ This policy is intended to relieve a remaining T&D company of a

68. See *infra* Section III.

69. 220 ILL. COMP. STAT. 5/16-101 (2001).

70. Customers with an average electric demand of 4 MW or more or who own ten or more sites that total at least 9.5 MW of demand are treated as large customers. ILL. COMMERCE COMM'N, A CONSUMER'S GUIDE TO ELECTRIC SERVICE RESTRUCTURING, available at <http://www.icc.state.il.us/icc/Consumer/plugin/guide.htm#Phased-in> (last visited Sept. 14, 2001).

71. *Id.*

72. *Id.*

73. 220 ILL. COMP. STAT. 5/16-111 (2001).

74. *Id.* at 119A(b).

temptation to discriminate against other generators in favor of its own affiliate-suppliers when providing access to the power grid.⁷⁵

1. Illinois's Rate Structure

The Customer Choice Law provides for several distinct rate components to ensure a smooth transition to a competitive electricity market. The legislation provides the following: immediate rate reductions for customers,⁷⁶ a power purchase option ("PPO") for commercial and industrial customers,⁷⁷ unbundling of generation and delivery service tariffs,⁷⁸ cost-recovery transition charges,⁷⁹ and the designation of an independent party to determine market value,⁸⁰ seasonal rates, peak and off-peak rates consistent with the Public Utilities Act.⁸¹ Each of the rate components of the Customer Choice

75. *Id.* at 119A(a).

76. The Customer Choice Law required Illinois's two largest utilities to reduce rates to residential customers by 15 percent as of August 1, 1998 and to reduce the rates of residential customers by another 5 percent in 2002. Illinois's smaller, lower-cost utilities reduced their customer rates by 2 to 5 percent and these rates may be reduced further in 2002 to a rate comparable to an average regional residential rate. RICHARD MATHIAS, ILL. COMMERCE COMM'N, RESTRUCTURING THE ELECTRIC INDUSTRY IN ILLINOIS 15 (2000), at <http://www.icc.state.il.us/icc/inside/docs.asp#cm> (last visited Oct. 28, 2001).

77. Commercial and industrial customers are allowed to participate in a power purchase option in which the customer mitigates some risk of potential price fluctuation by agreeing to a set annual price for the power it uses. The PPO is comprised of an established market value of electricity, a transition charge, a delivery tariff and an administrative fee. *Id.*

78. The Customer Choice Law provision allows customers to contract with alternative retail electric suppliers ("ARES") for the generation component of their electricity. For this reason, utilities are required to "unbundle" or separate the rates for generation, transmission and distribution that have historically been passed to customers in one "bundled" rate. Nevertheless, a customer that contracts with an ARES for generation still pays the incumbent utility for electricity delivery. *Id.*

79. One of the key concerns regarding electricity restructuring is the incumbent utilities' ability to meet the financial obligations of pre-restructuring capital investments. These investments, or "stranded assets," often refer to nuclear power plants or other investments, whose high initial cost and long cost-recovery periods may cause significant financial burden for utilities in a fully restructured electricity market. To address this problem, customers must pay the incumbent utility a monthly transition charge, regardless of the generation supplier chosen. In Illinois these transition charges may only be assessed until 2008 (2006 in the case of one incumbent utility). Market value of electricity is a major component in the determination of the transition charge. *Id.* at 10-11.

80. The Customer Choice Law calls for the market value of electricity in Illinois to be determined as a function of a traded exchange index, similar to the Chicago Board of Trade ("CBOT"). 220 ILL. COMP. STAT. 5/16-112(a) (2001). As trading in the index has not yet reached a mature level, the Illinois Commerce Commission has appointed a neutral fact-finder to calculate market value for electricity. The neutral fact-finder reviews contract summaries submitted by electric utilities and alternative retail electric suppliers to determine the market value. *Id.*

81. See PETER A. HOFFMAN, DELOITTE & TOUCHE, 2000 NEUTRAL FACT-FINDER'S CALCULATION OF MARKET VALUES FOR ELECTRIC POWER AND ENERGY FOR THE STATE OF ILLINOIS (2000).

Law is intended to provide fair, reduced electric rates for customers and adequate opportunity for utilities to recover capital expenditures incurred prior to restructuring.⁸²

The Illinois legislature has proceeded toward a competitive electricity market at a relatively slow pace. Such deliberate calculation, combined with long-term contracts and adequate generating capacity, has thus far alleviated most concerns about a potential market debacle in Illinois. Nonetheless, California has valuable lessons to offer Illinois's legislature, utilities, and electricity customers.

III. CRISIS IN CALIFORNIA

How did an early leader in national electricity restructuring veer from the goal of lower energy prices and a streamlined regulatory system into the turbulent waters of soaring prices, rolling blackouts, market instability and an uncertain energy future? The following Section examines the key elements that coalesced into California's crisis and how expanded transmission and customer demand response measures could have tempered the state's fall.

A. *What Happened?*

California's troubled markets have silenced many of the initial advocates of California restructuring.⁸³ Utilities' divestment of generating facilities,⁸⁴ diminished electricity imports,⁸⁵ and the state's

82. 220 ILL. COMP. STAT. 5/16-114.

83. Senator Steve Peace, originally a chief architect of the 1996 restructuring bill, later argued against the plan he had advocated and blamed the California Public Utilities Commission for requiring utilities to spin-off their generation-making way for higher priced out-of-state suppliers. *California Remains the Focus of Federal and State Actions Designed to Mitigate High Power Prices*, FOSTER ELEC. REP., Sept. 6, 2000, at 2.

84. The commonly held belief during the initial debates regarding restructuring in California was that once restructuring legislation passed, new, efficient generation plants would be built. *Hearings, February 8, 2001, supra* note 7, at 35-36 (testimony of Charles Stalon). Some new generators perceived the transition period, with its fixed costs, to be a potentially risky and less profitable period. Furthermore, until 1998, some generators did not consider the rules regarding the actual operation of the ISO and PX certain enough to justify entering the market. *Id.* at 91 (testimony of Jerry Keenan). For this reason, many resolved to bring new generation on-line only after the transition period was over, and when free-market forces would control prices. *Id.* at 89.

85. Increased demand in neighboring states limited the amount of electricity that was imported into California. "Utah and Nevada specifically have seen five, six, seven percent demand growth on an annual basis." *Hearings, February 8, 2001, supra* note 7, at 16 (testimony of Jerry Keenan). The increase in hydropower in the years 1997 through 1999 had also created a complacency that left California underpowered and ill-prepared when a decrease in

mandate that electricity be bought and sold through the California Power Exchange, left California with a decreased pool of power, while facing an annual 2.3 percent increase in overall demand.⁸⁶ Further, strict siting requirements for new power plants created a challenging environment in which to construct new generation facilities.⁸⁷ Faced with customers' refusal or inability to reduce usage during peak periods, combined with other factors such as particularly warm weather,⁸⁸ high natural gas costs,⁸⁹ and the mandated elimination of utilities' long-term contracting and hedging practices,⁹⁰ California's restructured wholesale market became a seller's paradise and a buyer's nightmare in the last months of 2000.⁹¹ Though the primary cause of the crisis was insufficient wholesale generation⁹²

hydropower began in July 2000. In February 2001, resources for hydropower in the western US were at 68 percent of their normal level; by comparison, during the previous five years, the western hydropower resource ran a surplus of over 100 percent of necessary capacity. *Id.* at 70. California's dependence on gas-fired generating makes it vulnerable to the fluctuating price of natural gas. Forty-seven percent of installed capacity in the California-Mexico Power Area is gas-fired generating units. N. AM. ELEC. RELIABILITY COUNCIL, RELIABILITY ASSESSMENT 2000-2009: THE RELIABILITY OF BULK ELECTRIC SYSTEMS IN NORTH AMERICA 76 (2000), available at <http://www.nerc.com/~filez/rasreports.html> (last visited Oct. 5, 2001).

86. See RICHARD ROHRER ET AL., CAL. ENERGY COMM'N, CALIFORNIA ENERGY DEMAND 2000-2010 (2000), at http://38.144.192.166/reports/reports_300.html (last visited Oct. 5, 2001).

87. Environmental restrictions can delay new generating facility openings by four to five years. *Hearings, February 8, 2001, supra* note 7, at 86 (testimony of Joel Newton).

88. The number of cooling degree days in the Pacific region increased by 13 percent in 2000. Edward N. Krapels, *Was Gas to Blame?: Exploring the Cause of California's High Prices*, PUB. UTIL. FORT., Feb. 15, 2001, at 28.

89. High gas prices (between five and twenty-five dollars per million BTU) meant that even for the most efficient gas-fired generating plants, the fuel cost component was between fifty and two hundred fifty dollars per MWh. For inefficient gas-fired plants that were forced to come on-line when electricity grew scarce, the fuel cost component was between one hundred and five hundred dollars per MWh. *Id.*

90. The gas and power market spot price increases of 2000 could have had a minor effect on the state if the utilities had engaged in routine hedging, creating a portfolio of fixed price purchases and diverse forward contracts. Krapels, *supra* note 88, at 28.

91. In July of 2000, California utilities, the primary buyers of wholesale electricity, paid \$4 billion more for electricity than they did in the summer of 1999. In December of 2000, electricity prices rose to \$1400 per MWh, more than twenty times the price the previous year. Laura M. Holson, *Government Acts to Calm California's Energy Market*, N.Y. TIMES, Dec. 16, 2000, at A14.

92. California has roughly one thousand generating facilities with approximately 55,500 MW of capacity. Seventy-five percent of the state's electricity is generated in-state. The remaining are: 11 percent from the Pacific Northwest (80% hydropower / 20% coal) and 14 percent from the southwestern states (74% coal / 26% natural gas). *Id.*; RONALD WETHERALL, CAL. ENERGY COMM'N, 1999 NET SYSTEM POWER CALCULATION 3 (2000), available at <http://www.energy.ca.gov/reports/> (last visited Oct. 5, 2001). Between 1996 and 1999, California's peak load grew by 5,522 MW; new generation during the same period amounted to only 672 MW. Kahn & Lynch, *supra* note 63, at 33. Without new generation construction, severe shortages will likely recur. Holson, *supra* note 91.

coupled with high demand by retail consumers, the factors that sent the market spiraling originated with political as well as structural flaws.

California's restructuring legislation was designed to allow utilities to recover some of the billions of dollars of capital invested in plants whose financial return appeared less certain in a competitive market. The cost recovery for these stranded assets⁹³ was to take place during a transition period in which retail customers' electricity prices were frozen. The frozen price would include a competitive transition charge ("CTC")—the difference between the retail price cap and the sum of all power costs to the utility.⁹⁴ Because the sum power costs to the utility were expected to be lower than the frozen retail cost, utilities would be able to recover their investment.⁹⁵ When the investment costs were recovered, the retail price cap would be lifted. Consumers would then be exposed to the market and, presumably, benefit from low wholesale prices.

The first utility to recover its investments and release its customers from the retail price cap was San Diego Gas and Electric. The timing could not have been worse. Customers were exposed to the fluctuations of the wholesale market at a point when generation capacity was strained, natural gas prices were high and an unusually warm summer was just beginning. During the week of June 14, 2000, purchasers of electricity in California spent \$1.2 billion on power, three times more than they had during the same period in 1999.⁹⁶ San Diegans saw their June electricity bills double.⁹⁷ Panicked by the soaring electricity prices, consumers called for government intervention.

In an effort to curb the financial casualties and appease a furious constituency, regulators reestablished retail price caps and then instituted caps on the purchase of wholesale power as well.⁹⁸ Utilities were still required to buy from the PX and they were still required to sell to their customers at fixed prices; the wholesale price caps,

93. *See supra* note 67.

94. *CERA Senate Hearing, supra* note 14, at 2.

95. *Id.*

96. Kahn & Lynch, *supra* note 63, at 3.

97. *Id.*

98. Reacting to the skyrocketing prices incurred by utilities over the summer in California, local regulators implemented a progression of wholesale price caps: from seven hundred fifty to five hundred dollars on July 1, 2000 and then again from five hundred to two hundred fifty dollars on August 7, 2000. Rebecca Smith, *Probe of California Power Prices Begins but New Plants Aren't Seen as Solution*, WALL ST. J., Sept. 11, 2000, at A4.

though providing some price stability, simply announced the highest price utilities would pay.⁹⁹ Ultimately, the retail price cap meant that utilities bought high and sold low, forced to absorb a substantial piece of each transaction and unable to pass full costs on to their customers.¹⁰⁰ Between the months of June and September 2000, Pacific Gas & Electric and Southern California Edison each incurred debts equivalent to half of their net worth.¹⁰¹

Some have explained this dysfunction of the market simply as “re-regulation.”¹⁰² While buyers (the utilities) were constrained by fixed prices, the sellers (electricity generators) were free from state regulation; as the utilities plunged toward bankruptcy, the companies that generated and sold electricity made record profits. In a single five-day period last June, for example, more than \$1 billion was spent on California electricity.¹⁰³

Until the Power Exchange was dismantled by a FERC order in December 2000,¹⁰⁴ if an insufficient amount of electricity was bid to meet the next day’s demand, the Independent System Operator had the authority (as the “buyer of last resort”) to make electric purchases on behalf of utilities and bill them later.¹⁰⁵ In such a tight market and knowing that the ISO had to balance transmission flows to keep the lights on, generators were able to set any price. One commentator compared these negotiations to “buying house insurance when your house is already on fire—you’ll pay anything for it.”¹⁰⁶ Utilities, still required to serve their retail customers, quickly accumulated an insurmountable debt—a liability that often amounted to hundreds of millions of dollars a day.¹⁰⁷

99. In some cases utilities would pay a wholesale rate of twelve cents per kWh and receive a retail rate of 6.5 cents retail for that same kWh under the frozen price; the same unit of electricity cost the utility 2.5 cents one year earlier. *California Remains the Focus of Federal and State Actions Designed to Mitigate High Power Prices*, FOSTER ELEC. REP., Sept. 6, 2001, at 2.

100. Smith, *supra* note 98, at A4.

101. *Id.*

102. See Severin Borenstein & James Bushnell, *Electricity Restructuring: Deregulation or Reregulation?*, REGULATION, Spring 2000, at 46.

103. Kahn & Lynch, *supra* note 63, at 3.

104. F.E.R.C. Docket Nos. EL00-95-000, *Order Directing Remedies for California Wholesale Electric Markets*, 93 F.E.R.C § 61,294 (Dec. 15, 2000).

105. The ISO was initially expected to purchase no more than 5 percent of the market’s daily demand. On days of extreme supply shortfall, ISO purchasing climbed to almost 30 percent of the daily demand. Timothy Egan & Sam Howe Verhovek, *How California Fell Prey to Power Sellers*, N.Y. TIMES, Feb. 11, 2001, § 1, at 28.

106. *Id.* (quoting Robert McCollough, a former utility executive and energy analyst).

107. *Id.*

Faced with utilities on the verge of bankruptcy, almost three weeks of near-blackout conditions from operating the state's electricity grid at maximum capacity levels and independent power generators withdrawing from the market for fear of breached contracts with the state's three largest utilities, the federal government intervened.¹⁰⁸

In December 2000 FERC eliminated the requirement that all purchases be made through the state-run PX and encouraged utilities to engage in long-term contracting.¹⁰⁹ As a presumed warning to generators against potential price manipulation, the FERC's December order included a stipulation that generators submit detailed data anytime they sold electricity in California for more than \$150 per MWh.¹¹⁰ At the same time, Governor Gray Davis invoked emergency measures to bring more generation on-line in time for summer 2001 and lobbied a reluctant state legislature to allocate \$400 million toward energy-efficiency and conservation efforts.¹¹¹ The state also began purchasing power on behalf of the struggling utilities and entering into long-term contracts with generation companies in the hope of avoiding scarcity-driven pricing in summer 2001.

By March 2001, one hundred ninety bills had been introduced in the California Legislature designed to restore the state's utilities to financial viability.¹¹² Proposals aimed at retaining the utilities' solvency included posting a \$10 billion bond to help pay for power and stabilize prices, and the state's purchase of Southern California Edison's transmission lines for \$2.76 billion.¹¹³

At the time of this writing, in August 2001, Governor Davis and the ISO are asking FERC to order electricity suppliers¹¹⁴ to refund \$8.9 billion to California's utilities and taxpayers for market manipulation.¹¹⁵ FERC, in turn, has announced a method for

108. *FERC Issues Final Order on California's Market Problems: Response is Mixed*, *supra* note 58, at 2.

109. *Id.*

110. This price was considered to be a fair estimate of the highest cost a generator could face in producing the electricity. Jeff Gerth & Joseph Kahn, *Critics Say U.S. Energy Agency Is Weak in Oversight of Utilities*, N.Y. TIMES, Mar. 23, 2001, at A1.

111. Laura M. Holson, *California's Choices All Look Painful*, N.Y. TIMES, Mar. 23, 2001, at C1.

112. *Id.*

113. *Id.*

114. Named suppliers include Reliant Energy, Dynergy, Williams/AES, Duke Energy and Mirant. *Id.*

115. *FERC Accepts ALJ's Recommendations on California Refund Methodology and Extends Refund Liability to Public Power*, FOSTER ELEC. REP., Aug. 1, 2001, at 7.

calculating “unjust and unreasonable” rates that is likely to result in a comparatively small \$4 billion in refunds.¹¹⁶ Governor Davis has demanded FERC change its order or face litigation.¹¹⁷ While remedies attempt to compensate for the mistakes of the past, it is worth considering two long-term approaches that would have kept California from stumbling into the competitive electricity market.

B. Solutions for Tight Markets

In the search for solutions to the problems that led to California’s electricity crisis, the need for more electricity generation is clear.¹¹⁸ Little discussion, however, has focused on the role that transmission plays in ensuring the reliable transfer of electricity, and on the role that demand-side management plays in allowing customers to fully interact with, and react to, market signals. This Section outlines the benefits of each of these approaches and discusses how, in particular, they would have helped the California market.

1. Expanded Transmission

Even with an influx of new generation, a state can experience supply problems if power plants are completed and then unable to run at full capacity because of a limited availability of transmission capacity.¹¹⁹ The North American Electric Reliability Council (“NERC”)¹²⁰ predicts that as states restructure their electricity markets, transmission systems throughout the country will be faced with increased congestion.¹²¹ Incentives must be developed to encourage investment in new transmission systems and resolve the

116. *Id.*

117. *Id.*

118. As of January 2001, California was about five thousand MW short of supply and state siting and permitting requirements prevented the development of new generators to supply the twelve hundred MW needed to keep demand and supply in balance. *CERA Senate Hearing, supra* note 14.

119. For example, a 965 MW plant currently under construction by CalCon in San Diego may be limited by transmission constraints to an output of only two hundred MW unless more transmission capacity is built. *Hearings, February 8, 2001, supra* note 7, at 85 (testimony of Joel Newton).

120. Electric utilities formed the North American Electric Reliability Council in 1968 to promote the reliability of the interconnected electric system in North America. See N. Am. Elec. Reliability Council, *About NERC*, at <http://www.nerc.com/about> (last visited September 28, 2001).

121. N. AM. ELEC. RELIABILITY COUNCIL, *supra* note 85, at 5.

problems involving transmission siting and development.¹²² Current estimates predict that six thousand new miles of electricity transmission lines will be built in the United States by 2009, an expansion of 1 percent, as compared to forecasts of 20 to 30 percent increases in electricity consumption during this same period.¹²³ The physical transmission infrastructure is the platform that supports competition in any region, regardless of how the electricity is produced.¹²⁴ Despite the importance of infrastructure, building transmission capacity has not been a priority for utilities in California.¹²⁵

In California, as in other locations around the United States, transmission proposals face numerous hurdles in government permitting, capital acquisition, and siting approval from local communities.¹²⁶ Though the construction of new transmission lines can be one-tenth the cost of building generation facilities,¹²⁷ the social, environmental and political hurdles to constructing new lines can be significant.¹²⁸ Further, planning agencies like the ISO acknowledge “considerable uncertainty” in determining where to place future transmission.¹²⁹ As new generators enter the market, the points of high electricity congestion shift to areas not anticipated by the original constructors of the grid.¹³⁰ Nevertheless, the long-term reliability of new and existing transmission systems depends on the placement of these new generators.¹³¹ Carefully matching generation and transmission capacity helps ensure that transmission systems stay

122. *Id.*

123. John B. Howe, *End the Gridlock: Why Transmission is Ripe for New Technology*, PUB. UTIL. FORT., Jan. 15, 2001, at 38.

124. *Id.*

125. See Peter Behr, *Shortage of Power Lines Looms; U.S. Consumers Face Higher Prices*, WASH. POST, Feb. 20, 2001, at A1.

126. The California ISO estimates seven to nine years are required to permit and build major transmission systems in California. GRID PLANNING DEPT., CAL. INDEP. SYS. OPERATOR, 2000 OVERALL TRANSMISSION EXPANSION PLAN OF THE CALIFORNIA ISO-CONTROLLED GRID 12 (2000).

127. See Brendan Kirby & Eric Hirst, *Maintaining Transmission Adequacy in the Future*, ELEC. J., Nov. 1999, at 3.

128. The public usually sees transmission facilities as “large, intrusive installations consuming broad swaths of forests, farmlands and suburbs [and] opponents of new lines continue to cite health concerns related to the electromagnetic fields produced by alternating current.” Howe, *supra* note 123, at 38.

129. *Id.*

130. Typically, vertically integrated utilities built transmission lines taking into consideration only the existing generation and anticipated load constraints. Utilities are unlikely to have considered all the possible configurations of generator and load placement that ultimately result from restructuring. See N. AM. ELEC. RELIABILITY COUNCIL, *supra* note 85.

131. *Id.* at 5.

in balance and that overloads and outages, like those in California, are less likely to occur.¹³²

As the California ISO prepared for the warm weather of summer 2001, it expedited eight transmission projects to be completed by early summer.¹³³ The ISO issued a report in early 2001 that outlined twenty-five transmission projects for Pacific Gas & Electric through 2005.¹³⁴ Farther south, San Diego Gas & Electric was carrying such a significant load that certain transmission and generator outages could have required it to cut supply to its customers.¹³⁵ Nine transmission projects were proposed to increase the capability of the utility to import power and to mitigate the reliability problem that could have otherwise occurred.¹³⁶

Additionally, the ISO recommended the development of a mitigation project for Path 15, the primary north-south transmission artery in California, which would allow more significant electricity orders to be sent between northern and southern parts of the state.¹³⁷ The ISO wrote that “current congestion problems and reliability impacts due to constraints on Path 15 are expected to continue into the future.”¹³⁸ Concerns about the reliability of a state’s “central nervous system,” as transmission systems have been called, would seem sufficient reason to spur investment for expansion. In a restructured market, however, utilities have a more difficult task justifying investment in regulated entities with low and long investment returns, when compared to unregulated generation plants with greater shareholder appeal.¹³⁹

In light of California’s troubles, additional transmission is a logical solution. Expanding transmission capacity throughout the state would allow an infusion of more out-of-state generators to participate in the California market. Ultimately, greater transmission capacity within an electricity market allows more suppliers to participate and gives consumers choice and control when making decisions about power. Additionally, the implementation of demand

132. *Id.*

133. *Id.*

134. Twenty-one of the projects are intended to address “emergency or thermal outages.” The remaining three projects will respond to the need for increased electricity imports into San Francisco. *Id.*

135. *Id.* at 10.

136. *Id.*

137. *Id.* at 6.

138. *Id.*

139. *Hearings, February 8, 2001, supra* note 7, at 85 (testimony of Joel Newton).

response technologies provides choice and control by allowing consumers to determine what they are willing to pay for electricity, based on time-of-use.¹⁴⁰

2. Demand Response for Consumers

California's growing economy, coupled with a delay in the construction of new generation facilities and transmission lines, will likely result in a struggle to consistently meet demand for the next several years.¹⁴¹ However, California can bolster its efforts to more accurately control demand,¹⁴² and in doing so, reduce costs for all those within its market.¹⁴³ The implementation of real-time pricing ("RTP") allows for immediate as well as future savings, and permits consumers to intelligently reduce their use during supply shortages.¹⁴⁴

Real-time pricing is made possible through the installation of meters that track usage and charge customers according to the wholesale price for electricity at any given time.¹⁴⁵ One study estimates that if RTP meters had been installed before the summer of 2000, California would have seen estimated load reductions of one thousand to two thousand MW, price reductions during peak periods of 6 to 19 percent, and overall cost savings ranging from \$300 million to \$1.2 billion.¹⁴⁶ Further, the North American Electric Reliability Council has found that reductions of demand during peak periods can be as effective in ensuring the reliability of the electricity system as the addition of new generation facilities.¹⁴⁷ Given the extended lead times of generation, RTP meters appear to be a logical choice.

While the immediate installation of the ten million meters necessary to allow all California customers to participate in RTP may be

140. See SEVERIN BORENSTEIN, FREQUENTLY ASKED QUESTIONS ABOUT IMPLEMENTING REAL-TIME PRICING IN CALIFORNIA FOR SUMMER 2001, at 1, available at http://www.ucei.berkeley.edu/ucei/Recent_Presentations/recent_present.html (last visited Oct. 5, 2001) (web page provides link to PDF document).

141. Kahn & Lynch, *supra* note 63, at 48; *Hearings, February 8, 2001, supra* note 7, at 19 (testimony of Jerry Keenan).

142. F.E.R.C. Docket Nos. EL00-95-000, *Order Directing Remedies for California Wholesale Electric Markets*, 93 F.E.R.C. § 61,294 (Dec. 15, 2000).

143. Reducing demand at peak demand and price times can save wholesale expense on the power that is not used and reduce the price of the power that is used.

144. BORENSTEIN, *supra* note 140; see generally Steven Braithwait & Ahmad Faruqui, *The Choice Not to Buy: Energy Savings and Policy Alternatives for Demand Response*, PUB. UTIL. FORT., Mar. 15, 2001, at 48.

145. BORENSTEIN, *supra* note 140, at 5-6.

146. Hirst, *supra* note 10, at 49.

147. *Id.* at 34.

unrealistic, installing meters for large commercial and industrial customers is a logical start.¹⁴⁸ Such a program would require the installation of approximately eighteen thousand meters at a cost of around \$30 million.¹⁴⁹ Though the cost is high, estimates hold that such an investment could be repaid through electricity savings during one to two weeks of summer temperatures.¹⁵⁰ Simply, the greatest savings come from allowing individuals to balance their energy needs with the market.

In February 2001, Governor Davis announced the allocation of more than \$4 million for investment in emergency efficiency and demand management programs.¹⁵¹ Included in these programs were radio and television announcements aimed at getting residential consumers accustomed to the idea of RTP. One such announcement told consumers: “[I]f you knew that by doing a full load [of laundry] after seven p.m., you could help avoid rolling blackouts, and make sure school kids don’t sit in the dark, and help keep your electric bills down, you might just let that sock stay dirty a little while longer.”¹⁵² Public announcements like this give a sense of how conservation efforts may proceed in the future.

Of course, the most dramatic savings will come with the full implementation of real-time pricing. However, given the current cost of the meters¹⁵³ and political resistance to allowing California customers to feel the full brunt of wholesale prices,¹⁵⁴ a pervasive implementation is unlikely to occur anytime soon. And while the technology to respond instantly to market prices is not currently available to all market players, the California Public Utilities Commission and the ISO have offered pilot programs that allow commercial and industrial customers to respond to prices by curtailing demand.¹⁵⁵

148. BORENSTEIN, *supra* note 140, at 6.

149. *Id.*

150. Preventing a single day of rolling blackouts would pay for the investment in RTP meters. It is estimated that one rolling blackout day costs each California citizen about one dollar in electricity costs. *Id.* at 7.

151. See Press Release, Office of the Governor of California, Gov. Davis Outlines \$800-Million Energy Efficiency and Demand Reduction Program (February 1, 2001), available at <http://www.governor.ca.gov> (last visited February 5, 2001).

152. *Id.*

153. The meters cost between two hundred and one thousand dollars per installation. This figure does not count potential savings from the new meters such as reduced meter-reading costs. BORENSTEIN, *supra* note 140, at 6.

154. See Holson, *supra* note 118.

155. The ISO has developed three new programs to compensate customers for reducing

Real-time pricing allows customers to break from the static, fixed-price model of electricity pricing, where price is determined long before consumption occurs.¹⁵⁶ Instead, as active participants in a competitive market, consumers can make energy choices knowing the price they will pay. California paid dearly for not preparing its customers for the volatility of the electricity market, and any state entering into restructuring without RTP risks a similar fate.

IV. COULD IT HAPPEN IN ILLINOIS?

While California struggles to resolve the initial economic and political fallout from its move to competition, Illinois should take a close look at the California experience and ask: “Could it happen here?” Simply, replicating California’s unfortunate combination of structural, market-based and weather-related catalysts would be difficult. However, the same results—high prices, disenfranchised customers, and calls for re-regulation—could surface in the Illinois market when rate caps are removed in 2005, fully exposing retail customers to wholesale market forces.

This Section considers some of the challenges for the Illinois electricity market, looking specifically to the effect transmission constraints and limited customer choice could play in the development of competition in Illinois. This Section also recommends new federal and state transmission policy as well as enhanced demand response and consumer education programs.

A. *Transmission and Market Power Concerns*

Consider a scenario of the Illinois electricity markets in 2005: incumbent utilities have divested many of their generation facilities,¹⁵⁷

load when notified during peak periods. *Id.*

156. Hirst, *supra* note 10, at 34.

157. Unlike California, Illinois does not have a divestiture requirement that forces public utilities wishing to recover stranded costs to divest nuclear and non-hydroelectric generating facilities to an unaffiliated entity. Thus, Illinois utilities can

unlock the hidden value in their generating facilities by . . . simply transfer[ring] ownership of their generating facilities to affiliated companies. . . . Central Illinois Public Service has transferred its generation facilities to an affiliate, Ameren Energy, and Illinois Power Company (I.P.) transferred its generation facilities to a generation subsidiary of I.P.’s Houston, Texas based parent, Dynegy Inc. These affiliates are free to sell electricity to their affiliated utilities and to unrelated third parties at market rates. In addition, ComEd sold its coal and gas fired generating facilities to an unaffiliated entity, Mission Energy Mid West, which is an

but still retain an ownership percentage great enough to exert power in the wholesale market. The retail market, still dominated by the incumbent utilities, faces volatility resulting from a lack of supply participants and from the transfer of wholesale supply and fuel costs directly to the retail consumer. Direct cost transfer and limited competition create little incentive for the incumbent utilities to invest in demand response measures to help customers make more informed decisions about the cost of using electricity. The once heavily regulated incumbents are trim utility distribution companies (known as “UDCs” or “wires companies”),¹⁵⁸ controlling the transmission and distribution of power. Because having fewer transmission facilities gives the incumbent utilities an opportunity to dominate specific geographic markets with an affiliate-generator’s power, the incentive for UDCs to invest in new transmission facilities and, in turn, bring generation competitors into the market, is low.

Imagine also that, though still bound by a statutory “duty to serve,”¹⁵⁹ the wires company is beholden to its unregulated generation affiliates, the new profit centers of the once-integrated utility. With no obligation to seek the lowest price for customers, the wires company purchases power on the open market and any pricing volatility is passed along to the retail consumer. Further, because of past mergers with out-of-state utilities,¹⁶⁰ customers seeking remedies from high local rates are forced to pursue relief across state lines, from the home offices of conglomerate utilities. Local customer service is now ancillary to national corporate shareholder satisfaction.

Such a scenario, though extreme, is possible. Illinois customers should not have to experience the degree of vulnerability that Californians experienced at the mercy of the volatile wholesale

affiliate of Southern California Edison. Also, I.P. sold its Clinton nuclear generating facilities to Amergen, a joint venture of Exelon and British Energy. Both ComEd and I.P. have power purchase agreements with their respective buyers which gives each the right to purchase substantial portions of the power produced by their divested facilities for several years.

RICHARD MATHIAS, ILL. COMMERCE COMM’N, CAN A CALIFORNIA ENERGY DEBACLE OCCUR IN ILLINOIS? 1–2 (2001).

158. A UDC is a distribution wires business or a regulated retailer that serves end-use customers. Cal. Indep. Sys. Operator, *supra* note 27.

159. The modern concept of a utility’s “duty to serve” can be traced to the Supreme Court’s ruling regarding whether Chicago grain elevators were devoted to public use. *Munn v. Illinois*, 94 U.S. 113 (1876). The Court determined that property is “clothed with a public interest when used in a manner . . . of public consequence [that affects] the community at large.” *Id.* at 126; BOSSELMAN ET AL., *supra* note 23, at 148.

160. MATHIAS, *supra* note 157, at 1.

electric market. To avoid a troubled 2005, the state legislature should examine three primary features within Illinois's electricity market: (1) the balance of power within the generation and transmission market, (2) the capability of consumers to respond to market signals, and (3) the depth of electricity restructuring education among the state's businesses and citizens, the soon-to-be players in the electricity market game.

Illinois must examine the potential problems unique to restructuring within its borders and pursue rulings at the state and federal level to prevent entering the electricity marketplace unprepared. The deliberately gradual pace of Illinois's restructuring law allows time for safeguards to be developed that could ensure a smooth transition into the open market. That measured speed will prove successful only if it allows for the preparation of all participants, regardless of the market knowledge or power they currently hold.

1. Examining Market Power in Illinois

One of the common misconceptions regarding generation facilities and the national move toward restructuring electricity markets is that generators holding local or regional monopoly power prior to restructuring are somehow stripped of that market power within the restructured market.¹⁶¹ While competition may open markets to new generators, limits in transmission capabilities and capacity can limit competition to relatively small geographic areas, where a small generating unit can wield market power. As a generator with market power in an unregulated environment stands to gain considerable profits,¹⁶² it will only voluntarily divest its market share if the financial benefits exceed the costs.¹⁶³

Ideally, competitors keep a generator's prices in check by using available transmission capacity to compete for customers. The availability of sufficient transmission capacity allows new suppliers to gain entry into the market and forces incumbent generators to face

161. Bushnell & Wolak, *supra* note 11, at 3.

162. Borenstein and Bushnell explain that a generator with even a small market share can drive up the price of electricity by withholding "a bit" of its supply, thereby boosting profits. Borenstein & Bushnell, *supra* note 102, at 49. "[I]f firms of notable size are not exercising market power, they are doing so out of the goodness of their heart and against the interest of their shareholders." *Id.*

163. In a geographic area with limited transmission capacity, a small electricity generator can exert significant market power because it knows that no other suppliers will be able to consistently bring electricity to customers. Bushnell & Wolak, *supra* note 11, at 3.

competition and lower prices.¹⁶⁴ Provided with a choice of suppliers, the consumer should benefit from lower prices. However, utilities, the companies with the greatest means to construct more capacity, have a disincentive to build new transmission lines.¹⁶⁵ To do so draws profits from their conglomerates' transmission and generation operations, entities still affiliated as a result of the limited divestiture provisions of Illinois's Consumer Choice and Rate Relief Law of 1997.

Illinois's restructuring law does not require incumbent utilities to divest of all generating or transmission facilities.¹⁶⁶ Unlike California,¹⁶⁷ in Illinois, many utilities retain control of transmission and distribution systems and have simply transferred ownership of some generating facilities to affiliated companies.¹⁶⁸ As a result, Illinois's incumbent utilities now still own, either directly or through a holding company, many of the generating facilities that they controlled under state regulation.¹⁶⁹ The potential conflict arising from these arrangements is clear.¹⁷⁰ If the wires division of a utility builds new transmission lines into a geographic area controlled by an affiliate-generator, it opens the possibility that the affiliate may be pressured by competition to lower its prices, and in turn, its profits. Thus, the wires company has a vested interest in assisting its unregulated generating facility to gain profits. In other words, transmission companies that are affiliated with generators have a disincentive to build additional transmission capacity.¹⁷¹

164. *Id.*

165. Behr, *supra* note 125, at A1.

166. 220 ILL. COMP. STAT. 5/16-119A(b) (2001).

167. The California Public Utilities Commission required all transmission operation be turned over to the independently operated ISO. Fearing the exercise of generation market power, the Commission required two of the three largest utilities to divest 50 percent of their fossil fuel generating facilities. CAL. PUB. UTIL. CODE § 330 (West Supp. 1997) as amended by stats. 1986, c. 854 (AB 1890, § 10).

168. MATHIAS, *supra* note 157, at 1.

169. *Id.*

170. This practice is known as cross-subsidization and involves leveraging the regulated division of a company to provide a competitive advantage for the unregulated division of the company. See generally Jim Rossi, *Universal Service in Competitive Electric Retail Power Markets: Whither the Duty to Serve?*, 21 ENERGY L.J. 27 (2000); Lawrence Sullivan, *Elusive Goals Under the Telecommunications Act: Preserving Long Distance Competition upon Baby Bell Entry and Attaining Local Exchange Competition: We'll Not Preserve the One Unless We Attain the Other*, 25 SW. U. L. REV. 487, 518-27 (1996).

171. See James Bushnell, *Transmission Rights and Market Power*, ELEC. J., Oct. 1999, at 77.

When such conditions occur in a fully restructured market, the prospects for significant consumer savings are bleak.¹⁷² As summarized by Illinois Commerce Commissioner Terry Harvill, when “consumers start shopping for the lowest rates from competing power producers, the transmission squeeze could hamper competition. . . . If you find that somebody in Wisconsin can sell you power cheaper, it may turn out that because of transmission constraints, they may not be able to get the power to you.”¹⁷³ Such a scenario contradicts a core tenet of electricity restructuring—that the mobility of electricity breeds competition.

In a market constrained by limited transmission, generators retain market power.¹⁷⁴ Consumers feel this control most dramatically during periods of high demand, when wholesale purchasers have little option but to take what they can from a local generator. Without concern for competition during these periods, generators can expect an above-market payment.¹⁷⁵ Within a fully restructured market, the incumbent utility simply passes the wholesale price directly on to the retail customer; utilities have little incentive to add transmission. Commissioner Harvill summarized: “[M]onopolies do absolutely nothing unless it is in their own best interest to do so, and in this instance divestiture [of transmission facilities] clearly is not.”¹⁷⁶ As the electricity industry moves toward competition, utilities should be given market incentives to expand transmission while local agencies work to streamline the procedure for siting new facilities.

2. Creating Competition Through Transmission

Resolving the problem of market power retained within an incumbent’s generation and transmission structure is complex. Because of the interstate nature of transmission lines, the jurisdiction for oversight of interstate transmission is left to FERC, while siting and other community concerns remain with the state’s public utility commission. Transmission issues in Illinois will need to be addressed,

172. MATHIAS, *supra* note 157, at 9.

173. Stevenson Swanson, *Energy Squeeze Lurks in U.S.; Illinois Keeps Up, but Its Rate Cap Expires in 2004*, CHI. TRIB., Feb. 4, 2001, at C1.

174. *Electric Policy Committee Meeting: The California Energy Crisis and Its Relevance to Illinois, Hearings before the Illinois Commerce Commission 103* (Feb. 7, 2001) [hereinafter *Hearings, February 7, 2001*] (testimony of Jerry Keenan).

175. Bushnell & Wolak, *supra* note 11, at 3.

176. Terry Harvill, *Major Electricity Crisis Unlikely in Illinois*, CHI. SUN-TIMES, Feb. 7, 2001, at 47.

particularly with respect to Wisconsin.¹⁷⁷ Wisconsin is currently in a distressed situation with limited electric supply, and Illinois, because of its location and electricity supply, is the natural candidate to provide the state with what it needs.¹⁷⁸ The political issues involved in such an interaction are complicated.¹⁷⁹ Successfully expanding transmission capacity hinges on demonstrating transmission as a productive economic investment decision while simultaneously minimizing the social and political concerns that come with significant regional projects.¹⁸⁰

In response to stakeholder debates around the country about the virtues of placing control of interstate transmission in the hands of Independent System Operators like California's, as compared to multistate Regional Transmission Organizations ("RTOs"),¹⁸¹ FERC issued Order No. 2000, requesting each utility that owns or operates interstate transmission facilities to file a proposal on how it plans to create or participate in an RTO.¹⁸²

Experts believe that no single state transmission market is large enough to sustain the efficiency and capacity necessary to establish a competitive electricity marketplace.¹⁸³ By placing the control of all transmission under one independent, managing body, RTOs should help eliminate the market power of some utilities.¹⁸⁴ However, unless

177. *Hearings, February 8, 2001, supra* note 7, at 101 (testimony of Jerry Keenan).

178. See WIS. PUB. SERV. COMM'N, REPORT TO THE WISCONSIN LEGISLATURE ON THE REGIONAL ELECTRIC TRANSMISSION SYSTEM (1998), at <http://www.psc.state.wi.us/writings/papers/energy/electrel/transsys.htm> (last visited Oct. 28, 2001) (web page provides link to report in Microsoft Word document format).

179. "[T]hat's going to be a difficult role for the [Illinois Commerce] Commission to play with the legislature because the legislature is unlikely to want to be giving leave for people to, you know, dig up everyone's backyards here in the south suburbs of Chicago so the cheese heads can have electricity." *Hearings, February 8, 2001, supra* note 7, at 101 (testimony of Jerry Keenan).

180. See ERIC HIRST, EDISON ELEC. INST., EXPANDING U.S. TRANSMISSION CAPACITY (2000), available at <http://www.ehirst.com/publications.html> (last visited Oct. 28, 2001) (web page provides link to PDF document).

181. James Bushnell, *Transmission Rights and Market Power*, ELEC. J., Oct. 1999, at 1.

182. F.E.R.C., Docket No. RM99-2-000, (Dec. 20, 1999).

183. "California is big [as the most populous state], but it's not big enough [to create stable electricity markets]. . . . If we had a wheat market that were limited by state, we would have wild fluctuations in the price of wheat in some states. What makes the price of wheat fairly stable is arbitrage between markets." *Hearings, February 8, 2001, supra* note 7, at 61 (testimony of Charles Stalon). Alternatives to RTOs include for-profit, independent transmission companies ("transcos") that own and operate their own lines, and not-for-profit, independent system operators who operate and maintain transmission facilities owned by others. See F.E.R.C., Docket No. RM99-2-000, Comments, Paul L. Joskow, Aug. 16, 1999 [hereinafter *Comments, Paul L. Joskow*].

184. HIRST, *supra* note 180.

new transmission is built, the market power advantage remains for generators in geographic areas with little competition.¹⁸⁵

The two primary barriers to the development of new transmission projects are (1) the difficulty in gaining local community and governmental approval and (2) the lack of financial incentive to make transmission investments.¹⁸⁶ As potential new transmission providers struggle to attract investors and mollify opponents of an expanded grid, they should be provided with new investment incentives and siting efficiencies at both the federal and state level.¹⁸⁷

3. Transmission Siting Challenges

The Federal Energy Regulatory Commission does not have strong eminent domain authority in siting transmission lines.¹⁸⁸ As a result, projects for new transmission can be quite complex, involving a multitude of federal, state, and local agencies, and may take years to construct.¹⁸⁹ Not surprisingly, local communities are often reluctant to agree to interstate construction designed to benefit customers and investors in states other than their own.¹⁹⁰ Such community resistance, coupled with the demands of multiple agencies and government organizations, acts as a disincentive for transmission advocates proposing future expansion.

As a means of expediting the siting process without losing sight of community concerns, the Illinois state legislature should work with the Illinois Commerce Commission to formalize a siting task force, comprised of representative organizations and individuals, with the authority to make decisions regarding the siting of new transmission. Such a “one-stop-shop” approach would allow a single, intergovern-

185. *Comments, Paul L. Joskow, supra* note 183, at 12.

186. *HIRST, supra* note 180, at 15.

187. *Id.*

188. EDISON ELEC. INST., MAKING COMPETITION WORK 2 (2001).

189. One project, begun in 1996, to build a thirty-nine mile 230 kV line to link facilities in Wisconsin and Minnesota crosses two states, involves an electric cooperative, has to cross a river, and involves a state park. As a result, the reviewing agencies include the Public Service Commission of Wisconsin, the Minnesota Environmental Quality Board, the Rural Utilities Service, the Army Corps of Engineers, the National Park Service, and the various local governments. A scaled down (161 kV) version of the project is now expected to begin construction in 2003 or 2004. *Id.*

190. Utilities claim that a transmission line project between Minnesota and Wisconsin is vital to increasing the reliability of transmission in the upper Midwest. Opponents of the plan claim the project would simply bring cheap hydropower from Canada to the lower Midwest, benefiting investors and consumers in states other than their own. Opponents also claim the transmission lines would lower property values and electromagnetic fields emitted from the lines could lead to adverse health impacts. *HIRST, supra* note 180, at 18.

mental authority to determine whether the construction of a new transmission line¹⁹¹ is in the best economic, social and political interest of the state.¹⁹² The proposed siting board would streamline the process of getting new transmission or generation built in Illinois by eliminating the repetition and conflict inherent in presenting to multiple agencies.¹⁹³

4. Transmission Investment Challenges

Potential investors in electricity transmission are often reluctant to assume the risk inherent in such a capital-intensive, long-term, low-return, and publicly contentious investment.¹⁹⁴ Add to that the initial concern regarding the uncertainty of future regulation, and it is no surprise to see utilities “like deer frozen in the headlights, waiting for state and federal legislators and regulators to define the structure of the industry in which they will operate, invest, and be regulated.”¹⁹⁵ In particular, investors in transmission are highly influenced by what the FERC will grant them as a return on equity (“ROE”), the base factor in determining how quickly their investments will be amortized.

As an example of the uncertainty utilities face, a pending case before FERC involves a California utility¹⁹⁶ that transferred its transmission assets over to FERC control only to have the FERC staff recommend a 2 percent reduction on the utility’s return on equity.¹⁹⁷ Frustrated by such experiences, utilities have appealed to

191. The same body could oversee new generation siting.

192. Ohio has such an intergovernmental entity. The Ohio Power Siting Board was established by the Ohio legislature in 1981 as a separate entity within the Ohio Public Utilities Commission. The Board issues certificates of environmental compatibility and public need for the construction, operation, and maintenance of major utility facilities, including electric generating plants and associated facilities designed for or capable of operation at fifty MW or more, electric transmission lines and associated facilities of a design capacity greater than or equal to 125 kV. Board membership is comprised of the Chairman of the Public Utilities Commission, the directors of the Environmental Protection Agency, the Department of Health, the Department of Development, the Department of Agriculture, and the Department of Natural Resources. A member of the public, specified as an engineer, is appointed to serve on the Board by the Governor from a list of three nominees provided by the Ohio Consumers’ Counsel. Also included, as ex-officio members of the Board, are two members from each House of the Ohio Legislature. Ohio Power Siting Board, *General Provisions*, at <http://www.puc.state.oh.us/pubrel/opsb/opsbrules/opsbrules.html> (last visited Sept. 30, 2001).

193. *Hearings February 7, 2001*, *supra* note 174, at 37 (testimony of Howard Learner).

194. HIRST, *supra* note 180, at 19.

195. *Id.*

196. Pacific Gas & Electric.

197. The trial staff recommendation of a reduction from 12.5 percent to 9.8 percent is not considered a final decision, but gives a good indication of how the FERC’s final decision will

the FERC, relying on cases like *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*,¹⁹⁸ that highlight a utility's need to attract investors by offering a fair ROE. The Supreme Court in *Bluefield* stated that

[a] public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. . . . The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.¹⁹⁹

Responding to Supreme Court precedent and investor concern, FERC should implement orders that provide transmission-controlling entities, whether ISOs, RTOs or traditional utilities, with increased rates of return on their transmission investment.²⁰⁰ The Federal Energy Regulatory Commission should establish incentives, such as performance-based rates ("PBRs"), to spur a transmission provider's efficiency, reliability and customer service.²⁰¹ Doing so will help provide a "more robust transmission network and enhanced operating capabilities than was the case during the era of vertically integrated, regulated utilities."²⁰²

Unless the federal and state governments develop new strategies to increase construction of transmission capacity, allowing new electricity suppliers to access Illinois customers, incumbent utilities will ultimately have the final say in whether electricity competition develops within the state.²⁰³ Without transmission incentives, the cost to consumers will be severe.²⁰⁴ Further, as access to increased

come out. See F.E.R.C., TO5 Docket No. ER01-66/000 (July 13, 2001).

198. 262 U.S. 679 (1923).

199. *Id.* at 692-93.

200. Telephone Interview with Vito Stagliano, former Vice President for Transmission, Commonwealth Edison Company (March 23, 2001). See also EDISON ELEC. INST., *supra* note 188, at 4.

201. Stagliano, *supra* note 200.

202. *Comments, Paul L. Joskow, supra* note 183, at iv.

203. Harvill, *supra* note 176, at 47.

204. Inadequate investment in transmission will "increase congestion costs, increase the incidence of local market power problems, increase ancillary services costs, [and] increase the frequency and magnitude of huge energy-price spikes." *Comments, Paul L. Joskow, supra* note 183, at 11.

transmission capacity moves forward, a parallel effort to assist consumers in gathering market information must be underway. For even with additional transmission capacity, without the knowledge and tools to interact in the marketplace, consumers will be left behind.

B. Demand Response: New Incentives for a New Market

One of the critical elements in the development of a competitive electricity market is the management of, and access to, real-time market data.²⁰⁵ Demand responsiveness is the ability of customers to respond to real-time prices in the form of seasonal pricing, time-of-day pricing and lower prices for interruptible service. If a customer has the opportunity to temporally react to peak prices by curbing usage, the supply and capacity markets should more directly reflect the true value of electricity.²⁰⁶ In a wholly or partially restricted market, in which prices are controlled through a regulatory price freeze, consumers are unable to react efficiently to price signals.²⁰⁷ In such a market, customers are not exposed to the true cost of their electricity consumption until their bill arrives in the mail.

1. The Customer's Choice

The central dilemma in determining whether to restructure electricity markets is usually that customers must either accept the prospect of retaining the high regional rates of the incumbent utility or embrace the restructured market and expose themselves to the cost-variability of electricity. Both paths require sacrifice. In a restructured market, customers forgo fixed electricity prices and the convenience of running a dishwasher or factory in the middle of the day with predictable financial cost. Customers exchange this convenience for the potential savings derived from leaving such high consumption activities to off-peak periods.

Within the safety of a regulated market, customers do not have an incentive to conserve.²⁰⁸ Customers are generally shielded from

205. Black & Pierce, *supra* note 25, at 1348.

206. When customers in San Diego first experienced the volatility of the electricity market, demand load in the San Diego basin decreased by 9 percent. *Hearings, February 8, 2001, supra* note 7, at 81 (testimony of Joel Newton). See also Eric Hirst & Stan Hadley, *Generation Adequacy: Who Decides?*, ELEC. J., Oct. 1999, at 8.

207. *Id.*

208. Braithwait & Faruqi, *supra* note 144, at 48.

the fluctuations in the price of electricity throughout the day.²⁰⁹ Because most customers are billed based on their total usage during a given month and a single monthly rate, there is little correlation between the pattern of power consumption and the cost of the electricity.²¹⁰ The prices customers pay to the utility are essentially fixed and consumers have developed their electricity consumption habits within this regulated environment.²¹¹ Once the market opens and consumers are subject to variable, time-of-day electricity rates, they may be shocked by the high cost of using electricity during peak periods, and the benefits of conservation during those periods.²¹² When customers experience the costs and benefits of consuming electricity during different times of the day, they have an incentive to alter their consumption to correspond with periods of cheap power.²¹³ If consumers choose not to alter consumption patterns, they will pay higher rates for that convenience.²¹⁴ Ironically, however, within a restructured market, utilities may have a disincentive to provide such demand response information.

2. The Utility Incentive

Both PURPA and the EPAct of 1992 contain provisions that require utilities to offer demand management options to customers. However, these acts are directed at traditional utilities, which typically control generation as well as transmission and distribution (“T&D”). Because traditional utilities are vertically integrated, they have a built-in financial incentive to induce customers to reduce demand during peak hours.²¹⁵

In a restructured market, traditional utilities are bifurcated into separate, but often affiliated, entities that control generation and T&D separately. The generation affiliates are unregulated bodies

209. *Id.*

210. *Id.*

211. *Id.* at 52.

212. See generally *Energy-Efficient Supplies Going Fast*, ASSOC. PRESS, Feb. 4, 2001, at http://www.enn.com/news/wire-stories/2001/02/02052001/ap_energy_41834.asp (last visited Oct. 5, 2001).

213. *Hearings, February 8, 2001, supra* note 7, at 30 (testimony of Jerry Keenan).

214. *Id.*

215. By reducing customers' demand at peak times, a utility can reduce the amount of electricity that it needs to have available to satisfy potential customer demand. The ability to reduce supply in turn reduces the operational costs required to generate or buy power. Ultimately, significant reductions in customer demand can lead to a reduction in the number of power plants that a utility needs to construct, saving the company considerable capital expenditures. HIRST, *supra* note 180.

and, like any business, are ultimately responsible only to their shareholders.

With these new roles come different priorities for utilities. Implementing demand response measures, arguably, is not one of them. Incumbent utilities will become wires companies whose function in the market is to transmit electricity to customers. With no responsibility for power generation and the high costs associated with operating power plants, these wires companies do not have the kind of incentive to invest in demand response technologies that vertically integrated utilities once did. During the transition to an open market, UDCs focus on recovering stranded costs, increasing profit margins, and retaining customers. Once engaged in an open market, the UDCs' primary responsibility is to pass through wholesale market charges to industrial, commercial, and residential retail customers while ensuring the reliability of the T&D system.

Electricity Service Providers ("ESPs"), the primary competitors to UDCs, face uncertainty as they consider the market's future and their role in it; such uncertainty does not spur an initial confidence in demand management investment.²¹⁶ As such, during this period of uncertainty and price volatility, customers are left without true market information and have little opportunity to react to market shifts. Without market tools and knowledge, consumers are unlikely to adequately seize potential savings or protect themselves financially when electricity markets fully open.

3. Demand Responsiveness in Illinois

Unlike California's restructuring bill, Illinois's Customer Choice Law contains provisions that allow residential and nonresidential customers to elect billing and real-time pricing experiments during the mandatory transition period.²¹⁷ Despite this provision, the number of participants is low.²¹⁸ Illinois electric industry representa-

216. The ESP acts as a financial intermediary between the electricity generator and the end user. Using the regulated distribution system of a utility distribution company, the ESP buys electricity wholesale and sells it retail to industrial, commercial, and residential customers. New ESPs' main concerns are operational and start-up costs and incremental price battles with incumbents. PAUL J. JOSLOW, WHY DO WE NEED ELECTRICITY RETAILERS? OR CAN YOU GET IT CHEAPER WHOLESALE? 2 (Mass. Inst. of Tech. CEEPR, Working Paper No. WP-2001-001, 2000), available at <http://web.mit.edu/ceepr/www/workingpapers.htm> (last visited Dec. 3, 2001) (web page provides link to PDF document).

217. 220 ILL. COMP. STAT. 5/16-106-07 (2001).

218. As of April 30, 2000, one incumbent utility had served more than fifty-four hundred nonresidential retail electric customers pursuant to the terms and conditions of pricing and

tives see the need for continued participation in such programs as a means of establishing greater price signals and transparency;²¹⁹ many have expressed concern regarding the low priority the state is giving to consumer education programs concerning electricity restructuring.²²⁰

Illinois has spent \$1.1 million on electric consumer choice education since passing the restructuring law in 1997.²²¹ This relatively small sum leaves the burden of establishing education programs on local nonprofit organizations. One such group, the Community Energy Cooperative, is funded by an incumbent utility, Commonwealth Edison. The organization is working with residential, industrial, and commercial energy customers to help improve distribution reliability²²² by changing behavior and energy use patterns in communities.²²³ With its \$14.7 million investment in the Cooperative, Commonwealth Edison hopes to help consumers reduce electricity demand, save customers' money, and help reduce peak loads that may threaten reliability in growth areas where demand could eventually exceed supply.²²⁴ Although programs like this should prove successful in reducing some demand in specific local areas, the Illinois legislature needs to adopt a restructuring plan that incorporates a statewide education program for its citizens.

4. Bridging the Information Gap

Communicating with residential consumers can be more difficult than with industrial or large commercial consumers. Because of the

billing experiments. MATHIAS, *supra* note 45, at 31.

219. *Id.* at 27.

220. Participants in the Illinois Commerce Commission Fall 2000 Roundtable noted that other states have allocated substantially more funds than Illinois for electric consumer choice education. Roughly three hundred thousand dollars was spent in Illinois in 1998 and 1999 for the education campaign, "Plug-in Illinois: The Electric Choice Law," during the first year of Customer Choice. This contrasts sharply with the first year spending of \$89 million for consumer education in California and between \$80 and \$90 million in New Jersey and Pennsylvania. While the Illinois fund has increased to \$850,000 for the second year of the consumer education campaign, this figure still falls short of the \$73 million allocated for the second year of consumer education in California. *Id.* at 41.

221. *Id.*

222. The incumbent utility, Commonwealth Edison, has experienced numerous reliability problems due to the age and deferred maintenance of its electricity distribution system. See generally THE LIBERTY CONSULTING GROUP, INVESTIGATION OF COMMONWEALTH EDISON'S TRANSMISSION AND DISTRIBUTION SYSTEMS, at XIX-23 (2000).

223. Press Release, Commonwealth Edison Company, Commonwealth Edison Investing \$14.7 Million into New Venture (June 6, 2000), at http://www.ccco.com/news/comed/display.asp?a=ComEd&rec_id=441 (last visited Oct. 5, 2001).

224. *Id.*

large number of residential consumers, their wide distribution and the relatively small size of their individual electricity usage, exacting a significant savings per dollar invested can be difficult.²²⁵ Nevertheless, by providing customers with the information they need through educational campaigns and demand management feedback, inadequacies in the information flow between supplier and consumer are attacked directly.²²⁶ Such programs accelerate a customer's ability to learn and to benefit from participation in the new energy marketplace.²²⁷

Creating an educated electricity consumer who can actively participate in the restructured electricity market is one of the most challenging aspects of moving from a regulated to a competitive market.²²⁸ For an industry that has never seen competition, the shift is difficult enough. But for consumers who are familiar with the concept of flat-rate electricity, any time, all the time, the suggestion that consumption behavior will be reflected in a monthly electric statement is not necessarily a cause for celebration. Solutions can be hard to find.

A progressive utility in Washington State has begun educating itself and its customers with a demand management program that gives four hundred thousand residential customers meters to monitor hourly electricity usage.²²⁹ Although customers still currently receive a flat monthly rate, included with their bill is a detailed account of peak and off-peak consumption. Though the utility has commercial customers on a real-time meter program, it believes that introducing residential customers to the practice of tailoring a small portion of electricity use to off-peak periods could pay off for parties on both ends of the distribution line.²³⁰ A simple concept—turning meters, “the cash registers of a utility,” into a “communication kiosk,”—may be ahead of its time.²³¹

225. Black & Pierce, *supra* note 25, at 1364.

226. *Hearings, February 8, 2001, supra* note 7, at 84 (testimony of Joel Newton).

227. *Id.*

228. *Id.*

229. Press Release, Puget Sound Electric, PSE Customers Practice “Next Generation” of Energy Management: Puget Sound Energy Urges Shifting Power Use to Off-Peak Times to Lower Demand (Jan. 8, 2001), at http://www.pse.com/pem/tday_pricing.html (last visited Sept. 30, 2001).

230. The company estimates that by getting its nine hundred twenty thousand customers to shift just 10 percent of their peak-hour electricity use to off-peak times of day, it can free up about 200 MW of power. *Id.*

231. Cinda Althoff, *Smart Metering Provides Competitive Advantages to Energy Service Providers*, at http://www.utilitiesproject.com/documents.asp?d_ID=157 (last visited Dec. 1,

Some economists have presumed that in the electricity market, "like all other markets, demand responds to price. . . . When electric rates rise, consumers consume less electricity and buy more energy-efficient equipment."²³² However, as demonstrated in San Diego, that economic assumption does not always hold true.²³³ Consumers without market information cannot respond to the market. San Diego customers, unable to gain real-time information regarding electricity prices, were blindsided by high electricity prices and could only implement and quantify conservation measures after they had received their electricity bill.²³⁴ Even then, customers did not have the information necessary to know when, during the day, electricity was most expensive.²³⁵ Therefore, customers interested in reducing their electric bills had to reduce their total electricity use, rather than reconsidering their energy use patterns.²³⁶ Clearly, it is difficult to change customers' electricity consumption behavior without access to real-time information.²³⁷

If ESPs and UDCs are allowed to pass the cost of electricity and ancillary services directly to consumers, as they should in a competitive market,²³⁸ then customers need the opportunity and tools to respond quickly. A successful market transition requires that a demand-side component to restructuring be in place before markets open.²³⁹ As demonstrated in California, a state runs a great risk in extolling the market system when its citizens do not have the information they need to become active market participants, and not merely passive ones.

CONCLUSION

Without the implementation of new transmission access and creative demand response programs, Illinois will perpetuate the

2000).

232. Black & Pierce, *supra* note 25, at 1364.

233. Borenstein, *supra* note 9, at 1.

234. *Id.*

235. *Id.*

236. *Id.*

237. F.E.R.C., STAFF REPORT TO THE FEDERAL ENERGY REGULATION COMMISSION ON WESTERN MARKETS AND THE CAUSES OF THE SUMMER 2000 PRICE ABNORMALITIES: PART 1, at 6-13 (2000).

238. Any attempt to try to curb a demand response market is dangerous in that it will hurt customers and hamper innovation. *Hearings, February 8, 2001, supra* note 7, at 118 (testimony of Joel Newton).

239. Hirst, *supra* note 10, at 34.

monopoly advantage of incumbents and create underinformed customers. Without the opportunity to participate actively in a fully restructured market, customers will be unable to reap the benefits, or mitigate the risks, inherent in the new competitive environment. Expansion of transmission can be brought about through federally ordered investment incentives and new, intergovernmental siting agencies. Adequate demand response measures require state incentives and prolific education.

Models for perfect competition exist when both buyers and sellers are armed with complete information about supply and demand.²⁴⁰ Electricity markets must resolve the information imbalance that currently exists among market participants. If market competition is to exist, price cannot be subject to government regulation or other artificial prohibitions that allow one participant to gain an undue advantage over another.²⁴¹

Every state considering electricity restructuring will grapple with the task of offering equal access to all market participants and delivering accurate signals to all consumers; Illinois's chances of success in adopting a competitive market system will improve with a streamlined and representative regulatory scheme, informed market participants, and dexterity in avoiding the unexpected squalls of restructuring.

240. John P. Gould, *Price Theory*, in *ENCYCLOPEDIA OF ECONOMICS*, *supra* note 11, at 759.

241. *Id.*

