

Electric Restructuring in New England – A Look Back

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By: Reishus Consulting, LLC

Executive Summary

State policymakers expressed a number of rationales in 1990s to support the adoption of electric retail restructuring at the time, in some cases explicitly stating their goals in the enacting legislation or orders. Among the goals most often cited were:

- Market mechanisms are preferred over regulation to set price where viable markets exist.
- Risks of business decisions should fall on investors rather than consumers.
- Consumers' needs and preferences should be met with lowest costs.
- Electric industry restructuring should not diminish environmental quality, compromise energy efficiency, or jeopardize reliability.

Notably, the New England wholesale market was opened first to competition by federal reforms, and thus all states in the region have been subject since then to some degree of market forces as reflected in generation prices. In the end, five of the six New England states, all but Vermont, followed by choosing to restructure some or all of their retail power markets as well. The characteristics shared by the state restructuring plans included divestiture of the bulk of the investor-owned utilities' generation fleet, authorization of stranded cost recovery in rates, and granting end-use customers the option of choosing from alternative suppliers.

Since the opening of wholesale competition, the region has increasingly relied additions of new natural-gas fired generation, which has led to improvements in overall fleet operating efficiency, as well as lower emissions of both conventional and carbon pollutants. Average consumer power prices have generally risen as they have during this time period across the US, in both restructured and non-restructured states.

A number of issues and dynamics have arisen in the years since restructuring. Many are technology based. These present new challenges and opportunities to state policymakers and others in connection with the future of the electric power system, means to serve consumers most cost-effectively and in a way that advances environmental objectives. Some of those issues are noted at the end of this paper.

Introduction

Electric restructuring swept through New England in the late 1990s near the end of a period of broad interest in deregulating a number of economic sectors that were once considered to be natural monopolies, including the provision of electricity supply. Reforms in federal regulation and statutes that began as early as the 1970s gradually opened up much of the wholesale power market to competition by the 1990s, but because of the split jurisdiction in regulation of the US power sector, it was left to each state's policymakers to choose whether to further open those energy markets to competition at the retail level, that is, to provide end-use customers with competitive electricity supply options.

This paper focuses on the events and underlying rationale that led to the enactment and implementation of state-level electric deregulation - more precisely referred to as "restructuring" - in five of the six New England states, by citing examples of the publicly stated objectives and goals that policymakers and stakeholders expressed when adopting the regulatory framework that opened retail electricity markets to power supply competition. A short review of the wholesale electric restructuring is included in order to provide some important historical context regarding its role as precursor to state-level restructuring.

At the request of NESCOE, this review also includes a brief examination of publicly available data points regarding the region's generation fleet and average customer rates before and after restructuring, as well as one specific feature of retail restructuring programs in New England, namely the approved treatment of different utility transition charges, i.e., stranded costs, that were passed on to customers for recovery in future rates. A larger description of the set of restructuring elements adopted by each state is included in Appendix 1.

Finally, the paper includes a brief synopsis of a number of relevant issues and goals that have arisen since the opening of wholesale and retail electric markets almost twenty years ago that New England stakeholders are currently grappling with, such as federally-imposed carbon policies and technology improvements in small-scale solar facilities that have made behind-the-meter distributed generation more attractive to retail customers.

Restructuring of the US wholesale electricity markets came first

Before delving into a review of New England states' electric restructuring, some context setting may be helpful, because the wave of federal and state electric restructuring activity did not occur in an historical vacuum: deregulation of certain transportation and non-electric utility markets all preceded federal and state efforts to reform the wholesale and retail electric markets.

Electric restructuring in fact came towards the end of a broader set of regulatory reforms were made in traditionally-regulated monopoly industries in the US. Indeed, support for a move toward more open competition across sectors of the economy can be found as early as the 1970s during the Ford and Carter administrations, and accelerated in the Reagan and Bush eras of the 1980s and 1990s, when the airlines, trucking, and railroad industries were all effectively deregulated, and large portions of the telecommunications and natural gas sectors were as well.

Deregulation of the telecommunications industry will likely be familiar to at least one set of energy industry stakeholders, namely, those state regulators who experienced a revolution in the telecom markets over the last two decades, starting with passage of the federal 1996 Telecommunications Act, and accelerated by massive technology changes that fundamentally reshaped the consumer market for telecom services since then. Although some might argue it was the breakup of AT&T by federal antitrust consent decree in 1982 that signaled the true start of telephony deregulation, it is remarkable to consider how much change the telecom industry has undergone since the 1996 Act, which explicitly opened both local and long telephone distance service to competition. Indeed, few state regulators then likely anticipated the consumer-focused technology advancements, including wireless data and internet services, which made possible today's societal preference for mobile phones over plain old telephone service, as evidenced by the simultaneous decline in number of deployed landlines and the rapid proliferation of smart phones, devices that obviously deliver to end-use customers far more than simple voice communication.

Meantime, sweeping energy reforms came first at the federal level to the natural gas sector, including the lifting of interstate price controls in the 1980s and the opening of access to gas pipelines in the early 1990s to large customers, including independent power plants. Significant technological improvements also provided for deployment of larger and more efficient combined cycle natural gas-fired power plants, supplanting previous utility reliance on less-efficient single-cycle fossil-fired steam units, leading many, including large industrial energy users, to believe that gaining direct access to new gas-fired capacity from non-utility players would be less expensive than the power that could be obtained exclusively from the existing monopoly utility's fleet. It is probably fair to infer an interrelationship between federal reforms and technology improvements; that is, increased demand from both independent developers and large industrial customers likely helped spur competition among international turbine manufacturers that led to a significant improvement in gas-fired machines deployed to generate electricity over the previous decades. The power sector as a whole has no doubt benefited from technology improvements gained by movement from aero-derivatives to frame machines deployed in the early 1990s, to today's flexible units that have even greater operating efficiency, as measured by lower heat rates, and flexibility characteristics.¹

Federal electric restructuring activity in the 1970s and 1980s that preceded state restructuring activity gradually removed most of the impediments to competition at the wholesale or bulk power generation level, while still leaving unchanged the market for the ultimate sale and price of electricity to end-use customers, i.e. the retail activity regulated by the states. Noteworthy federal reform actions included:

- Passage of the federal 1978 Public Utility Regulatory Policies Act (PURPA) legislation, which required local utilities to purchase under long-term contracts the energy produced from all

¹ For more information on the technical evolution of natural gas-fired generation, see discussions at www.gasturbine.org and archived papers of the Institute of Diesel and Gas Turbine Engineers, www.idgte.org.

“qualified” electric facilities (QFs) built and operated within their franchise territory. QFs as defined by the PURPA law were either industrial cogeneration plants associated with a thermal load related to large industrial processes like paper or chemical production, or small renewable power plants such as geothermal or waste-fired.

- The QF contracts were required to be priced at the utilities’ estimated long-term avoided costs (LTAC), i.e., an estimate of what it might otherwise cost the utility to build and operate a similar level of new capacity itself. While the explicit intent of the Act was to encourage diversity in power supply, the utilities’ LTAC estimates ultimately proved in many cases to be too high, resulting in long-term energy contracts signed in the late 1980s and early 1990s that ultimately formed the basis of some of the stranded costs recovered in the 2000s in utilities’ restructuring transition charges.
 - Still, in terms of its likely impact on sparking the growth of a non-utility generation market in the US prior to restructuring, PURPA could fairly be considered a success, as QF contracts started to proliferate in the late 1980s, after a slow start: in 1986, 80 percent of the net additions to total electricity generating capacity that year was still added by utilities, by 1989, however, the utility share of net capacity additions was just over 50 percent. In 1990 and 1991 non-utilities for the first time provided more than half of the net capacity additions annually.²
- The Energy Policy Act of 1992 (EPA92) among other actions created a new class of power suppliers, so-called exempt wholesale generators (EWGs), that gave both unregulated subsidiaries of existing utilities and merchant/independent power producers (IPPs) the opportunity to interconnect all types of new generating plants, no longer just QFs, to the regional wholesale transmission system and provided the option to “wheel” the generated power to neighboring utilities for sale at the wholesale level. Retail customers, including large industrials, still could not purchase the power directly from competitive providers. However, the result was a further acceleration of the dominance of new non-utility capacity additions, just a few years after implementation of EPA92. For example, the US Energy Information Administration (EIA) estimated that by 1998, 82% of the nearly 6.5GW of electric supply put in service that year in the US was built by non-utility players.³
 - After several rounds of inquiries and rulemakings that began in the late 1980s, the Federal Energy Regulatory Commission (FERC) issued a series of Orders, including 888 & 889 (April 1996), and 2000 (December 1999) that required electric utilities to open their transmission lines to outside, unregulated suppliers on a non-discriminatory basis and created independent transmission system operators, also known as regional transmission organizations (RTOs), to create and operate on a fair and transparent basis wholesale competitive electric markets across multiple utilities. As part of this federally defined role, RTOs are required to be both owner- and resource-neutral in the administration of those markets.

² US DOE EIA, “The Changing Structure of the Electric Power Industry, 1970-1991,” March 1993.

³ US DOE EIA, “The Changing Structure of the Electric Power Industry 2000: An Update,” October 2000.

In New England, the RTO is the Independent System Operator-New England (ISO-NE), which was established in 1997 by the region's then already-operating voluntary power pool, the New England Power Pool (NEPOOL). Under FERC jurisdiction, the ISO-NE operates the region's electric bulk power grid as well as administers its competitive wholesale electric market.⁴

- Other federal agencies also engaged in analysis suggesting that the electric sector was ready to be restructured. For example, the Congressional Office of Technology Assessment issued a report in 1989 analyzed five possible outcomes it forecasted if the electric retail markets were opened, while in 1993, the US Department of Energy provided a comprehensive review of energy restructuring activities over the prior twenty years, and suggested that the US was primed to move forward with creating fully competitive supply markets.⁵

By 2000, it was clear that changing the rules to allow unfettered competition in the wholesale electric market had succeeded in giving rise to a large set of non-regulated utility generation owners that deployed shareholders' capital to build new power plants. Other factors clearly played an important role in increasing competition, however, beyond federal regulatory rule changes that provided open access to the transmission system by unregulated players. The US Department of Energy's Energy Information Administration noted that:

"[s]everal factors have caused this structure to shift to a more competitive marketplace. First, technological advances have altered the economics of power production. For example, new gas-fired combined cycle power plants are more efficient and less costly than older coal-fired power plants. Also, technological advances in electricity transmission equipment have made possible the economic transmission of power over long distances so that customers can now be more selective in choosing an electricity supplier. Second, between 1975 and 1985, residential electricity prices and industrial electricity prices rose 13 percent and 28 percent in real terms, respectively. These rate increases, caused primarily by increases in utility construction and fuel costs, caused Government officials to call into question the existing regulatory environment. Third, the effects of the Public Utilities Regulatory Policies Act of 1978, which encouraged the development of nonutility power producers that used renewable energy to generate power, demonstrated that traditional vertically integrated electric utilities were not the only source of reliable power."⁶

The EIA further noted in the same report that, fifteen years ago, many states were actively moving forward to opening their retail markets to competition, for much the same reasons, in order to bring benefits to end-use customers:

"In recent years, economists and public policy analysts have extolled the advantages of competition over regulation and have promoted the idea that free markets can drive down costs

⁴ For more detail on the ISO-NE's history as well as its current activities, go to www.iso-ne.com.

⁵ Please see Appendix 2 for a list of sources reviewed during the drafting of this report.

⁶ US DOE EIA, "The Changing Structure of the Electric Power Industry 2000: An Update," October 2000.

and prices by reducing inefficiencies. Competitive industries may also be more likely to spur innovations with new technologies. Recent actions with regard to electric power by legislators and regulators in the United States are evidence of the changing approach to dealing with what until recently has been a regulated monopoly. Originally, protecting consumers was a primary motivation for decisions to impose regulatory constraints on the industry. Today, legislators and regulators are making laws and rules that promote competition across the economy for the same purpose, because they believe that consumers will benefit more from an industry whose members must compete for customers than from an industry composed of regulated monopolies.”⁷

“Not all State commissions have moved with the same zeal, even though most of them have under consideration the merits and implications of competition, deregulation, and electric utility industry restructuring. States with high electricity rates, such as California and those in the Northeast, have had compelling reasons to promote competition in the hope of making lower rates available to their customers in general.”⁸

Rationale offered at the time for restructuring retail electric markets

By the mid-1990s, at the same time that the competitive wholesale power market continued to evolve, at least half the US states, mostly those with higher-than-national average retail rates, began investigating the potential benefits of opening their retail markets to competition. California, New York, and New England were early leaders in the exploration, although by the late 1990s, the majority of US states, even those with electric rates close to or even below the national average, were also considering the beneficial prospects of deregulating their retail supply markets, particularly given seemingly unrelenting rate increases over the previous few decades. It is worth noting that at the time, there was virtually no discussion of reforming the distribution portion of the electric system, which was deemed by most to remain a natural monopoly, although that topic is now under active consideration in various “grid modernization” and distributed generation proceedings on-going in many states today. The final section of this paper explores this and other current, post-restructuring issues further.

Echoing many of the same arguments made in reform efforts heard in other deregulated industries, proponents of retail electric restructuring suggested that opening the generation markets to customers would:

- shift the risk of long-lived, capital-intensive investment decisions from utility ratepayers to the shareholders of unregulated players
- lead to cost savings to consumers, especially to large industrial customers
- provide new choices for all retail customers, such as the option to select “greener” electricity generated from renewable power sources

⁷ *id.*, p. 41.

⁸ *id.*, p. 81.

The US Government Accounting Office in 2002 offered a succinct explanation to Congress for the rationale behind states' interest in pursuing electric restructuring:

“The goal of restructuring the electricity industry is to increase the amount of competition in wholesale and retail electricity markets, which is expected to lead to a range of benefits for electricity consumers, including lower prices and access to a wider array of retail services than were previously available. Increasing the amount of competition requires structural changes within the electricity industry, such as allowing a greater number of sellers and buyers of electricity to enter the market. Competition is expected to produce benefits for consumers by increasing the efficiency of wholesale electricity generation and by encouraging innovations in retail electricity services. Such efficiency gains are expected to occur as a result of improved incentives for electricity suppliers to provide better service at lower prices.”⁹

The FERC elaborated, in a report to the US Congress on “Competition in Wholesale and Retail Markets for Electric Energy,” in 2006:

“In the early 1990s, several states with high electricity prices began exploring opening retail electric service to competition. While customers would choose their supplier, the local distribution utility would still handle the delivery of electricity. Retail competition was expected to result in lower retail prices, innovative services and pricing options. It also was expected to shift the risks of assuring adequate new generation construction from ratepayers to competitive market providers.” (p. 10)

“States adopting retail competition plans generally did so to advance several goals, including:

- lower electricity prices than under traditional regulation through access to lower-cost power in competitive wholesale markets where generators compete on price and performance;
- better service and more options for customers through competition from new suppliers;
- innovation in generating technologies, grid management, use of information technology, and new products and services for consumers; and
- improvements in the environment through displacement of dirtier, more expensive generating plants with cleaner, cheaper natural-gas-fired and renewable generation.”¹⁰

“Retail competition allowed customers to choose their electric supplier or marketer, but their electricity would still be delivered by the local distribution utility. The idea was that customers could obtain electric service at lower prices if they could choose among suppliers. For example,

⁹ U.S. Government Accounting Office, *LESSONS LEARNED FROM ELECTRICITY RESTRUCTURING Transition to Competitive Markets Underway, but Full Benefits Will Take Time and Effort to Achieve*, December 2002, p. 21.

¹⁰ FERC Report to US Congress, 2006, p. 88.

they could buy from suppliers outside their local market, from new entrants into generation, or from power marketers, any of which might charge lower prices than the local distribution utility. The ability to choose among alternative suppliers was intended to reduce market power that local suppliers might otherwise have, so that customers might see lower prices from local suppliers. Also, it was thought that new suppliers might offer innovative price and other terms to purchase electricity that could improve the quality of service.”¹¹

It was widely noted in other documents and discussions of the time, including at the state level, that competitive wholesale electric markets were essential for encouraging investment in new, more efficient generation that might lead to price reforms, and many observers saw the need to ultimately open the retail markets, to complete the transformation by offering end-use customers a choice of competitively-priced supply options. For example, a report from a Minnesotan government task force in 2000 stated that,

“[t]here is near universal agreement that the industry needs a robust, fluid and reliable competitive market for bulk power. Some believe that such a market would be a sufficient reform, others believe that it is a necessary component of a truly competitive retail market for energy. A robustly competitive wholesale market is critical to sending appropriate signals to investors regarding the need for new investment in generation and transmission resources.”¹²

Rationale offered by state policymakers

Specific rationale for adoption of retail-level restructuring was often included in state enabling legislation. For example, a 1999 New Hampshire Commission report described its Legislature’s intent in opening retail markets, noting

“...it has become apparent in industry after industry that the natural monopoly presumption no longer necessarily applies and that competition is appropriate in areas including local telephone service and electric generation. See, for instance, Laws of 1996, Chapter 129, where the Legislature found that ‘[m]arket forces can now play the principal role in organizing electricity supply for all customers instead of monopoly regulation’ and ‘[i]t is in the best interests of all the citizens of New Hampshire...to establish a competitive market for retail access to electric power as soon as it is practicable.’”¹³

More explicitly, Rhode Island’s legislation stated the following seven goals for opening the retail electric markets in its state:

“(1) that lower retail electricity rates would promote the state's economy and the health and general welfare of the citizens of Rhode Island;

¹¹ *Ibid.*, p. 87.

¹² Keeping the Light’s On – Securing Minnesota’s Energy Future” September 2000.

¹³ New Hampshire PUC, Biennial Report, July 1, 1997 – June 30, 1999, p iv.

(2) that current research and experience indicates that greater competition in the electricity industry would result in a decrease in electricity rates over time;

(3) that greater competition in the electricity industry would stimulate economic growth;

(4) that it is in the public interest to promote competition in the electricity industry and to establish performance based ratemaking for regulated utilities;

(5) that in connection with the transition to a more competitive electric utility industry, public utilities should have a reasonable opportunity to recover transitional costs associated with commitments prudently incurred in the past pursuant to their legal obligations to provide reliable electric service at reasonable costs;

(6) that it shall be the policy of the state to encourage, through all feasible means and measures, states {where fossil-fueled electric generating units producing air emissions affecting Rhode Island air quality are located to reduce such emissions over time to levels that enable cost effective attainment of environmental standards within Rhode Island};

(7) that in a restructured electrical industry the same protections currently afforded to low income customers shall continue.”¹⁴

Likewise, the Connecticut Commission offers the following summary of the rationale on its website explaining restructuring to the public:

“Overall, the General Assembly concluded that competition among electric generating companies is in the public interest, especially by:

- benefiting the state’s electric consumers by providing both choice and the opportunity for savings,
- benefiting the state’s economy by creating opportunities to bring in new electric generating companies and new generation technology,
- benefiting the state’s environment by encouraging generating companies to develop and new technologies which improve air quality,
- benefits the environment by mandating conservation and renewable resources portfolio.”¹⁵

Similar rationale was provided in state inquiries and legislation passed in states throughout the country, not just New England. For example, the findings of the Pennsylvania General Assembly in its enabling legislation made the following case:

¹⁴ Rhode Island Chapter 316 96H HB8124, revision to Title 39-1-1 (a)3(d).

¹⁵ CT PURA website, answers to frequently asked questions in regard to “An Act Concerning Electric Restructuring.”

“(1) Over the past 20 years, the federal government and state government have introduced competition in several industries that previously had been regulated as natural monopolies.

(2) Many state governments are implementing or studying policies that would create a competitive market for the generation of electricity.

(3) Because of advances in electric generation technology and federal initiatives to encourage greater competition in the wholesale electric market, it is now in the public interest to permit retail customers to obtain direct access to a competitive generation market as long as safe and affordable transmission and distribution is available at levels of reliability that are currently enjoyed by the citizens and businesses of this Commonwealth.

(4) Rates for electricity in this commonwealth are on average higher than the national average, and significant differences exist among the rates of Pennsylvania electric utilities.

(5) Competitive market forces are more effective than economic regulation in controlling the cost of generating electricity.”¹⁶

Rationale offered by other stakeholders

Many stakeholders weighed in as well with their perspectives of what they expected to gain from restructuring the US electric markets. Among the most ardent voices were those of the large industrial customers. For example, the Electricity Consumers Resource Council, better known as ELCON, is a national trade association representing industrial electricity users that has advocated for competitive energy markets since at least the early 1980s. In its paper, *Retail Competition in the US Electricity Industry: Eight Principles for Achieving Competitive, Efficient, and Equitable Retail Electricity Markets*, from the early 1990s, ELCON argued that

[c]ompetition in the U.S. electricity industry – particularly retail competition – will benefit all end users by: (a) providing a broader range of products and services with greater value at competitive prices, and (b) creating new business opportunities throughout the economy, with the potential for new jobs and income growth. (p. 2)

Similar rationale were provided in documents at the time by other stakeholders, including advocacy groups such as the Citizens for a Sound Economy, Americans for Affordable Electricity, and the utility-sponsored Alliance for Competitive Electricity, whose New England supporters included CMP and NEES.

Not all observers were as sanguine, however, about the benefits achievable from electric choice. For example, in 1998, the Utah Public Service Commission stated that

“[i]mplicit in the restructuring debate is the assumption that the potential benefits arising from competition -- lower prices, product innovation, quality and service enhancements -- will

¹⁶Pennsylvania legislation, HB 1509 (1995).

outweigh downside effects like increased transaction costs, price volatility, reliability problems, and loss of scope economies. Whether this is true is an unanswered empirical question.”¹⁷

A number of explicit concerns were raised, for example by consumer groups and some environmental groups, that retail restructuring could have adverse impacts, including possibly the

- Inability of low-income customers to reap the benefits of competition,
- diminished utility support for efficiency programs, and
- potential for market power abuses by incumbent utilities.

Retail restructuring moves forward in New England in the 1990s

The New England states, including Vermont, were among the first states in the US to explore the potential benefits of retail restructuring. Legislatures and public utility commissions began exploring the issue through a variety of initial inquiries and utility pilot programs, in the mid-1990s. By the year 2000, five of the six New England states had partially or fully restructured their electric retail markets.

Although the Vermont Public Service Board at the time also recommended moving forward with deregulation, restructuring legislation failed to win support in both chambers for several years. A statewide task force established by Vermont Governor Dean in 1998 also recommended restructuring but the House ultimately elected not to proceed and the state currently remains the only one in New England not to have adopted policies in some fashion to restructure its vertically integrated power utilities.

But the rest of the states in the region moved forward quickly. Following the success of several small pilot programs in the region, New Hampshire’s legislature in 1996 was the first state in the nation to pass a bill enabling restructuring. Rhode Island followed quickly and was the first state to officially implement restructuring in 1997, with Maine, Massachusetts and Connecticut all moving forward with their restructuring plans before the end of the decade. In fact, by the year 2000, roughly half of US states had passed restructuring legislation and begun implementation, including California, New York, and most of the mid-Atlantic states, while a number of other states were actively exploring the prospect. The national interest in and activity surrounding expansion of state restructuring came to an end, however, with the California energy crisis of 2000-2001.

Much has been written about the California energy crisis, and interested readers are urged to explore analysis of the event and its repercussions further; several reports listed in the bibliography included in Appendix 2 can provide a good starting point. It is fair to note that insufficient power supply along with the execution of large power contracts at above market rates and the bankruptcy of its largest utility, PG&E, played a significant role in prolonging California’s troubles at the time.

¹⁷ Public Service Commission of Utah, Report to the Electrical Deregulation and Customer Choice Task Force, October 1, 1998.

Although the specific details of the restructuring plans vary by each state and by affected utilities¹⁸ within a state, the elements of retail restructuring plans adopted across the country, including New England, are broadly similar. They generally included:

- Divestiture or structural separation of all or a significant portion of the generation fleet held by the formerly vertically integrated electric utility, either as mandated by law or a result of negotiations as part of an overall settlement agreement. The remaining franchise utility would continue to provide delivery service of power to end-use customers as a regulated local transmission and distribution (T&D) company, also referred to colloquially as “the pipes and wires” company;
- Proceeds from the sale or transfer of divested generation assets were typically put towards offsetting the size of the transition charge, also known as “stranded costs” imbedded in the utility’s rate base; the stranded cost figure represented the amount of regulator-approved but ultimately uneconomic investments in generation, regulatory assets, and above-market PPAs for QFs that were still being recovered from customers in rates prior to restructuring;
- A “provider of last resort,” (POLR) “default service,” or “standard offer” provision, in essence to supply power generation to customers who choose not to migrate to a competitive offer, or who were economically unattractive to competitors and therefore unable to secure alternative supply service;
- Multi-year rate freezes or mandated rate decreases in the first years of restructuring, to provide immediate savings to consumers or, at a minimum, to avoid unexpected rate increases for an initial period;
- Consumer protections in the form of competitive supplier rules and statewide efforts to educate consumers on their option to choose a competitive supplier;
- Unbundling of the bills, so that consumers could clearly see and better understand the disaggregated charges as separate line items that comprised their total electricity charge, which typically included distribution, transmission, system benefits (such as energy efficiency charges), stranded cost or transition charges, and the now-competitive generation component. In many states, competitive suppliers were given the option to have their generation charges appear on the distribution utility’s bill, so that customers continued to receive a single monthly bill, often as a means to reduce potential confusion among consumers.

The restructuring plans of the New England states generally included most of these elements. For example, of the five restructured states, all but Maine instituted immediate multi-year rate freezes or decreases for the default service retail rate at the start of the plans. Divestiture of the majority of the fossil-fired units in the region was either mandated by law or negotiated as part of the overall restructuring settlement agreements in each state. Please see Appendix 1 for a discussion of program

¹⁸Typically only the major investor-owned utilities in a state were restructured; smaller utilities, including cooperatives and municipals, were largely exempted.

highlights of each of the five restructured states, drawn from summaries provided by government sources, as well as a timeline of key events related to early New England state restructuring activity.

Stranded cost recovery was one of many key elements of state restructuring plans

Among the most significant elements of state restructuring at the time was debate over the recovery by ratepayers of the cost of utility stranded assets. These costs across the region were in excess of \$3.6 billion. Below is a brief description of the specific stranded cost amounts approved for recovery at or near the start of restructuring, found in documents such as the utility settlement agreements reached at the time electric restructuring was implemented. Note that the estimated stranded cost amount varied significantly across states and utilities, not just in New England, depending on the size and composition of the affected utility's generation fleet and long-term contracts held at the time of restructuring, as did the length of time authorized by state Commissions or legislatures to recover those amounts.

- Rhode Island: By state statute, transition charges for the termination for all-requirements contracts are to be recovered by non-bypassable charge paid by all customers of the distribution company. The charge to customers was set at 2.8¢ per kWh from July 1997 to December 2000. Subsequently the rate was reset by the Commission, with adjustments made for over- or under-recoveries in the initial period.
- Massachusetts: Stranded costs were awarded if conforming utilities had demonstrated that they had divested all non-nuclear generation and attempted to mitigate all other costs. A review of documents revealed the following amount of securitization bonds were issued, in association with approved levels of stranded cost recovery:
 - Boston Electric/NSTAR - \$725M issued July 1999
 - Western Mass Electric - \$155M issued May 2001
 - Boston Electric/NSTAR - \$675M issued March 2005, explicitly for remaining purchased power buyouts
- New Hampshire: The PUC first approved \$688M of recovery for PSNH with an additional 37\$M potentially eligible but legislation was required to fund any amount. When SB 472 was passed, authorizing the financing, PSNH issued 525\$M of bonds in 2001 with maturities varying between 1-12 years; i.e., the final maturity ended in 2013. The company issued another round in 2002 for out-of-market purchased power agreements of \$50M, which matured in 2008.
- Connecticut: The PURA authorized up to 1.5\$B in bonds for stranded cost recovery for CL&P. The Office of Consumer Counsel appealed the decision to Supreme Court; a settlement agreement resolving the appeal allowed the utility to issue 1.4B\$ in recovery bonds, of which approximately \$1B was for out-of-market contracts and \$400M was for paying down debt related to generation and other regulatory assets. The bonds were issued in the spring of 2001.
- Maine: Stranded cost rates were initially set for CMP, BHE and MPS effective March 1, 2000 for a 2-year period coinciding with the first 2-year sale terms of the utilities' entitlements. During

2001, the Commission initiated formal proceedings to reset stranded cost rates for the period beginning March 1, 2002 for BHE, CMP and MPS. For example, CMP's residential class stranded cost rate was set at about 1.4 cents per kWh, which was 20% of the total T&D rate for those customers. CMP's stranded cost account had a balance of about \$125 million as of March 1, 2002 and was amortized over the following four years.

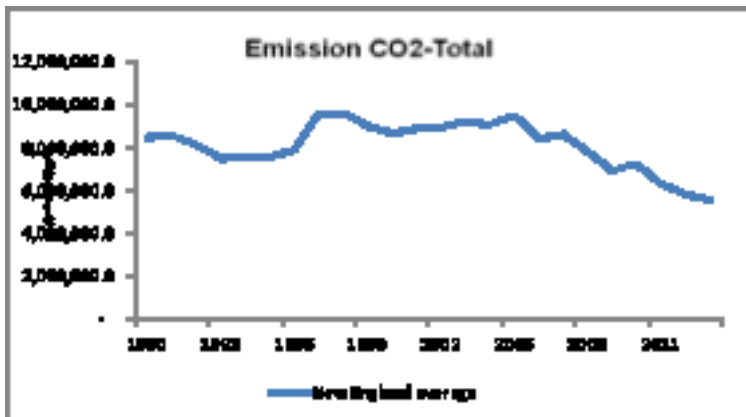
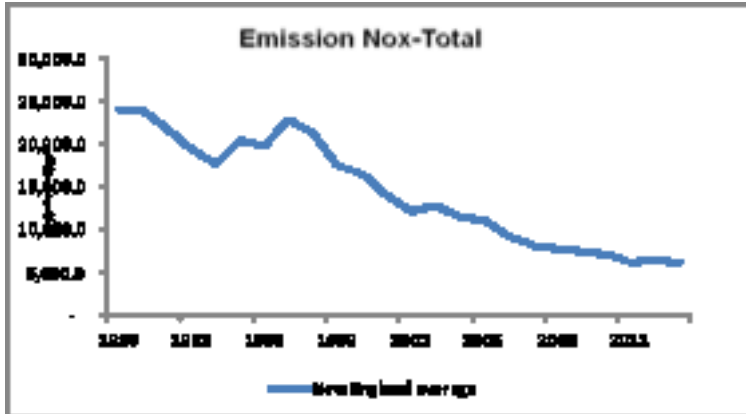
General observations derived from data, post-restructuring

Although this review is not intended to evaluate either the rationale for or the results of restructuring in New England, it is nonetheless informative to look at publicly available facts and data on various aspects of the electricity sector in the periods before and after retail restructuring. The discussion below is not meant to suggest that restructuring was the sole or direct cause of these changes, as it is fair to note that there are likely a large number of confounding factors involved in the evolution of New England's power sector in the last two decades.

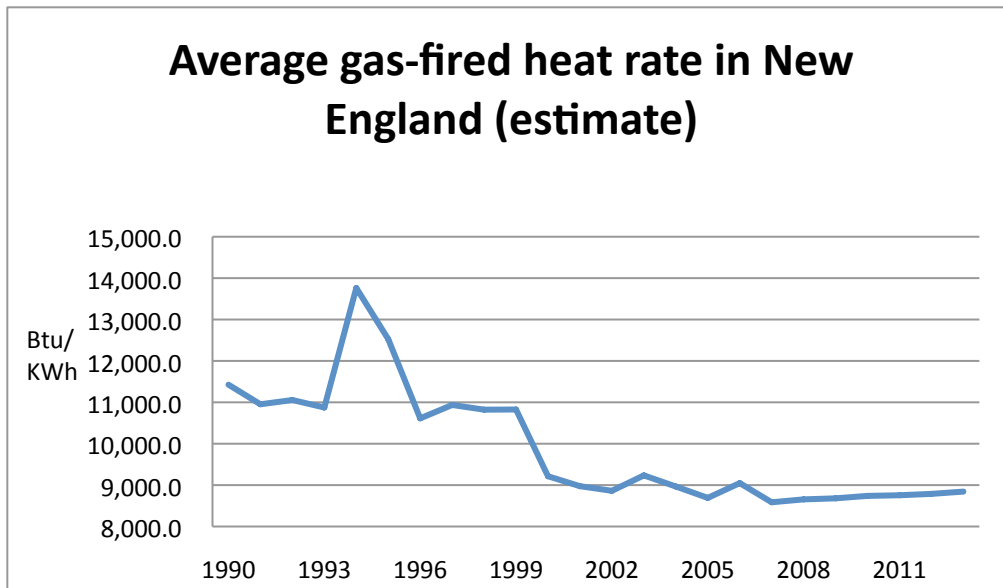
Characteristics of the generating fleet

The composition and thus attributes of generation fleet that supplies New England consumers with their electricity has changed significantly since the 1990s when large amounts of new non-utility generation was added to existing fleet. Based on information available from the ISO-NE, the US EIA, and other websites as noted, the following observations can be made:

- The proportion of generation added by non-regulated players, be it independent producers or the unregulated subsidiaries of utilities, rose dramatically in the 1990s prior to retail restructuring.
- In New England, natural-gas fired generation has been the dominant source of new capacity additions (and electric energy production) annually over the last twenty years, leading to increased reliance overall on natural gas to supply the region's power load, although renewables have also increased.
- Given that the fuel mix in New England has gradually been reshaped by new additions of more efficient combined cycle natural gas plants, as well as by smaller amounts of non-emitting renewable sources of generation, the region's emissions of both conventional pollutants and carbon from power plants have fallen over time. (Due to natural gas pipeline constraints during winter months, and the region's resulting reliance on fuel oil, emissions have risen over the past few winters.)



- Average heat rates for the region’s natural gas generating fleet, an industry measure of operational efficiency in converting fuel into electricity, improved as more efficient combined cycle plants have replaced less efficient, single-cycle steam units.



Customer related data

Much of the rationale offered above in support of restructuring the electricity supply markets related to the benefits that consumers would see, both from potential cost savings and from new options made available to customers by competitive suppliers.

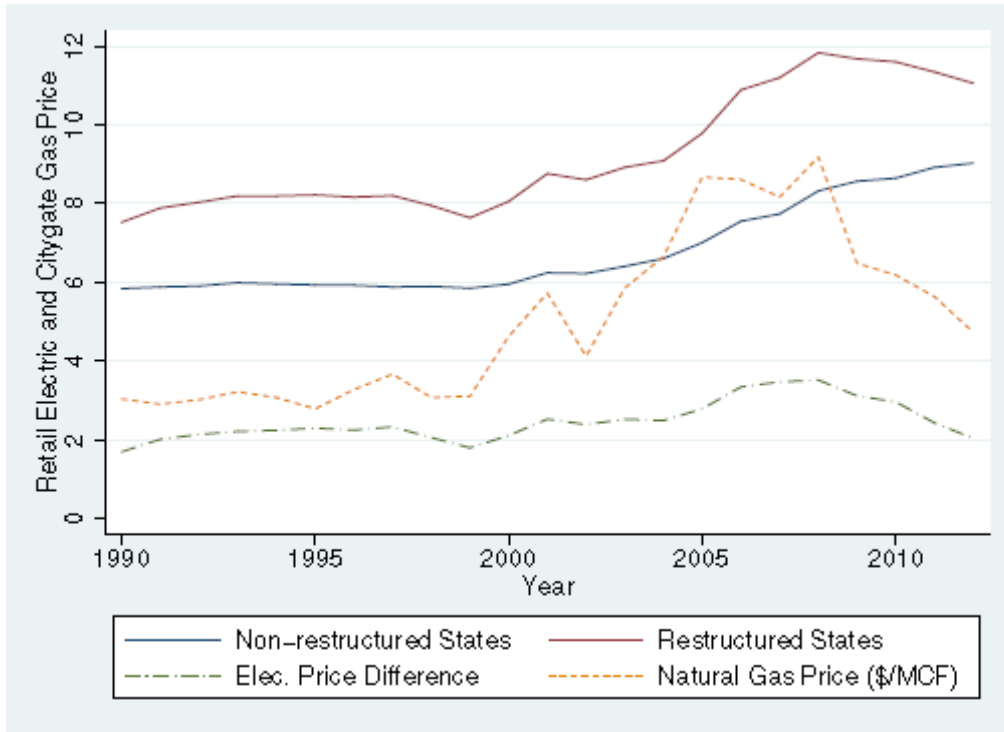
Electric rates for smaller customers in the initial years after retail restructuring remained steady or did go down briefly in some states, typically as a result of mandated rate cuts and freezes, but overall, the trend in consumer electricity prices since 2000 has been generally upward, as have rates of customers in non-restructured states and the national average rates.¹⁹ A recent paper by the Compete Alliance, using EIA data, grouped all US states into either restructured or non-restructured camps, and compared the two groups across several dimensions. Notably, it found that between the years 1997-2014, the cumulative average rate increase was roughly 40% for customers of the restructured states, but nearly 60% higher for the non-restructured states.²⁰

Similarly, a review conducted this year by researchers at the Energy Institute at Berkeley's Haas school compared estimates of the average annual electric retail rates for restructured and non-restructured states in aggregate over the past two decades, and plotted those rates along with the underlying natural gas price. Retail rates in both groups rose significantly over the period, although the authors argue that

¹⁹ Rate estimates in this review are derived from indirect data, such as from average revenue/kWh sold, because consistent historical tariff data is generally not easily accessible.

²⁰ Compete Alliance, *Evolution of a Revolution*, July 2015.

the influence of the volatile natural gas price is felt much more strongly in the restructured states. Its illuminating chart is included, below.²¹



A number of other market observers over the years have analyzed the retail rate trends since restructuring, and despite the difficulty in isolating the many confounding factors in play, have suggested that restructuring was on balance a net positive for ratepayers. For example, Bates White, a law firm, in its report *Retail Rate Comparisons and the Electric Restructuring Debate* offers a typical pro-restructuring comment about the price benefit it suggests has accrued to retail customers in the wake of restructuring:

“Electric restructuring has provided substantial benefits both up front, in the form of multiyear rate caps, and ongoing, through the expansion of wholesale markets, incentives for efficient investment and plant operation, and shifting risks associated with plant construction and performance away from consumers. Yet some increasingly vocal critics, such as the APPA, advocate a radical change in course that would eliminate the main elements of restructured power markets and reimpose regulatory methods of the past. To justify their claim that restructuring has failed, the APPA and others have advanced retail rate comparisons that purport to show that restructuring has caused rates to rise. Yet such rate comparisons ignore the myriad fundamental drivers of electric rates and ignore the fact that so-called “regulated” states have benefitted significantly from the pursuit of restructuring elsewhere. Such

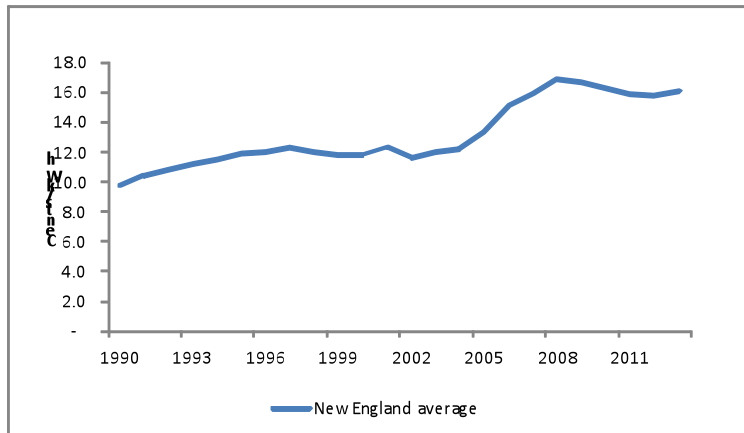
²¹ Borenstein & Busnhell, Haas School, UC Berkeley, *The U.S. Electric Industry after 20 Years of Restructuring*, (revised) May 2015.

comparisons are therefore useless for evaluating the relative merits of restructuring versus traditional utility regulation.” (p. 8)

A number of states in the US, including some in New England, required in their restructuring plans some form of rate freeze or mandated rate cuts at the start of the opening of competitive retail market. These rate cuts were touted by some in industry as examples of the success of restructuring and it is difficult to suggest that this was not at least a short-lived benefit to ratepayers at the time. For example, a press release issued at the time noted that

“US Gen New England and TransCanada have been providing transition service to Granite State Electric's customers since September 1, 1998, when affiliate New England Power Company sold its generation business. Customers have received, on average, 17% savings each month following the power plant sale... This agreement shows that the competitive market is developing and producing prices which will maintain the savings already provided to our customers under our settlement.”²²

New Hampshire was not the only New England state to implement a retail rate decrease at the start of restructuring. With the exception of Maine, rates were either frozen in place, when Rhode Island mandated flat rates for the first several years, or else were required to be set at a certain percentage level below pre-restructuring rates, such as in Connecticut, which mandated a 10% reduction below 1996 rates from 2000 to 2003, and in Massachusetts, which required a 15% decrease below the 1997 rates.



As illustrated in the chart above, however, after a short period at the start of restructuring in which the regional average rate for small consumers dipped or remained flat, overall rates have been climbing in the last 15 years.²³ There are a few empirical observations that can be made, to help readers understand why electricity rates have trended upward:

²² Granite State Electric, December 21, 1998, www.prnewswire.com

²³ For additional analysis of residential consumer electric rate trends over the past decade, please see the recent NESCOE report at <http://nescoe.com/resources/rates-analysis-oct2015/>

- Natural gas prices gradually increased over much of that period, and as the proportion of gas-fired generation in New England grows relative to power derived from other fuel, the relationship between the underlying price of the natural gas commodity and the resulting electricity supply price continues to strengthen. For example, in looking at the rolling five-year average of natural gas prices delivered to the region’s generation plants, EIA data shows a gradual increase, from 3.36\$/MMBTu in 2001 to a high of \$8.45 in 2008, before dropping to \$5.36 for 2014, the most current data point available. Natural gas prices increased significantly in the first decade of the century, culminating in significant spikes across the US during the supply disruptions caused by Hurricanes Rita and Katrina, then started to fall sharply as the impact of increased domestic supply from expanded fracking activity worked its way into delivered prices. However, annual prices have been higher in the last two years in New England because of regional supply constraints that caused certain winter months to spike, pushing up the region’s rolling average price in the last few years.
- T&D rates have also been rising, as investments continue to be made in the delivery-related assets, such as for new transmission lines and upgrades to the distribution system.
- Stranded costs, discussed above, are a relatively small portion of total rates charged to customers, and the majority of those charges were recovered within the first 10 years since restructuring was implemented.

Another measure of the relative benefit to consumers of retail restructuring might be the level of migration of customers to alternative suppliers from the default price or standard offer. In New England, migration of the majority of industrial customers to competitive options was relatively swift, but the migration of large number of smaller commercial and residential customers lagged for many years after the markets first opened, possibly because competitive offers that were significantly more attractive than the standard offer rate were not prevalent.

However, in recent years, a number of states, including several in New England, have seen a rise in the switching statistics for smaller customers, and observers have noted that competitive offers have been able to handily beat the default service price, whether set by, for example, three-year rolling auctions in Maine, or by assets that remain under the control of the incumbent utility. Regarding the latter, as noted in a recent NH PUC Staff report,

“[b]ringing the state’s electricity rates down to regional levels comprised a major goal of restructuring in the late 1990s. The legislature, the New Hampshire Public Utilities Commission (Commission), and the overwhelming number of stakeholders involved in restructuring saw the fossil and hydro resources of Public Service Company of New Hampshire’s (PSNH) as a major asset in achieving that goal. A little over a decade later, those resources, taken as a whole, have gone from saving customers money to costing them significantly, relative to available market alternatives. One measure of the gap that now exists is to measure the difference between PSNH’s default service rate, 9.5 cents per kilowatt-hour (kWh), and prevailing retail market

prices, 7.0 – 8.0 cents per kWh, which are lower than PSNH’s rate by approximately 15 to 25 percent.²⁴

Stakeholders also argued that a likely benefit to be derived from electric restructuring was the transfer of risk of investment choices from ratepayers of vertically integrated utilities to the shareholders of generation assets, post-restructuring. Recall that before retail restructuring, under traditional cost of service regulation, a utility company would propose to its regulators to build the generation investments it estimated would best meet the forecasted long-term supply needs of the utility’s customers. Once it received approval, the utility would construct those facilities with the expectation that future revenue from customers, via charges set in rate cases, would over time recover the cost of the investment, including the return on capital, as long as the investments were deemed to be prudently incurred. The risk of the utility’s investment decisions thus ultimately fell on its ratepayers, even if those investments proved later to be more costly than other alternatives or unnecessary because of changing conditions.

After restructuring, economic theory suggested that the “invisible hand” of competitive markets would guide those decisions instead, not the utilities and their state regulators. That is, the decision to build new plants was made by competitive players outside of the regulated framework, without an explicit rate recovery mechanism available to pass on those costs to utility ratepayers.²⁵

Before wholesale restructuring began, there were fifteen large electric utilities, excluding municipals and cooperatives, which owned essentially all the large generation plants operating in New England, excluding QFs. As the wholesale and retail markets opened, utility generation assets were divested and the merchant generation fleet greatly expanded. By 2006 there were thirty-five companies that owned and operated generation plants, representing either the now unregulated affiliates of the former utilities or entirely new merchant entrants. According to the ISO-NE, there were 25 new non-utility owned generation facilities built in the region between 1999 and 2005, representing over \$9 billion in capital investment that was not financed by utility ratepayers.²⁶ After a supply boom in non-utility capacity additions in the late 1990s and early 2000s, a number of IPPs with assets in New England struggled financially as a supply glut ensued, including Calpine, Mirant, and Dynegy. The impact of revenue losses in the wake of investment decisions that did not turn out to be as beneficial as expected fell mainly on the developers’ shareholders, not utility ratepayers. More than a few of these companies faced serious financial setbacks and losses which were borne by their shareholders and creditors.

²⁴ NH Staff report IR 13-020, Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impacts on the Competitive Electricity Market, June 7, 2013, p. 1.

²⁵ Although in some cases, it is fair to observe that a financially binding purchased power contract, a reliability agreement, or a capacity payment mechanism such as that eventually adopted by ISO-NE did provide indirect revenue support.

²⁶ ISO-NE 2006 Annual Markets Report.

For example, Dynegy is a merchant generation company that owns a mix of natural gas-fired and coal plants located across several US regions. In 2002, Dynegy struggled to avoid bankruptcy and did so by selling some of its assets at an estimated loss of more than \$500 million, then after a series of additional financial setbacks ultimately filed under Chapter 11 a decade later when in 2012 it was unable to keep up with its debt service. It emerged from bankruptcy less than a year later and continues to own assets in New England. Throughout this period, the generation plants it owned provided electricity to meet the needs of the region's ultimate customers, without causing financial distress to the distribution utilities. Finally, federal actions taken in the years since 2000 have continued to modify laws and rules to enhance support for competitive power markets, including Congressional passage of EPAct 2005 which modified QF requirements, so that incumbent utilities were no longer obliged to enter into contracts for larger PURPA projects, and removed many restrictions from the 1935 Public Utility Holding Company Act (PUHCA) that previously had prevented certain large utilities from owning generation outside their own franchise territory. More recently, FERC Order 1000, in 2011, placed additional requirements on RTOs and other transmission entities, which included removing impediments to competition in transmission development.²⁷

Current Issues

There are a number of emerging and current issues and challenges that were either not pressing at the time of restructuring or were at least not widely discussed at the time. Thus, debates regarding the merits of restructuring and the ultimate policy decisions made by stakeholders at the start of the process did not necessarily consider or capture the impact that these issues might have later, in a post-restructured power sector. A few of the primary issues of current interest follow.

Growth of Distributed Generation

Distributed generation (DG) resources, such as solar photovoltaic (PV) and combined heat and power (CHP), are becoming increasingly common. In contrast to central station electricity generators, DG provides power closer to the point of consumption. The smaller, more diffuse DG resources can provide economic, environmental, and energy security benefits to electricity customers. The growth in DG resources has the potential to affect wholesale electricity market dynamics, transmission and distribution system planning, and the utility business model.

Many New England states promote DG resources through a variety of policy mechanisms including net metering. In addition, increasing scales of production, associated cost efficiencies, and technology breakthroughs have reduced the costs of some forms of DG. The growing trend of residential solar PV installations, for example, illustrates the progress states have made in reaching new levels of DG resource penetration.

Increasing levels of distributed generation presents challenges to utilities under the traditional regulatory model, such as, for example, those that depend on the *volume* of retail sales for cost

²⁷ *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 Fed. Reg. 49,842 (Aug. 11, 2011).

recovery. For example, some argue that competition will lead to some electric suppliers “cherry picking” certain customers, leaving remaining fewer captive customers to pay the proportionately larger percentage of fixed system costs. This argument, offered during the restructuring debates, is now commonly heard in arguments in connection with DG resources. To the extent that customers with DG resources use less of the transmission and distribution system and generate on-site power for personal consumption, some are seeking ways to equitably distribute the costs of providing default (and stand-by) service. Another point of view is that if a large number of customers install DG, those customers may create new demands - and associated costs - on the transmission and distribution system.

The New England states are significantly investing in DG resources. In light of substantial ongoing state investments in DG and in recognition that these resources provide a reliability benefit to consumers that must be accounted for in determining system needs, ISO-NE has developed, at states’ request, a solar photovoltaic (“PV”) forecast which is used to help determine resource adequacy and capacity needs. ISO-NE has also begun to reflect the DG forecast in transmission planning studies.

Renewable Energy Development

Many thought retail competition would encourage substantial growth in renewable power, particularly from the demand pull once retail customers were allowed to choose among competitive supply, including new green-power options. Despite limited competitive offers for green energy, new build of renewable-sourced generation has flourished, albeit unevenly, across the US, as a result of state renewable portfolio standards (RPS) and renewable energy credit (REC) policies adopted in restructured and vertically integrated states.

In New England, renewable energy resource development faces several challenges. The ability to finance and develop new renewable resources based solely on market-based electricity and REC revenues is uncertain. To address renewable energy project finance-related issues, some New England states are increasingly utilizing other mechanisms, including but not limited to long-term contracts. In addition, much of the lower cost renewable resource potential is located (1) in an electrically weak portion of the New England system, such as Northern Maine, and (2) on the other side of transmission interfaces that limit delivery of renewable power to consumers in southern New England. These challenges are further complicated by delays associated with interconnecting new generators in the Maine portion of the system and the inability to use all of the output of current wind generators.²⁸ Such wind generator curtailment and high REC prices in recent years call attention to the question of whether additional infrastructure, in combination with measures to address project finance-related issues, may be necessary for further renewable energy development.²⁹

²⁸ PJM Interconnection et al., *ISO/RTO Joint Common Performance Metrics Report*, Docket No. AD14-15-000 (Oct. 30, 2015) (“2015 ISO/RTO Metrics Report”), at 94-95, available at http://www.iso-ne.com/static-assets/documents/2015/10/ad14-15-000_10-30-15_iso-rto_common_metric_rpt.pdf.

²⁹ September 16, 2015 ISO New England presentation to Planning Advisory Committee, available at

Increasing Reliance on Natural Gas

New England's use of natural gas-fired generation has increased significantly since restructuring. At the same time, the region's natural gas infrastructure has not kept pace. As a result, the natural gas infrastructure during the winter months in recent years has become constrained, leading to periods of high electricity prices and concerns associated with electric reliability. For example, ISO-NE has had to implement a "Winter Reliability Program" over the last several winters to satisfy its reliability concerns. This program will continue through 2018 pending the implementation of market design changes known as "Pay for Performance." In addition, due to a variety of factors, several non-gas-fired electric generators have, or are expected to, permanently retire. Based on the new resources seeking to interconnect to the New England system, most of the power that will replace the retired generators will likely be gas-fired. The combination of non-gas retirements, new gas development and the market's selection of low cost resources for consumers are likely to continue to trend of the region's use of natural gas for electricity generation.

Today, the relatively short-term price signals from the wholesale electricity market are not aligned well with the long-term contracts pipeline companies require for new natural gas infrastructure. Some proposed pipeline projects are moving forward with subscriptions only coming from regulated local gas distribution companies for retail gas customers. The wholesale electricity markets are also not otherwise poised to resolve the reliability issue, at least until certain market reforms are implemented in 2018. Even then, ISO-NE expects these reforms to result in additions of mostly dual-fuel capability, with on-site oil providing the alternative to constrained pipelines, and only experience will show whether all operational issues will be resolved.³⁰ The system operational/reliability risks that ISO-NE has identified in connection with natural gas constraints and the associated economic competitiveness and consumer cost implications are an ongoing challenge for New England.

Power Sector Air Emissions Trends

Since restructuring, power sector air emissions have been decreasing on an annual basis. This result is likely due to multiple factors. Environmental regulations enacted in the 1990s restricted the type of electricity generation that could be developed downwind from Midwestern coal-fired facilities. The competitive wholesale market gave rise to new gas-fired generation and improved the average efficiency of the generation fleet in New England. With the advent of hydraulic fracturing and horizontal drilling techniques ("fracking"), the increased supply of domestic natural gas has more recently led to

http://www.isone.com/staticassets/documents/2015/09/a5_generator_interconnection_and_queue_process_issues.pdf

³⁰ *ISO New England Inc.*, Fuel Assurance Status Report of ISO New England Inc., Docket Nos. AD13-7-000 and AD14-8-000. (Feb. 18, 2015), at 4, available at http://www.iso-ne.com/static-assets/documents/2015/02/Final_for_Filing_Fuel_Assurance_Report.pdf.

historically low gas prices in regions with adequate infrastructure. Increased natural gas-fired generation has displaced coal- and oil-fired resources in New England and elsewhere to a large extent. However, winter-time infrastructure constraints in New England have resulted in a resurgence of oil-fired generation and worsening winter-season air emissions.

The US EPA's Clean Power Plan (CPP) for regulating carbon dioxide emissions from existing and new generation resources will likely extend the trend toward natural gas-fired and renewable energy. New England's Regional Greenhouse Gas Initiative (RGGI) is an example of a market-based approach that states may utilize to comply with the CPP.

Grid Modernization and New Technology

States and utilities are exploring ways in which new technology can be used to modernize the grid. Such "grid modernization" efforts examine the role of the distribution utility in a future that has flat or declining load growth, increasing penetration of DG, energy consumption that is more responsive to wholesale prices, and a grid that integrates a growing number of electronic devices and vehicles. For example, in New York, stakeholders are considering an electric sector evolution where distribution utilities are a platform for new services. Utilities and state officials are investigating the costs and benefits of advanced metering, enhanced telecommunications and data management systems, and substation upgrades for a variety of uses, including distribution voltage optimization, enabling time-varying electricity rates, and improved system operation and awareness.

In addition, there is growing interest in making the grid more resilient to extreme weather, geomagnetic disturbances, and cyber-related threats to reliability. Utilities are also identifying critical energy infrastructure that is vulnerable to climate change impacts and other outside factors, based in large part on the experience of several major storms in recent years. Many are developing plans to address these challenges.

Lastly, technology improvements in the power sector moving closer to enabling a significant change in the way that electricity is produced and consumed. Research and development activities on a host of technologies, including lithium ion and flow batteries, hold promise for power system enhancements. Ranging from integrating power from intermittent resources to reducing consumption during peak periods of the day, storage technology continues to improve and identify ways in which it can provide value to producers, consumers, and utilities.

Energy Efficiency

Over the past 10 years, the New England states have dramatically increased investments in energy efficiency resources. Massachusetts, for example, has increased energy efficiency spending by 150% between the years 2009 and 2012.³¹ Today, it ranks first among the fifty states in energy efficiency

³¹ Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan (October 29, 2009), at Section II.B (p.68-84), available at <http://ma-eeac.org/wordpress/wp-content/uploads/ElectricPlanFinalOct09.pdf>; Massachusetts Department of Public Utilities Order in

spending. In fact, four of the New England states - Massachusetts, Connecticut, Rhode Island, and Vermont - are in the top ten of states nationally for energy efficiency investment, based on rankings by a national organization.³² To fully capture the value of that investment for consumers, ISO-NE, at the states' request, now reflects energy efficiency resources through an energy efficiency forecast in regional planning studies.

The most recent energy efficiency forecast showed that the New England states will invest a combined \$9 billion in energy efficiency programs over the next ten years and save 1,233 MW of on-peak energy demand and 9,105 GWh of total energy.³³ The forecast showed that, despite continued growth in the summer peak, the region's annual energy consumption is on the decline and energy efficiency investments deferred certain transmission projects that would have been needed for system reliability.

Demand Response

In May 2014, the DC Circuit Court of Appeals issued a decision in a case referred to as *EPSA v. FERC* vacating FERC Order No. 745. This case related to wholesale market payments to demand response (DR) resources in the wholesale energy market. Prior to the *EPSA v. FERC* ruling, ISO-NE planned to implement market rules that fully integrate DR into the energy and reserves markets on June 1, 2017.

While the Supreme Court considers whether FERC has jurisdiction over DR, and thus whether and in what form DR may participate in the wholesale markets, ISO-NE has delayed implementation of the energy and reserves market integration (FCM participation will remain the same, pending the outcome of the appeal). States have considered DR an important resource that contributes to resource diversity, market competitiveness, peak demand reduction, system operations and environmental objectives. It also provides consumers with savings opportunities. The future of DR participation in the regional wholesale markets is uncertain. One possible outcome is that DR will require state action on a going forward basis.

Docket Nos. 09-116 et seq. (January 28, 2010), available at <http://ma-eeac.org/wordpress/wp-content/uploads/1-28-10-DPU-Order-Electric-PAs1.pdf>.

³² American Council for An Energy Efficiency Economy, *2015 State Energy Efficiency Scorecard* (October 21, 2015), available at <http://aceee.org/research-report/u1509>.

³³ See ISO New England Energy-Efficiency Forecast for 2019 to 2024, at 3 and 32, available at <http://www.iso-ne.com/static-assets/documents/2015/05/eef-report-2019-2024.pdf>.

Appendix 1 – Description of state restructuring plans

Below are some notable key dates from the New England states' early activities to restructure retail electric markets, followed by a description of some elements from each state's restructuring program.

- June 1995 - the New Hampshire Legislature passes bill requiring pilot program for retail choice
- July 1995 - the Connecticut PUC issued a final report calling for retail restructuring
- October 1995 - the Vermont PSB issues an Order calling for retail restructuring by 1998
- May 1996 - NH implements a 2-year pilot program, and the legislature passes a bill requiring choice for all customers by 1998
- January to October 1996 – three Massachusetts utilities begin retail choice pilot programs
- December 1996 – the Maine PUC issued a plan requiring divestiture of generation assets and retail competition to begin by 2000
- January 1997 – the Massachusetts DTE issues an Order officially opening retail markets in 1998
- March 1997 – a NH utility files a legal complaint against NHPUC restructuring plan. Court rulings in lawsuit prevent NHPUC from implementing restructuring until 2000
- July 1997 – Rhode Island becomes first state in nation to fully restructure on a statewide basis, giving industrials choice; residential and commercial classes following a year later
- November 1997 – the Massachusetts House passes HB5117, requiring retail access by March 1998
- March 1998 – retail choice begins in Massachusetts
- April 1998 – Connecticut HB5005 passes, requiring open access to all customers by July 2000
- March 2000 – Maine's retail choice program begins
- June 2000 - the New Hampshire Legislature passes bill resolving the dispute with utilities and requires deregulation by mid-2001; some utilities implement restructuring
- May 2001 - PSNH implements electric restructuring for majority of customers
- May 2003 - the remaining NH utilities implement restructuring

Elements of New England states' programs

The following discussion provides highlights from each state's restructuring plans, directly citing where possible summaries provided on state or federal government websites, with a particular focus on stranded cost recovery. See bibliography in Appendix 2 for list of sources relied upon here.

Rhode Island

Among the elements of Rhode Island's electric utility restructuring plans, as excerpted from its PUC website:

- Utilities were required to file plans for transferring ownership of generation, transmission and distribution facilities into separate affiliates, with nondiscriminatory access to transmission and distribution facilities to wholesale and retail customers and to non-regulated power producers.
- Electric utilities to provide retail access to customers, with up to 10% of total kWh sales by 7/1/97 to new commercial and industrial customers with 200 kW demand, existing

manufacturing customers with 1500 kW demand, and the state of RI; up to 20% of total kWh sales by 1/1/98 to all existing manufacturing customers with 200 kW demand, all municipal accounts; all customers within three months after retail access is available to 40% or more of New England kWh sales, or by 7/1/98.

- Standard offer to equal price paid by customer in year ending 9/30/96, automatically adjusted for 80% of change in CPI and adjusted with Commission approval for other factors reasonably out of control of distribution utility and its wholesale power supplier.
- Once customer purchases from another supplier, utility is not required to provide standard offer.
- Utilities are to arrange for last resort power supply for customers no longer eligible for the standard offer and unable to obtain service from another supplier, by soliciting bids in the market plus a fixed contribution to be included in distribution rates charged all other customers.
- Transition charges for the termination for all-requirements contracts are to be recovered by nonbypassable charge paid by all customers of the distribution company. Fee to include following costs of wholesale supplier:
 - Regulatory assets, including those of affiliated fuel suppliers, and obligations for post-retirement health care costs;
 - Nuclear obligations, including decommissioning and costs independent of operation;
 - Above-market payments for purchased power plus buyout or buydown payments;
 - Net unrecovered costs of generating plants, including natural gas conversion costs and above-market pipeline demand charges.
- Transition charge will continue until liabilities satisfied, with annual reconciliation of items 2 and 3 above (except nuclear costs independent of operation). Recovery will be spread over period from 7/1/97 through 12/31/09. Charge to customers will be 2.8¢ per kWh from 7/1/97 to 12/31/00. Subsequently the rate will be set by Commission, with adjustment for over- or under-recoveries in first period.
- 2.3 mills/kWh will be collected at the distribution level to fund DSM and renewable resources for a period of five years. The Commission may increase this amount, and shall allocate these funds between these resources. After five years, the Commission will determine the level of this charge.

Massachusetts

The following description is excerpted from EIA's report on restructuring, issued in 2000, and reports from the state's commission describing the enacting legislation.

On November 27, 1997, HB 5117, the Electric Utility Restructuring Act, was signed by Governor Paul Cellucci to restructure the industry in Massachusetts. The law basically affirmed the state PUC's restructuring order of 1996. The Restructuring Act mainly affects the Commonwealth's eight investor-owned distribution companies, which supply 87 percent of the electricity in Massachusetts.

Retail access was required by March 1998, and a simultaneous rate cut of 10 percent to be followed 18 months later by an additional 5 percent cut was made law. Municipal utilities have the option to participate. Additionally, the divestiture of generation assets was encouraged.

Three generation service options are available to consumers: (1) Standard Offer Service, provided by distribution companies; (2) Default Service, provided by distribution companies; and (3) Competitive Generation Service, provided by competitive suppliers. The price the customer pays for generation service is dependent on the type of service that the customer receives. Standard Offer Service is a transition generation service available through 2004 to each distribution company's customers of record. The price of the Standard Offer Service is set in advance and will increase gradually. Initially the Standard Offer rates for each of the Massachusetts distribution companies approved by the Department of Telecommunications and Energy was equal to 2.8 cents per kWh. A customer that did not select a competitive supplier as of March 1, 1998, automatically was placed on the Standard Offer Service.

The rates for the Standard Offer Service are regulated by the Department of Telecommunications and Energy (DTE) and were set at levels that provided a 10 percent overall bill reduction to customers receiving the Standard Offer Service. The level of the overall bill reduction for the Standard Offer customers increased to 15 percent on September 1, 1999.

As of May 2000, 33 authorized competitive suppliers/electricity brokers were located in Massachusetts. An electricity broker is an entity that is licensed to facilitate or otherwise arrange for the purchase and sale of electricity and related services to customers, but is not licensed to sell electricity to customers. An applicant for a competitive supplier or electricity broker license must demonstrate, among other things, the financial and technical capability to provide the applicable services. Prices for Competitive Generation Service will be set by the competitive electricity marketplace; these prices will not be regulated by the DTE.

Massachusetts had awarded stranded costs if conforming utilities had demonstrated that they had divested all non-nuclear generation and attempted to mitigate all other costs. So far, approximately \$2 billion of the total \$6 billion that will eventually be paid has been transferred. Securitization then becomes permissible. If a utility had been unwilling to divest its generation, the DTE would have determined the level of stranded costs. (p. 86-88)

Massachusetts stranded cost recovery, as defined by legislative statute, included:

- The amount of any unrecovered fixed costs for generation-related assets and obligations which were collected in rates on January 1, 1997 and that become uneconomic.
- Nuclear entitlements by those electric companies which have divested their non-nuclear generation facilities and those previously incurred or known liabilities incurred for post-shutdown and decommissioning costs associated with nuclear power plants which are not recoverable from the decommissioning fund.

- The unrecovered amount of the reported book balances of existing generation-related regulatory assets as approved by the Department.
- The amount by which the costs of existing contractual commitments for purchased power exceeds the competitive market price for such power, upon reaffirmations, restructuring, renegotiation, or termination of such contracts, or the liquidated payments associated with the disposal of these contracts.
- In addition, certain costs incurred after January 1, 1996, including employee-related transition costs; any payments or payments in lieu of taxes; and any costs to remove and decommission retired structures at fossil fuel-fired generation facilities. (Sec.193, 1G(b))
- The Department shall identify and determine upon application by a distribution company and the applicable electric company those costs and categories of costs for generation-related assets, investments, and obligations, which may be allowed to be recovered through a non-by-passable transition charge authorized to be assessed and collected. (Sec.193, 1G(a1))
- Recovery: Any approved transition costs to be recovered from ratepayers through a non-by-passable transition charge. The Department shall impose a cap upon the level of the transition charge (no adjustment for inflation allowed). The Department shall require a reconciliation of projected transition costs by March 1, 2000, and for every 18 months thereafter through March 1, 2008, or the termination date of any transition charge allowed to be assessed. In no event shall the Department determine to allow any carrying costs for any period beyond the year 2009 on any unamortized balance of costs allowable as transition costs. A distribution company's use of securitization shall be approved by the Department and shall be subject to the achievement of mitigation efforts satisfactory to the Department. An electric company which fails to commence and complete the divestiture of its non -nuclear generation assets shall not be eligible to benefit from the securitization provisions and the issuance of electric rate reduction bonds.

Connecticut

This information is excerpted from CT PURA website³⁴:

Passed on April 15, 1998 as Amendment to Substitute HB Bill 5005, Connecticut's legislation establishing retail restructuring that offered all customers the option to choose their electric supplier by July 1, 2000. From 1/1/00 through 12/31/03, the current electric companies must provide a "standard offer" which will guarantee service to their customers. Rates to consumers were capped from 7/1/98 to 12/31/99 at rates in place on 12/31/96, although this did not apply to customers on a special contract already in

³⁴ Post originally on the predecessor agency website:

<http://www.dpuc.state.ct.us/electric.nsf/60a3df2c610b4cd6852575b3005ce06c/4d83a3b4c8480ecb852568bf00517c97?OpenDocument>

place. Bills for customers on the standard offer must be at least 10% below rates in effect on December 31, 1996. Customers will receive one bill; charges from the electric supplier will be recorded on the bill from either CL&P or UI.

If companies wish to receive any recovery for stranded costs they must divest themselves of non-nuclear assets through sale at auction by 1/1/00 and divest themselves of nuclear assets by 1/1/04 (with provision in the bill for financial recovery treatments between 1/1/00 and 1/1/04). The PURA authorized up to 1.5\$B in bonds for stranded cost recovery for CL&P. The Office of Consumer Counsel appealed the decision to Supreme Court; a settlement agreement resolving the appeal allowed the utility to issue 1.4B\$ in recovery bonds, of which approximately \$1B was for out-of-market contracts and \$400M was for paying down debt related to generation and other regulatory assets. The bonds were issued approximately 3/2001.³⁵

Maine

The following is excerpted from state PUC annual reports to its Legislature:

During its 1997 session, the Maine Legislature enacted comprehensive legislation to restructure Maine's electric utility industry. P.L. 1997, ch. 306 (codified at 35-A M.R.S.A. §§ 3201-3217). During 1998 and 1999, the Public Utilities Commission (Commission), with extensive input from the public, developed the rules and procedures that would govern the activities of transmission and distribution (T&D) utilities and competitive electricity providers (or suppliers) after restructuring occurred and conducted a consumer education campaign to prepare customers for restructuring. The Commission also disaggregated the existing vertically integrated utilities into their delivery and generation functions, determined rates for the future T&D-only utilities, and approved the sale or auction of the utilities' generating facilities and generation-related assets.

Because the Maine Legislation did not include support for securitization bonds, the Commission established "asset gain/sale accounts" instead, that were tied to stranded cost recovery.³⁶

According to the Maine PUC's 2001 Report to the Legislature, the restructuring statute allows CMP, BHE and MPS to recover stranded costs in the rates they charge for delivery service. These stranded costs reflect net, above-market costs of generation obligations the utilities incurred prior to restructuring. For example, stranded costs include the difference between payments the utilities must make pursuant to purchased power contracts (e.g. with qualifying facilities (QFs)) and the current market value of that power. Stranded costs also include, as an offset, the proceeds from the utilities' generation asset sales (the so-called Asset Sale Gain Account, or ASGA). These proceeds are amortized in rates and reduce the level of stranded costs ratepayers must pay.

³⁵ CT Office of Legislative Research, Research Report 2010-R-0015, *CONNECTICUT'S HIGH ELECTRIC RATES AND THE LEGISLATIVE RESPONSE*.

³⁶ Maine PUC 2002 Annual Report to the Legislature.

Stranded cost rates were initially set for CMP, BHE and MPS effective March 1, 2000 for a 2-year period coinciding with the 2-year sale terms of the utilities' entitlements. During 2001, the Commission initiated formal proceedings to reset stranded cost rates for the period beginning March 1, 2002 for BHE, CMP and MPS. Major issues included: expected entitlement sales; treatment of a \$20 million insurance termination disbursement received by Maine Yankee; expected revenue from special contracts; asset sale gain account amortization; and allocation of stranded costs among customer classes. On December 21, the MPUC approved a stipulation that resolves the CMP stranded cost case.

Under the terms of the stipulation, the stranded cost component of T&D rates will decrease for residential and small commercial customer classes. Medium and large nonresidential customers currently receive a rate mitigation of 0.8 cent per kWh, funded through an amortization of the ASGA. This mitigation will cease on March 1, 2002. As a result, these customers' stranded cost rates will increase on March 1. For the largest customers receiving transmission level service, the Commission approved continuation of mitigation at a level of 0.45 cents per kWh, resulting in a smaller increase in rates for those customers. CMP's stranded cost rates vary by rate class. The residential stranded cost rate is about 1.4 cents per kWh, which is 20% of the total T&D rate for those customers.

Stranded costs will be levelized over a three-year period to maintain rate stability. CMP's ASGA will have a balance of about \$125 million as of March 1, 2002 and will be amortized over four years. At the end of the four-year period, the ASGA will be gone, but remaining stranded costs will decline at that time as some QF contracts expire.

BHE's stranded cost rates also vary by rate class. The residential stranded cost rate is about 3.1 cents per kWh, which is roughly 1/3 of the total T&D rate for those customers. Stranded costs will be levelized over a period of four years to maintain rate stability. BHE's ASGA will have a balance of about \$12.5 million as of March 1, 2002, and will be amortized over two years. At the end of the two-year period, the ASGA will be gone, but stranded costs will remain stable, and then decline.

MPS's stranded cost rate is about 2.2 cents per kWh on average over all customers. MPS's ASGA will have a balance of about \$2.8 million as of March 1, 2002 and will be gone after one year. However, MPS's stranded costs will remain stable over the next decade. Low Income Program

New Hampshire

The following is drawn from EIA reports and information on the NH PUC website:

The New Hampshire legislature passed legislation in June 1995 directing the New Hampshire Public Utility Commission (NHPUC) to establish a pilot program to examine the implications of retail competition. In its order establishing preliminary guidelines for a retail competition pilot program, the NHPUC noted that the program was not necessarily a step toward wide-scale competition but was rather a way to examine the implications of an obstacle to a competitive retail market at a time when supply shortages are not a concern. Subsequent legislation (HB-1392), enacted in May 1996, directed

the NHPUC to undertake a generic proceeding to develop and establish a final order establishing a statewide electric utility restructuring plan.

The NH Commission issued on February 28, 1997 its statewide “Final Plan for Restructuring New Hampshire’s Electric Utility Industry” which directed all New Hampshire electric utilities to unbundle their retail services and provide retail customers the right to choose their electric energy supplier. Among other things, the Final Plan required utilities to unbundle their rates into generation, transmission, and distribution components and to provide competitive power suppliers nondiscriminatory access to their distribution systems so that suppliers could sell to retail customers.³⁷

Pursuant to requests for rehearing, the Commission on April 7, 1997 suspended and stayed the Final Plan and the interim stranded cost orders and granted PSNH’s request for rehearing of two discrete issues. The first issue was whether the methodology utilized by the Commission to establish PSNH’s interim stranded cost charge required the write-off of regulatory assets resulting in the potential for creditors to place PSNH in bankruptcy. The second issue was whether interim stranded cost order repudiates the 1989 Rate Agreement, which PSNH alleges is an enforceable contract with the State which affords it the right to stranded cost recovery.

After hearings on these issues were held in November and December of 1997, the Final Plan was amended by the Commission in an order issued March 20, 1998, which ruled on several parties’ requests for rehearing. The rehearing order also affirmed the interim stranded cost orders of all utilities other than PSNH. In lieu of issuing rulings on the rehearing requests relating to PSNH’s interim stranded cost charges, the Commission transferred two questions of law concerning the Rate Agreement to the New Hampshire Supreme Court. On December 23, 1998, the New Hampshire Supreme Court remanded the transferred questions to the Commission with certain guidance regarding the application of the standard for setting stranded cost charges under RSA 374-F and a conclusion that it could not find that the Rate Agreement was a contract with the State based upon the language of the document or the enabling statute. Moreover, the Supreme Court found that whether the Rate Agreement created a contract governing PSNH’s rates likely depended upon the intentions of the parties, which would require consideration of extrinsic evidence.

On February 4, 1999, the Commission issued an order vacating portions of those earlier orders which established the interim stranded cost charges for PSNH and the findings and conclusions of the Final Plan’s legal analysis pertaining to the Rate Agreement. That order also established a procedural schedule for additional evidentiary hearings on PSNH’s interim stranded cost charges.

A Memorandum of Understanding (MOU) between PSNH, the Governor of New Hampshire and Commission staff was filed with the Commission on June 14, 1999. The MOU sets forth the understandings to resolve the pending District Court litigation and bring retail competition to customers of PSNH. In order to implement the understandings, the New Hampshire Legislature must approve the

³⁷NH PUC 1999 report to the Legislature.

use of securitization and a comprehensive agreement must be approved by the Commission. Among other things, the MOU proposes to: provide all customers the opportunity to choose a competitive supplier; offer customers significant near term rate reductions funded in part by write-offs and the issuance of special purpose bonds (securitization); require PSNH to sell its power plants and certain power contracts; and provide customers the option of meeting their energy on a temporary basis through the purchase of transition service. The MOU also called for the Commission to stay several proceedings during the pendency of the review process and withdraw its federal lawsuit on the effective date of any final agreement. A comprehensive settlement agreement which expounds upon the MOU was filed with the Commission on August 2, 1999.

In regard to stranded cost recovery, the NH PUC first approved \$688M for PSNH with an additional 37\$M potentially eligible but legislation was required to fund any amount. When SB 472 was passed, authorizing the financing, PSNH issued 525\$M of bonds in 2001 with maturities varying between 1-12 years; i.e., the final maturity ended in 2013. The company issued another round in 2002 for out-of-market purchased power agreements of \$50M, which matured in 2008.

In the original legislation, stranded costs were defined as those costs, liabilities, and investments, such as uneconomic assets, that electric utilities would reasonably expect to recover if the existing regulatory structure with retail rates for the bundled provision of electric service continued, and that will not be recovered as a result of restructured industry regulation that allows retail choice of electricity suppliers, unless a specific mechanism for such cost recovery is provided. Stranded costs may only include costs of existing commitments or obligation incurred prior to the effective date of this chapter; renegotiated commitments approved by the Commission and new mandated commitments approved by the Commission. (374-F:2 (IV))

Appendix 2 - Bibliography

(Note: listed URLs last accessed between September and November 2015)

1. Enacting Legislation and Timeline

State	Legislation & date enacted	Major IOUs affected	Restructuring implementation date	Relevant URLs for primary source documents (LDs)
Maine	LD 1804, May 29, 1997 (following July 1995 request by Leg for PUC	CMP (Iberdrola), BHE (now EmeraMaine)	March 2000	http://legislature.maine.gov/statutes/35-A/title35-Ach32sec0.html

	to submit plan by Dec 1996)			
Vermont	n/a [Note that SB 62 passed Senate 4/97 but not brought up for vote in House]	n/a	Following several years of bills under consideration, Governor's Working Group formed in 1998; recommended restructuring; House chose not to act on it.	None
New Hampshire	HB 1392, May 1996 (Title RSA 374-F); SB341 delayed 3/98 start halted by HB 170, April 2003	Granite State (now Liberty, formerly NGrid), PSNH (Eversource, formerly NU), Concord and Exeter & Hampton (now UES companies/Unitil subsidiary),	Legislature ordered start by January 1998 but actual rollout: Aug 1998 (Granite); May 2001 (PSNH); May 2003 (UES, after merger in May 2002)	http://www.gencourt.state.nh.us/rsa/html/NHTOC/NHTOC-XXXIV-374-F.htm http://www.gencourt.state.nh.us/legislation/2003/sb0170.html
Massachusetts	HB 5117, November 1997	Mass Electric (NGrid), New England Power(NGrid)	NEES in March 1998, NGrid in 2000	https://malegislature.gov/Laws/Sessions/Laws/Acts/1997/Chapter164
Connecticut	HB 5005, April 1998	CL&P (EverSource)	December 2000	http://cga.ct.gov/P598/rpt%5Colr%5Chtm/98-R-0775.htm
Rhode Island	HB 8124, August 7, 1996	NEES (NGrid), Eastern (NGrid)	July 1997 (Industrial class); July 1998 (R&C classes)	http://www.ripuc.org/utilityinfo/electric/96H8124b.html

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Maine

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