EMBRACE ELECTRIC COMPETITION
OR IT'S DÉJÀ VU ALL OVER AGAIN

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About The Authors

This study was prepared by members of The NorthBridge Group, Frank Huntowski (Director), Neil Fisher (Principal), and Aaron Patterson (Principal). The NorthBridge Group is an independent economic and strategic consulting firm serving the electric and natural gas industries, including regulated utilities and companies active in the competitive wholesale and retail markets. NorthBridge has a national practice and long-standing relationships with restructured utilities in Regional Transmission Organization ("RTO") markets, vertically-integrated utilities in non-RTO markets, and other market participants. Before and throughout the restructuring process of the U.S. electricity industry, the authors have assisted clients with wholesale market design, competitive market analysis and strategy, regulated power supply procurement, state regulatory initiatives and strategy, and mergers and acquisitions.

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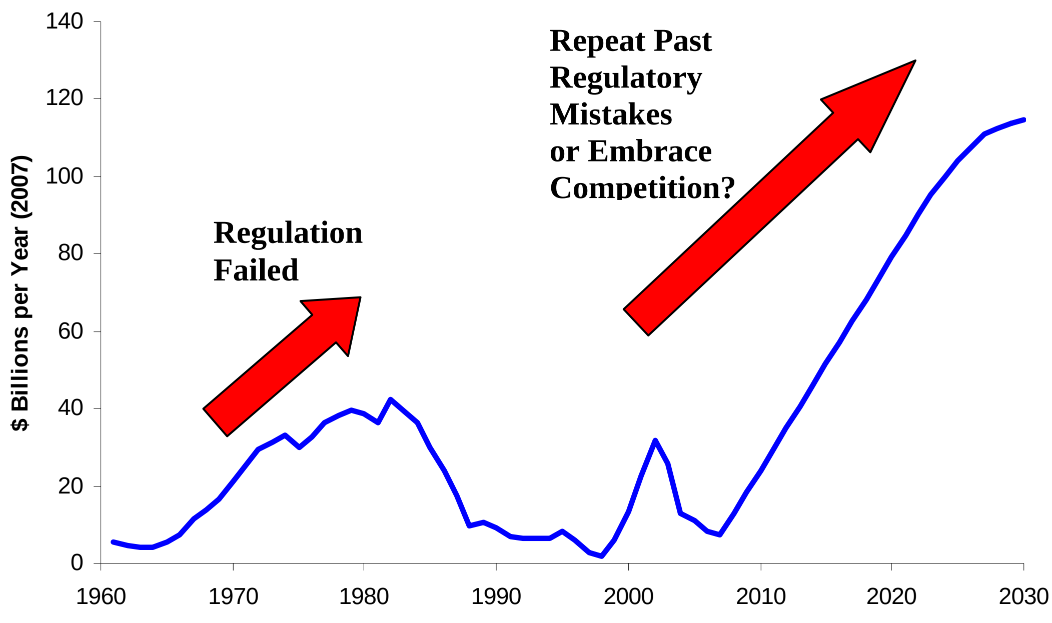
I. Executive Summary

Our nation strives for "reliable, affordable, and environmentally sound energy,"[1] but the electric industry must confront enormous challenges to meet this goal. Construction and fuel costs to generate electricity have increased dramatically, and proposed Greenhouse Gas ("GHG") legislation is expected to further boost costs. Over time, the combination of decreasing GHG emissions targets and the nation's current carbon-intensive generation fleet is likely to create the need for one of the most significant capital realignments in the industry's history (see Figure 1). At the same time, the electric industry is embroiled in a debate about the relative merits of competition, and many believe that we should return to the "good old days" of regulation.

But we should not forget that electric regulation has faced similar challenges in the more distant past…and it failed. The 1970s was a time of huge increases in fuel costs, substantial capital cost escalation, serious environmental concerns, and unanticipated changes in customer demand. Regulation tried to tackle these challenges with an administrative, command-and-control decision-making process, but the result was a massive overbuild of baseload capacity, skyrocketing rates, large shareholder disallowances, and huge cost overruns paid by customers. In the end, the regulated response to the events of the 1970s and 1980s likely amounted to a mistake on the order of $200 billion or more in today's dollars and resulted in excess supply and high rates that were felt for decades.[2]

Figure 1 Real Investment in Electric Generation, 1960-2030



Source: See Figure 8 and Figure 17.

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[1] National Energy Policy Development Group, "Reliable, Affordable and Environmentally Sound Energy for America's Future," May 2001, viii.

[2] This value represents the aggregate costs borne by customers and other electric industry stakeholders due to the failure to abandon high-cost nuclear plants and above-market contracts entered into as a result of regulatory interventions. See footnote 15 for more discussions.

A careful examination of the U.S. electric industry's response to the external shocks and uncertainty during the 1970s reveals four inherent flaws of regulation:

- **Lack of clear price signals:** The "price signals" to both suppliers and consumers in a regulated framework were the result of internal forecasts of a regulated entity subject to political influence and negotiation with the regulator during the ratemaking process. Later, when market conditions turned out dramatically differently than forecast, the lack of clear price signals contributed to a slow regulatory response marked by a failure to curb the over-building of baseload nuclear and coal capacity as costs spiraled and the need for capacity evaporated. As a result, the total U.S. reserve margin peaked at 42 percent in 1982, more than twice the 15 to 20 percent level generally deemed necessary to maintain system reliability. In terms of capacity additions, from 1970 to 1988, utilities added an average of 15,000 MW of coal and nuclear capacity per year (plus 4,400 MW of other capacity), while peak load grew by an average of only 13,800 MW per year.

- **Perverse capital incentives:** Regulated utilities had a tendency to favor large capital investments and consider sunk costs when making investment and abandonment decisions. These tendencies were on full display during the 1970s and early 1980s as regulated utilities continued to develop coal and nuclear plants long after those plants were clearly uneconomic in forward-looking terms. By 1980, the construction costs of nuclear power plants were approximately two to six times greater than the value of their output. Therefore, nuclear plants in the early stages of construction should have been abandoned, but more than 40 of these plants were eventually completed, which unnecessarily cost consumers hundreds of billions of dollars.

- **Improper allocation of risks:** Regulation improperly allocated risk (including the risk associated with technological choices, excess supply problems, and cost overruns) to consumers rather than to investors. Not surprisingly, the regulatory process significantly underestimated these risks when making long-term resource commitments. There are many examples of customer-funded commitments that turned out to be uneconomic.

- **Tendency for regulatory "fixes" to overcompensate:** Political and regulatory reactions to fix perceived problems tended to overcompensate with unintended consequences which further increased costs and inefficiencies. The turmoil of the 1970s led to a dissatisfaction with the existing regulatory process, and a search began for new regulatory solutions and models to counter the rate shocks experienced by consumers. The resulting administratively mandated qualifying facilities program burdened electric utilities and their customers with a $50 billion overhang of mandatory long-term contracts established at prices well above their actual avoided cost or any reasonable proxy of market prices.

None of these flaws were responsible for the shocks that placed the initial stress on the industry: the oil price shocks, cost inflation, and falloff in demand growth. However, the industry's response to these external shocks was heavily influenced by the flaws inherent in a cost-of-service regulation regime, and ultimately led to higher costs for consumers and less efficient resource allocation than likely would have occurred in a competitive framework.

In part due to these problems, the industry turned toward competition in the late 1990s. However, nationally the industry restructuring process has been lengthier and more difficult than many anticipated. Numerous studies, articles, and reports that have criticized competition focus on the recent rate increases in competitive states. But, for a number of reasons, such historical rate comparisons have limited value, especially as we look toward the future. Rates in regulated states, as in restructured states, have increased significantly since the late 1990s, and most of the increase in rates in restructured states occurring in the past several years can be traced to the expiration of rate freezes and the rise in natural gas prices. Further, rate increases in gas-dependent restructured and regulated states track one another very closely, and the magnitude of rate increases in particular states is closely related to the state's fuel mix and the rise in price of particular fuels. For example, had natural gas prices remained at the $3/MMBTU level as in the late 1990s, the rates in restructured states would have risen since then by about four percentage points less than rates in regulated states.

In the next twenty years, the industry will have dramatically different investment needs than it has had in the last ten years, and the true test of competition is still yet to come. The decision to support regulation or competition should not depend on the effects of external shocks (such as the recent rise in natural gas prices)[3] or whether regulated average cost prices are below or above market-based marginal cost prices at any particular point in time, but instead on whether a competitive or regulated model will foster more efficient decisions and ultimately better price and reliability outcomes over a sustained period of time and varying market conditions.

In spite of the recent criticisms, the case for competition in the electric industry is still compelling, supported both by economic theory and examination of empirical evidence:

- **Market prices provide the right price signals:** In a competitive market, market prices are a function of marginal costs, whereas regulated rates have traditionally been determined using "average cost" pricing. Over long time cycles, marginal cost pricing produces a more efficient and ultimately lower-cost outcome relative to regulated average cost pricing because it provides the correct price signal for the efficient allocation of new and existing generation and demand response resources. The level of market prices seen today are appropriate in that they provide the correct price signal and incentive for investment in the different types of low carbon resources that will be needed in the future.

- **Competition promotes efficiency improvements in:**

    - **Existing plant operations:** Competitive markets provide strong incentives to improve plant performance and administration in the short-term. Empirical evidence suggests that restructuring has improved the efficiency of power plant dispatch, extended the benefits of pooling and coordination across broader markets, reduced plant operating costs, increased baseload capacity factors, and reduced plant heat rates. Since 1999, nuclear plants operated by competitive

[3] Historical rate comparisons between restructured and regulated states would appear much more favorable to competition if natural gas prices remained at their level in the late 1990s, instead of increasing dramatically in the 2000s. See Figure 21.

generators have had an average capacity factor that is about two percent higher than that of regulated plants, producing savings of about $350 million per year. Restructuring also contributed to the substantial reduction in the average refueling outage for nuclear plants from 104 days in 1990 to 40 days in 2007, and has increased the average capacity factor for coal plants transferred from regulated to competitive owners from 59 percent to 67 percent.

- **Plant investment and retirement:** One of the most significant areas of potential savings from restructuring is more efficient long-term investments. Thus far, the industry has experienced significant restructuring of generating plant ownership. The experience of the gas combined cycle build-out in the competitive market of the late 1990s and early 2000s was very different from that of the regulated nuclear and coal capacity additions of the 1970s and 1980s as private investors responded much more quickly to changing market conditions. In response to the changing economics of gas combined cycle turbine plants, competitive builders cancelled 78 percent of capacity planned or under construction with a planned in-service date of 2003 or later while regulated builders cancelled only 37 percent of capacity. Unlike in the 1970s and 1980s, these uneconomic investments did not adversely impact customers in non-regulated states since unregulated investors – not ratepayers – bore the risk of these investments.

- **Customer consumption:** The competitive market price of electricity also provides a valuable price signal to customers that may affect customers' time of electricity use, overall level of electricity use, fuel choice, and investment decisions. Actions have been taken in restructured markets to increase economic demand response and expand market pricing to retail customers. High market prices that reflect environmental costs or peak demand periods will encourage reductions in consumption that will both reduce costs and greenhouse gas emissions. Specifically, some conservative estimates suggest that a 10 percent increase in the average price of electricity will result in a one percent or more decrease in electricity demand, which could decrease CO_2 emissions by 30 million tons per year and eliminate the need for nearly 5 gigawatts of new generating capacity, saving at least $10 to $20 billion in capital investment.

- **Retail competition is still developing and provides additional benefits:** Retail competition has developed to the greatest extent in restructured states where the market design allows the default price to reflect market prices. In several states, the vast majority of large commercial and industrial customer load is served by competitive retail providers, and the overall amount of customer switched load in the United States has more than quadrupled since 2001. Retail competition for residential customers thus far has developed largely in two states where market rules fostered competitive market development: broadly, in the ERCOT area of Texas and, less broadly, in New York. In Texas, more than 26 retail suppliers provide over 90 different residential products in each service area. Retail suppliers also provide "green" products, manage price and other risks, and offer load management and energy efficiency services that reduce and shift consumption during peak periods. In contrast, while default service rates that reflect market price levels promote retail competition, jurisdictions that have established fixed default service rates at below-market levels have virtually eliminated retail competition.

- **Other industries illustrate the benefits of competition:** The experience of other industries (e.g., airline, telecommunications, trucking) demonstrates that competition results in better utilization of resources, increased customer choice and access to new products and services, technological innovation, elimination of cross-subsidies, and lower prices.

To successfully navigate the confluence of an increasing public desire for environmentally-friendly resources with the rising cost of energy globally, participants in the electric industry must confront tough decisions and make difficult technological choices. The potential magnitude of future capital investments is unprecedented and the decisions required must be made in a highly uncertain environment with constantly changing information and significant risk. Decades of experience in the electric industry suggest that regulation is not well-equipped to meet such challenges. But recent experience in restructured electricity markets and significant experience in other competitive industries suggests that competitive markets are. We should learn from this history rather than repeat the regulatory mistakes of the past. By embracing competition, we can avoid "déjà vu all over again."[4]

[4] Yogi Berra, *The Yogi Book: I Really Didn't Say Everything I Said* (New York: Workman Publishing, 1998), 30.

II. The Electric Industry Faces Enormous Challenges

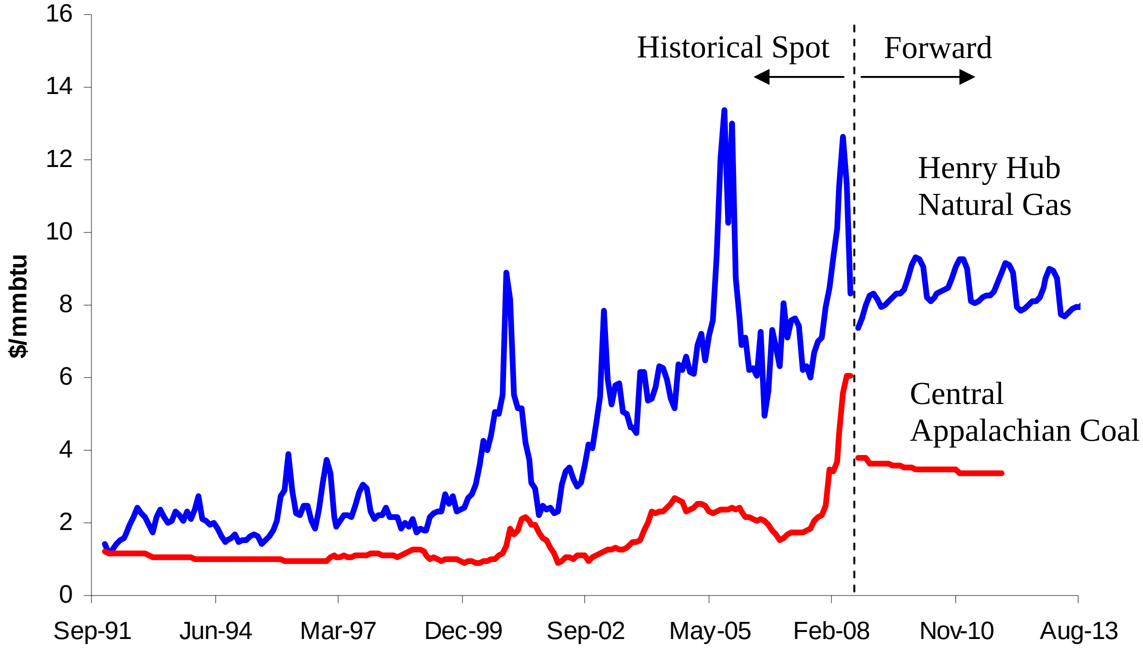
Looking forward, the electric industry faces a combination of significantly higher costs (both operating and capital) and massively increased need for capital investment, driven by ordinary load growth and, to an even greater extent, by the prospect of GHG regulation. Furthermore, a large degree of uncertainty and volatility will characterize the next twenty years: fuels markets and construction costs have become increasingly global and volatile, while the regulatory and technological uncertainties associated with carbon control are enormous. These conditions greatly increase the dollars at risk relative to recent history and will amplify any errors that are made in the coming years.

A. The Cost of Electricity is Rising and Increasingly Volatile

Electricity generation is primarily a fuel conversion process. Coal, gas, oil, and uranium (and, to a lesser extent, water, wind, and other renewable fuels) are converted into electricity by an electric generating plant. Both the cost of the input fuels and the cost of the plant used to convert these fuels have risen significantly in the last few years. As a result, electricity prices over both the short-term and the longer-term have increased.

Roughly 95 percent of the generating capacity built in the past ten years uses either coal or gas as an input fuel. These fuels currently generate roughly 70 percent of the country's electricity needs. As shown in Figure 2, after a period of relative tranquility in the 1990s, these input fuel costs to produce electricity have increased markedly and have reached unprecedented levels.

Figure 2 Increase in Natural Gas and Coal Market Prices, 1992-2013

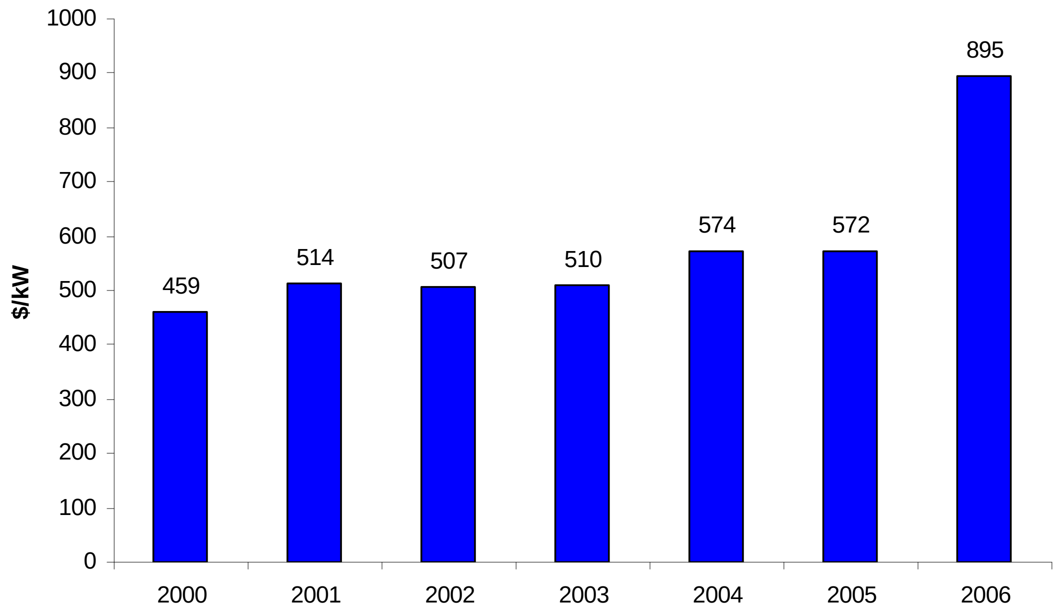


Source: Natural Gas: 1992-2004 – Bloomberg Daily Spot Price Assessment; 2005-2008 – ICE Day-Ahead Henry Hub Spot; 2008-13 – NYMEX Henry Hub Natural Gas Future (as of 9/15/08) Coal: 1992-2004 – Bloomberg Weekly Big Sandy Barge Spot Price Assessment; 2005-2008 – ICAP Prompt Month Big Sandy Forward; 2008-2011 NYMEX Central Appalachian Coal Forward.

Coal prices and natural gas prices have more than tripled since 1999. Current forward markets indicate that these relatively high fuel costs are expected to persist into the foreseeable future. Furthermore, fuel prices have also become more volatile: natural gas price spikes in the winter of 2000/01, in August/September 2005, and most recently in the first half of 2008 were at least twice as large as any price spikes seen previously.[5]

While fuel costs have increased, the cost to construct new power plants has also increased significantly in recent years, due to rising costs in materials and labor. The costs of steel and aluminum have grown by about 60 percent since 2003, and the costs of copper, nickel, and tungsten have tripled in the last few years. Primary drivers of these cost increases include increased global demand, increased production costs, and a weakening U.S. dollar. Labor costs, particularly costs for heavy construction and craft, have also increased at a rate much higher than inflation. As a result, the cost to build a new gas or coal plant has almost doubled over the 2000-2006 period. Figure 3 shows the increase in construction costs of a gas combined cycle turbine ("CCGT") plant since 2000.[6]

Figure 3 Increase in Gas Combined Cycle Installation Costs, 2000-2006



Source: The Brattle Group (Marc Chupka and Gregory Basheda), "Rising Utility Construction Costs: Sources and Impacts," prepared for the Edison Foundation, September 2007.

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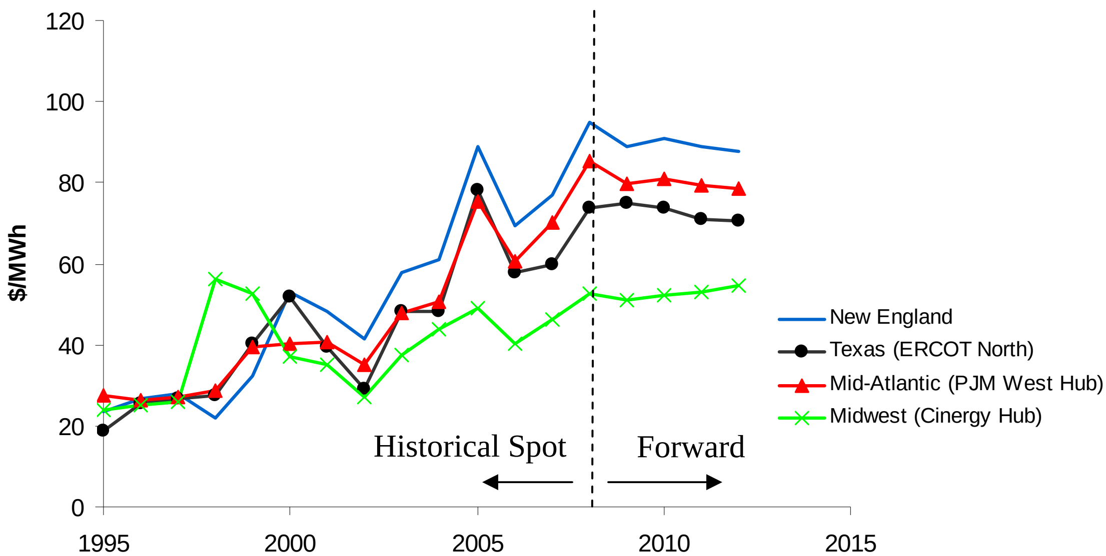
[5] While the reasons behind the increases in both natural gas price level and volatility are multiple and debated, there is consensus that the reserves of natural gas in North America have declined to the point where increasingly high-cost, marginal production sets the price for gas. In the long-term, the new-entry cost for liquefied natural gas ("LNG") will strongly influence the price for gas in North America, and this long-term price level is both relatively high and uncertain. Further, prices may exceed that level in the coming years, given the difficulty and time necessary to build new LNG import capacity.

[6] A more recent study from Cambridge Energy Research Associates suggests that these cost escalations have continued throughout 2007 and that the cost of all types of power plants as of early 2008 have increased by 130% relative to 2000, on average. ("U.S. Power Plant Costs Up 130 Pct Since 2000 – CERA," Reuters, 14 February 2008.)

These fuel and construction cost increases have caused wholesale electric prices to increase throughout the country, particularly in regions that rely heavily on gas-fired generation, such as in the Electric Reliability Council of Texas ("ERCOT") and New England, where wholesale electricity prices have increased by three to four times relative to the prices in the late 1990s. Other regions of the country have experienced significant price increases as well, as shown in Figure 4.

Figure 4 Increase in Wholesale On-Peak Electricity Prices, 1995-2012



Sources: Bloomberg Daily Spot Price Assessment for various regions; Megawatt Daily; ISO New England; Midwest ISO; PJM; Electric Reliability Council of Texas; New York Mercantile Exchange Forward Prices.

Wholesale electricity prices over the longer term will be a function of the total costs of new generation. Due to increased fuel and construction costs, the total costs of new gas and coal generation have nearly tripled and doubled, respectively, since 1999, as shown in Figure 5.

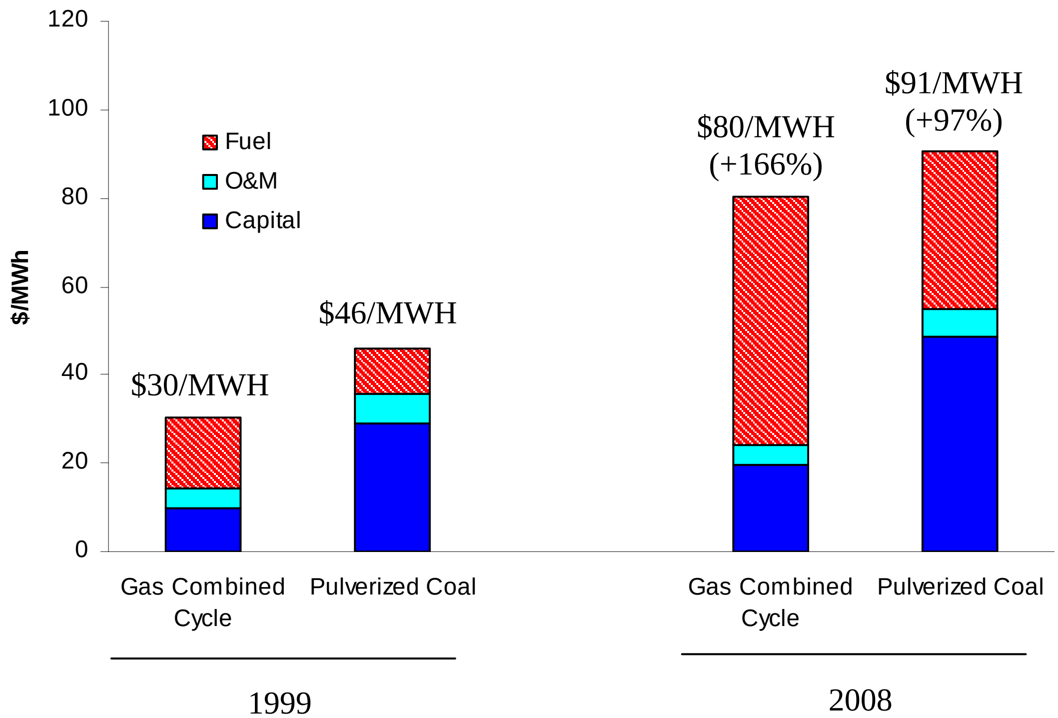
B. Climate Change Concerns Are Becoming More Critical and Are Expected to Further Increase Costs and Require Significant Capital Investments

The challenges posed by climate change and GHG emissions[7] add an unprecedented level of uncertainty and complexity to the challenges faced in the industry. Concerns regarding carbon dioxide (CO_2) and other pollutants affect the ability to site and build new power plants and also increase the cost of operating existing power plants. Both regulated utilities and unregulated developers have found it difficult to build new coal plants in several areas of the

[7] Gases that trap heat in the atmosphere are often called greenhouse gases. Some occur naturally, but the principal greenhouse gases that enter the atmosphere because of human activities include CO_2, methane, nitrous oxide, and fluorinated gases or ozone-depleting substances. CO_2 is the GHG most relevant to the electricity generation sector because it is emitted by power plants that burn fossil fuels such as coal, oil, and natural gas.

country,[8] and builders of new capacity face new regulatory and environmental hurdles in a carbon-constrained world, which will continue to put upward pressure on the cost of building new generation.

Figure 5 Increase in All-In Cost of New Build Generation, 1999 vs. 2008



Notes: Based on construction costs of $500/kW and $1,500/kW for CCGT and PC, respectively, in 1999 and $1,000/kW and $2,500/kW in 2008. Assumes baseload operation for both plant types (90 percent capacity factor), 10 percent after-tax weighted average cost of capital, and 40 percent tax rate. Does not include any provision for carbon-related costs.

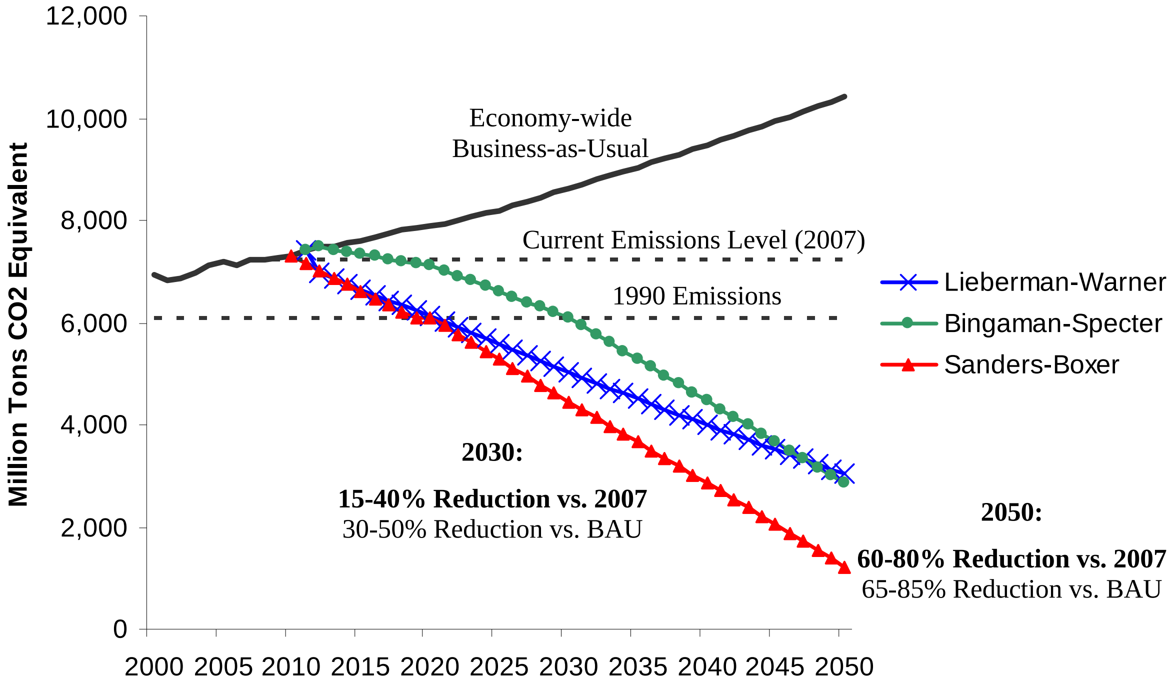
GHG regulation also will increase the cost of operating existing power plants. Most federal legislation being considered in Congress to control GHG emissions will place an explicit or implicit price on the right to emit CO_2 and other GHGs. This CO_2 price will be embedded in the marginal dispatch cost of CO_2-emitting generators, such as coal and natural gas fired generation plants, and will be reflected in wholesale electricity prices and generator costs. Thus, the economics of owning and operating existing capacity will change greatly under GHG regulation, along with capital investment incentives.

The recent concerns regarding new coal-fired plants are merely the opening act in what could potentially be the largest capital realignment in the history of the electricity industry, outdoing even the nuclear build-out of the 1970s. Most proposed GHG legislation in the United States contemplates extremely deep cuts in national GHG emissions by the 2030 to 2050 time frame. Figure 6 shows the mandated reduction path of the various proposals that have recently been advanced in the House and Senate. With few exceptions, all plans target a

[8] For example, Florida Power and Light shelved plans to build two gigawatts of regulated coal capacity due in part to environmental concerns. (Resource Media, "$45.3 billion in U.S. Coal-Fired Power Plants Cancelled in 2007: Rising Costs Force Energy Firms to Ditch Plans for 31 New Plants," Fact Sheet, 8 January 2008, 3.)

GHG atmospheric stabilization goal of 450 parts per million by 2050, implying reductions of 15 to 40 percent below the current U.S. CO_2 equivalent emission level by 2030, and 60 to 80 percent below the current level by 2050.

Figure 6 GHG Reduction Targets of Proposed U.S. Legislation



Source: Business-As-Usual Case: Energy Information Administration, Annual Energy Outlook 2008 with Projections to 2030, June 2008. Legislative cases based on NorthBridge analysis of relevant legislation.

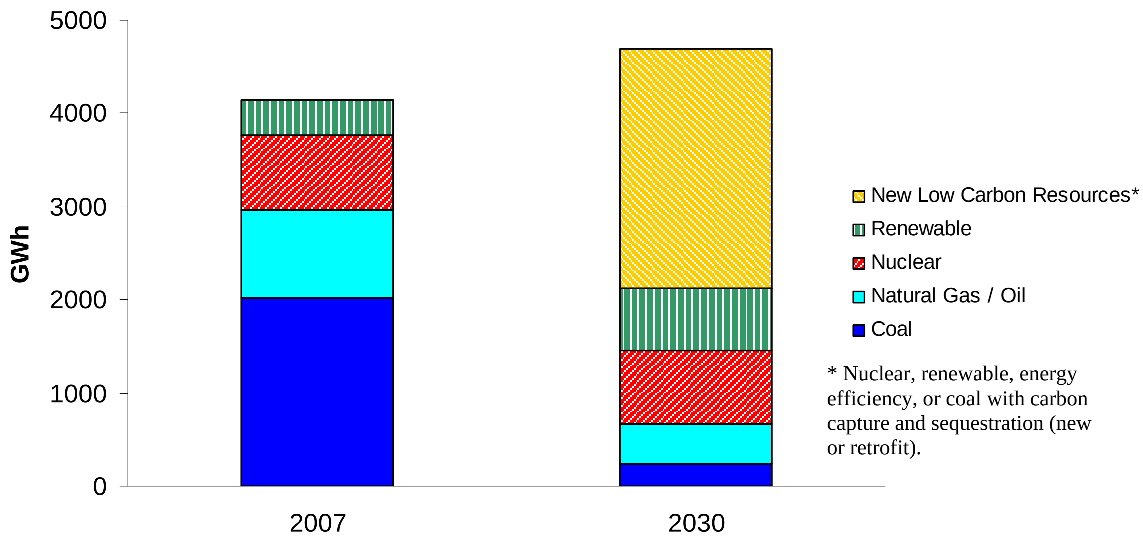
These emission reduction targets have enormous implications for the electric industry. The U.S. electric industry currently emits just under 2,500 million tons of CO_2 per year, or about one-third of total U.S. CO_2 emissions. Under the Energy Information Administration's "Business As Usual" projection, emissions are expected to rise to just under 3,000 million tons per year by 2030. If the electric industry bears a proportionate share of the emission reductions implied by the legislative proposals being considered (which is likely conservative since most models, such as the Energy Information Administration's National Energy Management System ("NEMS") model, suggest that the electric industry will bear a more than proportional share of emissions reductions), the industry must reduce emissions in 2030 by anywhere from 900 to 1,500 million tons relative to the "Business As Usual" amount. This reduction is equivalent to replacing between 250 and 400 average size coal units with zero-carbon capacity. The actual level of uncertainty is higher than that portrayed by this simple example: the relative costs of reducing emissions in other sectors of the economy and the degree to which the U.S. program is able to utilize international emissions reduction offsets add an additional layer of complexity. Achieving this emission reduction target will require that industry participants confront difficult resource decisions in the midst of tremendous uncertainty in future regulations, technology, and market conditions.

Unlike other types of pollutant regulation, there is currently no cost-effective, off-the-shelf means of reducing the CO_2 emissions of existing coal plants (such as Selective Catalytic

Reduction for NO_x or Flue Gas Desulfurization for SO_x). Consequently, to stabilize and reduce CO_2 emissions, the industry must make some difficult choices and respond to shifts in technology. Current supply choices – which include retrofitting existing coal plants[9] and increasing reliance on low carbon technology such as nuclear, coal with carbon sequestration, wind, solar, and, to some extent, natural gas – appear to have very high costs. Reductions in customer demand for electricity also will be necessary, but not sufficient, to reduce CO_2 emissions to target levels. The costs of these potential alternative low-carbon strategies are extremely uncertain and likely to be high.

The capital realignment necessary to ultimately achieve the proposed reduction targets is unprecedented. Figure 7 shows the generation capacity investment necessary to satisfy projected load growth and a CO_2 reduction target of 30 percent below current levels by 2030 (consistent with the Lieberman-Warner Bill) assuming no generation retirements. In order to meet this target, the industry will need to reduce its usage of existing coal generation by more than 80 percent and build enough low-carbon baseload capacity (nuclear, coal with carbon capture, renewables, and energy efficiency) to generate 80 percent of the output of the current baseload fleet. Overall, this implies increasing the industry's existing generation capital stock by a factor of 50 percent once retirements are considered.

Figure 7 Need for New Low Carbon Resources By 2030



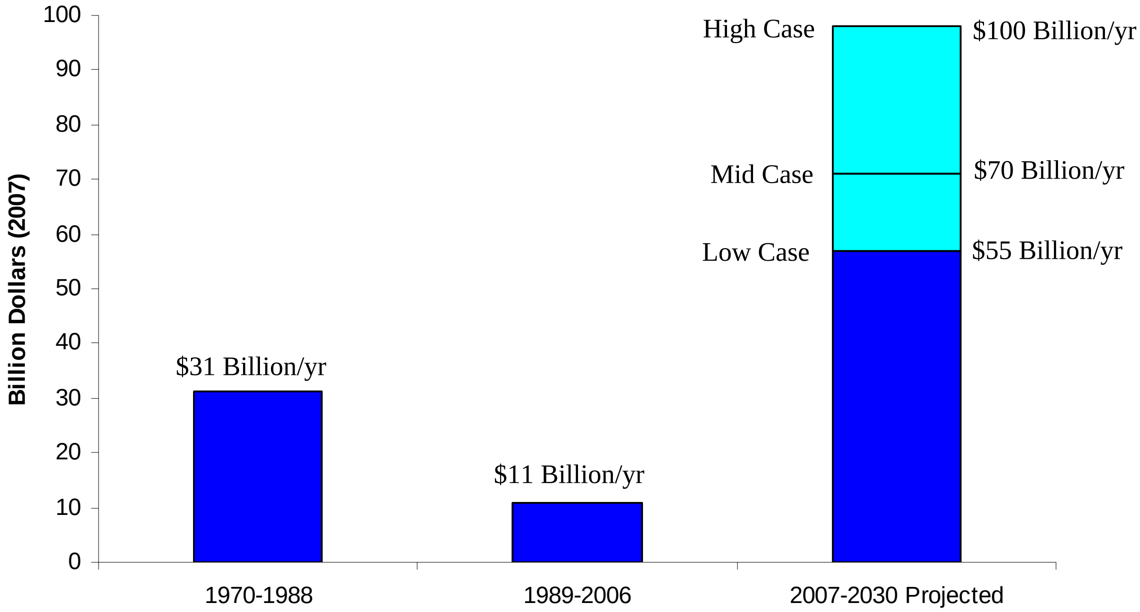
Source: Energy Information Administration, Energy Market and Economic Impacts of S. 2191, The Lieberman-Warner Climate Security Act of 2007, April 2008.

Figure 8 illustrates the financial impact of this capital realignment by comparing the average annual real generation capital investment from 2007 to 2030 with earlier periods. The required investment over the next twenty to twenty-five years will likely be five to nine times the level seen in the previous twenty years, and two to three times the level invested during

[9] In addition to any capital costs required to retrofit existing coal plants with carbon control technology, current estimates suggest that the output of these retrofitted coal plants would decline by 20 to 35 percent due to the carbon capture process.

the 1970s and early 1980s, when the industry built most of the nuclear and coal capacity in service today.

Figure 8 Expected Increase in Annual Real Investment in New Generation



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; NorthBridge analysis based on Energy Information Administration, Energy Market and Economic Impacts of S. 2191, The Lieberman-Warner Climate Security Act of 2007, April 2008.

The political demand for non-polluting, low-carbon sources of energy is very high, as evidenced by the aggressive GHG legislation currently being considered. However, the available supply-side alternatives of meeting this demand are both costly and uncertain. The dollars at risk are as large as they have ever been in the electricity industry, and the decisions made over the next twenty years may very well have implications for electricity consumers reaching over the entire century.

III. Regulation Has Failed to Meet Similar Challenges in the Past

While these future challenges loom large, the industry is currently embroiled in a debate about the relative merits of regulation versus competition. Rate shocks in restructured states such as Illinois, Maryland, and Connecticut have led some to question whether those restructured markets are producing an outcome beneficial to consumers. Concerns about high profits, market power, and market manipulation on the part of deregulated electricity suppliers began with the California energy crisis[10] and the Enron scandal and have continued as electricity prices have increased. Tighter generation reserve margins in many restructured states have led to fears that new competitive generation investment may not be sufficient to ensure electric system reliability.

In light of these concerns, some politicians and regulators are calling for a return to the "good old days" of regulation. But memories may be failing, because the good old days of regulation were not always good, especially during the times when the industry faced challenges similar to those of today. We should recall the 1970s, a time of tumultuous change in the electricity industry**,** when the industry first had to contend with an environment of sharply rising costs.

A. The Challenges Faced in the 1970s Have Similarities to Those of Today

Many of the challenges particular to the 1970s eerily echo the challenges facing the industry today. In particular, both eras have in common three sources of shock and uncertainty: 1) rising fuel costs, 2) significant capital cost escalation and new environmental concerns, and 3) future electricity demand uncertainty. These external shocks were the primary forces behind the turmoil of the 1970s. Examining the response of the regulated industry structure to each of these shocks illuminates the shortcomings of regulation and the dangers of similar shocks in the electricity market today.

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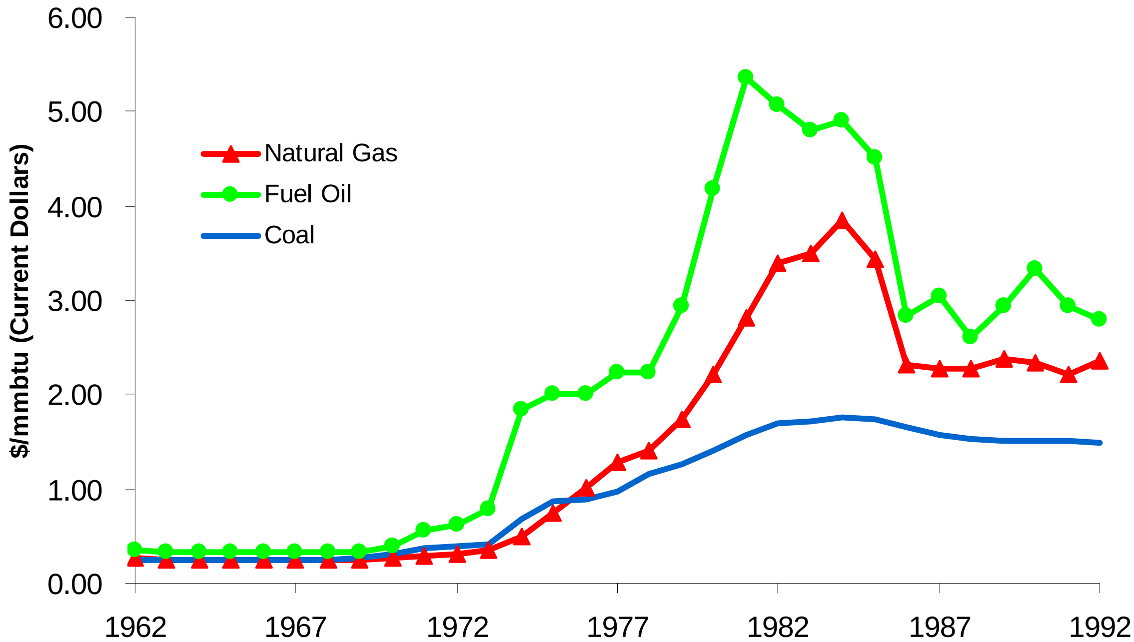
[10] In the summer of 2000, wholesale prices in California spiked above $1,000/MWH due to the convergence of several factors: hot weather with no demand response, limited supply from a capacity-constrained local market, a dry season limiting hydro-electric generation in the Pacific Northwest, high natural gas prices, and opportunistic behavior by wholesale suppliers. The high wholesale prices forced utilities to sell power to retail customers at prices far below their costs because there were no cost-recovery or rate adjustment mechanisms. The California market design left the utilities fully exposed to the spot market. Southern California Edison ("SCE") and Pacific Gas & Electric ("PG&E") had divested their fossil generating assets, and the utilities, as the provider of last resort, were to purchase electricity in high-priced spot markets and resell electricity to retail customers at lower, long-term fixed prices. This market design led to financial disaster for both companies, and ultimately large rate increases for retail customers. Dramatic price increases in late 2000 and early 2001 created a crisis that bankrupted PG&E and severely weakened SCE. PG&E and SCE suffered combined losses of billions of dollars in procuring power supplies to serve their load. As a result, retail access was halted, and the state government of California was forced to financially backstop procurement. Many economists and industry observers blame the California crisis on a flawed market design from a politically contentious regulatory and legislative process. (Frank Wolak, "Diagnosing the California Electricity Crisis," *The Electricity Journal*, Vol. 16, No. 7 (August/September 2003), 11-37; John Jurewitz, "California's Electricity Debacle: A Guided Tour," *The Electricity Journal*, Vol. 15, No. 3, (May 2002), 10-28; Paul Joskow, "California's Electricity Crisis," *Oxford Review of Economic Policy*, Vol. 17, No. 3 (2001) 6; Sally Hunt, *Making Competition Work in Electricity*, (Jon Wiley and Sons, New York: 2002), 378.)

1) Rising Fuel Costs

The dual shocks of the Arab oil embargo of 1973-4 and the Iranian revolution of 1979 caused world oil prices to rise to previously unprecedented levels in the 1970s. Natural gas prices and, to a lesser extent, coal prices followed suit. Figure 9 shows this rapid rise in the cost of input fuels for electric generators.

Figure 9 Rise in Nominal Input Fuel Costs for Electric Generators, 1962-1992



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992.

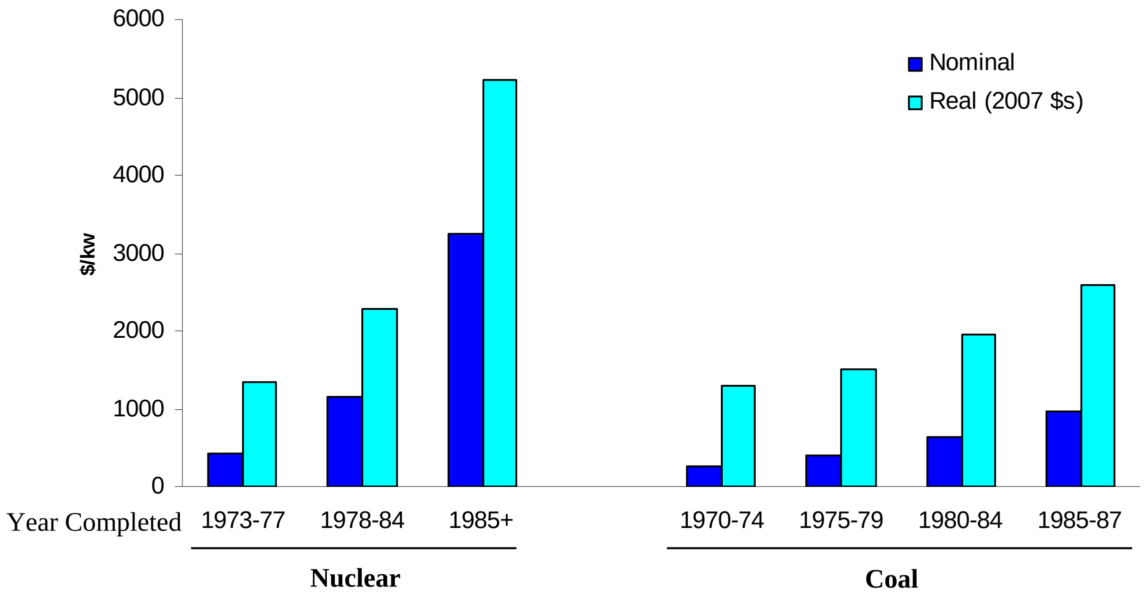
By 1982, coal, natural gas, and oil prices had risen to 6, 13, and 15 times their 1969 levels, respectively. As a consequence, variable generation costs for fossil fuel-fired power plants rose by a factor of 9 from 1969 to 1982. This increase led many utilities to develop fuel clauses that allowed the pass-through of higher fuel costs and/or contributed to numerous utility requests to increase rates.

2) Capital Cost Escalation and Environmental Concerns

Prior to the late 1960s, construction of new electric generating capacity had been characterized by increasing economies of scale. By increasing the size of power plants, utilities could achieve lower unit construction costs and greater thermal efficiency. This trend began to slow in the 1960s and essentially disappeared by the 1970s as reliability and economic dispatch problems associated with extremely large units began to appear. The average size of new coal units increased from 124 MW in the early 1950s to close to 600

MW in the early 1970s, but declined back towards 500 MW thereafter.[11] Around the same time, several legislative actions and market trends caused an increase in the cost of building and operating new power plants. In particular, the Clean Air Act of 1970 mandated that all new coal plants install equipment to reduce harmful air emissions, such as sulfur dioxide and nitrous oxide. Around 1973, the environmental movement also began to contest the construction and operation of nuclear plants, which led to construction delays, litigation, and increasing safety and environmental costs at nuclear units, a trend that intensified throughout the decade. The nuclear accidents at Brown's Ferry in 1975 and Three Mile Island in 1979 accelerated this trend, which ultimately led to long and expensive delays and re-designs for plants under construction throughout the late 1970s and 1980s. The costs of these delays in the construction and development cycle of coal and nuclear units were exacerbated by increasing input costs and inflation.[12]

Figure 10 Escalation of Generation Construction Costs in the 1970s and 1980s



Sources: Energy Information Administration, "An Analysis of Nuclear Power Plant Construction Costs," December 1986; Energy Information Administration, "Historical Plant Cost and Production Expenses For Selected Electric Plants, 1987."

All these factors put upward pressure on the cost of building and operating electric generation, with little or no offsetting gains in economies of scale and efficiency. Figure 10 shows the "overnight" construction cost per kilowatt of nuclear and coal-fired electric

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[11] Paul Joskow and Nancy Rose, "The Effects Of Technological Change, Experience, And Environmental Regulation On The Construction Cost Of Coal-Burning Generating Units," *Rand Journal of Economics*, Vol. 16, No. 1, (Spring 1985): 3, 4, and 24.

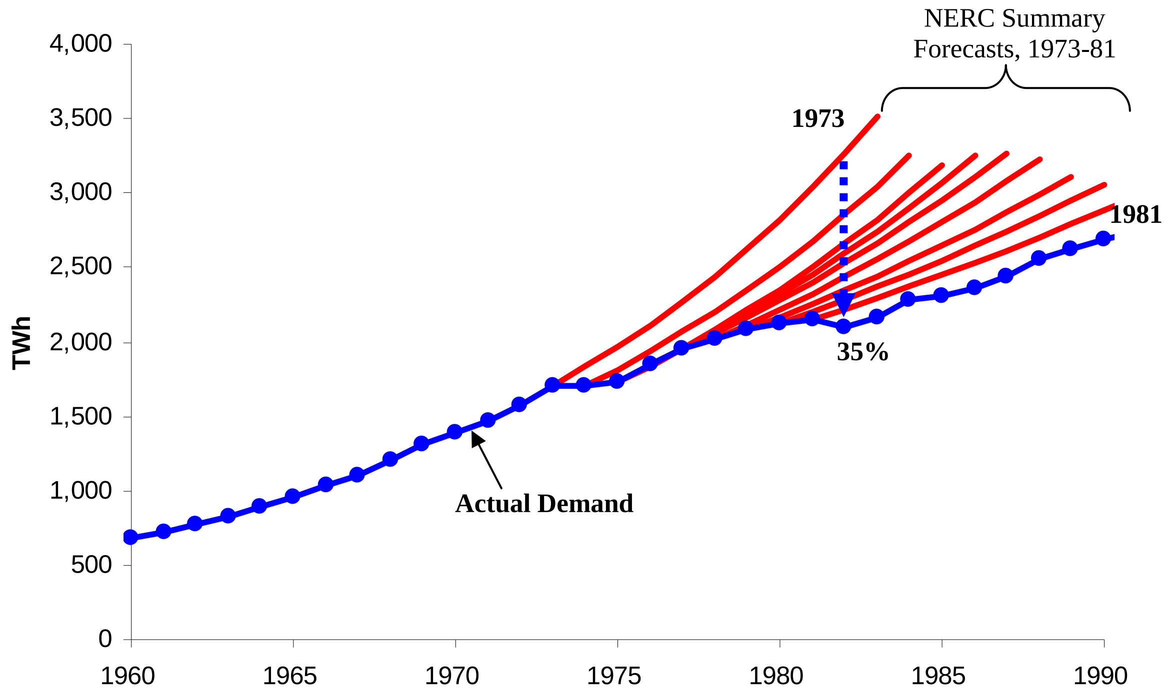
[12] Nominal construction costs for steam-electric power plants rose by 9 percent per year from 1973 to 1984, more than double the 4 percent per year increases from 1950 to 1973. (Based on data from the *Handy-Whitman Index of Public Utility Construction Costs*, Whitman, Requardt & Associates, various years.) Rising inflation, recession, and turmoil in financial markets also caused a dramatic increase in real and nominal financing costs. Nominal interest rates on utility bonds averaged over 11 percent from 1973 to 1984 compared to 6 percent from 1960 to 1972. (Edison Electric Institute, "Historical Statistics of the Electric Utility Industry through 1992," 1995.)

generation plants at different periods of time**.** Between 1970 and the late 1980s real and nominal nuclear construction costs increased by 113 percent and 679 percent, respectively, while real and nominal coal plant construction costs increased by 58 percent and 262 percent, respectively.

3) Demand Uncertainty

Prior to the early 1970s, demand for electricity grew at a rapid and fairly predictable clip. As Figure 11 shows, from 1960 to 1973 electricity consumption grew at an annual rate of 7.3 percent, with relatively little variance. Total electric generating capacity in this period grew by 7.7 percent per year, keeping approximate pace with demand growth. By the late 1960s, most utility demand forecasts reflected continued high load growth and a concomitant need for additional baseload coal and nuclear capacity. These demand forecasts buttressed a round of initial planning, completed between 1966 and 1973, for most units that were later built in the 1970s and 1980s. However, actual demand growth in the 1970s fell far below expectations. From 1973 to 1982 electricity consumption only grew by 2.4 percent annually, while generating capacity grew almost twice as fast at a rate of 4.5 percent per year. As Figure 11 shows, by 1982, actual demand was about 35 percent less than what it would have been had load continued to grow at its pre-1973 rate of growth.

Figure 11 Actual U.S. Electricity Demand Fell Below Projections in the 1970s



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Nelson, Charles, and Peek, Stephen, “The NERC Fan: A Retrospective Analysis of the NERC Summary Forecasts,” *Journal of Business and Economic Statistics*, Vol. 3, No. 3, July 1985.

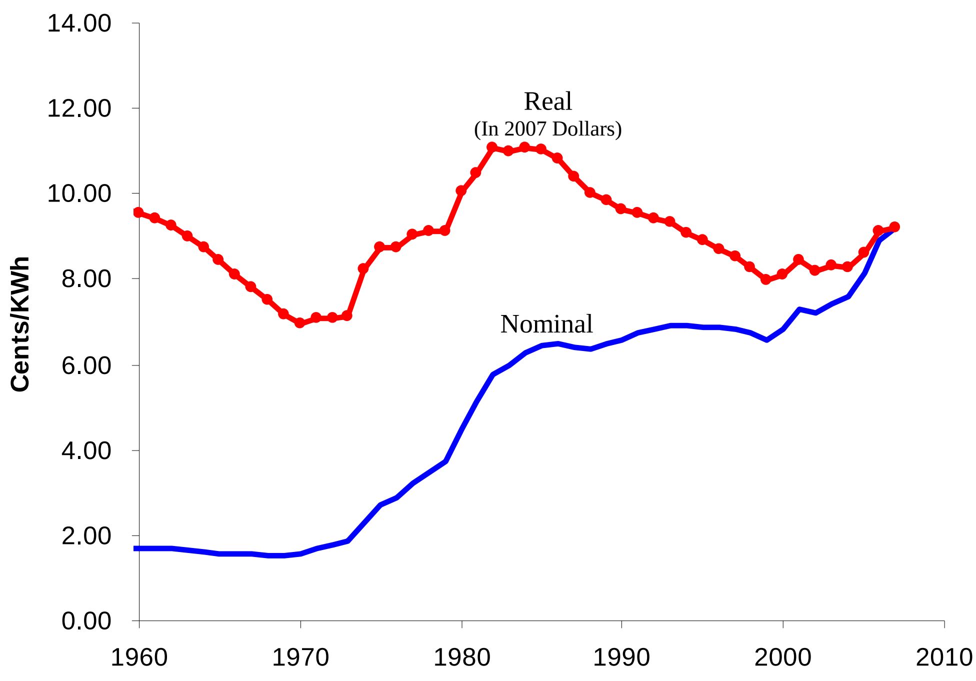
This falloff in demand growth was caused by a slowdown in the U.S. economy, a leveling-off of the nation's energy intensity,[13] and the inevitable demand response to higher electricity prices as rising fuel and capital costs eventually found their way into average-cost utility retail electric rates.

The overall effect of the lower-than-expected load growth was that the electric industry built up a huge oversupply of unneeded and expensive coal and nuclear capacity. The units built in the 1970s and 1980s were more expensive than originally estimated and the costs were spread over a smaller-than-expected customer base.

B. The Regulatory Response to the Challenges of the 1970s Was Poor

The ultimate effect of these three challenges – rising fuel costs, capital cost escalation and environmental concerns, and demand uncertainty – and policymaker's response to them was to create an unmitigated disaster for electricity consumers and utility shareholders. As Figure 12 shows, the increasing economies of scale in the electric industry that led to lower retail prices in the 1950s and 1960s virtually disappeared by the 1970s. Nominal electric rates rose by over 300 percent from 1970 to their peak in 1985, while real rates rose by 60 percent in the same time period.

Figure 12 U.S. Average Retail Electricity Prices Rose in the 1970s and 1980s



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006. 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly.

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[13] Energy intensity is a measure of the energy efficiency of a nation's economy that is generally measured in units of energy per unit of gross domestic product.

Electric utilities also endured approximately $60 billion in cost disallowances (in 2007 dollar terms) from the late 1970s to the early 1980s, costs which would have further raised rates had they not been borne by shareholders.[14] Overall, the regulatory response to the events of the 1970s and 1980s probably amounted to a mistake on the order of $200 billion or more in today's dollars.[15]

Figure 13 provides an indication of the misallocation of resources in the 1970s and 1980s. The figure shows capacity utilization for baseload coal plants from 1960 to the present. The economics of coal plants with high capital costs and low variable costs favor high capacity utilizations of 70 percent or more. In the 1960s and in recent years, coal plants have operated at this level of utilization. However, during the 1970s and 1980s, capacity utilization in the regulated electric utility industry remained low – at the 50 to 60 percent level.

When judged by the outcome of high electricity costs and low capacity utilizations, the regulatory response to the rising cost environment of the 1970s appears to have been a failure. But why was the response so poor? What portion of this poor outcome can be blamed on regulation, rather than exogenous shocks outside the control of industry decision-makers? And, would competition have produced a better result?

The external shocks that placed the initial stress on the electricity industry – the oil price shocks, cost inflation, and falloff in demand growth – were not caused by regulation of the industry. However, a careful examination reveals four inherent flaws of regulation behind much of the industry's response to the external shocks and uncertainty of the 1970s: 1) a lack of clear market price signals for both suppliers and consumers of electricity, 2) perverse capital incentives for regulated utilities to favor capital and consider sunk costs in investment and abandonment decisions, 3) improper allocation of risks that encourage regulated utilities to underestimate the risks of large capital-intensive investments that are borne by ratepayers, and 4) the tendency for political and regulatory "fixes" that overcompensate with unintended consequences. These flaws ultimately led to higher costs for consumers and a less efficient resource allocation than likely would have occurred in a competitive framework.

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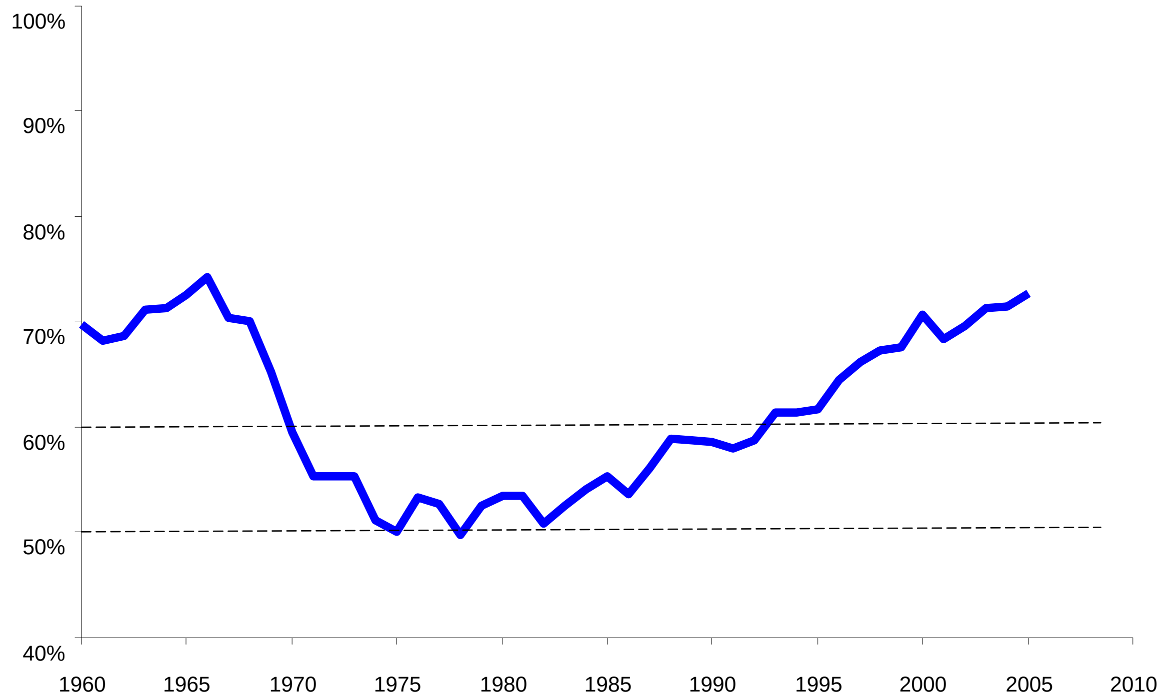
[14] Disallowances related to completed and in-service plants amounted to almost $31 billion in 2007$, or about $19 billion in mixed nominal dollars. (Thomas Lyon and John Mayo, "Regulatory Opportunism and Investment Behavior: Evidence from the Electric Utility Industry," *Rand Journal of Economics*, Vol. 36, No. 3, (2005): 628-644.) The other major source of disallowances was the sunk costs of abandoned nuclear units, which amounted to about $63 billion in 2007$, or about $36 billion in mixed nominal dollars. (Charles Komanoff, and Cora Roelofs, Komanoff Energy Associates, "Fiscal Fission, The Economic Failure of Nuclear Power," (December 1992), 15, Table 7.) These sunk costs were shared between ratepayers, utility investors, and taxpayers in a variety of ways depending on the jurisdiction. Assuming shareholders ultimately bore about half of these costs we arrive at a figure of about $60 billion in 2007$ for both sources of disallowances.

[15] This estimate is the summation of two sources of costs associated with the mistakes of regulation: the unsunk above-market cost of uneconomic nuclear units completed after the Three Mile Island incident, measured relative to avoided costs of fossil energy as of the early 1980s, and the above-market costs of uneconomic contracts entered into as a result of PURPA. We conservatively estimate the first source of costs at about $150 billion (in 2007$), while the second source has been estimated at close to $50 billion (also in 2007$) as of the mid 1990s (see Resource Data International, *Power Markets in the U.S.*, Boulder, CO, RDI, 1996). Note that these costs were shared among ratepayers, utility shareholders, and taxpayers.

Figure 13 Capacity Utilization of U.S. Coal-Fired Electric Generation Remained Low During the 1970s and 1980s



Sources: Energy Velocity; Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006.

1) Lack of Market Price Signals

In the regulated-utility environment of the 1970s, utilities and regulators made generation resource decisions based on their long-term expectations about fuel prices, economic conditions, and supply/demand balances. These expectations were infrequently updated, and the "price signals" in this framework were the result of internal forecasts of a single regulated entity subject to political influence and negotiation with the regulator during the ratemaking process. Not surprisingly, such an approach can – and did – lead to poor resource allocation decisions, particularly during periods of market turbulence and uncertainty, where the relative economics of different resource types can change rapidly.[16]

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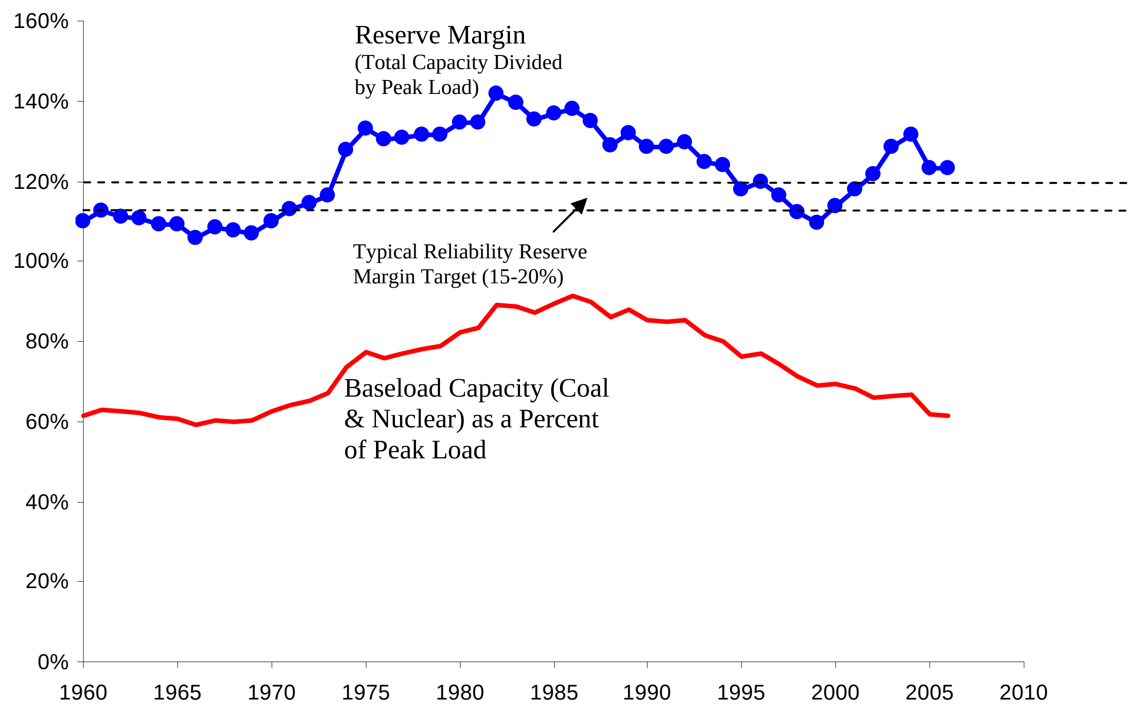
[16] Today, the decision-making process regarding resource allocation is very different in a region with a competitive, visible wholesale electricity market. A competitive power plant developer considering the possibility of building a new plant is able to continuously evaluate the forward-looking economics of different types of generation using the various price signals generated by competitive markets. The price signal for revenues is the forward price of electricity that reflects a market consensus on future electricity supply and demand and the marginal costs of conversion of different fuels into electricity. The price signal for costs are the forward prices for different types of fuel (gas, coal, etc.) that reflect supply and demand conditions in those markets. The developer can meld these price signals into a continuously-updated picture of the relative economics of different types of generation and then act accordingly, along with other competing developers. Different developers may have different long-term expectations and different appetites for risk, but each

The generation resource allocation decisions of the 1970s clearly illustrate the shortcomings of decision-making without clear market price signals. During the 1950s and 1960s, capital and operating costs for nuclear and coal units were expected to be quite low (in fact, Lewis L. Strauss, chairman of the Atomic Energy Commission, famously proclaimed in 1954 that nuclear energy would be "too cheap to meter").[17] Not surprisingly, as reserve margins declined in the late 1960s, electric utilities initiated the development of a large number of nuclear and coal units. As the 1970s progressed, capital costs for these units began to rise, and demand growth failed to materialize, leading to a rapid deterioration of the economics of new generation in general, and baseload units (especially nuclear) in particular. Despite this change in economics, however, a large proportion of the excess baseload units planned in the late 1960s and early 1970s were ultimately built over the course of the 1970s and 1980s. In the period from 1970 to 1988, utilities added an average of 15,000 MW of coal and nuclear capacity per year, and 19,400 MW per year of capacity of all kinds, while peak load grew by an average of only 13,800 MW per year. Figure 14 shows the increase in U.S. reserve margin and the amount of baseload capacity as a percent of peak electric load during this period.

Figure 14 Excess U.S. Reserve Margins and Baseload Capacity in the Mid 1970s to Early 1990s



Source: Energy Velocity; Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006.

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developer can monitor market prices and will need to bet its own money on decisions based on these differences in expectations and risks.

[17] Lewis Straus, Chairman of the Atomic Energy Commission, Speech to the National Association of Science Writers, New York City, 16 September 1954; "Abundant Power From Atom Seen; It Will Be Too Cheap For Our Children to Meter, Strauss Tells Science Writers," *New York Times*, 17 September 1954.

By 1986, coal and nuclear capacity reached 91 percent of national peak load, in comparison to approximately 60 percent today and in 1960. Similarly, total excess capacity as a proportion of peak load (i.e., the reserve margin) peaked at 42 percent in 1982, more than twice the 15 to 20 percent level generally deemed necessary at that time to maintain system reliability.[18] By the early 1980s, coal units, generally expected to have capacity factors greater than 70 percent, were operating at an average capacity factor of only 50 percent, indicating a large mismatch between the national generation supply portfolio and demand. As Figure 10 and Figure 11 show, both the falloff in demand and the escalation in generation capital costs were well underway by 1975 and were becoming readily apparent to utilities and regulators. However, utilities continued to overbuild baseload capacity well into the 1980s despite clear indications that such generation was no longer needed or economic.

Ultimately, over the course of the 1970s and early 1980s, electric utilities built a generation supply portfolio that was far too big in absolute terms, and too heavily-weighted towards capital-intensive coal and nuclear generation. The lack of clear market price signals was a significant culprit in this misallocation of resources. With no clear market pricing for electricity, utility builders and regulators lacked an unbiased indicator of future electricity supply and demand, and were thus slow to readjust their plans to build new generation as conditions changed. Furthermore, even when imperfect market price signals did exist, the command-and-control nature and perverse incentives of the regulatory process did not incorporate them well.

A more subtle problem was the lack of appropriate price signals for consumers of electricity. In the regulated utility framework, retail customers were charged a bundled rate that was based on the average historical cost of generating and delivering electricity to the customer. As such, the retail price incorporated the effects of numerous long-past decisions with respect to the historical costs and type of generation built by the utility. When the incremental cost of meeting load growth exceeded this historical embedded average cost (as it did in the rising cost environment of the 1970s and today) the retail price signal to customers was below the marginal cost of meeting the last increment of demand. Increases in retail rates lagged behind the increase in marginal cost. These artificially low price signals to customers encouraged over-consumption relative to the efficient level, which tended to exacerbate cost increases. While load growth did slow considerably in the 1970s and early 1980s relative to earlier periods (see Figure 11), it would have fallen faster and further had customers seen an appropriate marginal cost price signal.

Meanwhile, the lack of clear wholesale market price signals during this period led to poor resource decisions, in particular the over-build of regulated baseload capacity, which saddled the industry with the huge costs of oversupply.

[18] Large-scale nuclear and coal units in the event of an outage tend to require a greater reserve margin than do a series of smaller-scale gas units and demand resources. As technology improvements enable smaller, more efficient plants to be built and there is increasing reliance on smaller customer demand resources in broader competitive markets, reserve margins should shrink while continuing to maintain or even enhance reliability. In recent years, many competitive markets (e.g., ERCOT and PJM) have been able to reduce their target reserve margins to the 12 to 18 percent range.

2) Perverse Capital Incentives

Several perverse incentives created by the regulated structure also contributed to the poor industry response to the challenges of the 1970s and early 1980s. In particular, regulated utilities in a cost-of-service structure have incentives to over-invest in capital,[19] overestimate consumer demand for electricity, or continue to build facilities even when costs have significantly increased or slow-downs in load growth no longer require the investment. Regulated utilities with regulatory prudence oversight have a tendency to consider sunk costs[20] when making investment/abandonment decisions.

In a competitive market, a power plant builder with a partially-constructed plant will compare "to-go" capital costs – without any sunk costs – to forward-looking profitability when evaluating whether to continue, delay, or abandon construction of the plant.[21] Removing sunk costs from the decision-making process helps participants avoid "throwing good money after bad" if the prospects for an investment sour after resources have been sunk into the investment. For a regulated electric utility operating under the traditional "prudent investment" and "used and useful" investment cost recovery standards, such decisions are very different. Canceling an under-construction power plant and never putting it into service makes it less likely that the utility will be able to recover the investment sunk into the plant prior to cancellation. Therefore, relative to a non-regulated developer, a regulated utility will tend to finish large capital investments and place them into service even if the investment becomes uneconomic on a forward-looking basis at some point along its development cycle. While the utility certainly risks disallowance on an uneconomic completed plant, this risk is lower than that of trying to recover the sunk costs of an abandoned plant. Utilities were forced to confront the unpalatable decision to either build unneeded facilities or cancel construction and face the daunting prospect of trying to recover from customers the already-sunk costs of facilities that would not be placed into service, thereby failing the "used and useful" regulatory principle of cost recovery. This tendency to "build no matter what" was on full display during the 1970s and early 1980s, as utilities continued to develop coal and nuclear plants long after those plants were clearly uneconomic in forward-looking terms.[22]

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[19] Economists Harvey Averch and Leland Johnson in 1962 demonstrated analytically that firms subject to rate-of-return regulation will have a tendency to overcapitalize and have a high capital to labor ratio. This phenomenon in the economics of utility regulation became known as the Averch-Johnson effect. (Harvey Averch and Leland Johnson, "Behavior of the Firm Under Regulatory Constraint," *The American Economic Review*, Vol. 52, No. 5 (December 1962): 1052-1069.)

[20] Sunk costs are unrecoverable past expenditures. These should not normally be taken into account when determining whether to continue a project or abandon it, because they cannot be recovered either way.

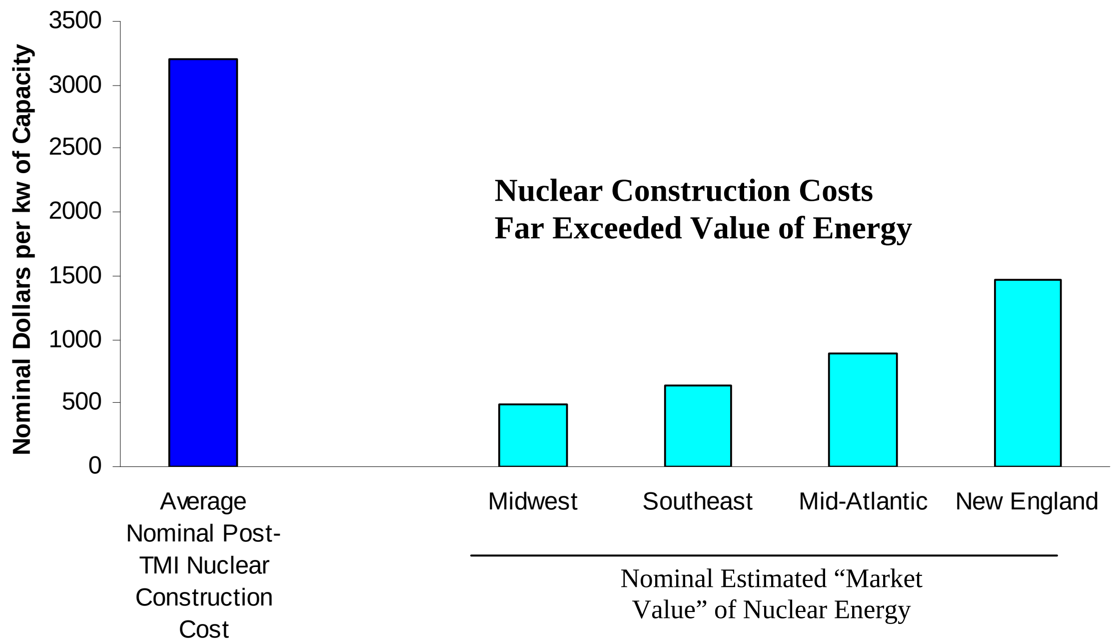
[21] Timothy Mount recognized this difference between regulated and merchant generators in a recent paper: "The important implication is that it is no longer realistic in a typical deregulated market to assume that a generating unit will be built after regulators have approved a license for construction. This was typically not the case under regulation. In a deregulated market, merchant generators have no obligation to complete projects if the prospects for recovering capital costs deteriorate during the construction process." (Timothy Mount, "Investment Performance in Deregulated Markets for Electricity: A Case Study of New York State," prepared for the American Public Power Association, September 2007, 28.)

[22] Further evidence of the tendency of regulated utilities to incorporate sunk costs into their decision-making has been found by examining the effect of nuclear plant cancellations on utility stock returns. For example, one analysis finds that utilities that cancelled nuclear plants under construction experienced significant negative excess stock returns. Furthermore, the larger the sunk costs relative to the size of the utility, the larger the stock price decline. This is consistent with the notion that cancelling a nuclear power plant under construction

For example, consider the situation in the nuclear industry in 1980. The Three Mile Island nuclear accident in March of 1979 led to a stoppage of new nuclear orders and a widespread questioning of the safety of plants in development.[23] The trend towards cost overruns and delays in the nuclear industry had been established for several years[24] and was likely to worsen in the current environment. Furthermore, it was apparent by that time that the country had reached a state of significant oversupply of generation, and that new nuclear plants were not needed – reserve margins had pushed above 30 percent by the mid-1970s and coal plant capacity factors averaged under 50 percent by 1975.

Figure 15 illustrates the forward-looking economics for nuclear power plants at the time by comparing nuclear plant construction cost to the approximate avoided cost of electric generation at the time in different regions of the country.

Figure 15 Nuclear Investment/Abandonment Decision, Circa 1980



Notes: Average nuclear construction cost based on data from Energy Information Administration, "An Analysis of Nuclear Power Plant Construction Costs," 1987. Market value of nuclear energy developed by estimating the nominal variable cost of energy produced from fossil fuel sources in each region, based on 1981 realized electric utility natural gas, coal, and oil costs.

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destroys value for the utility because it increases the likelihood that the utility will not be able to recover the sunk investment whereas taking the plant to completion provides at least some chance of recovering a portion of the investment. (Douglas Hearth, Darryl Gurley, and Ronald Melicher, "Nuclear Plant Cancellations: Sunk Costs and Utility Stock Returns," *Quarterly Journal of Business and Economics*, Vol. 29 (January 1990).)

[23] On March 28, 1979, a main feedwater pump malfunctioned at the Three Mile Island Generating Station near Middletown, Pennsylvania. A series of mechanical and human errors led to the most serious nuclear power plant accident in U.S. history.

[24] For instance, operations and maintenance costs for existing nuclear units, which is a barometer of the costs and difficulties of nuclear operations, rose in real terms by 73 percent from 1974 to 1979 and 137 percent from 1974 to 1980. (Energy Information Administration, "An Analysis of Nuclear Power Plant Operating Costs: A 1995 Update," April 1995, 7.)

By 1980, the construction costs of nuclear power plants were approximately two to six times greater than the value of the energy they provided. Put differently, only plants that had already sunk at least three-quarters of their likely final cost should have continued construction, and the rest should have been abandoned. Unfortunately, this did not happen. Ultimately, 53 nuclear units under construction at the end of 1979 were eventually completed, and of those, around 44 were less than 50 percent completed by 1980 (74 units on order were ultimately cancelled after 1979).[25] Six units were not completed until the 1990s. The costs associated with these decisions ran into the hundreds of billions of dollars and contributed greatly to the rise in rates in the 1970s and 1980s.[26]

3) Improper Allocation of Risks

Regulation improperly allocates risk between generation-building utilities and their customers. Prior to the 1970s, cost disallowances were virtually unknown in the electric utility industry. Should a generation facility prove uneconomic, the regulated model strongly suggested that the customers, rather than investors, would bear the risks of bad outcomes. Thus, there was little downside, and a great deal of upside, for utilities to bet large chunks of capital on big, capital-intensive baseload plants in the early 1970s. Customers still paid for the facility regardless of whether it was needed or not. The eventual disallowances of the 1970s and 1980s changed this calculus somewhat, but the risk distribution was still asymmetric, with customers paying for the majority of uneconomic capacity.

Not surprisingly, this inefficient allocation of risk creates an incentive problem for regulators and regulated utilities to underestimate risks, particularly risks associated with large baseload investments. The electricity supply business is inherently risky, because the future is uncertain with respect to those things that will determine the future market price of wholesale power: load growth, fuel prices, environmental costs, new technology, and so forth. For example, currently there is considerable uncertainty regarding the future cost and performance of new Integrated Gasification Combined Cycle (or "IGCC") plants, carbon capture sequestration technologies, and the costs and regulation associated with building new nuclear facilities. Therefore, large capital-intensive investments in new generation are unavoidably risky. Utility-built generation under a regulatory model or utility long-term contracts backed by ratepayer guarantees does not alter this fact – it merely shifts risks from the wholesale developer/supplier of generation to retail customers. In these risky electricity markets, unfavorable and unforeseen investment outcomes are common. Unfortunately, retail customers bear the responsibility of paying for those mistakes under regulation, while in competitive markets investors are responsible for the consequences of their decisions. Therefore, investors in competitive markets are more likely to respond quickly to changing market conditions than a regulated utility that can pass through its costs to retail customers. Indeed, under a regulated model of resource planning by utilities or regulators, with market risks assumed by customers, there have been many examples of long term generation commitments that turned out, after the fact, to be uneconomic. Whether the utility's commitments were in the form of utility-owned generation or long-term power purchase

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[25] Energy Information Administration, "An Analysis of Nuclear Power Plant Construction Costs," 1987.

[26] See footnote 15.

agreements, they were undertaken on behalf of ratepayers and were eventually paid for by ratepayers.

4) Political and Regulatory "Fixes" Overcompensate With Unintended Consequences

The turmoil of the 1970s led to a dissatisfaction with the existing regulatory process, and a search began for new regulatory solutions and models to counter the rate shocks experienced by consumers. Politicians and regulators then tried to "fix" some of the perceived imbalances in the energy industry. Related to the rise in fuel prices was an increase in concern that the nation's fuel supplies, oil and natural gas in particular, were insecure and limited in quantity. This concern led to a flurry of legislation and policy aimed at reducing the nation's dependence on oil and gas and promoting conservation, rationing, and end-use energy efficiency.

The most significant legislative response to the problems of the 1970s was the National Energy Plan, developed by the Carter administration and passed by Congress in 1978. The Plan actually consisted of several related pieces of legislation, the most important of which for the electric utility industry were the Power Plant and Industrial Fuel Use Act ("PIFUA") and the Public Utilities Regulatory Policy Act ("PURPA"). PIFUA and PURPA had unintended consequences that greatly influenced the course of the electricity industry through much of the 1980s and 1990s.

PIFUA was the culmination of a series of regulatory interventions in natural gas markets and federal restrictions on the development of gas-fired generation. PIFUA essentially prohibited development of new gas and oil power plants,[27] encouraged the conversion of gas/oil plants to coal, and limited the ability of utilities to run their gas/oil plants on a day-to-day basis. Starting in the 1950s, natural gas was subject to a complex regime of price controls that capped prices below their competitive market clearing levels and greatly limited the incentive to develop new gas supply. Exploration for new sources of gas production slowed, and the industry began to experience shortages by the mid-1970s. This regulatory interference with the gas market coupled with the federal restrictions placed on the use of gas as a power plant fuel (the Energy Supply and Environmental Coordination Act of 1974 and PIFUA in 1978) virtually eliminated natural gas as a viable fuel source for new generation, essentially forcing utilities to rely on coal or nuclear plants. While utilities were building up a huge surplus of coal and nuclear capacity, they also substantially reduced investment in less capital-intensive gas and oil capacity, building only about 2,400 MW, or about 2 to 4 plants, nationwide per year after 1975. Several studies of the natural gas industry have concluded that eliminating natural gas price controls and restrictions on gas-fired power plant investment would have provided a clear price signal and incentive to gas producers to increase production and develop new supply sources, ultimately lowering gas prices and potentially making natural gas a viable, cheaper alternative to much of the baseload generation developed in the 1970s and 1980s.[28] When gas prices were eventually decontrolled and PIFUA was scrapped, the

[27] There were exceptions in specific cases to maintain system reliability, and, after 1978, to promote the development of non-utility cogeneration facilities.

[28] Paul MacAvoy, *The Natural Gas Market: Sixty Year of Regulation and Deregulation*, (New Haven: Yale University Press, 2000).

incentive to build gas-fired generation did indeed develop. Ultimately, over the course of the 1970s and early 1980s, regulated electric utilities built a generation supply portfolio that was far too big in absolute terms, and too heavily-weighted towards capital-intensive coal and nuclear generation.

PURPA's stated purpose was to encourage energy efficiency in an environmentally-friendly manner by increasing the usage of alternative, renewable electricity generation.[29] To achieve these goals, PURPA created a new class of power generators called Qualifying Facilities ("QFs") that were exempt from most of the cost-based regulation applied to utility generation. To be deemed a QF, a power generation facility had to demonstrate that it was either a cogeneration plant or a small renewable generator. Utilities were required to purchase all the electric energy that these QFs could generate at the utilities' "avoided cost," which PURPA ambiguously defined as the incremental cost to the utility of alternative electric energy. PURPA did contain some innovative elements that, in time, were to contribute to the transition of the industry towards a competitive model; most notably, it created a class of non-utility generators that built and operated power plants outside the cost-of-service regulated model. However, the command-and-control elements of PURPA, especially the mandatory nature of the utility obligation to purchase QF energy and the administratively-determined purchase price, would prove enormously costly to electricity consumers.

The first five years after the passage of PURPA were spent determining what the "avoided cost" principle established in the legislation meant in practical terms. Even after the Federal Energy Regulatory Commission ("FERC") defined avoided cost in 1980, state regulatory bodies were charged with developing long-term avoided cost forecasts to set the prices for the QF contracts. While the process of establishing prices and structuring contracts varied considerably from state to state, prices were administratively-determined, not market-based, and several key mistakes were made:

- In some states, contract rates were established above avoided costs in order to spur QF development. For example, the New York state legislature mandated that the states' utilities pay a minimum 6 cents/kWh long-term price to QFs,[30] even though utilities

[29] "PURPA began the process of creating an independent generation sector and the supporting market and regulatory institutions to create a competitive market for new generating resources. The primary motivation for PURPA was to encourage improvements in energy efficiency through expanded use of cogeneration technology and to create a market for electricity produced from renewable fuels and fuel wastes. It was not motivated by a desire to restructure the electricity sector and to create an independent competitive generation sector. However, it turned out to have effects significantly different from what was intended when it was passed." (William Baumol, Paul Joskow, and Alfred Kahn, *The Challenge for Federal and State Regulators: An Efficient Transition from Regulation to Competition in the Electric Power Industry*, (Washington, DC: Edison Electric Institute, 1995) 8.)

[30] In New York, beginning in the 1980's in an effort to reduce reliance on utility-owned generation, the Public Service Commission ("PSC") required utilities to enter into contracts with non-utility generators at long-term fixed rates that were well above market prices. The New York Public Service Law was amended in 1981 to set the minimum sales price for the QFs' output at six cents/kWh. In practice, the PSC provided independent power producers the choice of six-cents or a fixed price stream equal to the PSC's estimate of long-run avoided costs ("LRACs"). The PSC's estimate of LRACs during the 1980s expected prices to rise well over six cents, and the PSC required that utilities provide the QFs with contracts of ten to fifteen years. Further, since the six-cent law provided no limit on the quantity of generation that could qualify for power contracts, QF developers planned projects with total capacity far in excess of what was reasonably required by load growth. Through this period,

estimated avoided cost at roughly half that amount.[31] In Maine, the rate was set at 9 to 10 cents/kWh based on the total all-in cost of the Seabrook nuclear generating station.[32]

- Many states did not readjust avoided cost rates as more QF capacity was added to the market. As QF capacity increased, the avoided cost (and the market price of electricity if it were known) should have gone down as the QFs displaced progressively cheaper capacity and energy. Many states failed to make this adjustment; however, with some establishing unvarying, above-market "standard offer" prices that QFs could receive without an avoided cost proceeding. This led to an oversupply of QF capacity in several states (California[33] and New York most notably), with long-term contract prices that were well above market.[34]

- Finally, many QF contracts were based on administratively-determined avoided costs using very high oil and natural gas price forecasts from the early to mid 1980s. Figure 16 shows the dangers of this approach. By the late 1980s and early 1990s, actual oil and gas prices had declined and were about 60 to 80 percent below the expected forecast levels from five to seven years earlier. Most long-term QF contracts, however, lacked any sort of adjustment clause to move the contract prices more in line with actual market conditions.

The overall effect of these mistakes was to burden electric utilities and their customers with a huge overhang of mandatory long-term contracts established at prices well above their actual avoided cost or any reasonable proxy of market prices. This burden was particularly concentrated in a number of states that set high, long-term, fixed PURPA prices without

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the PSC's forecast of LRACs failed to take into account the effect this excess supply would have on price until it was too late. When wholesale electricity prices fell dramatically in the 1990s, utilities and their customers were then saddled with onerous above-market long-term commodity contract costs. In addition, these contracts were structured as "must-take" agreements resulting in substantial uneconomic dispatch of New York generating plants, further exacerbating the collapse in wholesale electricity prices. The six-cent law was partially repealed in 1992, but many of the contracts already in place were grandfathered, preserving the six-cent minimum.

[31] Frank Graves, Philip Hanser, and Greg Basheda, The Brattle Group, "PURPA: Making the Sequel Better than the Original," prepared for the Edison Electric Institute, December 2006, 15-16.

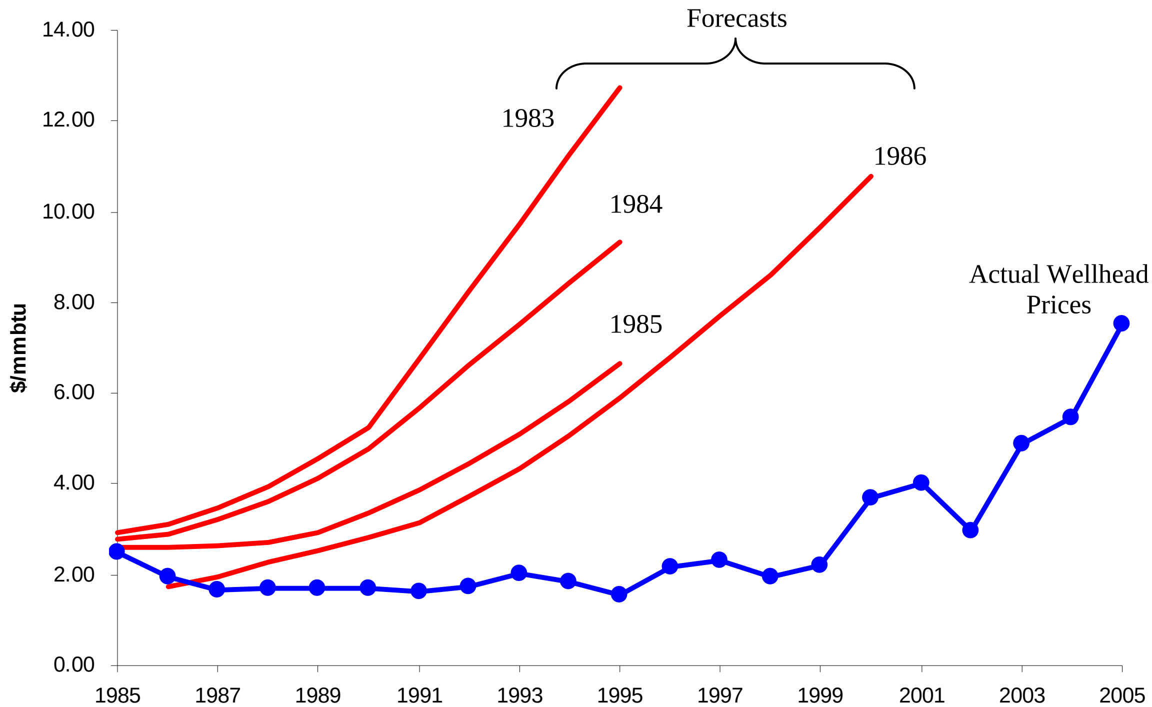
[32] Carroll Lee and Richard Hill, "Evolution of Maine's Electric Utility Industry, 1975-1995," *Maine Policy Review*, Vol. 4, No. 2 (1995): 22.

[33] Like New York, following the passage of PURPA, the California Public Utilities Commission interpreted the utility's obligation to purchase non-utility generation administratively. California utilities were required to purchase power at the utilities' long run marginal costs based on the expected cost of oil. At the time, oil was very expensive and expected to increase further in the future so the purchase price from QFs was set very high. California utilities were required to contract for all of the power offered at the state-determined price during an extended period. Unexpectedly, QF cogenerators were able to rely on low natural gas prices that were well below the oil price used to set the QF contract price. As a result, California utilities committed to contract for several thousand MW of QF electricity at high prices before the offer was terminated.

[34] Graves, Hanser, and Basheda, 16-17.

regard to the impacts of this QF supply on the price.[35] Overall, the cost to consumers from the mid-1990s onward was estimated at almost $50 billion in 2007 dollars.[36]

Figure 16 Actual Natural Gas Prices Fell Below Forecasts of the Mid-1980s



Source: Forecasts – Energy Information Administration, *Annual Energy Outlook*, Various Editions; Actual wellhead prices from Energy Information Administration, *Annual Energy Review*, 2005.

Problems similar to those experienced with the PURPA contracts have recurred in other later situations where regulators mandated long-term contracts. Most recently this happened in 2001 when the California Department of Water Resources stepped in to buy power under long-term contracts in the midst of the California energy crisis. Just a year later, the California Public Utilities Commission estimated that these contracts had burdened customers with approximately $21 billion in above-market costs and filed a (largely unsuccessful) complaint with FERC to allow the state to abrogate the contracts and to replace the contracts with lower-priced power at prevailing market prices.[37]

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[35] By the time restructuring was being contemplated in the second half of the 1990s, the difference between PURPA contract prices and competitive market prices was estimated to be a major contributor to regulated utilities' stranded costs - roughly 30 percent nationwide and as much as 70 percent in certain regions such as New York and California.

[36] Resource Data International, *Power Markets in the U.S.*, Boulder, CO, 1996.

[37] California Public Utilities Commission (CPUC), "PUC to Make Complaint to FERC Against Sellers of Long-Term Contracts," CPUC Press Release, 24 February 2002.

C. Key Lessons of the Past Should Not Be Forgotten

Reviewing this past experience in the electric utility industry reveals several lessons on the shortcomings of regulation:

1. First and foremost, future electricity costs and prices are inherently uncertain. Because future load levels and fuel prices are unknown – as are changes in technology and environmental requirements – investments in long-lived generation assets are inherently risky. We can centrally plan these decisions, and impose the risks on retail customers, but we should not be surprised when things turn out badly for customers, particularly when we evaluate projects over 30 year time horizons and the risks are not borne by investors.

2. Decision-making under regulation performs particularly poorly in times of uncertainty. As the prior discussion makes clear, many of the difficulties in the electric industry arose from the fact that the administrative, command-and-control approach to resource allocation under regulation was too inflexible and too slow to respond to external stresses and changing market conditions.

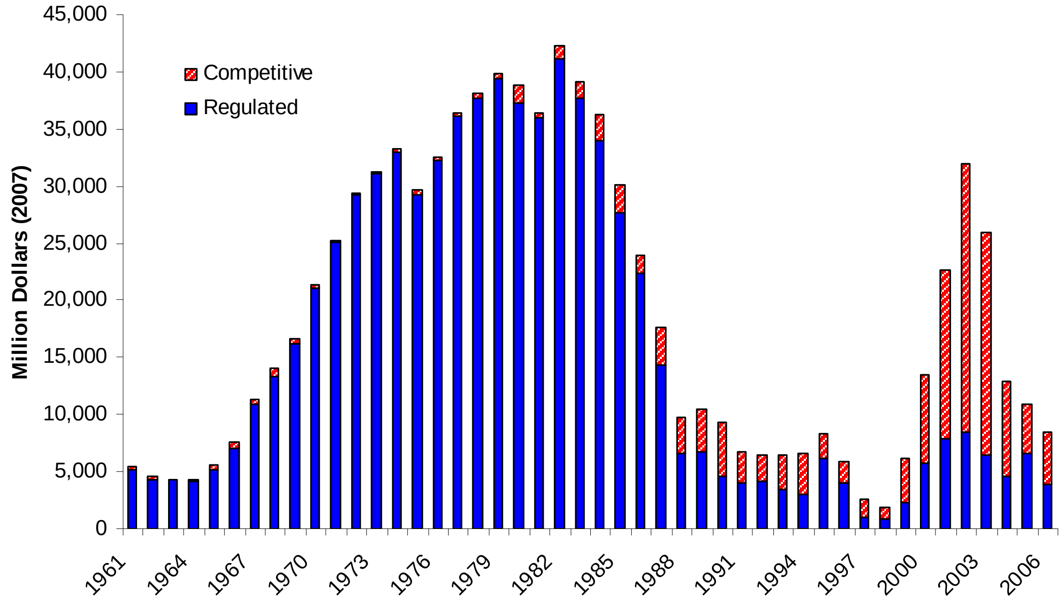
3. Inherent incentive problems with regulation create a tendency to take into account sunk costs when making decisions and to significantly underestimate the risks associated with high-capital cost investments. Much of the excess of planned baseload capacity at the start of the 1970s energy crises and the failure to trim that excess sufficiently in response to changing conditions can be attributed to improper incentives for regulated utilities.

4. Political and regulatory "solutions" to perceived problems can produce costly and unintended consequences. While PIFUA and PURPA may have seemed like reasonable responses to the headline problems of the time, their failure to incorporate market elements led to costly, inefficient responses that took years to correct.

Some might suggest that we can create a new, better form of regulation that would not repeat such mistakes. But the problems with regulation are inherent: decisions are administratively-determined versus market-driven, and the dollars at risk are highest and the potential for damage greatest during times of high capital investment. The mistakes of the 1970s were amplified by the sheer scale of the investment that utilities put at risk through baseload investments.

Figure 17 shows real investment in electric generation capacity in dollar terms since 1961. From 1970 to 1988 regulated utilities invested an average of $30 billion dollars per year in generation, compared to an average of $5 billion per year from 1989 to 2006. Over the past twenty years, because of the capacity overhang from the 1970s, there has been relatively little generation investment activity in the electric industry, particularly by regulated utilities. Thus, the opportunity for regulatory mistakes has been much lower. But, as discussed earlier, a new wave of investment is coming.

Figure 17 Real Investment in Electric Generation Capacity, 1961-2006



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; NorthBridge analysis.

Some industry observers have advanced the notion that the coal and nuclear plants of today, with capital costs largely paid off and collected from customers, represent beneficial low-cost generation that is badly needed in today's rising-cost environment and that policy-makers should be glad that these plants were built. While it is true that coal and especially nuclear plants that were built in the 1970s and 1980s represent low-cost generation today, this is only because the high capital cost of those plants was borne by customers over the thirty-odd years since they were put into service. Measured over their entire life-cycle, many of these plants represented a bad investment for ratepayers and resulted in substantial excess capacity in the 1970s and 1980s and billions of dollars in higher costs relative to alternative supply strategies.

IV. The Case for Competition is Still Compelling

The case for competition is still compelling, supported by both economic theory and a careful examination of empirical evidence. While the restructuring of the electric industry has proven to be a lengthier and more difficult process than anticipated, many of the recent arguments criticizing competition do not warrant returning back to regulation. Competition and market pricing encourages: (1) greater improvements in existing plant operations and administration, (2) greater efficiencies in plant investment and retirement decisions, (3) better customer consumption decisions, and (4) a wider selection of retail products and services. This innovation throughout the electric industry value chain, spurred by competitive forces, is greater than that experienced under regulation. Many of these benefits have already been evidenced in the brief history of electric competition, and the additional benefits that will materialize over time are illustrated by the experience of other competitive industries.

A. Many Criticisms of Competition Have Emerged Recently

Today, electricity competition is under attack in the press and in many state legislatures and regulatory commissions. Since the beginning of the restructuring process, the public has read newspaper headlines about the California energy crisis, the Enron scandal, skyrocketing fuel prices, competitive generating company bankruptcies, and competitive generating company excess profits. Numerous studies, articles and reports have criticized competition or various aspects of restructuring. These complaints can be categorized into four broad concerns – high prices, high profits, poor resource planning, and limited customer switching to competitive suppliers.

First, opponents claim that competition has led to high prices – either high rate levels and/or high percentage rate increases – in restructured states relative to those experienced in regulated states.[38] Large rate shocks recently experienced in many states (e.g., Maryland, Delaware, Connecticut, and Illinois) are used as evidence to question the merits of competition.[39] While opponents acknowledge the recent increases in fuel costs, they argue that markets are not workably competitive[40] and competition has imposed new administrative

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[38] Based on a comparison of percentage rate changes in industrial prices in restructured and regulated states, Jay Apt finds no improvement in prices in restructured states. (Jay Apt, "Competition Has Not Lowered U.S. Industrial Electricity Prices," Electricity Journal, Vol. 18, No. 2, (2005), 52). On the other hand, Mark Fagan developed an econometric model of industrial prices in 1970-1997 by state that he used to predict prices in 2001-2003. From his analysis, he concludes that predicted prices were higher than actual in restructuring states relative to states without restructuring, suggesting that restructuring has lowered prices. (Mark Fagan, "Measuring and Explaining Electricity Price Changes in Restructured States," Kennedy School Working Paper, No. RPP-2006-02, June 2006.)

[39] Paul Davidson, "Shocking Electricity Prices Follow Deregulation," *USA Today*, 10 August 2007.

[40] Synapse Energy Economics in a study prepared for the American Public Power Association ("APPA") states that the LMP approach to electricity pricing generally supports the efficient operation of existing resources, if the LMP pricing reflects short run marginal costs, but because electricity markets are bid-based, not cost-based and markets are not perfectly competitive, implementation of LMP is compromised and opens the door for the exercise of market power under certain conditions. (Ezra Hausman, et. al, Synapse Energy Economics, Inc., "LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers," 5 February 2006, ix.) London Economics prepared a study that compared simulation-based estimates of prices that would result if all generators in PJM Classic were bidding their short-run marginal cost of producing electricity with actual market

and regulatory costs on customers, including high RTO costs,[41] capacity prices, congestion costs, and reliability payments.

Second, several studies claim that competition has led to high profits and profiteering, particularly for unregulated owners of baseload nuclear and coal generation that was built under prior regulation.[42] Opponents of restructuring argue that it has led to an enormous wealth transfer from retail customers, who paid for these assets, to unregulated utility affiliates, who now own this generation. The high profits of restructured utilities as compared to those that remain regulated are cited as evidence of market failure. Part of the concern stems from marginal cost pricing, which reflects the variable generating cost of the most expensive unit needed to meet load. Opponents argue that generator payments to baseload and mid-merit plants based on the higher marginal costs of peaking plants unjustly pays the operators of baseload and mid-merit plants more than their costs, allowing them to earn more than they would under cost-of-service regulation.[43] Some blame large capacity payments to owners of existing generation, while others raise issues of market price

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clearing prices for a 43-month period, January 2003 through July 2006. The study reported that for most months studied the price-cost markup indices, especially for peak periods, are significantly higher than zero and that further study and analysis is necessary before conclusions can be drawn about the efficacy of the market system in PJM. (Julia Frayer, Amr Ibrahim, Serkan Bahceci, and Sanela Pecenkovi, London Economics International LLC, "A Comparative Analysis of Actual Locational Marginal Prices in the PJM Market and Estimated Short-Run Marginal Costs: 2003-2006," 31 January 2007.) In a paper prepared by John Taber, Duane Chapman, and Timothy Mount, the authors developed an econometric model of total average rates as well as residential, commercial, and industrial rates, by utility, for the period 1990-2003, controlling for differences in climate, fuel costs, and electricity generation by energy source. Their analysis does not support a conclusion that deregulation has led to lower electricity rates. They find that even though most customers in deregulated states saw declines in the real price of electricity, they faced higher prices relative to customers in still-regulated states. (John Taber, Duane Chapman, and Timothy Mount, "Examining the Effects of Deregulation on Retail Electricity Prices," Cornell University Working Paper, February 2006, 45.)

[41] A GDS Associates report examines the operational and administrative costs incurred by the nation's RTOs for 2001 through 2005. It finds that in 2005, RTO participants paid over $1 billion in total costs, most of which (75 percent) consists of administrative costs with the remainder (25 percent) operational. As RTOs mature, these costs on a per MWH basis tend to decrease, but as RTOs expand their services, costs tend to increase. (GDS Associates Inc., "Analysis of Operational and Administrative Cost of RTOs," prepared for the American Public Power Association, 5 February 2007, 28.) John Kwoka reports that many of the studies he reviewed fail to address the rising costs of RTOs, inadequate RTO governance processes, and the failure of RTOs to deal with transmission congestion or encourage new investment in transmission. (John Kwoka, "Restructuring the U.S. Electric Power Sector: A Review of Recent Studies," prepared for the American Public Power Association, November 2006, vii.)

[42] Edward Bodmer performed a study in February 2007 for the APPA, "The Electric HoneyPot: The Profitability of Deregulated Electric Generation Companies," that concludes that profits for deregulated generation are far higher than they would be if the plants were still under cost-based regulation. His analysis reviews the profitability of the largest sellers of unregulated generation in the PJM market and compares their financial performance with that of regulated, vertically owned utility companies. He observes that companies that fared the best tend to be owners of baseload generating assets that were formerly regulated. The APPA claims that certain sellers into RTO-run centralized markets are leveraging baseload generation built under prior regulation and are making very substantial profits and that incumbent sellers in PJM are making profits well-above what they would make under cost-of-service pricing. (Comments of the APPA, FERC docket RM07-19-000 and AD07-7-000, September 2007, 27)

[43] Baseload plants tend to be cheaper to operate but more expensive to build, while peaking plants tend to be more expensive to operate and less-expensive to build. Mid-merit or intermediate plants are in between.

manipulation and the potential exercise of market power, concluding that RTO prices appear "unjust and unreasonable."[44]

Third, there is considerable concern within the industry that competitive wholesale markets are not encouraging enough new investment in generation.[45] Parties cite projected declines in reserve margins in restructured regions of the country as compared to reserve margins in regions that remain regulated. Some opponents believe that only regulation and cost-of-service rate-making will ensure reliability, and others suggest that utilities be allowed or required to enter into long-term contracts, backed by regulatory guarantees, to promote the development of new generation. Other opponents lament the separation of generation and transmission functions and the loss of benefits associated with vertical integration.[46]

Finally, in most states (with the exception of Texas), there is the complaint that competition has resulted in little customer switching, especially among residential and small commercial customers. This lack of retail shopping is used as evidence for the failure of restructuring.[47]

In evaluating these arguments, it is important to recognize that many recent studies focus on the past ten or so years of restructuring experience, several of which are cited throughout this paper. But as described earlier, many of the challenges experienced in the industry today are more similar to those of the 1970s than those of the past ten years.

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[44] See Comments of the APPA, FERC docket RM07-19-000 and AD07-7-000, September 2007, 18. Kenneth Rose also prepared a study for the APPA, "The Impact of Fuel Costs on Electric Power Prices," (June 2007) that concludes while fuel price increases have played a role in higher electricity prices, they do not explain everything. He points out that while electricity price and natural gas costs often moved together, other factors are also important (e.g., customer load and its seasonal variation, and supplier costs and risks embedded in full requirements service retail rates). Mr. Rose raises the possibility that "strategic actions by suppliers" or "market design and structure" may also explain price changes in wholesale markets. In another study for the APPA, John Kwoka reports that studies generally do not consider that restructuring has been accompanied by market power, market manipulation, and numerous mergers among utilities. They also ignore costs of the loss of vertical integration and risk of market power abuses. (Kwoka, 73-75.)

[45] Timothy Mount prepared a study for the APPA that reviews NERC capacity margin forecasts 2003-2006 by region. He concludes all deregulated regions are having trouble getting investors to commit to building new generating capacity when it is needed. He notes that resources in deregulated regions are not being committed as far in advance as they used to be under traditional regulation, and the current performance of deregulated markets is poor in terms of ensuring that there is enough installed capacity to meet projected loads reliably. Meanwhile, substantial payments have been made to existing generators that supplement their earnings in the wholesale market. (Timothy Mount, "Investment Performance in Deregulated Markets for Electricity: A Case Study of New York State," September 2007, 1-10.)

[46] Jerry Taylor and Peter Van Doren of the Cato Institute argue that unfortunately, price deregulation has been accompanied by rules encouraging the legal separation of generation from transmission and the purchase of wholesale power through organized spot markets. Vertical integration of generation and transmission is efficient – since an integrated owner would not "hold-up" new investments, would consider substitution effects, and provide for more coordinated real-time operation. (Jerry Taylor and Peter Van Doren, "Short-Circuited," *Wall Street Journal*, 30 August 2007.)

[47] Davidson, "Shocking Electricity Prices Follow Deregulation."

B. Historical Rate Comparisons to Date Are of Little Value

Authors of the competition versus regulation studies, as well as critics, acknowledge a variety of difficulties with attempting to compare regulated and competitive markets.[48] Many of the recent studies focus on historical rate comparisons – both before and after restructuring in the same state, and across regulated and restructured states. Presumably, the purpose of such rate comparisons is to determine whether competition has produced higher or lower rates than would have existed under regulation. However, it is difficult, if not impossible, to know what rates would have been in the absence of competition, making a fair rate comparison problematic.[49]

To further complicate state comparisons of restructuring and regulation, restructuring is not well-defined. In fact, many studies often do not agree on whether a particular state should be included in the "restructured" or "regulated" category. Unlike restructuring in other industries, which often occurred as a result of changes in federal legislation, restructuring in the electric industry occurred in a more decentralized manner. Key elements of the restructuring process include: a) providing utilities and non-utilities open-access transmission service, b) splitting up vertically integrated utilities by separating control of transmission and generation assets, c) the formation of ISOs and RTOs and centralized wholesale electricity markets, d) developing stranded cost recovery mechanisms for past utility investments and past contracts that regulators approved/required during regulation, e) establishing transition periods and default service pricing to move from a regulated to a competitive market structure, and f) allowing retail access programs (including customer switching, customer protection, deposit and disconnect rules, and systems for processing retail market transactions). These changes both in wholesale and retail electricity markets have occurred in stages that vary in form over time and often by U.S. region, state, service area, and even customer type. And in several instances, there has been considerable conflict between federal and state authorities over legal jurisdiction over market structure design. The lack of consistent policies, along with fundamental changes in economic conditions since the advent of restructuring, has made it difficult to compare regulated and competitive market structures.

In addition, certain market initiatives integral to industry restructuring, such as open-access transmission and the expansion of competitive generation have also benefited regulated states, even though those states do not have retail choice. For example, almost 72 GW of unregulated generation were constructed in regulated states between 1997 and 2007. This construction reduced both prices in these states and the need for regulated utilities to build rate-based plants, further complicating comparisons between regulated and restructured states.

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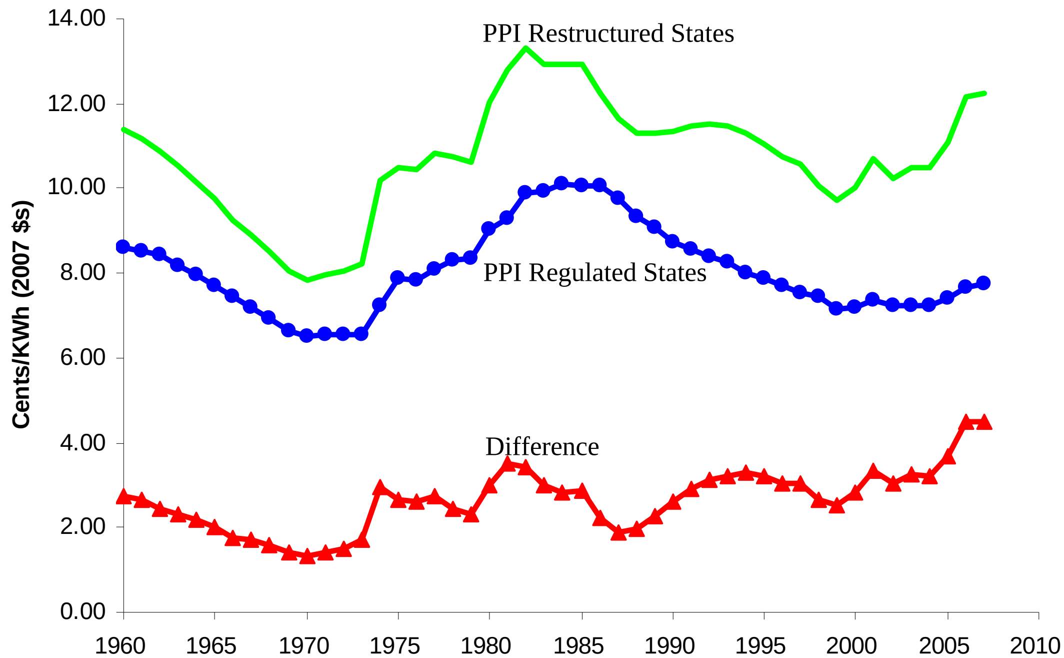
[48] Efforts to date attempting to compare regulated and competitive markets have proven difficult due to the lack of sufficient data and other fundamental complications with such an analysis. John Kwoka, in his review of restructuring studies, found three common problems with most studies: 1) lack of precision about what is meant by restructuring, 2) failure to recognize that post-reform prices were set administratively and do not reflect market levels, and 3) failure to control for other factors that affect prices unrelated to restructuring. (Kwoka, 7-24.)

[49] Several econometric studies have attempted to control for some of the variables and changes that have occurred since restructuring. However, the results of these studies are mixed. See citations within these footnotes.

Most studies, however, attempt to compare regulated and restructured states, and acknowledge that rates in states that have restructured have been higher than rates in regulated states for a long time, and that this price gap predates restructuring and the introduction of competition. Figure 18 compares historical average real rates for states that have restructured with states that have remained regulated based upon the state characterization utilized in a recent analysis by Power in the Public Interest (hereafter referred to as "PPI Restructured States" and "PPI Regulated States").[50]

Figure 18 Real Retail Electric Rates in PPI Restructured and PPI Regulated States, 1960-2007



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006; 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly; Average rates are weighted by consumption in each state.

The significant rate gap between states that restructured and those that remain regulated is due to regional differences in a wide variety of factors: fuel and construction costs, state regulatory policies, generation mix, customer types, consumption patterns, population density, and supply and demand balances.[51] The gap between the two groups actually closed as competition was introduced in the late 1990s – primarily due to rate cuts embedded in the

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[50] For purposes of this comparison only, we utilize the same definition of restructured states as a recent analysis by Marilyn Showalter of Power in the Public Interest, "Trends in State Electricity Prices and Policies" (*Presentation to MEAG*, 17 July, 2007.) This analysis defines CA, CT, DC, DE, MA, MD, ME, MI, NH, NJ, NY, RI, and TX as restructured/deregulated. While we disagree with certain elements of this categorization (particularly the inclusion of California and the exclusion of Illinois and Pennsylvania), we adopt this definition to allow for comparison of our results with other studies that take a critical view of competition.

[51] Local transmission monopolies facilitated the disparity in retail rates by restricting the ability to move electricity economically across service territory boundaries. When purchasing electricity, a buyer often had to pay the transmission rate to each utility that it moved through, commonly referred to as rate "pancaking." This limited the ability to move power from low-cost areas to more expensive areas.

restructuring deals and transition periods[52] – but has expanded since 2005. Once transition periods and rate controls began to expire in restructured states, market conditions were dramatically different than at the start of restructuring. Significant increases in fuel costs, unrelated to the restructuring of the electric industry, have caused wholesale market prices to increase significantly throughout the United States (see Figure 2 and Figure 4).[53] As a result, when rate caps expired at the end of restructuring transition periods, many consumers of electricity were exposed to sudden price increases. In several instances, these rate shocks resulted in legislative and/or regulatory intervention, which ultimately led to phase-ins of market rate increases and deferred cost recovery.

While acknowledging this long-running rate gap between regulated and restructured states, many opponents of competition focus on a snapshot comparison of rates as they are today in restructured states to the rates in effect in those same states in the late 1990s, prior to restructuring. This comparison misses several key points. First, rates in regulated states have also experienced significant rate increases over the same period.[54] Figure 19 shows the annual change in nominal rates for both PPI Regulated and PPI Restructured States indexed to 1997, just prior to restructuring in most states. By 2007, nominal rates in PPI Restructured States had increased by 44 percent relative to 1997, but had also increased by 28 percent in PPI Regulated States.

Second, most of the increase in rates in PPI Restructured States has occurred in the past three years. This lag in the rate of increase in restructured states was primarily due to rate freezes that were part-and-parcel of the restructuring process. These negotiated rate structures, which did not reflect market prices, prevented more gradual increases in rates like those experienced in regulated states or restructured states with market adjustable rates. The price increases in restructured states from 2005 onward can be primarily traced to the expiration of rate freezes[55] coinciding with an increase in marginal generation costs, largely due to the rise in natural gas prices. Had natural gas prices not increased dramatically, the rate comparisons between restructured and regulated states may have appeared substantially different. Figure 20 shows a similar comparison between PPI Restructured States and PPI Regulated States, but compares only states where natural gas either strongly influences the competitive market price in restructured states or forms a large portion of fuel costs in regulated states.

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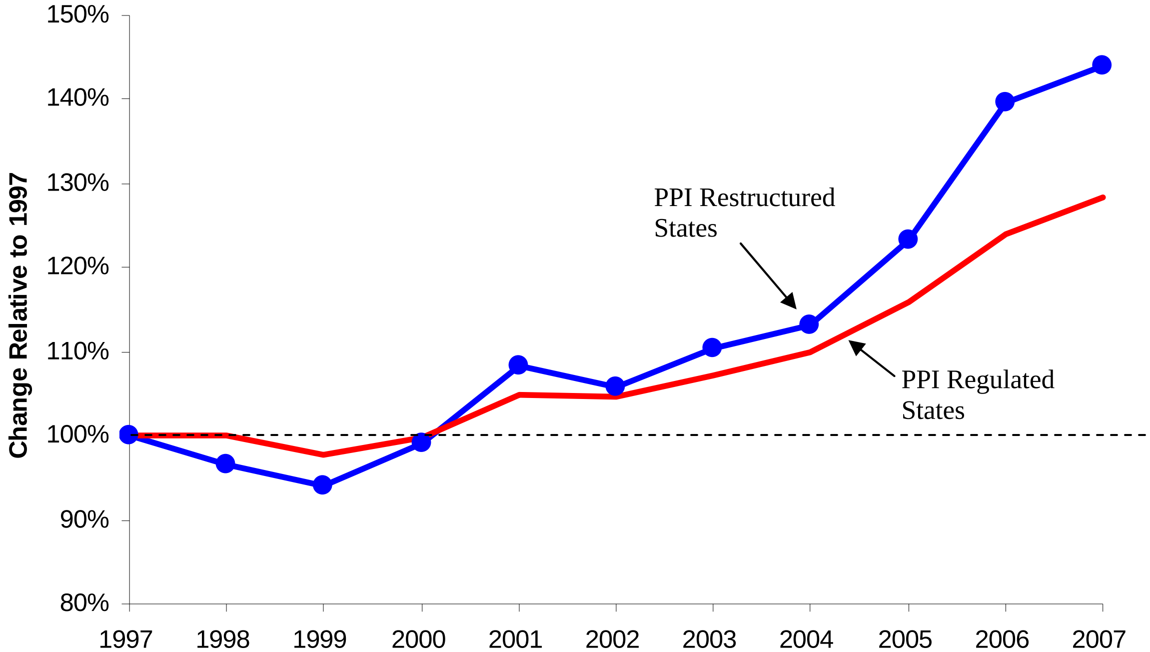
[52] Past restructuring deals included stranded cost determinations along with negotiated rate decreases and/or mandated rate freezes during prescribed transition periods.

[53] A Brattle Group report finds that, "On an industry-wide basis…fuel and purchased power costs account for roughly 95 percent of the cost increases experienced by utilities in the last five years. The increases in the costs of these fuels have been unprecedented by historical standards, affecting every major electric industry fuel source." (Greg Basheda et. al., The Brattle Group, "Why are Electricity Prices Increasing? An Industry-Wide Perspective," prepared for The Edison Foundation, June 2006, 2.)

[54] Studies performed both by The Brattle Group and the Analysis Group also find that regulated states have seen substantial increases in average annual retail prices similar to that observed in the restructured states. (Analysis Group, "Electricity and Underlying Fuel Prices - A Survey of Non-Restructured States," April 2006; Greg Basheda, Johannes Pfeifenberger, and Adam Schumacher, The Brattle Group, "Restructuring Revisited: What We Can Learn From Retail-Rate Increases In Restructured And Non-Restructured States," *Public Utilities Fortnightly*, June 2007, 64-69.)

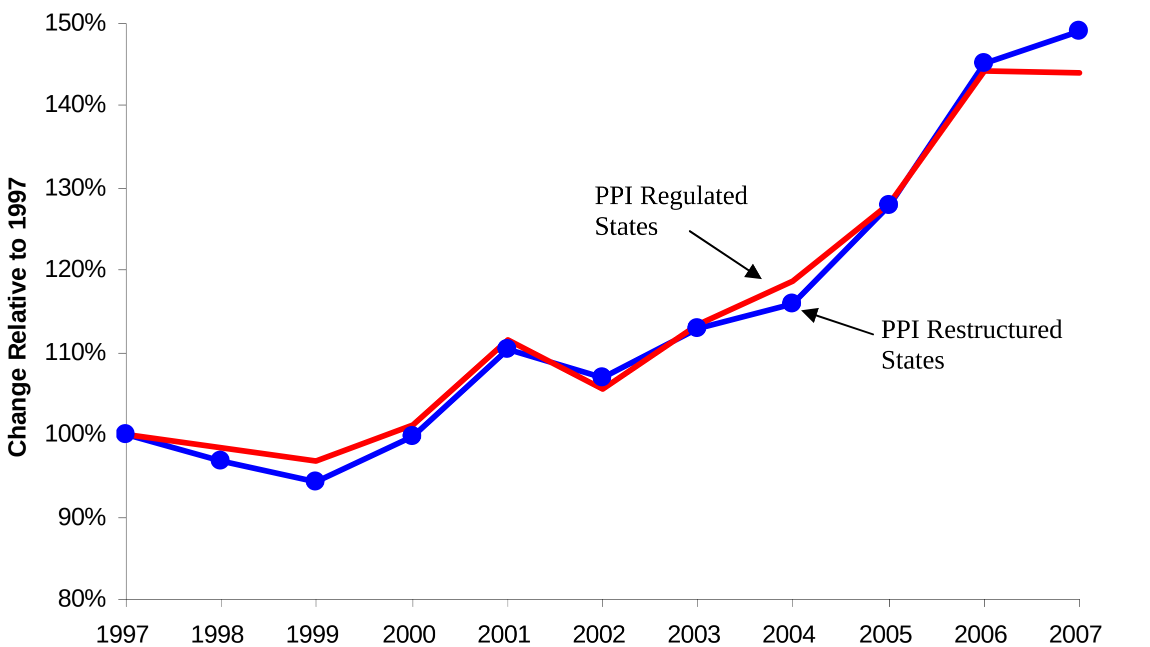
[55] Since 2005, several major restructured states such as Illinois, Massachusetts, Connecticut, and Maryland have transitioned from rate freezes to auction-based frameworks in which customers receive competitive wholesale market prices. Other states such as Texas and New Jersey had transitioned to a market price framework earlier.

Figure 19 Rate of Change in Nominal Electric Rates in PPI Restructured and PPI Regulated States, 1997-2007



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006; 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly; Average rates are weighted by consumption in each state.

Figure 20 Rate of Change in Nominal Electric Rates in Gas-Dependent PPI Restructured and PPI Regulated States, 1997-2007

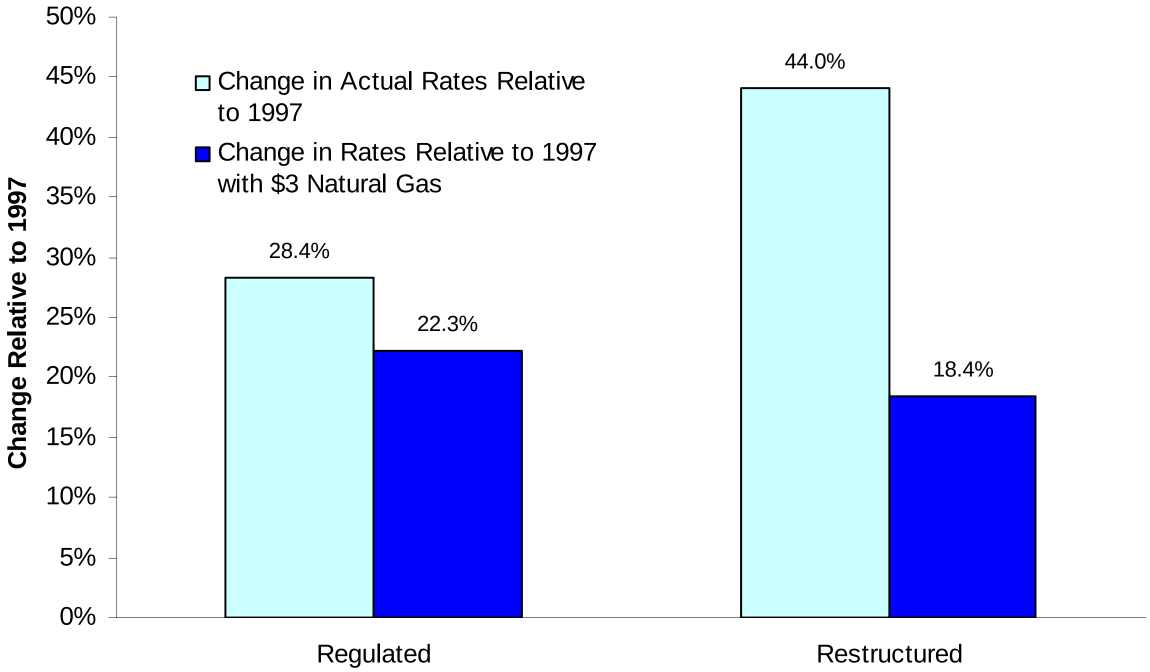


Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006**;** 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly; Average rates are weighted by consumption in each state; Gas-dependent restructured states are from the ISO-New England, NY ISO, ERCOT, PJM East, and CA ISO market regions and include all PPI Restructured States except Michigan; Gas-dependent regulated states are defined as any regulated state where gas/oil generation comprises 30% or more of total generation output (FL, LA, NV, MS, and OK).

When compared in this manner, rate increases in both PPI Restructured and PPI Regulated States track one another very closely.

Figure 21 compares actual price changes over the 1997 to 2007 period to an estimate of what rates would have been had natural gas prices remained at $3/MMBTU, approximately their level in the late 1990s.

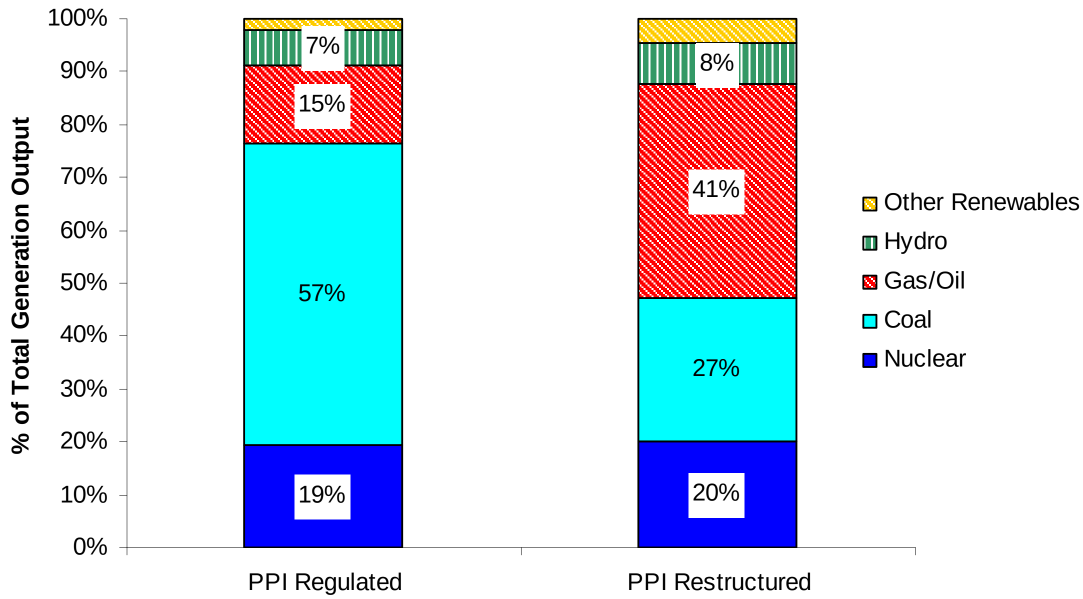
Figure 21 Change in Nominal 2007 Rates Relative to 1997, Actual vs. If Natural Gas Remained at $3 Per MMBTU



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006; 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly; Average rates are weighted by consumption in each state**;** NorthBridge Analysis.

Under this comparison, rates in PPI Restructured States would have only risen by 18 percent by 2007, relative to 1997, while rates in PPI Regulated States would have risen by 22 percent. These differences are primarily caused by the variation in fuel inputs used to produce electricity combined with differences in how electricity is priced to end-use customers in regulated and restructured states (as discussed later). Figure 22 compares the electric generation by fuel type in both PPI Regulated and PPI Restructured States.

Figure 22 Electric Generation By Fuel Type: PPI Regulated vs. PPI Restructured States



Source: Energy Information Administration, State-Level Spreadsheets, 1990-2006. Data shown is for 2006.

PPI Restructured States generate 41 percent of their electricity from natural gas, compared to 15 percent in PPI Regulated States.[56] This difference dates back at least to the 1980s and is not a product of restructuring or competition. Instead, it reflects decisions made by utilities and regulators in favor of cleaner gas generation relative to cheaper, but dirtier, coal.[57] As a result, PPI Regulated States, as a group, emit about 30 percent more CO_2 per MWH than do PPI Restructured States. The reliance on natural gas in restructured states has the effect, however, of amplifying the effect of changes in natural gas prices on rates in restructured states. Florida, a similarly gas-dependent regulated state, has experienced much larger rate increases – 26 percent – from 2004 to 2007. This is much larger than the average rate increase of 17 percent in other regulated states, but similar to the average rate increase of 27 percent in restructured states over the same period.

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[56] "…some regions (like New England, California, and Texas) that rely significantly on natural gas to produce power have relatively high electricity prices…States in parts of the country (such as the South, the Mountain states, and the Midwest) that produce more than 50 percent of their power from coal have among the lowest electricity rates in the country. Of the 30 states with rates below the average state electricity rate in 2006…, 26 of them were from these regions with a high percentage of power produced by coal." (Susan Tierney, Analysis Group, "Decoding Developments in Today's Electric Industry – Ten Points in the Prism," commissioned by the Electric Power Supply Association, October 2007, 4.)

[57] While both natural gas and coal are fossil fuels, natural gas burns more cleanly than coal. Per megawatt-hour of power produced, relative to a typical coal plant, a natural gas combined cycle plant will emit about 40% of the CO_2, 5-50% of the acid-rain causing nitrogen oxides (depending on the level of control at the comparison coal plant), and essentially zero sulfur, mercury, and particulate matter.

C. Market Prices Provide the Right Price Signals

Retail rates in most restructured states are now based on competitive wholesale prices. In a competitive wholesale market, the variable generating cost of the most expensive generating unit needed to meet load sets the wholesale price for all generation in the market.[58] The price is determined by the market: all transactions between sellers and buyers tend toward one price for the same product (electricity at a given time and location), taking into account available supply and demand. The price obeys what is referred to in economics as the "law of one price."[59] This is commonly referred to as "marginal cost" pricing. The price-setting marginal unit will be a higher-cost unit, such as a gas/oil unit or older coal plant. Therefore, the price for the entire market will be based on the higher variable costs of these types of units, regardless of whether coal or nuclear units with lower variable costs are also online and generating electricity.

Regulated retail rates, however, have traditionally been determined using "average cost" pricing. Under this approach, the total cost of the portfolio of resources needed to serve load, from baseload plants to peaking units, is averaged across total load, and this average price is charged to each increment of load. This total cost includes both variable operating costs as well as the historical embedded capital costs of building and financing generation. These two types of pricing differ most significantly in how generators recover their capital and fixed operating costs: in market-based marginal cost pricing all fixed cost recovery flows through the market price (although recovery is not guaranteed), while in average cost pricing generators are allowed to pass through their variable costs and recover their capital and fixed operating costs through regulated base rates. All else equal (ignoring any demand-side effects), we would expect both marginal cost pricing and average cost pricing to yield a similar average price over long time periods. However, there are two important differences. First, in the presence of uncertainty and rising/falling costs, the two types of pricing will usually differ at any particular "snapshot" in time. Second, because market-based marginal cost pricing reflects the variable generating cost of the most expensive unit needed to meet

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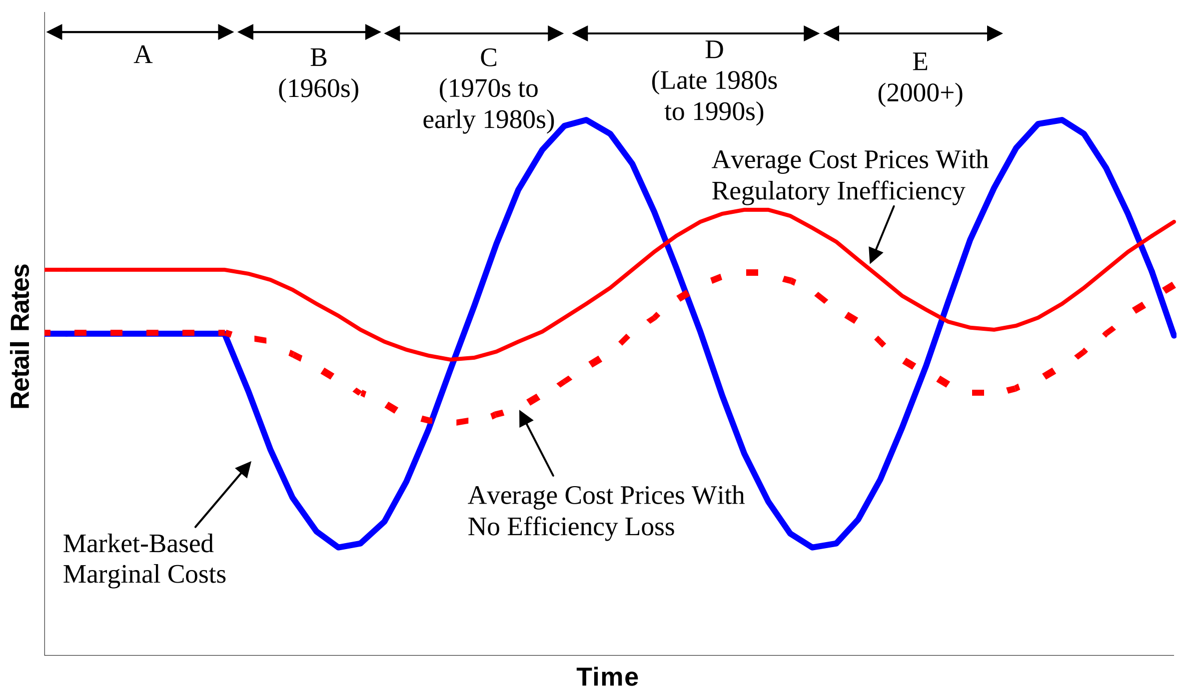
[58] In a pool trading system, an auctioneer can see all the bids and can choose between two broad payment schemes. The auctioneer can pay dispatched generators what they bid – this is similar to the bilateral trading model described in the footnote below. Alternatively, the auctioneer can pay dispatched generators a uniform market price based on the marginal cost of the highest cost generator operating. In theory, neither the market structure nor the payment scheme should make any difference for the level of wholesale prices. In a bidding system where generators are all paid the same market clearing price – like in the United Kingdom and most U.S. energy markets – the generator bidding strategy changes but the resulting market price does not. As before, no generator would rationally bid a price below its marginal cost. However, rather than bid the estimated market clearing price, each generator will have an incentive to bid its actual marginal costs. Economist William Vickrey (1961) noted that by making the price received by a player independent of its own bid, marginal cost pricing can be induced as a dominant bidding strategy for all participants. This system is perhaps more efficient since it encourages generators to reveal their true marginal costs rather than attempt to estimate the market price – although the price outcome is essentially the same in markets with good information flows.

[59] Bilateral transactions allow buyers and sellers to propose prices and indicate desired quantities with different payments. However, with good information available and many buyers and sellers, i.e. a liquid market, traders are aware of each other's price quotations, and they come to have nearly identical opinions of the prevailing market price at any moment. For a buyer to quote too far below "the price", or for a seller to quote too far above it, is essentially to withdraw from the market, and there is no reason to expect such extreme quotations to be accepted. Commodity exchanges organize this type of trading at a single point in time on a trading floor. The outcome of this competitive trading process is that all buyers and sellers are price takers, not price makers.

load, it provides a superior price signal (as described further below) for dispatch of existing resources, new entry of generation, innovation, and customer demand response than does average cost pricing. Market-based marginal cost pricing will ultimately lead to a more efficient allocation of resources than would average cost pricing, and will result in lower average prices over the long-term.

These two differences are best illustrated through an example. Figure 23 shows an illustrative example of the behavior of market-based marginal cost and average cost rates through a progression of changing cost environments over time, with a relative abundance or shortage of generation resources.

Figure 23 Comparison of Marginal Cost vs. Average Cost Rates



Because marginal costs represent the incremental cost of serving the final unit of demand while average cost rates represent the historical embedded cost of serving every unit of demand, market-based marginal costs rates are much more sensitive to changes in input costs (such as fuel and capital costs) and the marginal supply/demand balance of generation and load. For average cost rates, however, historical embedded costs tend to dominate and changes in marginal unit economics represent only a small portion of the average. This difference causes average cost rates to lag behind market-based rates as electric input costs change and the supply/demand balance fluctuates. Segment A shows an initial period of unchanging costs: all else equal, market-based marginal cost rates and average cost rates will be the same. As marginal costs fall (over segment B), market-based rates will fall faster than average cost rates because average cost rates contain the higher embedded costs from segment A. When marginal costs start rising (segment C) average cost rates will lag behind market-based rates in reflecting these rising costs in prices. Eventually, however, this will lead to average cost rates overshooting market-based rates when costs start falling again (segment D). This pattern is what occurred as we moved from the 1960s (falling costs) to the 1970s and early 1980s (rising costs), to the late 1980s and 1990s (falling costs again). Indeed, much of the impetus for restructuring in the late 1990s centered on the observation that average generation costs (reflected in retail rates) substantially exceeded marginal generation costs (as observed in wholesale market prices), just as the illustration predicts. Since 2000, however, costs have begun to rise again and we are now on segment E of the curve. Recent changes in retail electricity rates confirm this, as rates based on wholesale electricity prices (such as those produced by wholesale auctions or competitive retail offers) have risen quickly over the past three years, while rates in regulated states have lagged behind.[60]

As the illustration makes clear, a "snapshot" comparison of current rates does not imply that market-based, marginal cost rates are inherently higher than regulated average cost rates. The appropriate comparison is over the longer-term, which allows a more complete evaluation of a full cycle of changing cost environments. In the end, the historical rate evidence to date is of little value to the ongoing debate on competition; it does not definitely prove that competition has reduced rates over the last ten years, nor does it conclusively show that competition has increased rates. Furthermore, a definitive answer to this question may not help us solve the challenges ahead. If we accept that rates in competitive states were lower than they would have been if those states had remained regulated through 2005, but, because of high natural gas prices, are now higher than they would be if those states had remained regulated, would this mean that the industry should return to regulation? We believe the answer to this question is "no." The decision to support competition or regulation should not depend on external shocks (such as the recent increase in natural gas prices) or whether regulated average cost prices are below or above market-based marginal cost prices at any particular point in time, but whether a competitive or regulated model will foster more efficient decisions and ultimately better price and reliability outcomes over a sustained period of time and varying market conditions.[61]

Thus far, given the large oversupply of capacity built during the regulated period of the 1970s and 1980s and the recent unregulated generation development of the early 2000s, there has been relatively little need for significant regulated generation investment since the start of restructuring. As we have already discussed, the electricity market in the next twenty years will look very different than it has in the past ten years. Therefore, the recent historical "test period" of the past ten years examined in most studies does not provide a complete picture – especially of what is to come as we confront the significant challenges ahead.

Over longer time cycles, marginal cost pricing will produce a more efficient and ultimately lower-cost outcome relative to regulated average cost prices because it provides the correct

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[60] Jerry Taylor and Peter Van Doren of the Cato Institute acknowledge that regulation delivers lower prices than the market during shortages, but regulation delivers higher prices during times of relative abundance. (Taylor and Van Doren, "Short-Circuited.")

[61] At the time of restructuring, utility retail rates based on regulated average costs were much higher than competitive marginal cost prices in the wholesale market. Buyers, especially large customers, wanted direct access to these lower wholesale prices. This large gap between high utility retail rates and low wholesale market prices provided much of the impetus for restructuring. Today, the situation has reversed. Marginal prices have risen above average cost rates in many places. Hence, there is increasing pressure to look back more fondly upon regulation.

price signal for the efficient allocation of new and existing generation and demand response resources. Market-based, marginal cost prices provide the correct entry signal for new resources, whether in real time (such as committing a peaking unit) or over a longer time horizon (such as building new capacity or developing demand response resources).[62] As noted earlier, the rising costs observed over the past few years are unlikely to disappear soon, and will become even more pronounced in a carbon-constrained world. High market prices in the context of today and the near future are appropriate in that they provide the correct price signal and incentive for investment in the different types of low-carbon resources that will be needed in the future.

In an effort to limit "high" profits, some critics of competition argue that today's low cost generators (e.g., nuclear and coal plant owners) should not be paid the price associated with the higher marginal cost unit (e.g., a gas plant), but rather should be paid according to their individual (and much lower) variable costs of production. This logic represents a key misunderstanding about how competitive markets function. As Figure 23 suggests, in the presence of market volatility, prices and ultimately profits for all types of units will fluctuate, often significantly, in a competitive electricity market with marginal cost pricing. "High" profits in one period provide the necessary incentive for market entry and an eventual reduction of those profits through increased supply and competition. High market prices do not necessarily imply market manipulation or the exercise of market power.

Allowing the market to determine the price, of course, should rest upon the existence of a "workably" competitive market. Clearly, developing competitive markets are not perfect, and legitimate concerns exist that require safeguards and regulatory oversight (see discussion in Section V.B.). Examples of inappropriate generator bidding behavior, price manipulation, and poor market design have been uncovered during the transition period. Just as the industry experienced unanticipated consequences from past legislation and regulatory policies, it should not be surprising that new restructuring initiatives and market designs do not always work as anticipated. However, these are reasons to improve markets, not abandon them. There are several key reasons why policymakers should support the continued development of competitive markets, as discussed in the remainder of this section.

D. Competition Promotes Efficiency Improvements in Existing Plant Operations and Administration, in Plant Investment and Retirement, and Customer Consumption

Market-based marginal cost price signals, while not always lower than regulated average cost rates, provide a superior price signal to power plant operators, investors in new generation and new supply and demand side technologies, and consumers of electricity. In the short term,[63] competitive markets provide strong incentives to improve plant performance and

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[62] The incremental cost of serving the final increment of load represents the true opportunity cost that new resources appropriately measure themselves against: if market prices rise to a level where they allow new capacity to cover its operating and capital costs, then that capacity will have an incentive to enter, if market prices remain below this level the market will utilize cheaper existing resources.

[63] In economics, "short-term" generally refers to the period of time over which the quantity of some inputs (e.g., such as existing plant capacity) cannot, as a practical matter, be varied, while the "long-term" refers to the period of time long enough for all inputs to be varied.

administration. Restructuring also has increased the geographic size of regional markets, extending the benefits of pooling and coordination across a broader market area. In the long term, competition provides efficiency gains in resource planning and investments, making investors, not ratepayers, responsible for a host of decisions (e.g., choice of technology, fuel, timing, pollution control, etc.) in an electricity market that is inherently risky. This shift in responsibility will allow customers to avoid having to pay for the stranded costs associated with investments or long-term contracts that later turn out to be uneconomic. Market price signals, when visible to customers, ultimately will lead to more efficient customer consumption and investment decisions both in the short and long term – impacting a customer's time of electricity use, overall level of electricity use, fuel choice, and investments in equipment and energy efficiency.

1) Competition Promotes Efficiency in Existing Plant Operations and Administration

a) The Theory

Competitive markets provide strong incentives to improve plant performance and administration in the short term. This improvement is often called "static" efficiency, which refers to the benefits that can be realized within the existing fleet of generators. In a competitive wholesale market, generators sell their output by either bidding directly into the spot market or through bilateral contracts based on expected spot prices. As discussed earlier, in most competitive wholesale markets, the market-clearing bid of the marginal plant is paid to all plants that are dispatched. High-cost bidders will be less likely to be dispatched and less likely to earn revenue, while plant operators that reduce costs and are able to submit lower bids are more likely to get dispatched and increase their profit margin between their own costs and the market price. This competitive structure, as opposed to a regulated model that allows plant operators to pass through their operating costs to customers, provides a strong financial incentive to lower both variable and fixed operating costs, since each incremental dollar of cost reduction benefits the plant owner. Competition impacts decisions related to operating and maintenance budgeting, capital improvements, fuel procurement, environmental compliance, and so forth. When evaluating specific operational changes, a number of incremental performance measures (e.g., increased availability, heat rate reduction, increased maximum output, increased ramp rates, start-up cost reduction, reduced minimum generation levels, etc.) provide the critical link between market prices and decentralized decision-making. By weighing the relative costs and benefits of any decision, managers can implement actions that are economic based on market price signals.

b) Early Results – Improvements in Dispatch Efficiency, Plant Performance, and Fuel Efficiency

First, restructuring has improved the efficiency of power plant dispatch (i.e., how generators are turned on or off to meet customer demand). Efficient dispatch is a function of marginal operating costs subject to transmission and unit commitment constraints.[64] Restructuring has increased the geographic size of regional markets, extending the benefits of pooling and

[64] Neither sunk capital nor fixed operating costs, nor who paid for them, is relevant to dispatching existing generators efficiently.

coordination across a broader market area.[65] Non-discriminatory open transmission access combined with broad geographic energy markets improves economic dispatch and coordination within the industry, ultimately lowering overall system supply costs. Restructuring reduces the level of rate "pancaking" through each utility service area that allows parties to trade more easily within a broad geographic area. Numerous studies have quantified these benefits, and the magnitude of estimated savings far exceeds the incremental RTO administrative and operating costs.[66] A particularly striking example of increased dispatch efficiency in a competitive market is provided by the large shifts in plant dispatch and physical power flows that occurred when the PJM market expanded to incorporate the service areas of American Electric Power, Commonwealth Edison, and Dominion. In each case, capacity utilization of relatively cheap baseload capacity in the newly incorporated area rose, and power flows into the high-cost, congested area of Eastern PJM increased. This

[65] The benefits of coordination have been recognized within the industry for many years. The reliance on relatively short-term coordination services among nearby integrated utilities developed in order to reduce system operating costs and the costs of maintaining reliability through reserve sharing and emergency support. This coordination expanded dramatically after 1973 due to the increase in oil prices as the gap between oil, gas and coal prices widened. Utilities began to rely on medium and longer term wholesale contracts to allow them to defer construction of new facilities when other utilities had excess capacity or to reduce operating and maintenance costs of higher cost generating facilities. This "sharing" of resources in the wholesale market provided benefits to both buyers with capacity shortfalls and/or high-cost generation and sellers with excess capacity and/or low-cost generation.

[66] Scott Harvey, Bruce McConehi, and Susan Pope of LECG prepared an econometric study of customer savings in PJM and the NY ISO as a result of implementing coordinated markets, comparing 1990-2004 average residential rates in PJM classic and NY ISO with those in traditional markets, namely SERC and Florida. They used data for munis and co-ops in order to isolate the effects of retail access. Regressions were used to isolate the effects of RTO participation, regional fuel mixes, utility size, sales per customer, and the portion of industrial load, and to derive the "would have been rates" in order to calculate savings in PJM and the NY ISO regions. Based on this analysis, they concluded that the implementation of coordinated markets has led to residential customer savings of $0.50 to $1.80 per megawatt-hour (or $430 million to $1.3 billion per year) in PJM and NY ISO. These savings are net of RTO costs. (LECG, "Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges," November 2006, 1.) Polestar Communications and Strategic Alliance performed a calculation of customer savings in New England due to restructuring based on historical trends in prices. They examined average retail rate growth from 1990 to the year of restructuring to construct "would have been" rates and compared those to actual rates. They concluded that customers have saved $6.5-$7.6 billion in New England between 1998 and 2005, including the savings associated with rate cuts and freezes. (Polestar Communications and Strategic Analysis, "A Review of Electricity Industry Restructuring in New England," prepared for members of the New England Energy Alliance, September 2006, 4.) Cambridge Energy Research Associates developed econometric models of total average electric prices in 1981-1997 for four regions and predicted 1998-2004 prices. They found that predicted prices were above actual prices in 3 out of 4 regions, and concluded that U.S. residential electric customers paid about $34 billion less over a 7 year period than they would have under regulation. ("Beyond the Crossroads: The Future Direction of Power Industry Restructuring," 2005). Global Energy Decisions performed a simulation of expected market prices had deregulation not occurred in the Eastern Interconnect, 1999-2003. They concluded that wholesale customers in the region saved $15.1 billion as a result of deregulation, attributed to increased operating efficiencies at power plants (e.g., shorter refueling outages, better capacity factors and improved reliability). (Global Energy Decisions, "Putting Competitive Power Markets to the Test – The Benefits of Competition in America's Electric Grid: Cost Savings and Operating Efficiencies," July 2005, ES-1.) Charles River Associates performed an analysis of customer benefits in SPP from having coordinated dispatch and an energy imbalance service market, concluding that transmission owners would save $373 million between 2006 and 2015 as a result of the energy imbalance market, net of implementation costs, and transmission owners would save $71 million between 2006 and 2015 as a result of coordinated dispatch. (Ellen Wolf et al., "Southwest Power Pool: Cost-Benefit Analysis," performed for the SPP Regional State Committee, July 2005, Tables 1 and 4.)

indicates that previously unrealized opportunities for economic dispatch and wholesale power trade were unlocked by pooling resources within an expanded competitive market.[67]

Second, U.S. generating plants are now more efficient than in the past. Some of this improvement in performance is attributable to improvements in technology over time, but some of it also is due to powerful profit incentives to adopt best practices and invest in productivity gains in an economic manner. A recent study of all large steam and combined cycle gas turbine plants in the United States suggests that municipally-owned plants, whose owners were largely insulated from market reforms, experienced the smallest efficiency gains, while investor-owned plants in states that restructured their wholesale electricity markets have improved efficiency the most. Investor-owned plants in states that did not restructure were in between these extremes. Industry restructuring reduced labor costs by 6 percent and non-fuel costs by 12 percent, holding output constant, relative to government and municipal-owned plants.[68] In general, studies suggest that restructuring has led to substantive operating efficiency gains in a relatively short period of time.

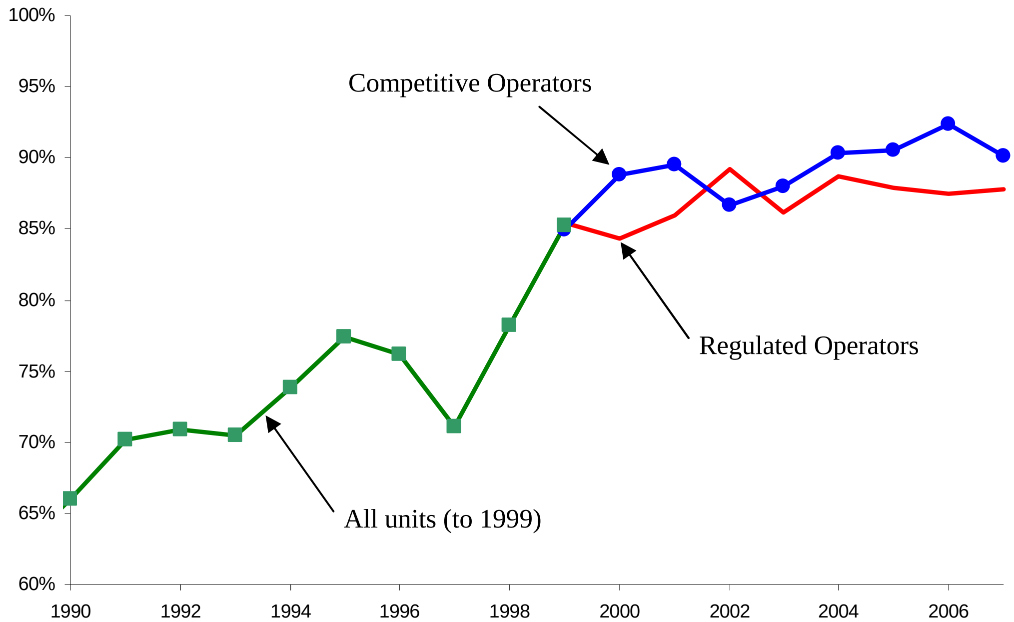
Competitive power plant operators have a strong incentive to maximize the output and capacity factor of baseload units such as nuclear and coal units. As shown in Figure 24**,** capacity factors of nuclear plants, while generally improving over time, improved dramatically since the time of restructuring from around 70 percent to the 90 percent level. Furthermore, since 1999, nuclear plants operated by competitive generators have realized an average capacity factor that is close to 2 percent higher than that of regulated plants, producing savings of about $350 million per year at current market prices.[69]

[67] Energy Security Analysis calculated prices across the expanded PJM pre- and post- its expansion from PJM Classic, and also examined market heat rates, price convergence across different zones, and price flows over interfaces. They concluded that the PJM region-wide price would have been $0.78/MWH higher in 2005 without expansion, resulting in 2005 savings of over $500 million. (Edward Krapels and Paul Fleming, "Impacts of the PJM RTO Market Expansion," prepared for PJM, November 2005, 58.)

[68] Kira Fabrizio, Nancy Rose, and Catherine Wolfram, "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency," *American Economic Review*, Vol. 97, No. 4, September 2007, 29. See also James Bushnell and Catherine Wolfram, "The Guy at the Controls: Labor Quality and Power Plant Efficiency," *National Bureau of Economic Research Working Paper No. 13215*, June 2007, 5-6. An earlier analysis of the 1981 through 1999 period found that plant operators most affected by restructuring reduced labor and non-fuel operating expenses by 5 percent or more relative to other regulated IOU plants, and by 15-20 percent relative to government and cooperatively-owned plants.

[69] Capacity factor improvements at divested nuclear plants add about 5 million MWH per year from these plants. We estimate that running these nuclear plants versus running the marginal unit in their particular market produces savings of about $70/MWH (at current forward market prices), leading to annual savings of just under $350 million per year.

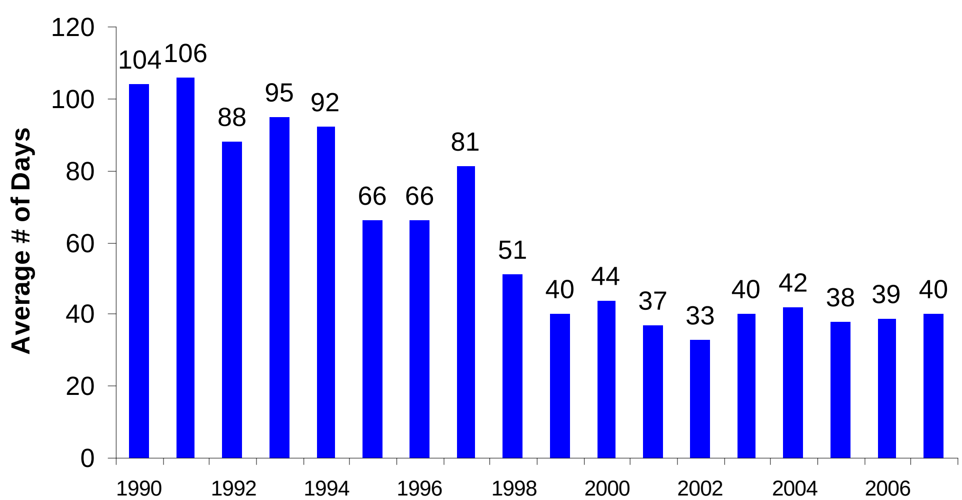
Figure 24 Improvement in Nuclear Capacity Factors, 1990-2007



Source: Based on plant-level output data from the Nuclear Regulatory Commission. Several units passed to competitive ownership prior to 1999, but reliable separation of competitive and regulated data is not possible prior to this year.

Restructuring also has led to a consolidation of nuclear plant operators. These firms tend to specialize in the operation of nuclear plants and implement best practices. The improvement in capacity factors occurred mostly through reducing the period of time needed to refuel the plant as well as better management and preventive maintenance. In 1990, the average refueling outage was 104 days, and by 2007, it had been reduced substantially to 40 days, as shown in Figure 25.

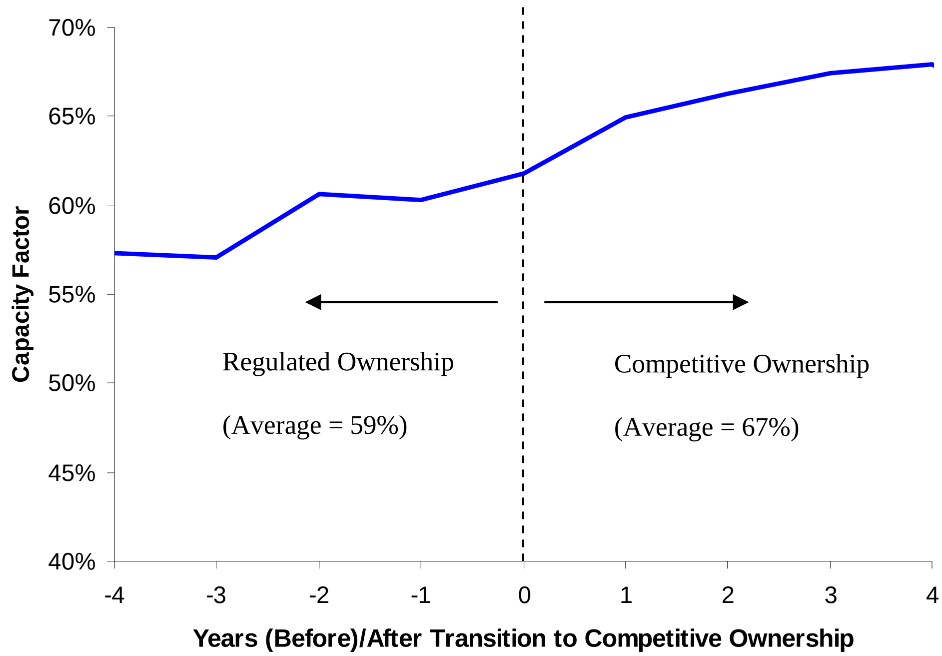
Figure 25 Reduction in Nuclear Refueling Outage Days



Source: Nuclear Energy Institute.

The evolution of coal plant operations is also significant. As Figure 26 shows, previously-regulated coal plants that have been acquired by a competitive operator have experienced significant gains in capacity factor and availability after transitioning to competitive ownership and operation, producing savings on the order of $300 million per year at current market prices.[70]

Figure 26 Improvement in Capacity Factor for Coal Plants Transferred to Competitive Ownership



Source: Based on data from FERC Form 1 (Annual Report of Electric Utilities) for various years as well as data from the EPA Continuous Emission Monitoring Systems (CEMS) database. Values shown are an average for 55 coal-fired power plants that were either purchased by a competitive operator or transferred to an unregulated generation affiliate.

Finally, restructuring also appears to have led to better fuel efficiencies (i.e., better heat rates) of fossil-fueled plants. Divested generating plants improved their fuel efficiencies compared to other comparable plants. Controlling for output level, deregulated plants used 2 percent less fuel per MWH of electricity produced, averaged across different fuel types than regulated plants, producing savings of about $550 million per year.[71]

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[70] Improved capacity utilization at divested coal plants adds about 34 million MWH per year from these plants. We estimate that running these coal plants versus running the marginal unit in their particular market produces savings of about $30/MWH (at current forward market prices and inclusive of environmental costs), leading to annual savings of just over $1 billion per year. Roughly 70% of this value can be attributed to changes in market conditions (such as rising gas prices) and improvements in technology that affected both regulated and competitive plants. The remaining 30% is attributable to gains made by competitive plants in excess of improvements observed at always-regulated plants. Multiplying $1 billion by 30% we arrive at an annual savings estimate of $300 million for the gains attributable to competitive ownership.

[71] James Bushnell and Catherine Wolfram, "Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants," Center for the Study of Energy Markets (CSEM) Working Paper Series, March 2005, 21-22.

2) Competition Promotes Efficient Plant Investment and Retirement Decisions

a) The Theory

One of the most significant savings from restructuring is believed to be efficiency gains in long-term investments (sometimes referred to as "dynamic efficiency"). Dynamic benefits are those that can be achieved over a longer term, including changes in the capital stock such as investment in new generation, demand response, and energy efficiency. Economic theory suggests that a properly functioning competitive wholesale market (including customer demand response) will induce the right amount of generating capacity with the appropriate levels of reliability, as well as the right mix of generating technologies in the right locations.

Competitive markets can provide significant improvements in resource planning and capital additions. Price signals, rather than administrative determinations, guide economic retirements and capacity improvements, economic new entry, and environmental compliance strategies. In a competitive market in long run supply/demand equilibrium, prices will approximate long run marginal costs, a figure which includes the cost of capacity and therefore provides for capital recovery. As supply and demand become more balanced over time and the market for bulk power reaches long run equilibrium, prices will increase to the point where capital is recovered. The dynamics of a competitive market continually pushing toward equilibrium are responsible for these forces. If returns exceed full cost recovery, new generation will be built that will tend to drive profits and prices down. On the other hand, if profits are suffering and capital is not recovered, generators will not add capacity. If profits on existing plants do not cover their fixed costs, operators will shut down units, and may make plans for early exit – activities that allow prices to rise.

Markets also provide the necessary incentives for investments in different fuel sources. Competitive generators have the appropriate price signals (including environmental costs) to evaluate the relative economic value and risks of alternative generation fuel sources in order to develop the most economically efficient combination of generation fuel sources over time. New solid fuel (nuclear or integrated gasification combined cycle) or renewable generation will be built when it is economic, that is, when expectations of gas prices and/or CO_2 allowance prices are sufficient to make such investments economic on an expected basis. If such plants are not economic for investors, then they will not be built in the absence of regulatory mandates. If a new plant with a particular fuel type can be constructed at a profit based on expected market prices, it will be. This investment decision is similar to that of other capital-intensive industries, as Paul Joskow explains, "investors finance oil refineries, oil and gas drilling platforms, cruise ships, and many other costly capital projects where there is considerable price uncertainty without the security of long term contracts."[72]

Competition makes investors, rather than consumers, responsible for investment decisions with no assured recovery of the investment. In the 1970s and 1980s, a competitive market would have allocated risks appropriately: it would have transferred the risks of technology choice, excess supply problems, and cost overruns from the consumers to the investors. Instead, under regulation, electricity consumers bore these risks. In a competitive market,

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[72] Paul Joskow, "Competitive Electricity Markets and Investment in New Generating Capacity," AEI-Brookings Joint Center for Regulatory Studies Working Paper 06-14, May 2006, 39-40.

where a new plant is not guaranteed a return, there is no incentive for investors to over-invest in capital or "gold-plate" investments, overestimate consumer demand for electricity, or build facilities even when costs have significantly increased or slow-downs in load growth no longer require the investment. A competitive market model will allow regulators and customers to avoid future situations in which a utility makes a long-term commitment that later becomes uneconomic and costly for customers. Rather, investors in the competitive market will bear these risks.

b) Early Results – Significant Improvements in Open Access and Price Signals That Support Development of Competitive Generation

To date, significant progress has been made in the development of wholesale markets and non-utility generation. A series of FERC policies and orders has improved investors' access to information that they can rely on to plan and invest in new generation. The Energy Policy Act of 1992 expanded FERC's authority to order utilities to provide transmission service to facilitate wholesale power transactions. In 1996, FERC Order 888 required transmission-owning utilities to offer open access transmission service. FERC Order 889 required utilities to provide information about the availability and the price of transmission service on their system. In late 1999, FERC Order 2000 encouraged the formation of RTOs to further promote competition. These actions have led to considerable improvements in non-discriminatory, open transmission access that facilitate coordination and promote competitive entry into the market.[73]

Most regions that have created ISOs have implemented bid-based security constrained dispatch[74] with locational or nodal pricing. Differences in locational prices highlight transmission congestion within regions to allow an efficient allocation of scarce transmission capacity and to provide market signals that indicate the need to make new investments in either generation, transmission or load response resources. These price signals adjust to changes in supply and demand conditions and allow both investors and regulators to more accurately identify resource needs. As of 2007, about two-thirds of customers in the United

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[73] Utilities that own transmission either directly or through an ISO/RTO have developed standardized, cost-based transmission service tariffs to third-parties. Third parties also have real-time information on transmission availability and prices. Utilities are required to interconnect independent power producers to their networks and must provide certain network support services, including balancing services to third parties. Utilities are also required to follow functional separation rules between the operators of their transmission networks and affiliated generators to mitigate self-dealing. Utilities are required to use best efforts to expand their transmission system in order to meet service availability requests when there is not sufficient capacity available. These changes are discussed in more detail in Paul Joskow's paper, "Markets for Power In the United States: An Interim Assessment," *The Energy Journal*, Vol. 27, No. 1 (2006), 5-7.

[74] Bid-based security constrained dispatch refers to a regime under which each generation unit is bid by its operator into a centralized market at a price that the owner sets at its discretion subject to market rules. The centralized market first considers dispatching all available on-line generating resources and power purchases to achieve the lowest possible cost to satisfy load. Once this "pure" economic dispatch is developed, reliability and other constraints (such as transmission congestion) are considered in order to modify the economic dispatch with the minimum increase in cost. Many markets have developed integrated day-ahead, hour-ahead and real-time energy prices based on these bids.

States are served by an ISO or RTO.[75] Many of these changes have led to increased competition from non-utility generation both in restructured and regulated states.

Thus far, the industry also has experienced a significant restructuring of the ownership of generating plants. In 1996, investor-owned utilities ("IOUs") owned 580 gigawatts of capacity. Since 1996, about 100 gigawatts were divested by IOUs and another 100 gigawatts were transferred to unregulated utility affiliates. Between 1999 and 2004 about 200 gigawatts of new generating capacity was completed, about 80 percent of which was owned by unregulated generating companies. By 2004, over 40 percent of the power produced in the United States (excluding federal, state, municipal and cooperative generation) came from unregulated power plants.[76]

More new generating capacity entered the market between 2001 and 2003 than in any other three-year period in U.S. history.[77] Most of this capacity relied on natural gas and was built by unregulated developers using project finance without long-term contracts. When wholesale market prices fell after 2001, many of these projects could not meet their debt obligations and went bankrupt or faced severe financial difficulties.

The experience of the competitive market gas combined cycle build-out of the late 1990s and early 2000s was very different from that of the regulated nuclear capacity additions of the 1970s and 1980s. Figure 27 shows the forward price signals applicable to new build gas combined cycle generation (in the form of the on-peak spark spread, which is the difference between electricity prices and the variable cost of a gas combined cycle).[78]

From late 1998 through early 2001, combined-cycle new entry economics were highly favorable and triggered a huge wave of new CCGT plants. In early 2001, however, the forward price signal dropped well below the threshold needed for new units to make money. This crash in the price signal triggered a quick response from competitive builders, and a much slower response from regulated builders. For competitive builders, 78 percent of capacity with a planned in-service date of 2003 or later (relatively little of which would have been sunk by late 2001) was ultimately cancelled, while for regulated builders only 37 percent of capacity was cancelled. Comparing this to the nuclear industry experience we can see that: 1) a price signal improves the responsiveness of generation builders to changes in market conditions, and 2) regulated builders still respond much less efficiently to price signals than do non-regulated builders. This experience also demonstrates that, regardless of the market structure, investors in capital-intensive generation plants face enormous risks and make mistakes; but, in a competitive market, the recognition of and response to these mistakes is much more rapid than in a regulated environment. Private investors responded much more quickly to the crisis of the early 2000s than regulated builders did in the 1970s and 1980s. Further, the crisis of the early 2000s had little impact on customers in non-

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75 ISO/RTO Council, *About the ISO/RTO Council (IRC)*, 2007, Accessed 24 March 2008, http://www.isorto.org/site/c.jhKQIZPBImE/b.2603917/k.7A3F/About_the_IRC.htm.

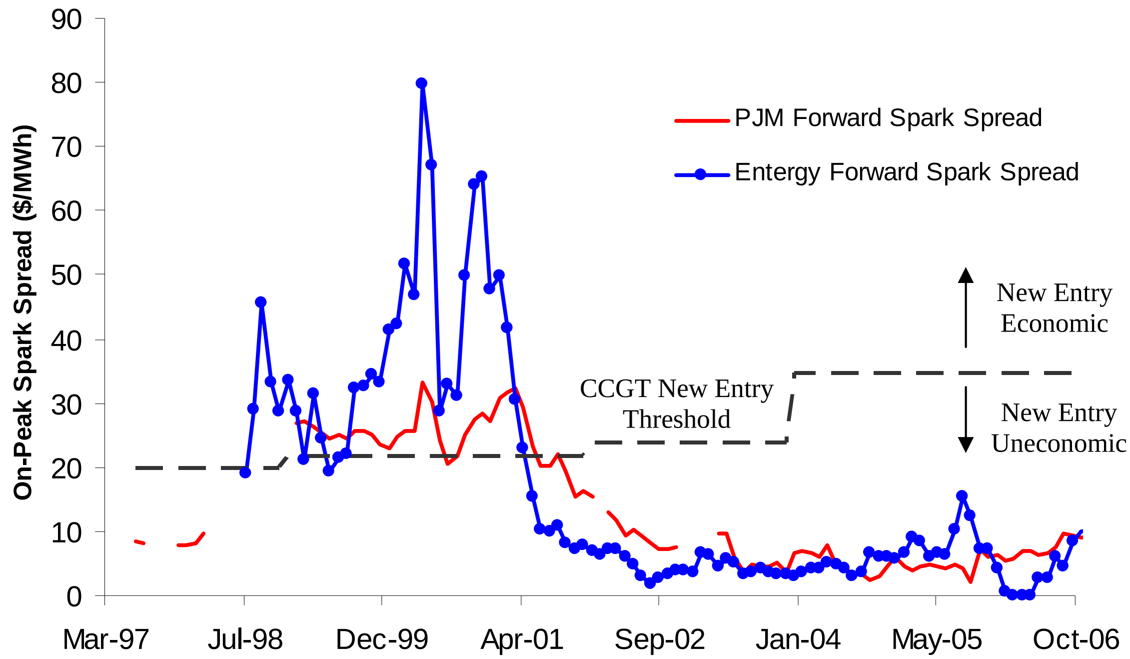
76 Joskow, "Markets for Power in the United States," 7.

77 Joskow, "Markets for Power in the United States," 7.

78 While competitive power plants were built throughout the country, reliable forward market price information going back to the 1990s is limited to only a few locations. Entergy and PJM provide the longest-running forward market datasets available.

regulated states, since unlike prior investments in new capacity; unregulated investors – not ratepayers – bore the risk of these uneconomic investments. We estimate that private generation developers lost about $30 billion (in 2007 dollars) in economic profits over the period 1996 to 2005 – losses that likely would have been paid for by ratepayers had they been incurred by regulated builders.

Figure 27 Decline of Gas Combined-Cycle New Entry Economics in 2001



Source: Based on year-ahead forward market data from Bloomberg, Inc., Intercontinental Exchange, and the New York Mercantile Exchange.

Currently, locational market energy and capacity prices in constrained regions, such as Eastern PJM, are providing price signals for new entry by both generation and demand response resources – and these signals have generated a response from investors. PJM has experienced 10,000 MW of net new resources since the Reliability Pricing Model ("RPM") auctions were implemented.[79] Further, several generators in PJM plan to build additional new capacity in response to RPM. For example, PSEG Power recently announced plans to build up to 1,000 MW of peaking capacity in response to recently-observed forward energy and capacity prices.[80] Exelon is actively pursuing development of a 600 MW combined cycle plant and Reliant reversed plans to mothball a 315 MW gas/oil plant in Pennsylvania.[81] Constellation and PP&L also announced plans to expand capacity and return mothballed capacity in PJM.[82] Similarly, over 1,300 MW of new demand response resources have been

[79] "PJM Reliability Pricing Model Draws Largest Amount of New Capacity So Far," PJM Press Release, 1 February 2008.

[80] "PSEG Plans Up to 1,000 MW of Peakers," *Megawatt Daily*, 15 October 2007.

[81] "Capacity Prices Support PJM Additions: Reliant," *Megawatt Daily*, 2 May 2008.

[82] "Constellation, PPL See Gold In Tight Markets," *Megawatt Daily*, 6 September 2007.

added in PJM over the first four RPM auctions.[83] The ISO-New England also completed its first forward capacity auction in February 2008 and received an excess of bids to meet its targeted reliability margin at the auction's floor price.[84] The auction resulted in 626 MW of new generating capacity and 1,188 MW of new demand resources from energy efficiency, demand response and distributed generation.[85] Many of the new resources are concentrated in areas of high demand, including Connecticut and Massachusetts.

Lastly, the restructuring process in many regions has been accompanied by more efficient environmental compliance. One study concludes that utilities in restructured states have been able to meet environmental requirements with less expensive pollution abatement techniques than regulated utilities, since regulated utilities tend to favor more capital-intensive approaches that can be included in rate base:

> Although state regulators have allowed electricity generators to earn a positive rate of return on capital investments in pollution control equipment and recover the average costs of operating pollution controls and purchasing permits (profits from the sale of permits are also passed through to rate payers), the opportunity costs of using or holding allocated allowances are not reflected in regulated rates. Regulated firms have an incentive to choose compliance options that require more capital investment relative to pollution permit "inputs" than is consistent with cost minimization.[86]

These capital-intensive solutions tend to be more costly for customers.

3) Competition Promotes Efficient Customer Consumption Decisions

a) The Theory

The retail price of electricity also provides a valuable price signal to customers that may impact customers' time of electricity use, overall level of electricity use, fuel choice, and investment decisions. Unfortunately, most markets for electricity suffer from the lack of customer demand response. This lack of customer response is reinforced by retail rate design in both regulated and many restructured states. As shown earlier in Figure 23, conventional utility tariff rates based on average costs often diverge substantially from marginal cost market prices. Tariff rates, when exceeding market prices, limit the economic use of electricity, prevent economic development, and encourage customers to bypass the system even when it is uneconomic to do so. Tariff rates, when below market prices, encourage

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[83] PJM Interconnection, "2010/2011 RPM Base Residual Auction Results," 1 February 2008.

[84] "ISO New England's First Forward Capacity Market Auction Completed Successfully," ISO New England Press Release, 6 February 2008.

[85] "Demand-Side Trumps Plants in ISO-NE Auction," *Megawatt Daily*, 14 February 2008.

[86] Meredith Fowlie, "Emissions Trading, Energy Restructuring, and Investment in Pollution Abatement," University of California Energy Institute Center for the Study of Energy Markets, Paper CSEM WP-149, November 2005, 8-9.

customers to over-consume electricity especially during high-priced hours when capacity is in short supply and energy is expensive to produce.

This mismatch between conventional retail rates and market prices creates several problems. First, it results in inefficient use of electricity. The failure to induce customers to shift consumption from higher-price on-peak periods to lower-price off-peak periods creates poor capacity utilization of both baseload and intermediate power plant resources, and requires a greater level of installed capacity in order to accommodate higher peak loads. Second, because customers do not see a time-varying market price, they are generally unable to curtail their usage in times of high demand and/or supply scarcity. As a consequence, demand for electricity is almost completely inelastic in the short-run; during periods of scarcity, market prices can increase by orders of magnitude without inducing any reduction in load. Third, to the extent that regulated or default service price cap rates do not reflect overall market price levels, even over longer time periods, retail customers are forced to make investment decisions based on distorted price signals, which leads to over- or under-investment in energy efficiency and inappropriate fuel choices.

In contrast, when customers see competitive, market-based marginal prices, there are several types of efficiency benefits. Customers can respond to changing power market prices and reduce their electric bill by shifting or curtailing their consumption. An extensive body of research has been conducted to estimate customer response to changing electricity price signals. This research suggests that electricity is similar to most other commodities, whereby decreasing prices leads to greater consumption and increasing prices leads to less consumption, all other things being equal. While customer response is hard to measure precisely, the research in the industry and growing empirical results convincingly demonstrate that customers do respond to changes in electricity prices, and relatively low customer response can still result in significant benefits to society. Some conservative estimates suggest that a 10 percent increase in the average price of electricity will result in a one percent or more decrease in electricity demand,[87] and with each one percent reduction in demand nationwide, the industry could avoid CO_2 emissions of 30 million tons per year and the need for nearly 5 gigawatts of new baseload/intermediate generating capacity, saving $10 to $20 billion or more in capital investment.[88]

Market price signals also guide customer investment decisions in energy efficiency equipment and business expansion and productivity enhancements. Customers also can benefit by investing in new technologies that automatically regulate the power consumption of certain appliances or machines (commonly referred to as "direct load control"). For example, automated price signal thermostats that control air conditioning and hot water heaters have been used in residential markets and heat and energy storage systems have been installed on a commercial scale. There also is renewed interest in hybrid electric cars. These cars with advanced battery technology use a small amount of liquid fuel but can "plug-in" to the electric grid. These cars could serve as distributed off-peak storage of electrical energy,

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[87] Christian Crowley and Frederick Lutz, "Weather Effects on Electricity Loads: Modeling and Forecasting," Study Prepared for EPA, 12 December 2005; Steven Wade, "Price Responsiveness in the AEO2003 NEMS Residential and Commercial Buildings Sector Models," Study Prepared by the Energy Information Administration, 2003.

[88] Assuming a capital cost for low-carbon baseload/intermediate generation of $2,000/kW to $4,000/kW.

using off-peak energy to displace oil consumption as well as potentially provide power for individual homes.[89] Market pricing makes the value of such products and equipment more visible to customers, and competitive providers of these products and services have strong incentives to help customers capitalize on their value.

Demand response also can provide customers with reliability benefits by reducing the likelihood of involuntary curtailments. While the relationship between market prices and regulated average embedded costs will vary depending on the weather, time of day, time of year, supply and demand balance, and other factors, providing customers with these market price signals will ultimately lead to more efficient customer consumption and investment decisions both in the short and long term. Here again, competitive providers have strong incentives to develop innovative ways to assist customers in taking advantage of these opportunities.

More efficient price signals and demand response also complement and improve the performance of the competitive wholesale market, resulting in better resource and generation investment decisions and enhanced system reliability. The integration of supply and demand resources will improve system load factors and defer capital investments in generation, and may result in a shift in the mix of peak versus baseload capacity needed. Market pricing can enhance system reliability by enabling price to balance supply and demand. When demand tightens, prices will increase; customers will see and respond to the price increases by reducing consumption; demand will fall, prices will fall, and the system will balance. The ability of customers to lower consumption during high marginal cost periods also provides the added benefit of mitigating market power concerns when capacity is scarce.

Competition improves retail pricing efficiency by reducing subsidies inherent in "one size fits all" rates. Traditional utility rates typically include cross-subsidies within and among rate classes. For purposes of ratemaking, customers within a rate schedule are generally assumed to be homogenous in terms of consumption patterns. In reality, however, customers within the same rate schedule may have very different consumption patterns. Competition allows retailers to develop tailored pricing by customer, which will more appropriately reflect individual consumption patterns of a customer and will drive costs out of the system as customers modify their behavior in response to the true costs of supply.

Finally, customer demand response and customer-owned resources provide other benefits, including enhanced reliability to protect customers from outages, reduced air emissions, and utility deferral of transmission and distribution upgrades.

b) Early Results – Increase in Retail Market-Based Pricing and Customer Demand Response

Several states and utilities within restructured markets have taken actions to increase economic demand response and have expanded market pricing initiatives. While demand response programs, time-of-use pricing, and interruptible programs have also been

[89] Peter Huber and Mark Mills, *The Bottomless Well: The Twilight of Fuel, the Virtue of Waste, and Why We Will Never Run Out of Energy* (New York: Basic Books, 2005) 75-90. See also "Can better batteries pummel US oil addiction in a few years?" *Restructuring Today,* 29 January 2008.

implemented at a number of regulated utilities over the years, such programs ultimately must be tied to market-based, marginal cost rates in order to be efficient.[90] As transition periods are completed, customer rates increasingly reflect market prices and more customers are experiencing more frequent price adjustments that vary by year, by season, by time-of-use period, or by hour. More customers, especially large C&I customers, are beginning to see the proper price signals associated with their consumption at a specific place and time. There are at least sixteen utilities in five states that now offer hourly price default service to large C&I customers.[91] Competitive retailers in Texas, where there is no longer utility-provided default service, also offer Market Clearing Price for Energy ("MCPE") products based on spot market electricity prices. Customers on hourly price default service or MCPE receive a clear price signal and have the ability to act immediately to reduce demand during times of high prices or increase their consumption during times of low prices. These benefits are clearly transparent in a competitive market that allows retail pricing to match real-time market conditions.

Currently, there is about 21,000 MW of demand response in the United States, consisting of capacity (73 percent), energy (15 percent), and ancillary services (12 percent).[92] The level of interest in demand response has increased as generation costs have increased and as market prices have become more visible. RTOs and utility companies have established economic curtailment programs and demand reduction programs that are tied to these visible energy and capacity markets. As shown in Figure 28, RTO and ISO regions with organized wholesale markets lowered system peaks by over 8,300 MW on peak days during the summer of 2006.[93]

These customer demand resources can avoid substantial capital costs in peaking capacity. As an example, 8,300 MW of customer demand response could avoid roughly $3.7 to $5.8 billion of capacity costs.[94] In addition, by reducing demand at critical times, system operators can enhance system reliability on short notice in the event of unexpected generation or transmission failures and/or extreme weather conditions. Demand response plays an even more valuable role in load pockets, such as in southwest Connecticut and New York City-Long Island,[95] since demand response typically requires shorter lead times and can be less costly than building new generation, transmission, or distribution facilities. Several RTOs

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[90] For example, many interruptible customer load programs provided by regulated utilities traditionally were used only in cases of "system emergencies" or as a means to offer fixed discounts to large users, but in developing competitive markets, the economic use of customer resources is increasing.

[91] These include utilities in Maryland (APS, BGE, DPL, Pepco), New Jersey (AECO, JCPL, PSEG, RECO), Illinois (ComEd), New York (NIMO, CH, NYSEG, O&R, RGE, ConEd), and Pennsylvania (DLC).

[92] ISO/RTO Council (IRC), Markets Committee, "Harnessing the Power of Demand: How ISOs and RTOs Are Integrating Demand Response Into Wholesale Electricity Markets," 16 October 2007, 8.

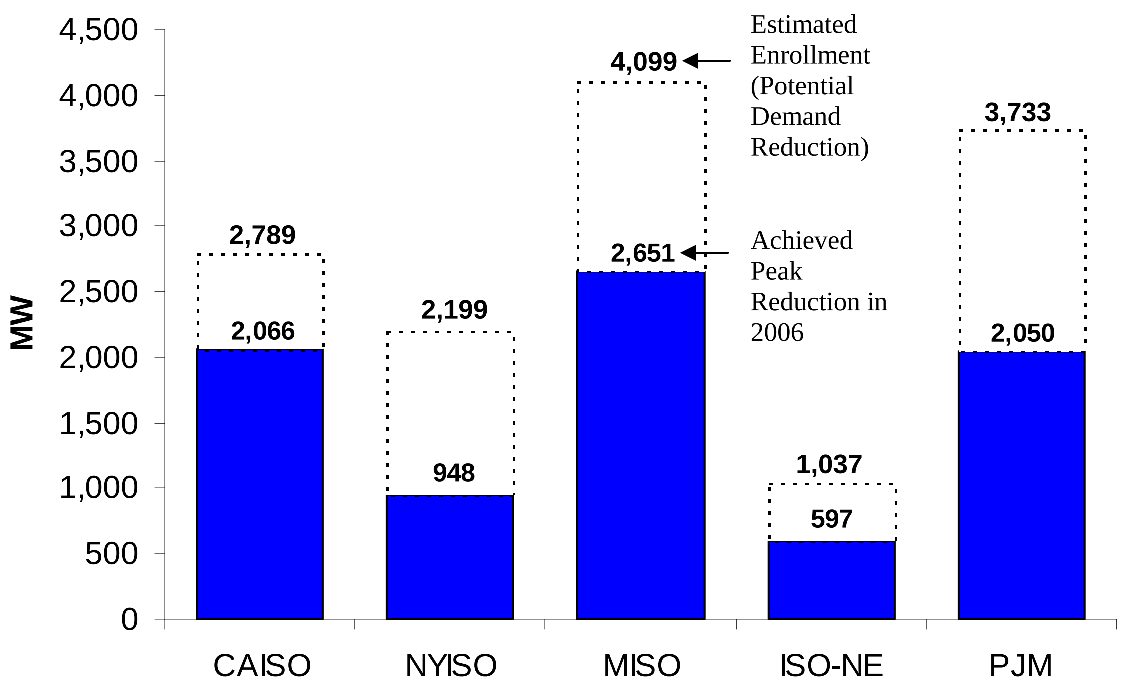
[93] "2007 Assessment of Demand Response and Advanced Metering," FERC Staff Report, September 2007, i.

[94] This assumes that the cost of a peaking combustion turbine ranges from $450 per kW, as it did around 2006, to $700 per kW, which is a more current estimate. (PJM, "PJM RPM Proposed CT Cost of New Entry (CONE) Update, corrected 12-04-07, http://www.pjm.com/markets/rpm/downloads/20071204-rpm-ct-cost-new-entry-update.xls.)

[95] FERC, "2007 Assessment of Demand Response and Advanced Metering," 6.

also report that demand response reductions during peak hours have reduced wholesale prices, particularly during periods of price spikes.[96]

Figure 28 Customer Demand Response In RTO/ISO Programs, Summer 2006



Source: "2007 Assessment of Demand Response and Advanced Metering," FERC Staff Report, Table B-1, September 2007. Enrollment figures from FERC Staff analysis. Achieved peak reductions based on called demand response in summer of 2006. CAISO: Emergency Stages 1&2, FERC estimate based on difference between forecast and actual peak load; NYISO: Emergency DR activated, "Responses to FERC," FERC Wholesale Demand Response Technical Conference; MISO: Max Gen Warning NERC EEA2, actual reductions based on MISO survey to Balancing Authorities; ISO-NE: OP-4 Action 12, ISO-NE 2006 Annual Markets Report, June 11, 2007, 116; PJM: Full Emergency Load Response Mid-Atlantic only, "PJM 2006 State of Market Report," Vol. 1, 12-13.

More recently, demand resources have been included in forward capacity markets and certain ancillary services markets, so that they can be assessed along with competing generation resources.[97] Third party firms, who aggregate demand reductions across customer groups,

[96] In competitive spot markets, demand response on the margin can lower the overall price for all energy traded in the market. PJM reported estimated energy payment reductions of more than $650 million in one week during 2006. (PJM, "Early Aug. Demand Response Produces $650 Million Savings in PJM," PJM press release, 17 August 2006.) ISO-New England attributed average savings of $1.74/MWH during hours with interruptions over the period April to September 2006. (ISO New England, "2006 Annual Markets Report," 11 June 2007, 11.) The Midwest ISO found a reduction of $100 to 200/MWH in market clearing prices during a peak day in August 2006. (FERC, "2007 Assessment of Demand Response and Advanced Metering," 6-7.)

[97] In the first 2007 capacity auction in PJM, demand response offers that cleared were about 41 percent of the new capacity that cleared (127 MW versus 311 MW). In the second auction in 2007, the demand response offers that cleared increased to 536 MW. (PJM, "PJM Completes First Reliability Pricing Model Auction," PJM News Release, 16 April 2007 and PJM, "PJM Reliability Pricing Model Producing Results," PJM News Release, 13 July 2007.) The ISO-NE forward capacity market allows different types of demand resources to participate, including energy efficiency, load management, distributed generation, and real-time demand response.

are increasingly able to bid customer demand resources into markets in an integrated manner side-by-side with supply resources.[98] Customer enrollment in RTO/ISO demand reduction reliability and economic programs also has increased, with the total number of MW enrolled growing by more than 50 percent since 2003 in the Eastern markets of PJM, ISO-NE, and the NYISO.

The level of interest in advanced metering infrastructure ("AMI") has also increased and utilities recently have announced plans to install more than 40 million advanced meters during the period 2007-2010. The increase in AMI market activity, as measured by the number of meters planned or installed, has nearly tripled from 2005 to 2006, and is projected to double again in 2008.[99] While advanced meters are being installed in both regulated and restructured states and not all of these plans will be implemented, the installation of more sophisticated metering and control technology will allow retail customers in competitive markets to respond efficiently to market energy prices and to provide capacity as demand-side bidders in competitive wholesale markets. Expansion of these customer resources, especially among smaller customers, will become more feasible with smart metering, faster internet connections and improvements in direct load control technology. Finally, as more retail customers begin to see accurate market price signals, customer demand response will increase and competitive suppliers will have the incentive to offer expanded choices of products that will manage customer load and hedge market price risks. For example, some competitive suppliers offer large C&I customers "swing" products that fix a portion of the customer bill based on some defined consumption pattern, but allow prices to adjust with market when consumption deviates from certain levels. Competitive suppliers have strong incentives to provide these types of new products and services when considered valuable to customers.

E. Retail Competition is Still Developing and Provides Additional Benefits

1) The Theory

In a well-designed market, retail competition will produce the most efficient outcomes, provide customers with more choices and improve customer value and customer satisfaction. First, retail competition increases customer choice in suppliers and in products. Traditional utilities typically offered "one size fits all" service with limited service options and no choice of supplier. Retail choice allows customers to choose their supplier, manage their demand, and determine the level of risk they want to assume. Second, competition leads to service improvements and innovation. Competition provides new incentives to develop value-added services and product offerings as competitive retailers gain access to customers and become more familiar with their needs and desires. Competitive retailers have strong incentives to attract and retain existing customers to maximize the lifetime value of the consumer in order

[98] For instance, EnerNOC reports that it currently manages over 1,100 MW of customer demand response (EnerNoc, "EnerNOC Reports Fourth Quarter and Year-End 2007 Financial Results," EnerNoc News Release, 27 February 2008) and Comverge reports that it has over 600 MW of customer capacity under contract (Comverge, "Comverge Announces 2007 Third Quarter Financial and Operating Results," Comverge News Release, 6 November 2007).

[99] FERC, "2007 Assessment of Demand Response and Advanced Metering," 31.

to capture market share and enhance profitability.[100] This can be accomplished through better understanding of customer desires (e.g., recognizing that customers are different and developing products that address customers preferences: length of fixed price term, renewable energy, demand response, smart energy, quicker response times, eliminating busy signals, and so forth). Finally, retail competition aligns the industry value chain with the customer. Competitive suppliers have strong incentives to satisfy customer demand for supply and services, while avoiding the generation overbuild problems and the one-size-fits-all service of the 1970s and 1980s.

2) Early Results – Retail Competition is Still Developing and Provides Additional Benefits

The first retail competition and restructuring programs began in Massachusetts, Rhode Island, and California in early 1998. By the end of 2000, more than a dozen states had initiated their own restructuring programs. While the slow pace of the development of retail competition has disappointed many observers both within and outside the electric industry, very few states have enacted the rules and infrastructure necessary to allow retail competition to develop. Nonetheless, overall customer switching to competitive suppliers has more than quadrupled from 22 GW in 2001 to 91 GW in 2007 of customer peak load as shown in Figure 29.

Across the United States, approximately 480 terawatt-hours from 8.3 million customers are currently served by competitive suppliers.[101] This competitive load represents about 30 percent of the eligible load in retail access states, and most of the shopping load (over 80 percent) is non-residential.[102] Competitive markets have expanded as transition periods have ended and retail rates have become more aligned with market price levels. In particular, large C&I customer switching rates have grown significantly in certain parts of the country. In fact, the majority of large C&I load is shopping in service areas within Texas, New York, New Jersey, Maryland, and Massachusetts, with switching levels that range from 60 percent to 98 percent.[103]

Retail competition for residential customers thus far has developed largely in two states where market rules fostered competitive market development – broadly in the ERCOT area of Texas and less broadly in New York. Although residential customer shopping has been limited in other parts of the country, small C&I customers in restructured states have had a larger number of competitive service options and somewhat higher switching levels than residential customers. This difference is due in part to state regulators allowing competition at the large C&I level to gradually work its way down to smaller customers.

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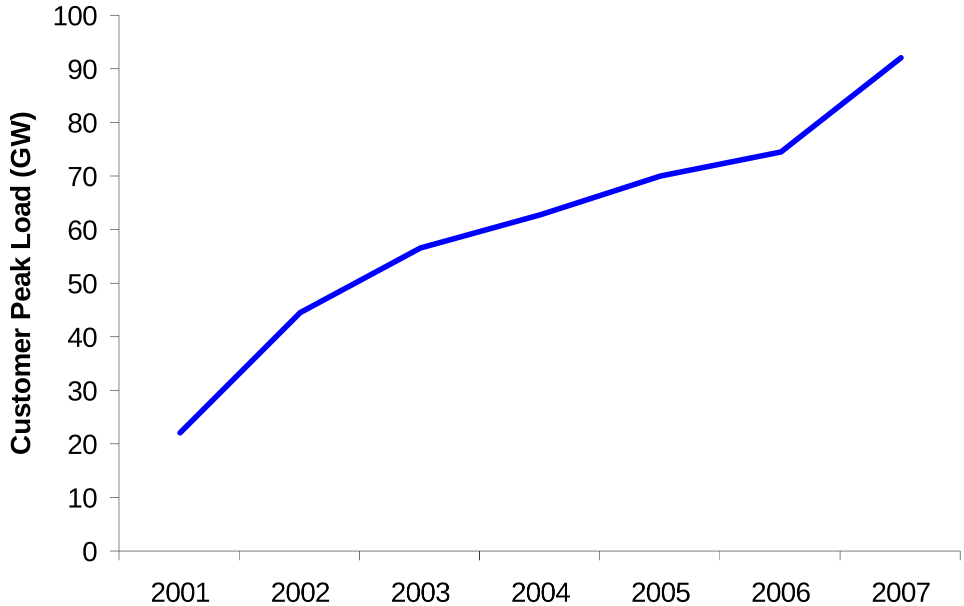
[100] Customer acquisition costs can be high, particularly for smaller customers. Retail suppliers, therefore, have strong incentives to retain customers.

[101] KEMA, "Sharp Increase US Competitive Power Market," KEMA News Release, 6 August 2007.

[102] KEMA, "Sharp Increase US Competitive Power Market."

[103] While jurisdictions have different definitions of what constitutes a "large" customer, more and more customers are facing hourly or short-term market prices over time as regulators expand the definition of a "large" customer and become more comfortable with market pricing to smaller size customers.

Figure 29 Increase in U.S. Retail Shopping Levels, 2001-2007



Source: KEMA

Retail competition among residential and smaller customers in many jurisdictions has been hampered by below-market default service rates, lack of standard market rules, policies that favor utility default service, and a variety of other factors. While default service rates that reflect market price levels promote retail competition, jurisdictions that have established fixed default service rates at below-market levels have virtually eliminated retail competition.[104] In many ways, retail competition – and the lack thereof – is a function of policy decisions made by regulators and politicians.[105] In service areas where substantial customer switching has occurred, it has been accompanied by a regulatory commission, legislature, and/or utility that has allowed market-based default pricing.

In markets with significant retail competition, customers can choose new suppliers and products. In Texas, the most active retail market in the United States, more than 26 retail suppliers provide over 90 different residential products in each service area.[106] Customers

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[104] In some instances, "blended" default service rates, which are based on the average prices from a mix of wholesale supply contracts, also have not been conducive to retail competition. Blended average market-based rates resulting from competitive solicitations at different points of time provide customers rate stability, but they can differ from prevailing market prices at a particular point in time. During prolonged periods of rising market prices, this makes it difficult for retail suppliers to attract new customers, since utility default service rates are likely to be lower than current market price offers. This has contributed to the lack of retail shopping among residential and small C&I customers in some jurisdictions that rely on a portfolio of laddered supply contracts.

[105] A key question for policymakers is how often utility default service rates should adjust to changes in market prices. In general, a reasonable transition to market prices that adjust more often will improve economic efficiency and customer demand response; but as a practical policy matter, the optimal frequency often depends upon a number of factors, including customer sophistication, market price volatility, the number of competitive service alternatives, what customers are accustomed to, and the costs and benefits associated with exposing customers to greater price volatility.

[106] *Texas Electric Choice, 2008*, Public Utility Commission of Texas, accessed 1 April 2008, www.powertochoose.org.

have a wide range of choices in contract length, pricing options, and exposure to risk. Contract lengths offered by retail suppliers range from one month to many years. Pricing may vary by hour, may be indexed to wholesale prices, may be completely fixed, or may have some combination of fixed and variable prices. Customers can choose among varying levels of green power. But in all cases, prices reflect the current market price for the product selected. Customers choose the product they wish, including their desired level of market price stability. Depending on the individual needs and desires of market participants, short-term commodity fluctuations can be borne by speculators, generators, retail suppliers or customers.

Competition also has led to service improvement and innovation. Retail suppliers provide "green" products, manage price and other risks, and offer load management and energy efficiency services that reduce and shift consumption during peak periods. Retail suppliers can aggregate multiple customer locations and provide bundled services, such as total energy management for other fuels (gas, oil, etc.). As retail suppliers have grown in size, they have been able to lower their administrative overhead costs on a per unit basis. The top competitive suppliers in terms of size currently supply between 10,000 and 20,000 MW of customer peak demand, which is equivalent to that of a large-sized regulated utility.

Nationally, it is clear that retail markets are still evolving and we are still in the early stages of retail market development. Unfortunately, price increases driven by commodity costs have caused regulators in many states to react negatively to a perceived lack of control over price. The reluctance of regulators to allow utility default service to reflect market prices in the face of escalating prices only exacerbates the problem. Given the lack of market-based pricing for utility default service in many parts of the country, it is not surprising that many customers still remain on utility default service. Thus, customer switching statistics should not be relied upon to justify the failure of retail markets. Rather, the success of retail competition should be judged by the new value-added services,[107] market-based pricing, and efficient customer consumption decisions that competition encourages. It also is worth noting that in areas where retail rates more closely reflect market prices, electric retail shopping development compares favorably to the telecom industry. Six years after AT&T's divestiture, AT&T still had more than a 60 percent share of the long distance market.[108] In 1990, six years into a competitive retail electric market in Texas, the incumbents' share of their traditional markets is less than 60 percent.[109]

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[107] Paul Joskow originally suggested this notion in his article, "Why Do We Need Electricity Retailers? or Can You Get It Cheaper Wholesale?," 13 February 2000, 4-5. He concluded that the success of retail competition should be judged by the new value-added services it brings, not by the number of customer who switch from default service. He further adds that regulators who focus on retail switching statistics and who are subsidizing customer switching are likely to be making customers worse off than if the default supplier simply provided them basic electricity service at the spot market price.

[108] Federal Communications Commission, Industry Analysis and Technology Division "Statistics of the Long-Distance Telecommunications Industry," May 2003, pg. 17, Table 7.

[109] ERCOT, *Retail*, 2008, Electric Reliability Council of Texas, accessed 25 March 2008, http://www.ercot.com/mktinfo/retail/index.html. See Historical Number of Premises Switched January 14, 2008.

F. Other Industries Illustrate the Benefits of Competition

The benefits of competition are evidenced by the experience of other industries that have deregulated (e.g., airlines, telecommunications, and trucking), other competitive industries in the U.S., and electricity deregulation in the United Kingdom.

Figure 30 Overview of Deregulation in Other Industries

	Pre-Deregulation	Deregulation	Post-Deregulation
Airlines	• Civil Aeronautics Board determined routes, set fares, regulated entrance into markets, and approved mergers and acquisitions.	• Airline Deregulation Act of 1978 mandated that domestic route and rate restrictions be phased out over four years.	• Decline in fares, an increase in passenger miles, new ways to improve asset utilization, and new services.
Telecom	• Federal Communications Commission imposed service requirements at regulated rates. Any deviation required government approval.	• The Justice Department's antitrust suit forced AT&T to divest its regional local exchange companies in 1984. • The Telecommunications Act of 1996 opened up competition between local telephone companies, long distance providers, and cable companies.	• Significant improvement in technology, lower long-distance rates, and numerous new products and services.
Trucking	• The Interstate Commerce Commission regulated operating permits, approved trucking routes, set tariff rates and required market entrants to apply for certificates of public convenience and necessity.	• Motor Carrier Act of 1980 eased regulation of entry and pricing and eliminated most restrictions on commodities and routes.	• Significant decline in rates, improved service quality, reduced empty return hauls, reduced complaints, simplified rate structures, and an increase in new entry.
U.K. Electricity	• Central Electricity Generating Board was responsible for central planning of all aspects of electricity generation, transmission and investment in England and Wales.	• The Electricity Act of 1989 established a wholesale pool, broke down existing vertical monopoly structures, and eventually led to the privatization of regional electricity companies and retail access.	• Lower electric rates and a greater variety of retail products.

As suggested by Figure 30, the benefits of competition in these cases are clear and definitive. Compared to other industries that have deregulated, electric restructuring in the U.S. has proceeded in a patchwork, state-by-state fashion, often with prolonged transition periods and rate stabilization plans. Furthermore, most U.S. electricity markets that are today considered "restructured" lack most of the retail customer market-based pricing flexibility that was one of the critical elements of deregulation in industries such as airlines and trucking. Ultimately, however, the underlying economic forces that govern these other industries are also present in the electricity industry, and we would expect restructured electricity markets to provide similar results over time, provided regulators remain supportive of competition and efforts to improve market price signals to retail customers. In particular, competitive markets will encourage 1) a more efficient utilization of resources, 2) increased customer choice and access to products and services, 3) technological innovation, 4) elimination of cross-subsidies, and 5) lower prices.

1) More Efficient Utilization of Resources

Competition promotes more efficient utilization of resources on both the supply and demand side. On the supply side, firms that receive a competitive rather than an average cost-based price for their output have a strong incentive to efficiently utilize their productive resources and reduce operating costs. On the demand side, firms in a competitive, deregulated market will have flexibility to tailor their prices based on their products' differing value to different consumers at different points in time. This pricing flexibility aligns the marginal cost of production with the value customers' place on the product, resulting in a more efficient utilization of productive resources over time.

The deregulation of the airline industry provides an example of both these supply and demand effects at work. Prior to deregulation, airlines received a regulated cost-based price and were restricted by regulation to an inefficient point-to-point route structure. This command-and-control approach resulted in considerable excess capacity – load factors (the fraction of seats filled on an average flight) averaged about 50 percent in the decades prior to deregulation. On the supply side, deregulation provided airlines with strong incentives to reduce costs and the ability to improve utilization of their aircrafts. Deregulation exposed airlines to a competitive price signal and allowed them flexibility in developing their route structure to best fit their operations. The result was a move to a more efficient hub-and-spoke routing system as well as stronger emphasis on minimizing turnaround times, maintenance downtime, and matching capacity to demand. Furthermore, on the demand side, removal of price regulation allowed airlines to tailor their pricing to different groups of customers to better match supply and demand over time. For example, airlines were able to time-differentiate their fares such that late-booking, time-sensitive customers on heavily booked flights were charged a higher price while customers with more time flexibility could shift their travel to another flight and receive a lower price. Many customers currently can buy discounted tickets with advance purchases, weekend stays, and non-refundable tickets. By using price as a tool to allocate a limited number of airline seats to the appropriate passengers, airlines could offer discounted prices for seats that would otherwise not be filled and improve capacity utilization. This price and route flexibility, along with intense competitive cost pressures, led to significant improvements in the utilization of airline resources. The overall effect of these changes on resource utilization was dramatic: carriers added more seats on their planes – the average went up from 136.9 in 1977 to 153.1 in 1988 – and succeeded in filling a greater percentage of those seats.[110] Load factors remained between 50 and 55 percent in the years immediately preceding deregulation, but increased after deregulation, reaching 77 percent by 2005.[111]

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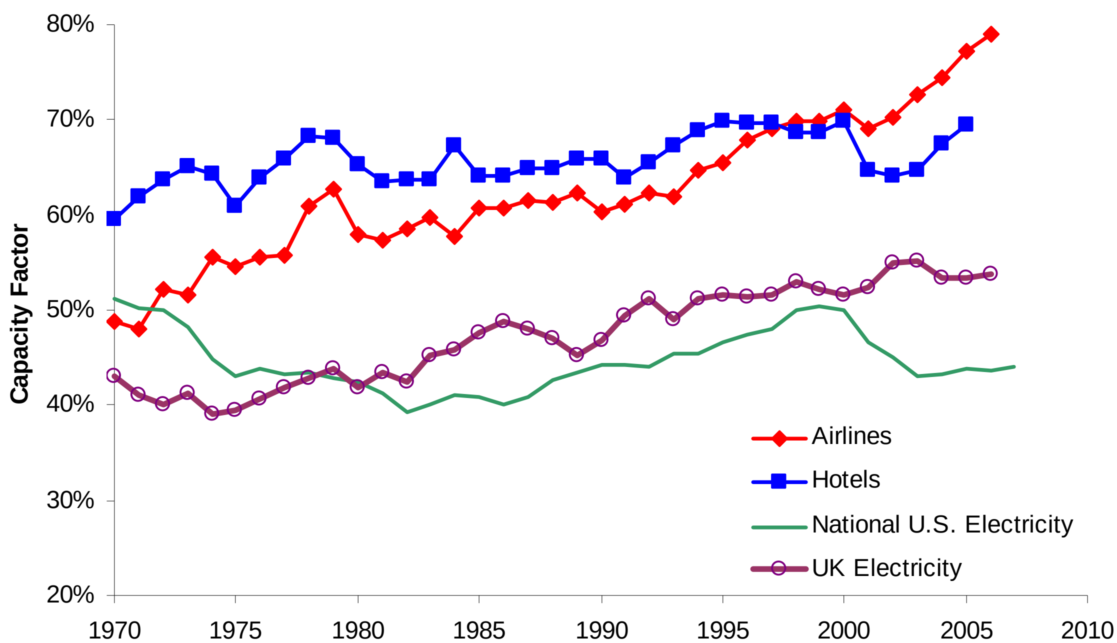
[110] Alfred Kahn, *Airline Deregulation*, 2002, The Concise Encyclopedia of Economics, Accessed 26 March 2008.

[111] Severin Borenstein and Nancy Rose, "How Airline Markets Work, or Do They? Regulatory Reform in the Airline Industry," 30 October 2006, 22.

In general, we expect the electricity industry to also show improvements in resource utilization when and if it transitions from today's patchwork and incomplete implementation of restructuring to a broader and deeper form of competition. Figure 31 compares capacity utilization in the U.S. electricity industry with several other capital-intensive industries that feature a relatively non-storable or perishable product.[112] These other industries include: a) airlines (which deregulated in 1978), b) hotels (which have always been a competitive industry), c) and U.K. electricity (which began introducing elements of competition in the early 1990s).

Figure 31 Capacity Utilization in Selected Capital-Intensive Industries

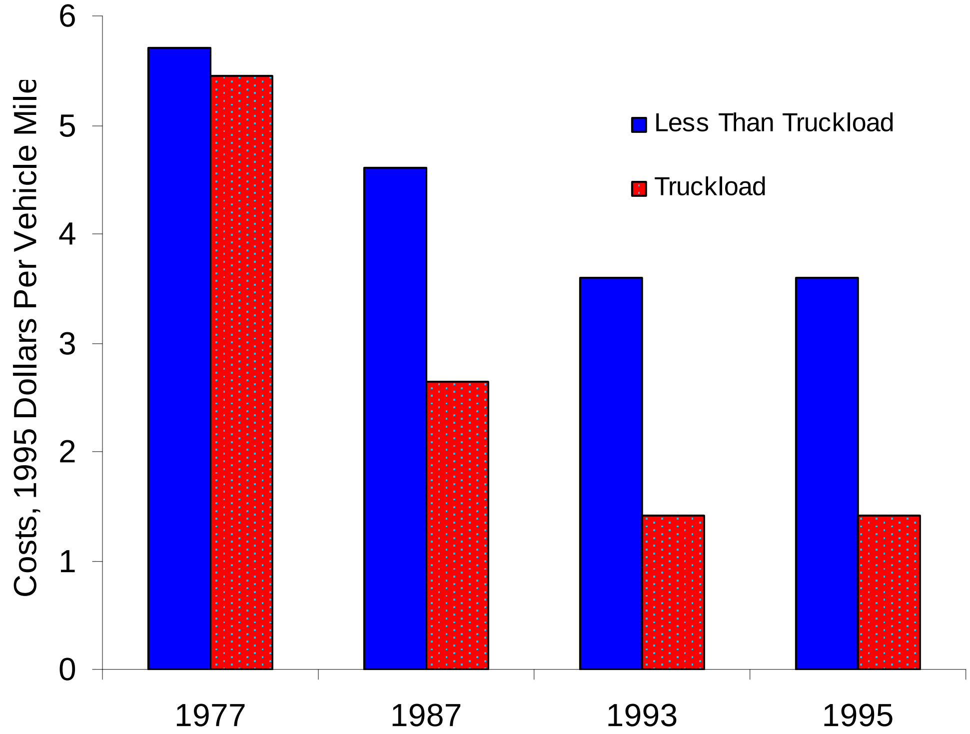


Sources: Airlines Pre-1990: Air Transport Association (http://www.airlines.org/economics/traffic/Annual+US+Traffic.html); Post-1990: U.S. Bureau of Transportation, *National Transportation Statistics*, Table 4-21. Hotels: PKF Hospitality Research, *Trends in the Hotel Industry, 2005*. U.S.: Edison Electric Institute, Historical Statistics of the Electric Industry to 1992, and Energy Information Administration, State-Level Electricity Spreadsheets, 1990-2006. U.K. Electricity: U.K. Department for Business, Enterprise, and Regulatory Reform, *Digest of United Kingdom Energy Statistics*, various years.

The trucking industry also experienced significant declines in operating costs (which include both improved utilization of capital stock as well as reductions in variable operating costs) following deregulation in 1980. As Figure 32 shows, real operating costs per vehicle mile dropped by 35 percent in the less-than-truckload sector ("LTL") for shipments less than 10,000 pounds and by 75 percent in the truckload sector ("TL") for shipments over 10,000 pounds between 1977 and 1995.

[112] Capital-intensive industries with storable products (such as iron and steel, refining, and pulp and paper) tend to have higher capacity utilization than the electric industry with limited storability. The reason for this is that there is little need for a "cushion" of rarely-utilized peaking capacity to meet peak period demand because that need can be met with inventory.

Figure 32 Cost Reductions in the Trucking Industry, 1977-1995



Source: T. Lakshmanan and W. Anderson, "Transportation Infrastructure, Freight Services Sector and Economic Growth," February 2002, 3.

A review of the airline and trucking industries in the U.S. and the electric industry in the U.K. suggests that competition in electricity will lead to higher long-run capacity utilization and ultimately lower prices for customers. Deregulation in both airlines and trucking led to a dramatic improvement in capacity utilization for both industries. In fact, President Carter stated at the time of trucking deregulation that "regulation needlessly wastes our Nation's precious fuel by preventing carriers from making the most productive use of their equipment, and by requiring empty backhauls and circuitous routings."[113] More specific to electricity, the gradual deregulation of U.K. electricity over the course of the 1990s coincided with an improvement in capacity factor of about 10 percent, from an average of about 45 percent in the 1980s to between 50 and 55 percent since 2000.

2) Increased Customer Choice and Access

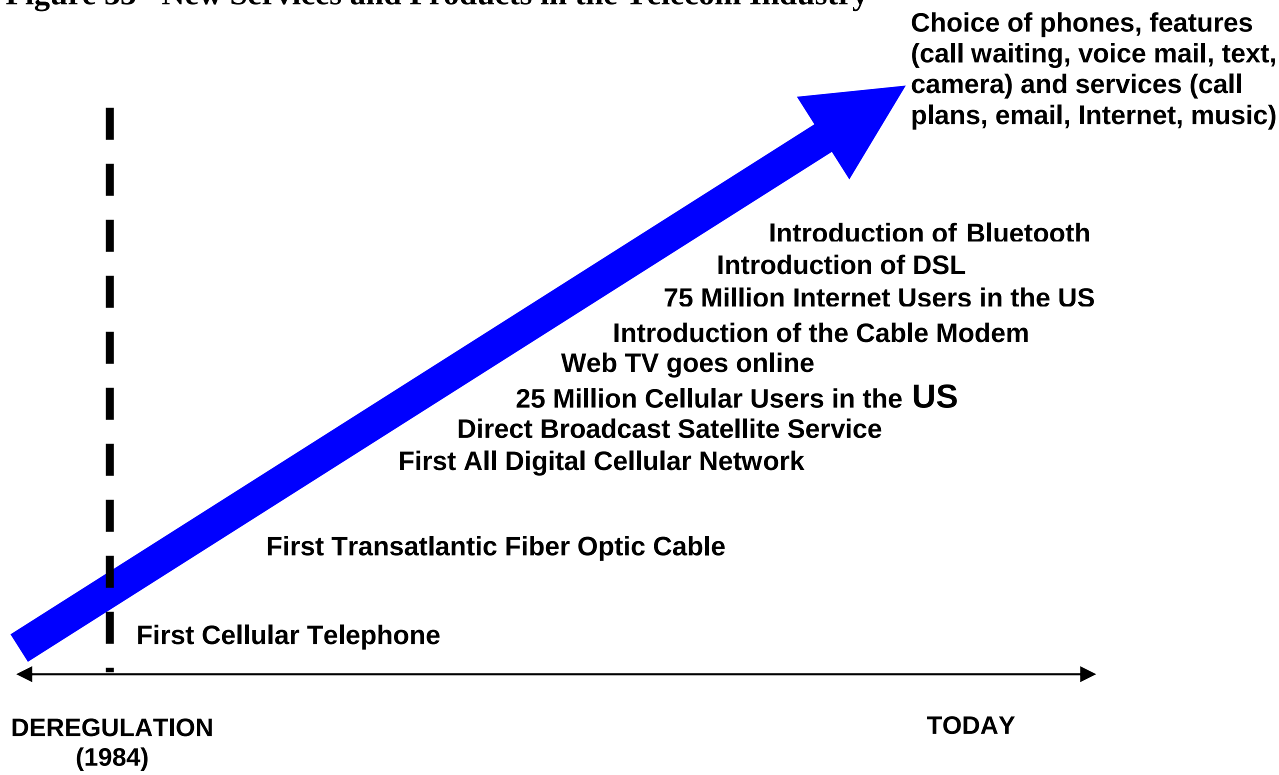
Competition in many industries has also led to increased customer choice and access to products and service. Regulation in telecoms, airlines, and trucking greatly restricted the degree to which firms could tailor their product, service, and price packages to different customers, and limited the ability of firms to reach customers for whom the regulated "one-size-fits-all" product was of limited value. In all three industries, deregulation led to an

[113] President Jimmy Carter, "Trucking Industry Deregulation Message to the Congress Transmitting Proposed Legislation," 21 June 1979.

explosion in the number and variety of product/price offerings as well as attempts to reach new customers not well served under the regulated model.

AT&T's breakup in 1984 and ensuing deregulation of the telecommunications industry has led to a broad range of new products and services as shown in Figure 33. Customers initially were presented with greatly increased variety in pricing and service packages from both local and long-distance carriers. Over time, competition led to the introduction of a wide selection of additional features and choices such as voice mail, call waiting, and mobile phones, all the way to today's integrated services and devices allowing voice, data, e-mail, and Internet, all through one device and service package.

Figure 33 New Services and Products in the Telecom Industry



In the airline industry, competition led to more frequent service, increased routes, fewer connections, and an estimated 25 percent increase in the average number of airlines per route. For example, between 1979 and 1988 American Airlines and United Airlines increased the number of domestic airports it served from 50 to 173 and from 80 to 169, respectively.[114] Overall, the number of airlines certified for scheduled service with large aircraft has increased from 43 in 1978 to 139 by 2005.[115] Airlines developed marketing innovations to segment their customers with differentiated pricing and services. Virtually all airlines created customer loyalty programs, through which customers could accumulate "miles" to apply to

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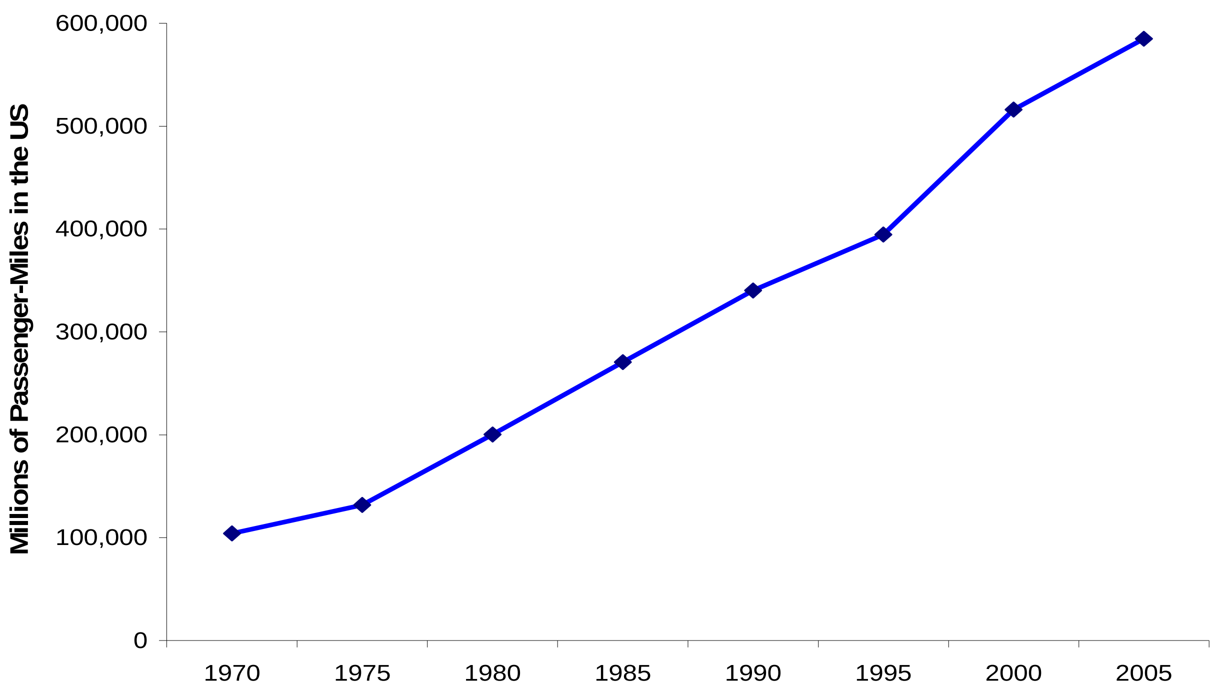
[114] Kahn, *Airline Deregulation*.

[115] "Airline Handbook Chapter 2: Economic Deregulation," 20 November 2007, Air Transport Association of America, Accessed 26 March 2008, http://www.airlines.org/products/AirlineHandbookCh2.htm.

future ticket purchases or other goods and services. Loyal frequent flyers also are rewarded with cabin upgrades, priority check-in, priority boarding, lounge access and other benefits. More recently, the industry has developed marketing partnerships tied to these programs to help promote other services such as credit cards, and in some cases, even electricity. Meanwhile, newly developed reservation and Internet services over the years have provided customers with greater access to flight and fare options. This increased access and product/service tailoring, accompanied by competition reductions in prices, greatly expanded the number of consumers utilizing air travel. Airline capacity grew significantly from 306 billion available seat miles in 1978 to 758 billion in 2005,[116] and as Figure 34 below shows, the number of total domestic revenue passenger-miles flown has more than tripled since deregulation in 1978 – from 188 to 584 billion revenue passenger miles.

Figure 34 Increase in Air Travel, 1970-2005



Source: US Government Accountability Office, "Airline Deregulation: Re-Regulating the Airline Industry Would Likely Reverse Consumer Benefits and Not Save Airline Pensions", June 2006, 10.

In the trucking industry, competition led to the simplification of highly complex regulated tariffs and increased competition on service quality. In 1975 (pre-deregulation), the Interstate Commerce Commission handled 340 complaints against truckers; in 1976, it handled 390 complaints. By 1980, after deregulation, this number had decreased to 23 cases.[117] The number and variety of companies exploded as regulatory barriers to entry were removed. In

[116] Government Accountability Office (GAO), "Airline Deregulation: Regulating the Airline Industry Would Likely Reverse Consumer Benefits and Not Save Airline Pensions," Report to Congressional Committees, GAO-06-630, June 2006, 10.

[117] Thomas Gale Moore, *Trucking Deregulation*, 2002, The Concise Encyclopedia of Economics, 26 March 2008.

1975 only 18,000 trucking firms nationwide were authorized to provide service, compared with nearly 500,000 by 2000, with most firms specializing in a particular segment or product type.[118] With deregulation and improvements in technology, trucking and warehousing firms developed logistical services throughout the entire transportation process that enabled firms to manage all aspects of the movement of goods between producers and consumers. These changes led to value-added services to track packages, to maintain and retrieve computerized inventory information on the location, age, and quantity of goods available in order to better manage inventory, and to provide other customer services.

Meanwhile, retail electricity competition in the U.K. provides a glimpse of the potential for customer product/service tailoring in electricity. Small customers in the U.K. have seen greater choice in the number and variety of different supplier offers. As a result, the level of customer switching has grown steadily over the last eight years. According to a recent government report on residential retail markets, the incumbent Retail Energy Companies have lost nearly half of their customers to new suppliers.[119] In order to attract customers, suppliers are offering new products, such as fixed and capped price offers, online discounts, and supply from "green" resources. Such products now account for 20 percent of all electricity and gas accounts.[120] In addition, some suppliers are beginning to offer new services, such as free energy surveys and discounted energy efficient appliances along with their regular products. A 2005 survey of customer experiences in the U.K. retail market indicated that 97 percent of customers were aware that they could switch suppliers, 47 percent had switched suppliers at some point, and 85 percent were satisfied or very satisfied with their current supplier.[121] A review of currently available offers for residential customers in urban areas suggests that customers typically can choose from between 40 to over 50 distinct offers from 8 to 12 suppliers.[122]

3) Technological Innovation

Competition provides incentives for firms to innovate and improve technology. Most regulated companies are unable to retain much, if any, of the economic value of the innovations or technological developments they may introduce. While this may seem like a good deal for consumers, it tends to slow technological progress by dampening the incentive of regulated companies to innovate. Therefore, in the long-run, customers lose.

Deregulation in most industries has been accompanied by significant improvements in technology. In the airline industry, new technology was developed to attract and retain customers and improve financial performance. For example, two airline companies,

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[118] U.S. Department of Transportation, Bureau of Transportation Statistics, *The Changing Face of Transportation – Chapter 2: Growth, Deregulation, and Intermodalism*, (Washington DC: 2000), 2-40.

[119] Office of Gas and Electricity Markets (OFGEM), *Domestic Retail Market Report – June 2007*, Ref. No. 169/07, 4 July 2007, 23.

[120] OFGEM, *Domestic Retail Market Report – June 2007*.

[121] U.K. Office of Gas and Electric Markets, *Domestic Retail Market Report - June 2005*, Ref. No. 24b/06, 7 February 2006, Detailed Appendix Tables 1 and 3 and Figure 3.

[122] TheEnergyShop.com, 2006, Energy Services Online Limited, Accessed 27 March, 2008, www.theEnergyShop.com.

American and United, developed sophisticated computerized reservation services to better offer services and segment customers. These reservation systems allowed airlines and travel agents to track fare and service changes more efficiently for hundreds of millions of passengers. Over time, these reservation systems increased in functionality and were divested from airlines as separate independent businesses. Today, this technology has evolved, making it possible for individual travelers to book reservations, purchase hotel rooms, rent cars, and arrange other travel services online.

Furthermore, the incentive to reduce costs brought on by competition led airlines to demand a greater focus on fuel economy and operating economics in aircraft design from the airline manufacturers. The most recent Airbus and Boeing aircraft are around 35 percent more fuel efficient than late 1970s vintage designs.[123] The improved sensitivity to customer demands brought on by competition led to the development of regional jets, a technology that was not used in the United States until 1993, but proved highly successful in bringing jet travel to previously underserved routes and timeslots. To further reduce costs and expand services, airlines developed code-sharing agreements that allowed two or more airlines to offer a broader array of services to their customers than they could individually. These marketing arrangements enabled airlines to expand service at a reduced cost by allowing them to issue tickets on a flight operated by another airline as if it were its own. These programs typically link marketing and frequent flyer programs and facilitate convenient connections between the code-sharing partners. In addition to code sharing, several groups of airlines have formed global alliances that compete against each other for international passengers, whereby participating airlines benefit from expanded networks and reduced costs through the sharing of staff, facilities, and sales offices.[124]

The telecommunications industry offers a similar example of significant innovation unlocked by technology. Similar to electricity, most of the early groundbreaking innovation that established the industry took place in the late 19th and early 20th century, prior to any form of deregulation. From the point when the Federal Communications Commission was created in 1934 to oversee interstate telephone service through to deregulation in the early 1980s, innovation in the industry slowed. While direct-dialing, touch-tone phones and pagers were all developed and adopted during this period, other innovations from the time, such as communications satellites and mobile-phone technology were not significantly adopted until after deregulation. In the twenty-odd years since deregulation, however, the industry has experienced an explosion of groundbreaking innovations, including, among others, fiber optic cables, computer switching equipment, and wireless data/internet services.

Competition has also driven innovation in the trucking industry. Examples of new technologies that have been introduced since the advent of deregulation in 1980 include electronic data interchange, new vehicle location detection systems, voice and data communication services, and just-in-time delivery services.[125] In addition, because trucking companies are no longer bound to deliver goods along pre-specified routes, as was the case

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[123] P.M. Peeters, J. Middel, and A. Hoolhorst, National Aerospace Laboratory NLR, "Fuel Efficiency of Commercial Aircraft: An Overview of Historical and Future Trends," Report No. NLR-CR-2005-669, 12.

[124] Air Transport Association, http://www.airlines.org/products/AirlineHandbookCh2.htm.

[125] Cynthia Engel, "Competition Drives the Trucking Industry," Monthly Labor Review, April 1998, 39.

under regulation, they continually seek to optimize routes. Consequently, there has been a surge of services over the last 20 years that provide sophisticated dispatch management. These optimization and dispatch services provide fuel savings by reducing empty miles and increase truck utilization.[126]

4) Elimination of Cross-Subsidies

In many industries, the transition to competition eliminated cross-subsidies that distorted consumption and customer decision-making. Regulatory restrictions on pricing and product structure led to some groups of customers receiving higher or lower prices than they would under competition, encouraging inefficient over- or under-consumption. For example, in the telecommunications industry, regulated rates did not reflect the cost for each service offered. Rates were broad averages designed to recover total revenue requirements across all services. Embedded in this structure were numerous cross-subsidies among different customer groups: long-distance customers subsidized local service while large customers subsidized small and individual customers. Deregulation of the telecommunications industry resulted in elimination of these cross-subsidies as competing suppliers unbundled these two services and priced each individually based on their separate cost structures and value to consumers.

Similar subsidies existed in the regulated airline industry due to regulatory restrictions on pricing and routing. Routes with high density (many travelers), and thus more favorable cost structures, generally subsidized higher-cost routes with low density in more rural areas. These subsidies eroded as markets became competitive and suppliers were able to price different routes individually based on their unique economics.

Competition can be expected to reduce similar subsidies in the electric industry as competitive suppliers develop tailored pricing for a variety of customer services and consumption patterns.

5) Lower Prices

Ultimately, industry deregulation and the introduction of competition have resulted in lower prices for consumers. Figure 35 shows real prices as they have evolved in the airline, trucking, and telecommunications industries indexed to the years immediately around deregulation. All three industries saw sustained price reductions beginning with deregulation and continuing to the present in most cases, with airline[127] and telecoms customers realizing real price reductions of close to 40 percent since deregulation. These price reductions are the consequence of increased competition from a larger group of competitors, improved incentives to drive down costs, and better utilization of resources.

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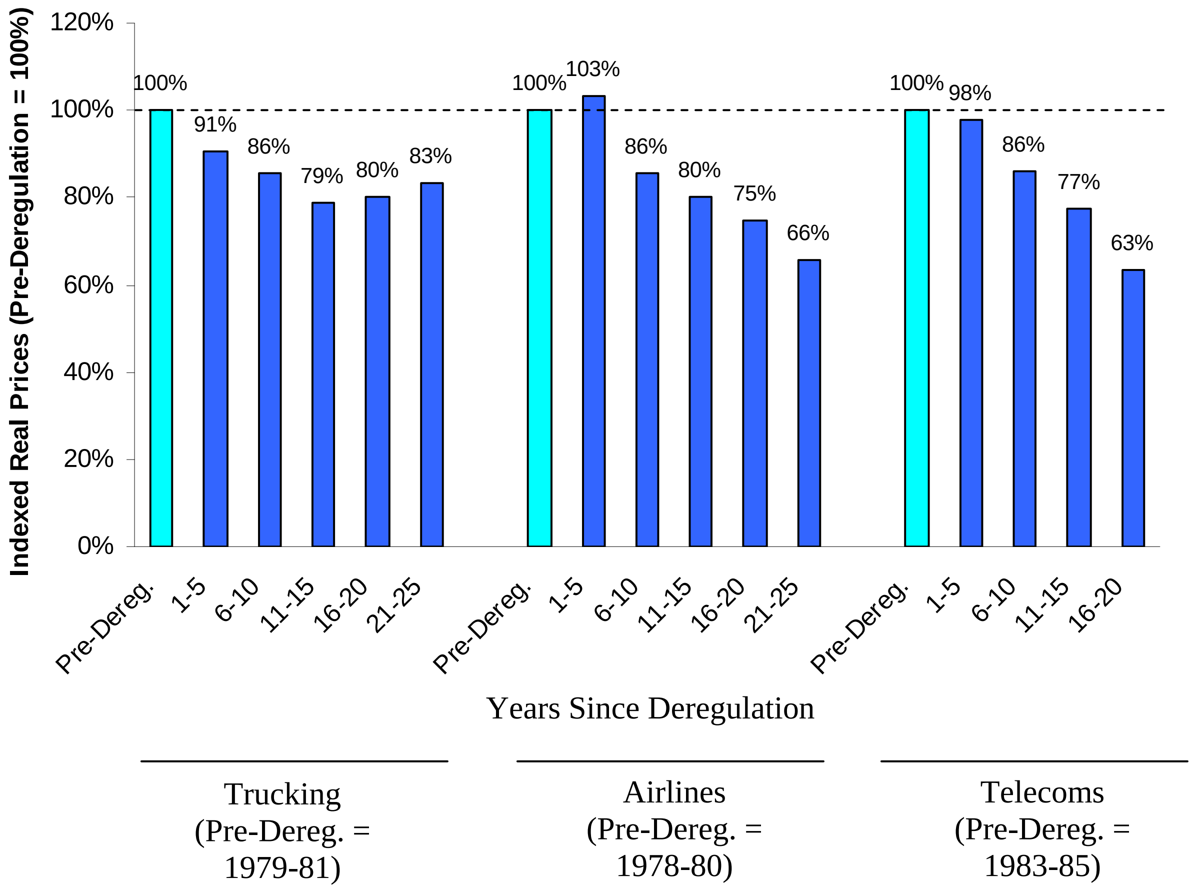
[126] Steven Strong, "Optimization Leads Quiet Revolution in Trucking," SupplyChainBrain.com, Global Logistics and Supply Chain Strategies, June 2001.

[127] A June 2006 report by the GAO concluded that "reregulation of airline entry and rates would not benefit consumers and the airline industry. Although some aspects of customer service might improve, reregulation would likely reverse many of the gains made by consumers, especially lower fares." (GAO, Airline Deregulation, 36.)

Figure 35 Post-deregulation Prices for the Trucking, Airline, and Telecommunications Industry



Source: Based on the U.S. Bureau of Economic Analysis Gross Domestic Product and Chained Price Indices by Industry, 1977-2006. See http://www.bea.gov/industry/gdpbyind_data.htm. Nominal prices are deflated using the GDP deflator.

As Figure 35 shows, the initial years after deregulation were not always marked by significant price declines, and certainly other external factors such as changes in input costs (e.g., fuel costs) or non-related changes in technology may affect overall price levels from one period to the next. However, as competition drove costs out of the system and the industry adjusted, sustained deep price declines were the norm in trucking, airlines, and telecoms. Given that competition in electricity has been a far less complete transition than these other industries and that electric generation construction and fuel costs have increased significantly in recent years, it is not surprising that the price benefits for electric consumers in the United States are harder to discern. Nonetheless, our expectation is that a competitive electricity market will show similar benefits over the long-term, provided competition is allowed to continue to develop.

V. Competition Will Provide a Better Path to Confront the Enormous Challenges Ahead

The experience of the 1970s and 1980s in the electric industry suggest that regulation is not well-equipped to navigate the industry's future challenges of the rising global cost of energy and environmental requirements. The more recent experience of the electric industry and those of other industries suggest, however, that competitive markets will provide a better path to confront the enormous challenges ahead.

A. Re-Regulation Will Not Fix the Perceived Problems

In response to the perceived problems associated with competition, some states are moving back toward regulation.[128] Some of this backpedaling, like re-regulation bills, is very direct. Other actions are more subtle: there are new efforts to pick the "right" generation technologies, to mix cost-of-service and market-based new construction, to establish "vintage pricing" with special higher pricing for new builds, and to rely on rate-funded, customer-guaranteed long-term contracts using an integrated resource planning process in an effort to stimulate new capital investment. All of these actions are forms of re-regulation that are not only intended to "fix" competitive pricing issues but also ensure that "enough" investment in new generation is made on a timely basis. Proponents of these initiatives argue that they are necessary to ensure adequate reliability, environmental compliance, fuel diversity, and even national security.

Some policymakers likely will try to characterize these efforts as a new, better form of regulation or a mix between regulation and competition. But these actions are nothing more than a return to the central planning of the past – the same central planning that tried to select the right amount and the right mix of technologies in the 1970s and failed. There is no reason to believe that this "new" least-cost planning approach will be more successful today. The inherent flaws, especially the underestimation and misallocation of risks, are still present. And, as before, customers will become responsible for inefficient choices and significant risks inherent in future electricity markets. Re-entry of regulated utilities into the generation business, whether through direct utility ownership or allowing utilities to enter into long-term contracts with new generators, is risky for customers. Either action is a centrally planned, ratepayer-funded approach to new generation that transfers risk from the developer and utility to the retail customer. Long-term contracts and/or investments increase the risk that costs will be above market, potentially for significant periods of time.

Further, re-entry of utilities into the generation business is incompatible with wholesale competition and will deter – and perhaps even eliminate – market-based entry of new generation. It is not likely that rate based investments could co-exist with competitive generation. The different risk profiles of rate-funded investments, compared to competitive investments, lead to more and earlier building under the regulated model. This occurs because investment decision rules for rate-funded new generation are less stringent than those for competitive generation – there is a lower investment "hurdle" for rate-funded

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[128] These efforts are particularly being made in states which made little effort to have retail competition at the residential level.

commitments than for competitive investment because the risks are shifted from the investor in generation to retail customers.[129] As a result, under most circumstances, a project will appear economic on a rate-funded basis before it would appear economic on a market-funded basis. So, under the utility procurement model, new rate-funded commitments will be made before new market commitments. Once these rate funded commitments are made, they serve to depress the visible forward price signals, and resulting market price expectations will be inadequate to bring forth investment on a competitive basis. Hence, the continuation of cost-of-service rate-making for generation – either with utility-owned generation or long-term contracts guaranteed by ratepayers – is a barrier to the emergence of a competitive market model. Therefore, both immediate re-regulation and gradual re-entry of regulated utilities into the generation business are likely to end up in the same place – that is, a *de facto* return to the regulatory decision-making of the 1970s that relied on a sluggish, administrative, command-and-control process to solve inherently risky resource allocation problems.

B. A Competitive Market Should Remain the Desired End State

Relying on markets to make investment decisions, rather than on central planning backed by ratepayer guarantees, is sound public policy. The industry must tackle an ongoing need for new generation investment to serve growing load, to replace its aging power plant fleet, and to achieve ambitious environmental objectives. Reliance on a well-structured competitive market model, in which end-use customers receive efficient price signals and do not assume long-term investment risks, and investors and market intermediaries actively manage such risks, will serve customers better in the long run.

Although relying on competitive markets is preferable to the traditional regulatory model, there is still a need for safeguards and regulatory oversight. In order for market-based pricing to result in an efficient and effective outcome, generation markets must be "workably" competitive. A well-structured competitive market model should include wholesale and retail competition, central energy markets using locational prices, non-discriminatory open-access transmission, and new generation built without utility long-term contracts or regulatory guarantees funded by ratepayers. In order to ensure non-discriminatory open access of the transmission system and to ensure that companies cannot exercise market power, regulators and/or system operators must monitor market activities to ensure a fair and level playing field. As competitive generation markets develop, federal and state actions have already been taken and continue to be improved upon to monitor electricity markets. These safeguards include: federal oversight of non-profit RTOs to ensure non-discriminatory open-access of the transmission system, state and federal oversight of market power and concentration (mergers, market price manipulation, etc.), state

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[129] Rate-funded projects typically evaluate, on a present value basis, the projected production cost savings from the project over its assumed operating life to the incremental capital or demand charge payment required. The discount rate used in this evaluation usually reflects the utility's cost of capital, which is typically lower than that used by a competitive developer. Competitive project evaluation incorporates a higher discount rate, or hurdle rate, and often a shorter payback period requirement, in recognition of the uncertainty of future market prices. While it may appear that the lower utility hurdle rate results in lower cost to consumers, this is not the case when the continued risks that consumers bear under that model are taken into consideration. A regulatory guarantee does not eliminate any of the risks associated with the generation asset; it merely shifts the risks from the investor to ratepayers.

certification/licensing of retail suppliers (e.g., rules governing communication and marketing practices, supplier credit requirements, state oversight of consumer protections and services including education, disconnection, low-income assistance, etc.), federal oversight of wholesale trade accounting, federal and state safety standards, federal and state environmental emission requirements, and so forth. These oversight and monitoring functions will likely be necessary for the foreseeable future and should not be ignored. Meanwhile, incidents of market abuses in relatively young markets should not be used as an excuse to return to the mistakes of the past. Nor should the unfavorable and unforeseen outcomes of certain negotiated transition plans or settlements that were used to "unwind" the regulatory past be relied upon to demonstrate the failure of competitive markets. Unfavorable and unforeseen outcomes are likely to occur in electricity markets that are inherently risky and mistakes will be made whether there is competition or regulation. Key questions for policymakers are who should pay for those mistakes – investors who make the decisions or ratepayers who have to live with the consequences of central planning – and which model is likely to respond more quickly to ever-changing market conditions. The authors of this paper believe that competitive markets allocate these risks more efficiently, and that the benefits of competition can be achieved while continuing to maintain or even enhance funding for public policy programs, such as low-income assistance, energy efficiency, and customer education.

We also believe that retail competition, if given a chance to develop, is likely to play a bigger role in the future and can reinforce competitive wholesale markets with market pricing and customer response. Many larger customers face market prices and have already switched to competitive suppliers. Utilities also need to establish retail prices at market levels for smaller customers still on default service, so that these customers can see the "true costs" (including environmental costs) of their consumption decisions. This transparency will become increasingly necessary as we strive to meet the challenges of climate change. Over time, competitive suppliers will be able to extend the benefits of value-added services to smaller customers, especially if improvements are made in market design, metering, communications, computer, and energy control technologies.

C. Embrace Electric Competition or It's Déjà Vu All Over Again

It has been said that those who cannot learn from history are doomed to repeat it.[130] Many states that have embarked on electric industry restructuring are at a turning point – trying to decide whether to go back to a regulatory model or move forward with restructuring. As Paul Joskow concluded:

> …the jury is still out on whether policymakers have the will to implement the necessary reforms effectively…Creating competitive wholesale markets that function well is a significant technical challenge and requires significant changes in industry structure and supporting institutional and regulatory governance arrangements. It requires a commitment by policymakers to do what is necessary to make it work…the revisionist history about the 'good

[130] Based on quote by George Santayana, a Spanish-born American author and philosopher. (*The Life of Reason*, *Vol. 1, Reason in Common Sense*, New York: Charles Scribner & Sons, 1905, 284.)

> old days of regulation' has conveniently ignored the $5,000/MW nuclear power plants, the 12 cents/kWh PURPA contracts, the wide variations across utilities in the construction costs and performance of their fossil plants, and the cross-subsidies buried in regulated tariffs that characterized the regulatory regimes in many states. As we look at the costs and benefits of competition we should not forget the many costly problems that arose under regulation.[131]

Either policymakers will take steps to facilitate competitive markets or they may find themselves – consciously or not – back in the 1970s. Under the latter scenario, we will be entrenched in a regulated model that requires utilities and regulators to make billions of dollars of resource choices in a centrally-planned manner supported by ratepayer money, while confronted with tremendous uncertainty about technology, carbon control, fuel prices and demand levels. Poised now at a point where generation supply must accommodate higher natural gas prices on the one hand and the need for carbon control on the other, it is critical to rely on the market to make choices about fuel type and technology for new investments and actively manage the associated risks. We do not need another round of regulated investments that later prove to be uneconomic and cost consumers billions of dollars.

The goal of policy changes should not be to attempt to reverse the impacts of the increased costs of producing electricity, but rather to focus on ways to improve future investment, operating and consumption decisions – that is, to increase efficiency and provide customers with a greater choice of products and services. This ultimately will produce lower costs for consumers. In order to achieve these efficiency benefits, the electricity industry should not repeat the mistakes of the past, but should instead embrace competition.

[131] Joskow, "Markets for Power in the United States: An Interim Assessment," 32-33.