NCEP Technical Appendix

Chapter 5: Strengthening Energy Supply Infrastructure

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U.S. ENERGY INFRASTRUCTURE:

Demand, Supply and Facility Siting

Report to the National Commission on Energy Policy

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Introduction

Virtually all of our primary energy sources require complex infrastructure to transform them into the right forms and deliver them to the right locations. Oil must be extracted, shipped, refined, and transported before it can be used as a transportation fuel. Natural gas, coal and oil must also be extracted, processed and transported before they can be burned for heating, industrial processes, and other end-use applications. These fuels (and others) must be converted at power plants into electricity and instantaneously moved on interconnected transmission and distribution grids in order to light streets and houses, or run our computers, appliances and telecommunication and information networks. Finally, we must have infrastructure to treat or dispose of the byproducts of energy supply and consumption in a manner that reduces the substantial short- and long-term risks they pose to public health and the environment. This underlying physical infrastructure – the facilities needed to extract, process, and transform primary energy sources into useful forms, to deliver it by pipe or transmission lines to end uses, and to address its public health and environmental risks – typically attracts far less public and political attention than the end-use price or the adequacy of supply at the source.

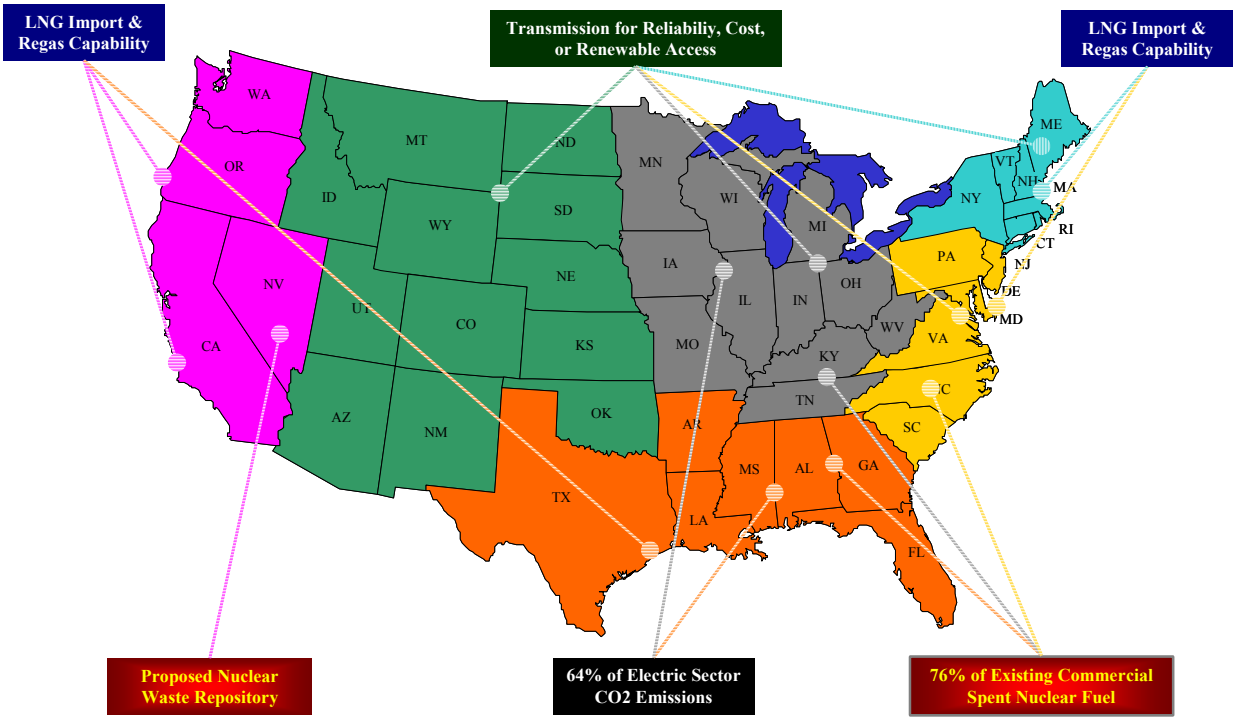
Yet the capacity and efficiency of our underlying "energy infrastructure" is vital to the reliable provision of end-use energy at acceptable costs. For example, the August 2003 power system blackout in the U.S. and Canada did not demonstrate the need for additional primary energy supply; it revealed weaknesses in the underlying electric infrastructure – in the hardware and procedures that comprise and govern operation of the electric transmission grid. Similarly, recent escalations in the price of natural gas do not only reflect the cyclical nature of the North American natural gas supply/demand balance, but also reveal weaknesses in underlying gas transport infrastructure – specifically, the physical and economic limitations on the capacity to process and transport abundant supplies from distant domestic and international sources to gas-consuming regions. A critical question facing the U.S. energy future relates to the adequacy of our underlying energy system infrastructure, and how to improve and expand this infrastructure in a manner deemed acceptable on economic, environmental, and public interest grounds.

A high-level review of regional forecasts of energy supply and demand identifies looming and potentially important deficiencies with respect to critical energy infrastructure of one form or another in virtually every major region of the U.S. Figure 1 highlights several examples of infrastructure needs across the country, including the need to add electric transmission capacity in the Northeast and MidWest to ensure reliability or reduce excessive wholesale costs due to existing transmission constraints; demand for gas pipeline and liquefied natural gas (LNG) import and regasification capacity, particularly along the East and West coasts and in the gulf, to increase accesss to world natural gas supplies; permanent or safe and secure interim storage capacity for the growing volumes of spent nuclear fuel and other high-level nuclear waste that are currently dispersed throughout the country, with particularly high concentrations in Mid-Atlantic and Gulf Coast states; and carbon sequestration capacity and/or carbon reduction policies to mitigate national greenhouse gas emissions, with over 60% of electricity sector CO_2 emissions emanating from generating capacity in the MidWest and Gulf Coast states.

While much needed energy infrastructure has been added in certain regions in the past several years, particularly with respect to electric generating capacity and natural gas pipelines, critical needs remain and there are numerous examples of abandoned projects, difficult and time-consuming infrastructure siting processes, and strong political opposition. These siting difficulties stem from the friction between a public that is increasingly unwilling to accept the construction of energy and other industrial infrastructure in their local communities, and the growing need to add critical energy infrastructure to meet business and consumer demands and minimize the potential rippling effect on other economic sectors of major infrastructure-related outages or losses.[1]

Figure 1
Energy Supply and Impact Infrastructure

ENERGY *SUPPLY* INFRASTRUCTURE NEEDS



ENERGY *IMPACT* INFRASTRUCTURE ISSUES

Large infrastructure projects can impose significant and lasting changes on the communities in which they are located, and these local impacts must be comprehensively reviewed and addressed – indeed, this is generally the intent and practice of most energy facility siting rules and procedures. On the other hand, energy facility siting procedures often overlook the broader

[1] Given the strong interdependencies between energy sectors and the dependence of major economic sectors on energy goods and services, major losses in one energy sector can have a cascading effect, with potentially significant economic consequences. See for example James Peerenboom, Ronald E. Fisher, Steven M. Rinaldi, and Terrence K. Kelly, *Studying the Chain Reaction*, Electric Perspectives, January/February 2002.

regional or national context – that is, the importance of energy infrastructure to meet regional and national reliability, economic and environmental needs. These factors also should be accurately assessed and recognized in local and state siting reviews. Historically, such consideration has been limited by legal or jurisdictional barriers, the lack of an organized or convincing demonstration of the regional context in state or local siting reviews, and/or real or perceived conflicts between regional infrastructure needs and state economic or environmental interests. On a going-forward basis, as the coordination between and interdependence of all U.S. states and regions grow with respect to energy supply, delivery and market structures, so must the ability to incorporate regional and national perspectives and needs in the context of state and local siting procedures. In effect, there needs to be a better understanding of energy infrastructure issues as one of "common interests and equal burdens."

This report reviews the status of regional needs to site critical energy infrastructure to meet the public's need for reliable and affordable sources of energy, and examples of the difficulties of meeting these needs given local concerns over the impact of infrastructure build-out on the quality of life in the cities and towns in which infrastructure would be located. Specifically identified are several examples of critical energy infrastructure requirements across the country – ones that can be viewed as necessary to support regional reliability and economic goals, but whose benefits do not necessarily accrue to any significant extent in the local communities that would be affected by their construction. The report presents the features and experiences of state and federal siting processes that have, to varying degrees of success, resulted in the siting of needed infrastructure, and considers the applicability of these procedures to the task of meeting the infrastructure needs identified in this report. Finally, based on this review, recommendations are provided to better reconcile potential conflicts between local and regional needs, and improve the likelihood that critical energy infrastructure can be sited in the future.

US Energy Infrastructure Needs

The discussion of critical energy infrastructure is divided into four categories: electricity, natural gas, oil, and impact mitigation.[2] Electricity infrastructure includes the power plants used to convert primary fuel sources into electricity, and the transmission infrastructure required to transport generated electricity to end users. Natural gas infrastructure includes pipeline systems to move gas within North America, gas storage, LNG import facilities, and liquefaction and regasification capacity. Oil infrastructure includes import facilities, continental pipeline transport, and refinery capacity. Finally, impact risk mitigation refers to the capacity to securely store, dispose of, or otherwise mitigate the two major sources of potential long-term public health and environmental hazards associated with energy supply and consumption: high level nuclear waste (including spent nuclear fuel), and emissions of carbon dioxide and other greenhouse gases.

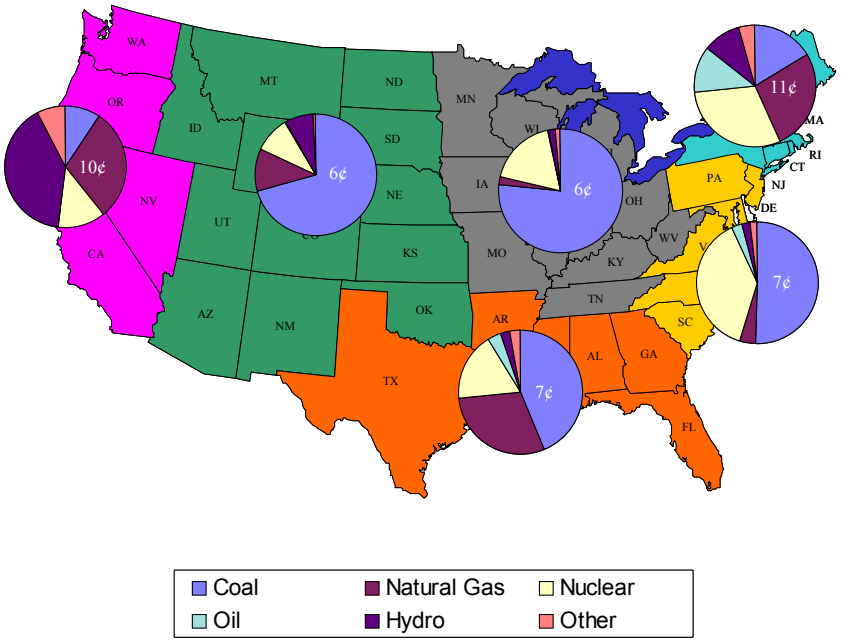
[2] These sectors were selected for review because each requires major investments in and construction of infrastructure, as a group they contain a broad spectrum of the energy goods and services used to meet the energy needs of U.S. residential, commercial, industrial and transportation sectors, and they are responsible for or address a majority of the most difficult and potentially dangerous long-term impacts of energy supply and use.

Electricity

The two major categories of energy infrastructure unique to electricity are electric generating capacity and high-voltage transmission lines.[3] Electric generating capacity infrastructure must be both adequate (in absolute MW capacity terms) and diverse (in size, location, and fuel source) in order to meet customer needs at the lowest cost possible, and to have in place sufficient generating reserves to meet aggregate electricity demand and energy requirements under realistic combinations of scheduled and unscheduled generating capacity outages.

The most significant infrastructure challenge related to electric generating capacity is the development, siting and construction of power plants in amounts and locations suitable to the meet regional demands for electricity. While to some extent within a region the configuration of the transmission system provides flexibility with respect to generating facility size and location, this flexibility is not absolute – the maintenance of adequate system voltage, system stability and system recovery (in the event of an outage) favors the siting of generating capacity in proximity to electrical load. In addition, it is important for economic and reliability reasons to maintain a degree of size and fuel source diversity among the generating resources within a region. Nonetheless, the primary influence on the selected fuel source for proposed generation facilities historically has been driven mostly by project economics, which is in turn influenced by technology design, timing, relative fuel prices, regional fuel supply constraints, and the availability of suitable and economic facility site options. This mix of factors,

Figure 2
Electricity Fuel Mix and Price by Major U.S. Region, 2003



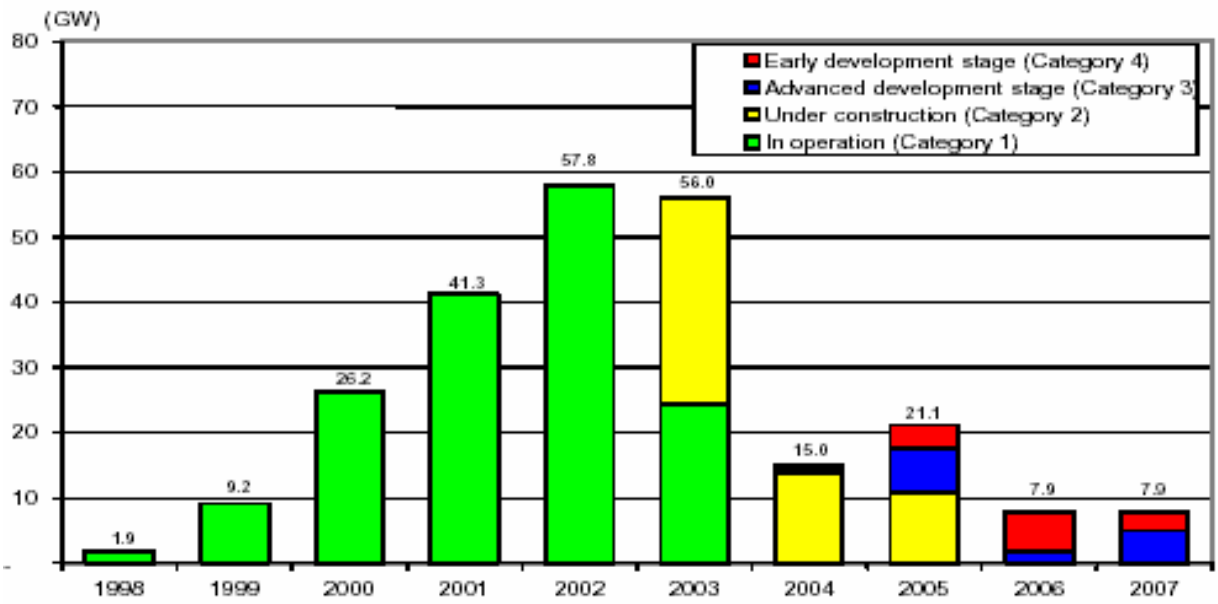
Sources: EIA, *Historical 1990 through Current Month Retail Sales, Revenues, and Average Retail Price of Electricity by State and by Sector* (http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls); and Platts BaseCase database.

[3] The production of electricity requires infrastructure that spans several of the categories reviewed in this report, including (in addition to generating and transmission capacity) the extraction and transport of all primary fuels used in electricity generation, and mitigation of the impacts associated with nuclear and fossil-fuel power plant operations. However, for ease of presentation, infrastructure issues associated with the delivery of natural gas – including to end-use customers as well as power plants – is discussed in a separate section (Natural Gas), as is the contribution of electricity generation to the production of carbon dioxide and high-level nuclear wastes (Impact Mitigation).

their variability by geographic region, and their evolution over time, has led to significant national variations in the mix of fuel types for generating capacity across the US, and the resulting average prices for generation over time. Figure 2 portrays the variation in the fuel mix and price for electricity generation by region of the country.

The siting of electric generating capacity can be difficult and controversial. However, in several regions of the U.S. significant additional generation capacity has been developed and constructed in the past several years. Specifically, the North American Electric Reliability Council (NERC) reports the addition of well over 100 gigawatts (GW) of new, mostly gas-fired, electric generation capacity in the U.S. since 1998, with over half that amount again in the construction or development phase (see Figure 3). With the current and expected capacity additions, there will be adequate capacity to meet projected electricity demands through 2007, and there should be adequate capacity through 2012 provided the projected new capacity in development comes to fruition.[4] While the overall status of generation adequacy for the U.S. is not necessarily the same as individual regions' abilities to meet electricity demands, the NERC data reveals that only one region (SERC, at 13%) is projected to have a reserve margin below 15% in the year 2008.

Figure 3
New Gas-Fired Turbine Capacity by Year and Development Status



Source: NERC, *Reliability Assessment, 2003 – 2012*, December 2003 at 5.

The other major category of electricity infrastructure is high-voltage transmission. High voltage transmission capacity must be configured and operated to maintain regional bulk power system stability and ensure that customer load is met under conditions involving plausible failures of generation and transmission system components (e.g., loss of major transmission lines or generating units). In this and other ways, generating capacity needs and transmission capacity needs are to a large degree interdependent. Typically, generating capacity location influences the development and operation of transmission capacity, and new generating units can not be

[4] NERC at 5-6.

interconnected with the high-voltage transmission system in a region without demonstrating that the interconnection will not reduce the operating stability of the system. Obtaining this demonstration often requires transmission system upgrades at least near the point of interconnection. Similarly, inadequate operation or development of transmission system infrastructure can limit the ability to offer generation output in regional markets, reducing the economy of system operation and, in some regions, increasing the environmental impact associated with meeting customer needs.[5] Combined, the growth in generation and transmission capacity has been the primary determinant of whether reliable and affordable electricity is available to meet the growing needs of consumers and businesses within regions, states, and electrical sub-regions (or "load zones").

While recent development of new power plants in most regions of the country suggest an adequate level of generating capacity relative to electrical load, it is far less obvious that regional transmission infrastructure will be adequate to deliver generation from source to end use reliably or economically. Recent analysis indicates that the transmission infrastructure in the country may be weakening, particularly from the perspective of keeping up with electrical demand (and by extension, the growth in generating capacity). For example, in reviewing transmission investment and growth in the quantity of transmission infrastructure, Hirst has found that since 1982, and projected through 2012, growth in transmission capacity has declined (and will continue to decline) relative to the level of peak electrical demand.[6] Further, Hirst notes that even where there currently is transmission investment, very few proposals are moving forward with the exception of those related to local reinforcements or interconnections for new generation facilities.[7]

Similarly, a May 2002 study of the U.S. transmission system by the U.S. Department of Energy concluded that declining transmission system investments and deteriorating infrastructure, combined with growing electricity demand, were creating regional bottlenecks in transmission that significantly decrease reliability, impair wholesale electric competition, increase consumer prices, and increase system vulnerability.[8] DOE's analysis identified numerous existing transmission constraints and estimated the cost to consumers from the congestion associated with these constraints in the hundreds of millions of dollars.[9]

NERC has also concluded that as customer demand increases and transmission systems experience increased power transfers, portions of regional transmission systems are reaching their reliability limits and, even where systems are operating reliably, portions of the grid will not be able to transmit new unit generation to target markets.[10] NERC suggests that the lagging

[5] Potential environmental impacts associated with transmission system limitations come in at least two forms. First, the siting of renewable resources, particularly wind generation capacity, can be geographically limited to sites with favorable physical characteristics. To the extent these locations are on the "wrong" side of constrained transmission interfaces, or distant from load-consuming regions (as is the case for wind potential in Maine and the upper Midwest), inadequate transmission infrastructure can limit access to regional energy and capacity markets, reducing or eliminating project profitability. Second, transmission constraints can limit the ability of new, regional gas-fired capacity to displace generation from higher-emission gas, oil and coal generation located within transmission-constrained load pockets.
[6] Eric Hirst, *U.S. Transmission Capacity: Current Status and Future Prospects*, June 2004 (Hirst) at v.
[7] Hirst at 1.
[8] U.S. Department of Energy, *National Transmission Grid Study*, May 2002 (DOE) at 25.
[9] DOE at iii.
[10] NERC at 5.

pace of transmission investment is due to the existence of viable alternatives and public, regulatory and financial obstacles to the construction of new transmission facilities.[11] In the absence of additional investments, reliability coordinators have needed to rely more and more on generation redispatch through either locational marginal pricing or NERC transmission loading relief (TLR) procedures to control the flow on the system within operating reliability limits.[12]

In light of this trend and as a result of transmission reliability analyses, NERC and/or the regional NERC councils have identified at least the following critical transmission infrastructure projects that need to be developed to maintain system reliability over time, and/or to reduce or eliminate the growing cost impact on electricity prices of regionally-specific transmission constraints. Some of these examples are proposed projects that are under way or that expect to be completed in time to meet regional needs, while others are currently delayed by regulatory proceedings, a lack of clear regional transmission planning, and/or cost allocation review procedures.[13]

1) Connecticut to Long Island Cross-Sound Cable
2) ATC Minnesota – Wisconsin (MAIN – MAPP) 345 kV line
3) PG&E/WAPA Path 15 California reinforcement upgrade
4) Southwest Connecticut 345 kV loop
5) ERCOT Dallas-Fort Worth and Houston transmission constraints

Natural Gas

Historically, the U.S. has relied primarily on North American sources for natural gas supply, transported over a growing Canadian and U.S. interstate gas pipeline system to consuming markets that are generally distant from the supply sources. Within consuming regions, pipeline delivery capacity, supplemented by underground and above-ground gas and LNG storage, must be adequate to meet customer needs under regional peak demand conditions. In addition to meeting regional peak demands, the diversity of a consuming region's natural gas supply sources and delivery and storage capacity affect the region's exposure to additional gas transportation costs and gas price volatility. Consequently, pipeline capacity, LNG import (and regasification) capacity, and storage capacity represent the infrastructure required to meet natural gas demand in the U.S.

Demand for natural gas is growing, particularly in the electric generation sector, yet traditional North American sources for natural gas are in decline. EIA projects the demand for natural gas in the U.S. to increase at an average annual rate of 1.4%, from 22.8 trillion cubic feet (Tcf) in 2002 to 31.4 Tcf in 2025.[14] Much of this projected growth is due to increasing use for electricity generation.[15] However, from the perspective of the natural gas infrastructure required to meet

[11] NERC at 10.
[12] NERC at 34-35. For example, NERC's data indicate a "troubling" increase since 2000 in the number of TLRs called at level 5 or higher, the point at which firm transactions are cancelled.
[13] While these represent a set of projects identified by NERC and/or regional councils, it is not meant to represent a complete list of economic- or reliability-related transmission issues facing NERC regions at this time.
[14] U.S. Energy Information Administration, *Annual Energy Outlook 2004*, January 2004 (AEO 2004) at 4.
[15] EIA projects the contribution of natural gas to U.S. electricity generation to increase from 18% in 2002 to 22% in 2025. AEO 2004, at 4-6.

this growing demand, the most significant recent changes in EIA's outlook for natural gas relate to the decline in projected continental natural gas supply over the forecast horizon. Based on current data, the projection for conventional onshore gas is now lower due to decreases in expected reserve growth and new discoveries, and increases in projected exploration and development costs.[16] Specifically, EIA now projects the natural gas reserves added per well drilled to be 30% lower than the same projection made in 2003 for the mid-continent and Southwest regions. Domestic natural gas production in 2025 is now projected to be 24.1 Tcf, a decrease of 2.7 Tcf, or more than 10%, from the same projection a year ago.

Unfortunately, the outlook is not much better for our other major source of natural gas supply – Canada. Net imports from Canada are projected to remain at the 2002 level (2.6 Tcf) through 2010, and then decline to 2.6 Tcf in 2025. This is sharply lower than EIA's forecast from a year ago, which amounted to nearly twice this level of imports from Canada in 2025. The lower forecast primarily reflects reduced production expectations.[17]

Table 1
U.S. Natural Gas Supply and Demand (Tcf)
Source: EIA AEO 2004

	2002	2010	2015	2020	2025	Avg. Annual Change
Production	19.1	20.6	21.7	23.9	24.1	1.0%
Consumption	22.8	26.2	28.0	30.4	31.4	3.2%
Net Imports	3.5	5.5	6.2	6.5	7.2	1.4%

Combined, then, AEO 2004 projects a sharply increasing demand for natural gas in the U.S. electricity sector, as well as consumption growth in other sectors, and a dwindling level of productivity from U.S. and Canadian sources (see Table 1). This will result in an increasing domestic supply/demand deficit, a deficit that will need to be made up by a combination of greater production from unconventional (and more costly) continental sources, additional imports from LNG, or both.

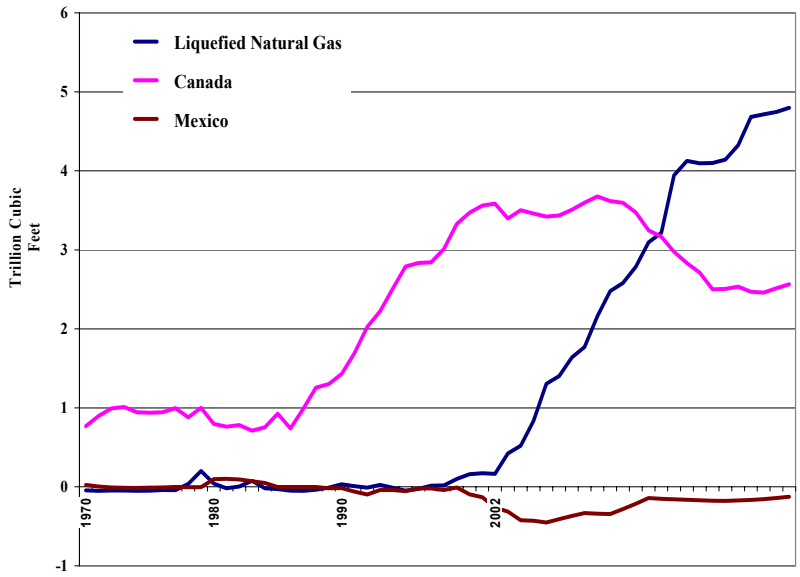
While global natural gas reserves are abundant, the capacity to process and transport these supplies from source countries to world markets remains relatively weak, the demand for these resources outside the U.S. is growing, and the capacity within the U.S. to import these sources through LNG import facilities is underdeveloped. These factors, combined with the projected growing deficit between natural gas demand and North American sources, highlight the long-term need for development of LNG infrastructure. Indeed, EIA forecasts that much or most of the growing demand in the U.S. will have to be met by LNG imports through the addition of new LNG terminals and an expansion of existing ones, in total capable of increasing LNG imports from 0.2 Tcf in 2002 to 4.8 Tcf in 2025; this is more than double the projected contribution from LNG in 2025 presented in the AEO2003 forecast.[18] See Figure 4. The ultimate level of contribution needed from LNG will also be influenced by the level and cost of additional development in "frontier" regions in continental North America, such as parts of the Rockies,

[16] AEO 2004 at 7.
[17] AEO 2004 at 8.
[18] AEO 2004 at 8.

deepwater offshore supplies, Alaska, and the Mackenzie Delta; estimates of the contribution from these sources are as high as over 10 Tcf/year by 2020.[19]

In light of these fundamental data with respect to U.S. projected natural gas demand and supply, it appears that development of additional LNG import and regasification capacity will be critical to meet demand and to mitigate potential price increases associated with the growing difficulty and cost associated with maintaining current North American supplies in the long term. In addition, it is likely that more pipeline infrastructure will be needed to increase delivery from existing continental sources, and to support transport of gas supplies from new LNG import locations and/or remote frontier regions.

Figure 4
U.S. Net Imports of Natural Gas By Source



Source: AEO 2004 at 91

While LNG appears critical in the long term, in the near term natural gas infrastructure needs may be driven more by regional requirements tied to regional supply/demand balances, pipeline delivery infrastructure, and storage capacity. In some regions, recent demand growth – particularly in the electric sector – has stretched existing gas supply infrastructure to its limits, and has led to the rapid development of additional pipeline capacity and import/storage infrastructure. New England is an excellent example of recent rapid growth in demand and the need for significant additional infrastructure to meet that demand, since the region has no indigenous sources of natural gas and virtually no below-ground gas storage potential. Yet since 1998, electric power companies have added 23 new power plants in New England, representing over 9,000 megawatts (MW) of new summertime generating capability in the New England electricity market. All of this new electric generation capacity in New England is fired by natural gas – primarily on a single-fuel basis. Additional generating capacity is expected to be added to meet the region's peak demand over the next several years, and most of this new capacity will also likely be natural-gas-fired.

In response to the rapid growth in demand for natural gas, New England's gas supply quantities, supply alternatives, and peak-day delivery capability have increased substantially with the introduction of several new infrastructure projects that have entered operation or soon will do so. New pipeline infrastructure has improved access to supplies from the newly-developed natural

[19] Energy and Environmental Analysis, *An Updated Assessment of Pipeline and Storage Infrastructure for the North American Gas Market*, Prepared for the INGAA Foundation, June 2004 at 6.

gas fields in Eastern Canada and from the Gulf Coast, and other projects have added LNG storage and sendout capacity, increasing the region's daily gas sendout capability by approximately 5 billion cubic feet. Yet it recent experience demonstrates that additional sources and infrastructure will be needed. Due to extremely cold temperatures, at the time of the 2004 winter peak *less than half* of the capacity of New England gas-fired electricity generators was available, due primarily to fuel availability problems associated with gas supply curtailment actions taken by gas pipeline operators. Combined with record wintertime electricity demand levels, the regional system operator was forced to rely upon emergency operating procedures to address regional electrical capacity deficiency issues.[20]

In light of the projections of electric sector and other demand growth, and the longer-term picture with respect to natural gas supply and demand, many analysts suggest that an expedited build-up of additional natural gas infrastructure is required, focusing on at least the following infrastructure projects. Some of these examples are proposed projects that are under way or that expect to be completed in time to meet regional needs, while others are currently delayed by regulatory proceedings, or local security or safety concerns.[21]

6) LNG Import and Regasification Capacity on the East and West Coasts
7) Islander East
8) Rockies
9) Alaska Natural Gas Pipeline

Petroleum

The importance of transportation fuel to the U.S. economy is self evident, and refinery capacity is the most important component of transportation fuel infrastructure. U.S. crude oil imports have increased over time from approximately 20 percent of national consumption in 1970 to 55 percent in 2000, and this trend is expected to continue, with U.S. imports approaching 70 percent by 2025.[22] While we rely to a great extent on imports to meet crude oil needs, the U.S. has historically been one of the world's largest petroleum refiners (the largest, in fact, until 2001), and has consistently met the majority of domestic refinement needs. The U.S. benefits from domestic refinery capacity in part by being able to facilitate production of the forms of refined petroleum products needed to meet various needs, demands and fuel quality/emission standards; to maintain independence with respect to this portion of the transportation fuel supply chain; and to control refined product costs.

However, no new refineries have been built in the U.S. since the 1970s, and the quantity of refined petroleum products imported into the U.S. from other countries has grown significantly in the past ten years. Since 1970s, the number of operating U.S. refineries has decreased by approximately half, but the total operable capacity remains roughly the same due to increased capacity at remaining refineries. Further, over the past decade the operating rate of operable

[20] ISO New England, *Interim Report on Electricity Supply Conditions in New England During the January 14-16, 2004 "Cold Snap"* May 10, 2004, at 1-2, 13.
[21] While these represent a set of projects identified by several parties, it is not meant to represent a complete list of economic- or reliability-related natural gas infrastructure projects warranted at this time.
[22] Guy Caruso, US Energy Information Administration, *Outlook for Natural Gas and Petroleum*, presentation to the IOGCC Conference, Williamsburg Virginia, August 2003 (corrected version).

refineries has increased to nearly 95% as demand has grown. Thus, the number of refineries in the U.S. is down, and opportunities to increase operable capacity and annual output are diminishing. These factors raise questions about the adequacy of U.S. domestic refinery capacity, and whether additional capacity is needed to meet the country's growing need for affordable and environmentally-preferable refined petroleum products, or whether international refinery capacity will expand to meet these needs in an economic fashion. EIA projects that by 2025, the U.S. will need an additional 7 million barrels per day due to projected increases primarily in transportation demand.[23] If domestic refineries are used to supply this need, this will require a significant increase in U.S. refinery capacity. Whether the national interest dictates that steps should be taken to facilitate the addition of domestic refinery capacity depends on a combination of cost, security, reliability and environmental factors, and on the interest of international sources to produce refined petroleum products that meet U.S. quality and environmental specifications.

Impact Risk Mitigation

No assessment of long-term energy infrastructure needs would be complete without acknowledging the impacts and risks of energy production and use on public health and the environment, or without consideration of the infrastructure that has been required, and will be required, to eliminate or reduce these impacts and risks to levels deemed acceptable by the public and policy makers. In this sense, *impact mitigation* infrastructure is not the same as the *supply* infrastructure discussed in previous sections – that is, it is not required to obtain primary energy sources, to convert them into useful forms, or to transport or deliver them to end uses. Instead, it is required to prevent or address the byproducts of energy supply and conversion, in order to minimize their impacts on individuals and environmental systems.

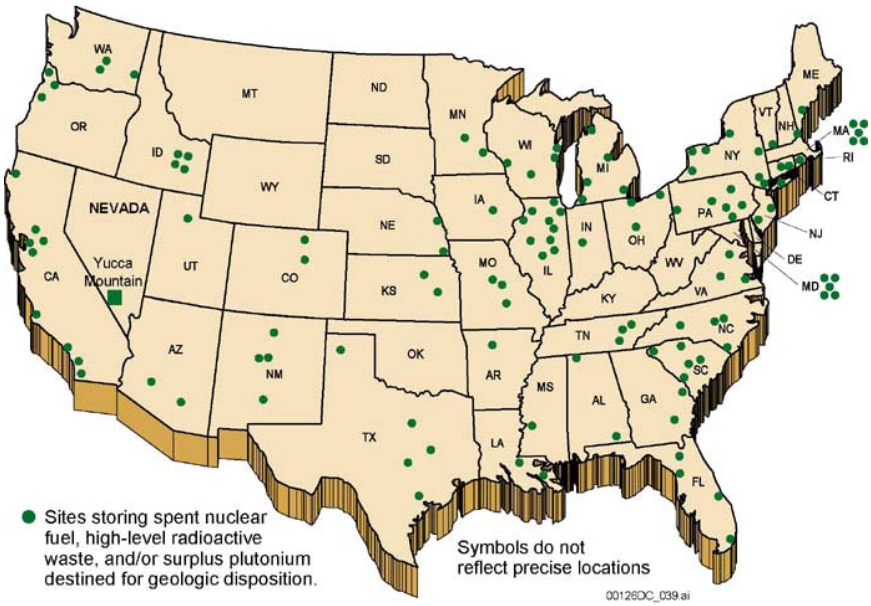
In virtually every energy sector, local, state and federal public health and environmental requirements to reduce or eliminate emissions of criteria air pollutants and liquid and solid wastes from energy supply and use have driven the development of pollution-control infrastructure at every stage of the energy cycle – including resource extraction and processing, combustion/operation, transport/delivery, and effluent treatment and disposal. The technology requirements and infrastructure to mitigate known public health and environmental impacts are diverse, including: minimum design specifications for energy technologies; standards for the treatment of fuel and water inputs; combustion controls; air, liquid and solid effluent capture, processing, and reduction technologies; and procedures and standards for the disposal of process effluents.

Despite the widespread development of this infrastructure, there remain two energy impact/risk categories – high level nuclear waste (including spent nuclear fuel) and emissions of carbon dioxide and other greenhouse gases – that are qualitatively different than others, and whose solution has been and promises to continue to be significantly more difficult than others in several ways. First, the risks associated with spent nuclear fuel and climate change are

[23] Joanne Shore and John Hackworth, Energy Information Administration, *Challenging Times for Making Refinery Capacity Decisions*, Presentation to NPRA Annual Meeting, March 2004.

characterized by potentially extreme consequences,[24] but the probability, timing, magnitude and location of these impacts remain highly uncertain and controversial. Second, the magnitude of each risk to some extent does and will continue to influence the magnitude of the other – that is, without major technological breakthroughs in alternative resources, meeting global electricity demand growth over the next half century will almost certainly require *major and increasing* contributions from nuclear generation, coal (and other fossil-fuel) generation, or both. Substituting nuclear generation for that of coal due to concerns over climate change risks would amplify the need to address the proliferation, public health, security and environmental risks associated with increased volumes of spent nuclear fuel; substituting coal generation for that of nuclear in order to reduce HLNW burdens would magnify the risks associated with climate change impacts. Third, the risks introduced by the generation of spent nuclear fuel and carbon dioxide are associated with impacts that would mostly be felt geographically and temporally distant from the source of the effluents. Finally, there is a high degree of irreversibility: once spent fuel is generated or carbon dioxide is emitted, they – and their potential impacts – persist for a *very* long time, from hundreds to many thousands of years. Thus addressing these risks requires not only establishing the appropriate control or mitigation infrastructure and institutions, but also maintaining the effectiveness of these infrastructures and institutions for centuries or longer.

Figure 5
Locations of HLNW Destined for Geologic Disposal



Source: US DOE Office of Civilian Radioactive Waste Management
http://www.ocrwm.doe.gov/newsroom/photos/photos_natlmap.shtml

With respect to HLNW, most countries faced with the need to safely and securely treat and/or dispose of it have pursued deep geologic disposal of the waste, to permanently isolate it for as long as is necessary in order to avoid unacceptable public exposure to the associated radiation, and to keep it out of the hands of those who would use it for malicious intent. Within the U.S., for decades this effort has included extensive engineering analysis, regulatory review, and political and legal efforts to establish a deep geologic repository at Yucca Mountain, Nevada. Establishing a permanent deep geologic repository remains the first and most important legal and engineering step in creating the infrastructure to process, transport, and dispose of HLNW. Under current regulations, Yucca Mountain could accept up to 70,000 metric tons (MT) of spent fuel equivalent, significantly less than the estimated 105,000 MT quantity

[24] Including the proliferation and potential use of nuclear weapons; the diversion of intensely radioactive material for malicious intent; the accidental release of HLNW; and the severe global economic, public health and environmental impacts possible under plausible climate change scenarios.

expected, at a minimum, to result from the current fleet of U.S. nuclear reactors.[25] The majority of existing spent nuclear fuel resides in states along the coasts and in the upper Midwest. See Figure 5.

There are at least two implications of the history and status of U.S. efforts to site a HLNW repository at Yucca Mountain. First, our inability to date to successfully develop Yucca Mountain (or any alternative permanent or temporary retrievable disposal location or option) means there continues to be a large and growing quantity of highly radioactive spent fuel dispersed throughout the country, with its attendant safety, security and proliferation risks.[26] Second, absent a change in the legal limit of Yucca Mountain to increase the allowed HLNW disposal capacity, or a breakthrough in the development of politically- and economically-acceptable alternatives to the current design for deep geologic disposal of HLNW, a repository at Yucca Mountain would not be sufficient to accept even the spent fuel and other high-level nuclear waste that will ultimately generated by existing commercial nuclear reactors in the U.S. This fact, along with the possibility of realizing quantities of HLNW exceeding current expectations (due to additional life extensions at existing plants or the construction of new nuclear facilities in the future), means that the legal, political and engineering efforts to find locations for deep geologic disposal in the U.S. are unlikely to end with the Yucca Mountain process.[27] The existence of unsecured waste and the continued difficulties with the Yucca Mountain proposal and siting process add urgency to the need to complete the Yucca Mountain evaluation, and to consider the need for additional HLNW storage and disposal infrastructure to accommodate the waste associated with current and future nuclear generation.

Equally daunting to many are the risks associated with failing to achieve stabilization of greenhouse gas concentrations over the next century. Some suggest that in order to avoid serious, widespread damages associated with climate change, concentrations need to be stabilized at or below 450 ppm.[28] It is certain that governments, energy industries, public interest organizations and others will continue to debate what the ultimate stabilization goal should be, and by when it should be achieved. In the meantime, at current emission rates we are quickly using up the existing slack in the carbon "budget" – the remaining quantity of carbon that can be emitted and still achieve proposed concentration targets. See Figure 6.

[25] Ansolabehere, Stephen, John Deutch, Michael Driscoll, Paul E. Gray, John P. Holdren, Paul L. Joskow, Richard K. Lester, Ernest J. Moniz, Neil E. Todreas, and Eric S. Beckjord, *The Future of Nuclear Power*, An Interdisciplinary MIT Study (MIT Study), 2003, Chapter 7, Endnote 12, page 63.

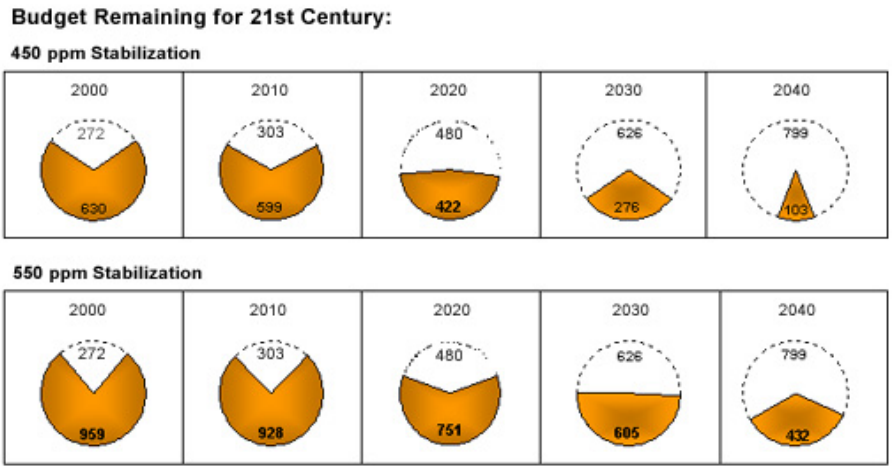
[26] The difficulties experienced to-date in the U.S. is mirrored in the efforts of other countries' efforts to develop HLNW disposal programs. Specifically, more than 40 years after the first commercial nuclear reactor began operation, no country has succeeded in the disposal of HLNW. See MIT Study at 53.

[27] The MIT Study estimates that growth in nuclear generation in the U.S. could lead to significant additional quantities of HLNW. For example, a three-fold increase in U.S. nuclear generating capacity would require the addition of HLNW storage capacity equal to Yucca Mountain every 12 years, or every 25 years if one assumes the estimated physical storage capacity of Yucca Mountain rather than the current legal limit of 70,000 MT. MIT Study at 61.

[28] Testimony of David Hawkins before the U.S. Senate Committee on Environment & Public Works, June 12, 2002 ("Hawkins").

The task of climate stabilization does not seem daunting from the perspective of our technical ability to achieve it, through combinations of increasing fuel efficiency in transportation, electricity generation and all other consuming sectors; accelerated deployment of non- or low-carbon energy technologies; reduction in deforestation activities; and the development of secure and permanent sequestration of carbon dioxide emissions. Rather, it seems daunting when considering the fundamental role that carbon-emitting technologies play in virtually every aspect of countries' economies and peoples' lives, and the potential costs that could be incurred to meet climate stabilization targets.

Figure 6
Projected World Carbon Budget

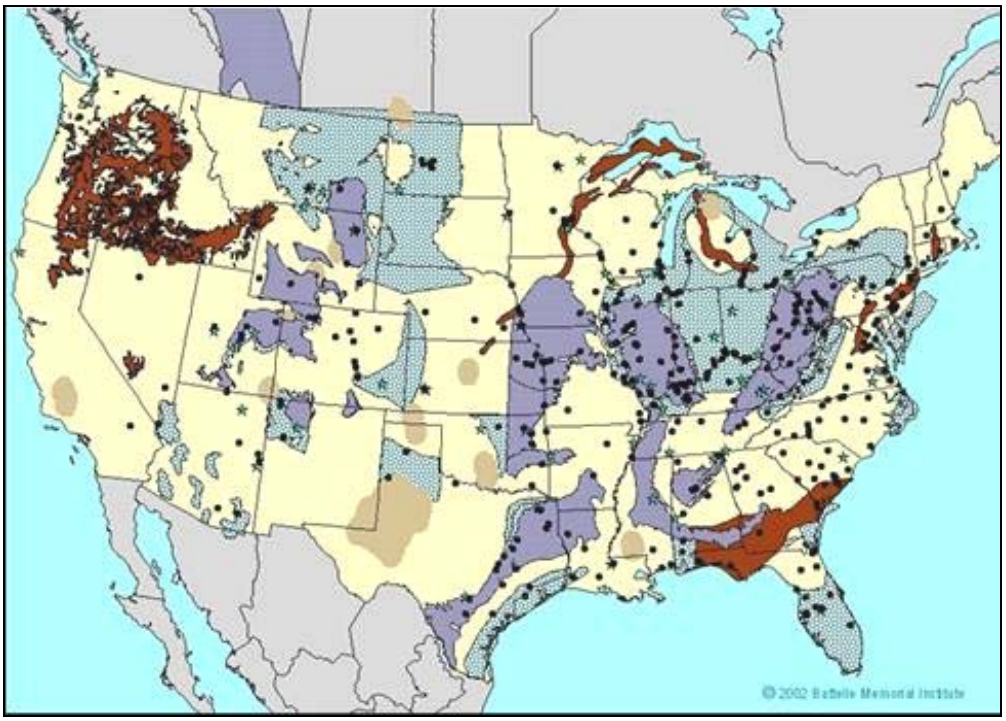


Source: Hawkins

Geologic sequestration of carbon dioxide in underground formations such as depleted oil and gas reservoirs, unmineable coal seams, and deep rock formations is being pursued in many countries as an infrastructure approach that could provide a potentially large and economic net reduction of CO_2 emissions. In the U.S., geologic sequestration site options are found across the country (see Figure 7), with many located close to areas of high coal resources plant generating capacity. Drawing on energy industry knowledge and experience related to geologic formations, gas extraction and injection practices and technologies, and gas pipeline transport, the development and siting of needed infrastructure for carbon sequestration may be a relatively straightforward and potentially quick effort. Given these attributes and its potential value as a net carbon-reduction activity, the development of carbon sequestration infrastructure should be viewed as an important national energy infrastructure priority.

The magnitude of the risks associated with the production of long-lived HLNW and greenhouse gases from energy production and consumption activities and the apparent long-term dependence of our economies and well-being on increasing fossil and/or nuclear generation highlight the critical national importance of developing infrastructure and/or policies to address these impacts as soon as possible, and the need to include consideration of impact mitigation infrastructure as a key consideration in any long-term energy strategy. In the near term, the specific focus of these efforts should include finalization of the Yucca Mountain repository siting review for HLNW, and accelerated research to determine the potential magnitude, feasibility and cost of sequestering carbon in geologic formations.

Figure 7
Location of Geologic Formations Potentially Suitable for Geologic Carbon Sequestration



- **Red**: Basalt Formations; **Beige**: Enhanced Oil Recovery Sites
- **Purple**: Unmineable Coal Seams; **Blue**: Brine Formations

Source: US DOE MRCSP Website; from JJ Dooley. "Clean, Affordable, Secure Energy for a Carbon-Constrained World." Strategic Initiatives for Coal and Power, US Department of Energy, Office of Fossil Energy. Wye Plantation, MD. PNNL-SA-37737. December 2002.

Energy Infrastructure Siting

The trends in energy demand and the status of underlying infrastructure discussed in the previous section suggest that the siting of additional energy infrastructure may be needed in virtually every region of the U.S. In several regions, many infrastructure projects have successfully gone forward in recent years when market conditions presented opportunities, particularly with respect to development of electric generating facilities and upgrades to natural gas pipelines. Yet it is also true that other recent efforts to site certain needed infrastructure projects have been frustrated by a decrease in usable and affordable land for siting infrastructure, an increase in the proximity of needed infrastructure to populations, and a concomitant increase in the level and organization of local and state opposition to infrastructure projects. Local residents and officials will typically oppose the siting of power plants or electric/gas transmission projects in their communities despite convincing demonstrations that the project (1) would improve system reliability; (2) would lower prices; and (3) would provide net environmental benefits by displacing generation from older, less efficient fossil fuel plants with significantly higher per-unit emissions of air pollutants and liquid and/or solid waste. Experience has shown that regardless the category of infrastructure, and even when the regional or national benefits are well understood, facility siting opposition is almost universally driven by concern over the impacts on local residents. In effect, local residents are more often than not unwilling accept what are perceived as significant impacts on their community and way of life in order to provide cost, reliability and environmental benefits to regional or national populations.

The effectiveness of local and organized opposition to infrastructure projects also can be closely related to the complexity of and duplicity in the steps that must be taken to receive siting approvals. Siting process complexity in turn varies by the category of infrastructure under review and the state in which it will be located, which determines the jurisdictional responsibilities of local, state and federal agencies; the need and environmental standards by which a project is to be judged; and the processes and bounding timelines of filing requirements, public hearing procedures, review and decision-making processes, and opportunities for appeal.

This section reviews recent experience with siting processes, and highlights features that affect the success or failure of infrastructure development proposals.

Energy Infrastructure Siting Processes

The success of infrastructure siting efforts depends in part on the authorities of various local, state and federal jurisdictions, and the processes implemented by these jurisdictions through regulations, procedures and case precedence. With respect to energy infrastructure, there are significant differences among infrastructure technologies (power plants, transmission lines, gas pipelines, LNG, nuclear facilities, refineries) in the rights and obligations of local, state and federal authorities. For example, states have primary jurisdiction over approvals to site, construct and operate non-nuclear electric generating and transmission facilities and commercial refinery operations, whereas the federal government has primary siting authority for natural gas pipelines, nuclear facilities (including waste repositories), and off-shore LNG proposals. Further, the administrative processes, need and environmental standards, and public review and

hearing requirements within an agency's review process can vary significantly across technologies and jurisdictions.

Over the past ten years there are numerous examples of successful siting efforts, meaning that proposals for significant energy infrastructure received approvals for construction and operation in a timely manner, approximately within the timeframes generally expected of the regulatory processes involved as revealed by statute, regulation, or precedent. For example, the interest in participating in wholesale electricity markets has led to an unprecedented number of electric generating facilities proposed and constructed over very short timeframes in several states, particularly in California and the Northeast. In California, siting success can be attributed in part to the existence of a one-stop siting process with clear substantive and procedural requirements and timelines, a strong public education component, and adequate agency resources. In the wake of the energy crisis in the late 1990s and the urgent need for additional capacity resources, this administrative foundation was given a strong boost by state emergency lawmaking and active political support.[29] In the Northeast, the restructuring of the industry in several states (often accompanied by provisions in restructuring laws and regulations to streamline the siting process) combined with the prospects of a growing need and expectations for the retirement of aging generation to create a boom in new capacity proposals and eventual construction.

Siting Example 1:
Bonneville Power Administration – Kangley-Echo Lake

The Kangley-Echo Lake transmission line proposed and developed by the Bonneville Power Administration (BPA) represents an example of a successful planning and siting process. Foremost, the BPA used a comprehensive process to demonstrate need, to study alternatives, and to offer all information for public comment. This up-front and public planning and development approach allowed their siting proposal to meet with success under conditions that have stalled similar projects.

The BPA held an initial public meeting in September 2000 to discuss the possibility of a transmission line upgrade, though talks of such a proposal had been ongoing for months beforehand. The initial proposal was for a 500 kV transmission line to run nine miles through the Cedar River watershed. This would allow the Puget Sound area power grid to maintain power during winter peaks. At the time, the system was strained and it was expected that major power outages would occur within the next few years unless something was done.

The Cedar River watershed is roughly 90,500 acres and supplies 70% of the water to some 1.3 million people in the Seattle area. Many were concerned that the transmission line would upset the fish and wildlife of the area, as well as contaminate the drinking water that so many relied upon. The BPA agreed to postpone plans for construction in 2002 and began researching alternative paths for the line.

Four alternative paths were looked at, each having a section running through some residential areas. This coupled with costs that ranged from $44-88 million and a longer time frame discouraged most views that alternative paths would be acceptable. Other alternatives were also looked at, such as demand-side management, distributed generation, additional large generation, and conservation, but it was deemed that these would not satisfy power demands.

In the end, the BPA also offered to purchase 600 acres of adjacent land to donate for fish and wildlife habitat and gave $6 million for water quality and habitat enhancement. Finally, to cover for any possible damages during construction, the BPA took out a $1 million insurance policy. With a final cost of $33 million compared to the original $15 expected, the proposal was accepted by the Seattle City Council in July 2003, as well as additional state environmental approvals.

With respect to electric transmission, Bonneville Power provides an example of controversial transmission line project near Seattle (see Siting Example 1) that was successfully sited due in part to a revamping of the transmission planning and investment process to include a full and credible assessment of alternatives to new transmission lines in solving reliability and congestion problems; this planning process may have the effect of increasing the credibility of proposed transmission projects when brought forth for siting approval. Similar to the electric experience,

[29] See, for example, Susan F. Tierney and Paul J. Hibbard, *Siting Power Plants: Recent Experience in California and Best Practices in Other States*, February 2002 (Tierney) at 13-16.

numerous new gas pipelines and expansions of gas pipeline capacity have been recently approved by the Federal Energy Regulatory Commission. Since the early 1990s, additions to the U.S. natural gas pipeline system have grown steadily -- in 2002 alone, more than 3,571 miles of pipeline and 12.8 Bcf/day of gas pipeline capacity were added in the U.S.[30]

While there are numerous examples of siting successes, there are also numerous examples of siting failures, failures that are not limited by the regulatory jurisdiction involved, the technology at issue, or the time the proposal was made. As discussed below, local opposition has the potential to derail virtually any energy infrastructure project, regardless of how important the project may be for the reliability, economic, environmental or security needs of the region or country, and regardless of the jurisdiction, or the competence and effort of the developer involved.

Given the magnitude of the public health, environmental, security and proliferation risks associated with the temporary on-site storage of spent nuclear fuel at reactor locations throughout the country, it is difficult to imagine an energy infrastructure project more appropriate for a critical national infrastructure designation than the construction of a geologic repository for HLNW. Further, there are few if any examples of siting process requirements that have a stronger central or federal jurisdictional role, or that have involved more extensive engineering and environmental review than the effort to establish a geologic repository at Yucca

Siting Example 2:
The Connecticut-Long Island Cross-Sound Cable

Experience with the Connecticut-Long Island Cross-Sound Cable (CSC) combines reasonably successful siting procedural review with an ugly mix of poor development implementation, state political opposition and bad timing. In effect, the CSC experience defines both the interstate cooperation needed to site electric transmission infrastructure with regional importance, as well as the full extent of the barriers that can arise to such development if a receptor state concludes it is on the losing end of the "burden-sharing" bargain.

In 2000, TransEnergie filed a permit to construct a 26-mile, 330 MW high-voltage transmission line across the Long Island Sound connecting Connecticut with New York. The line has been opposed, most vocally by the Connecticut Attorney General, on environmental and economic grounds (specifically, the CT AG views the line as economically beneficial to Long Island, while increasing electricity costs to Connecticut consumers). Nevertheless, the project received necessary approvals to construct from Siting Council and Department of Environmental Protection. And then the games began.

When constructed in early 2002, construction crews encountered solid bedrock and failed to bury the Cable to the minimum six-foot depth in accordance with permit requirements, then subsequently requested a waiver of permit requirements. DEP and the CT AG viewed this as a permit violation, as a legal issue important to state precedent, and perhaps more importantly as an opportunity to continue its opposition to the Cable on economic grounds.

Concurrently, the Connecticut Governor and Legislature moved to place a moratorium on development activities in Long Island Sound that has been renewed annually and in effect continues to this day, in light of the perception that electric industry deregulation and other factors were leading to an excessive cumulative impact of energy and other infrastructure within Connecticut's jurisdictional boundaries.

While DOE ordered the line energized following the August 2003 blackout pursuant to its authority to do so in light of perceived electric reliability emergency, in May of this year he terminated the order upon concluding that the emergency condition no longer exists.

Thus, development missteps, perceived state disadvantages, political opportunism, and poor timing combined to overwhelm the procedural findings of the siting regulatory agencies that reviewed the proposal In some sense, while it is difficult to imagine many transmission projects that would have a stronger justification on regional economic and reliability grounds, it is equally difficult to see how greater federal jurisdiction could have overcome the problems posed by the events as they occurred, and prevented the operational delay that has occurred today. Interestingly, consistent in some ways with the theme of common interests and equal burdens, it appears state approval for commercial operation of the line will be granted as part of an agreement to proceed with development of both the CSC *and* a replacement cable under the Sound that was sought by Connecticut utilities and interests, but being held up by a Long Island utility.

[30] U.S. Energy Information Administration, *Expansion and Change on the U.S. Natural Gas Pipeline Nework – 2002*, May 2003 at 1.

Mountain. On the other hand, it is hard to imagine a siting process that has been more difficult and time consuming, involved more complexity, or engendered stronger emotions and concerns on behalf of local and statewide communities. In effect, Yucca Mountain is the prototype example of the friction between local community concerns and national infrastructure priorities.

Other (less intense) examples exist for each of the major categories of energy infrastructure. Several electric transmission facilities or proposals that were or are significantly delayed appear to be well justified based on local and regional system reliability, and based on potentially significantly reductions in wholesale power costs and/or lower local emissions of air pollutants from older generating facilities. These include the Connecticut-Long Island Cross-Sound Cable (see Siting Example 2), AEP/Virginia, and Arrowhead-Westin. With respect to natural gas, similarly important infrastructure projects have met delay or rejection, including Islander East (see Siting Example 3) and two recent LNG proposals for the coasts of California and Maine (see Siting Example 4). The latter two examples reveal the unique difficulty facing LNG development due to a combination of local concerns and government jurisdictional uncertainty.

Siting Example 3:
Islander East Natural Gas Pipeline

Islander East began the application process for a natural gas pipeline under the Long Island Sound in June 2001. The Long Island Sound has long been an environmental hotspot in the Northeast region, with development opposition coming from state and federal groups and state agencies. Partly in consideration of local sensitivities, Islander East held public meetings and received feedback that altered the proposal before beginning any the formal siting process. Regardless, Connecticut Governor John Rowland issued Executive Order No. 26 in April 2002, which prohibited state agencies from approving any utility projects across Long Island Sound until 6/15/03. Further, Connecticut Public Act No. 02-95 imposed a one-year moratorium on such projects in June 2002. While these issuances were not necessarily directed only or specifically towards the Islander East project, they did directly affect it.

Regardless of state activities, FERC gave approval to Islander East in September 2002, a significant step given FERC's jurisdiction over interstate natural gas pipelines through the Natural Gas Act. FERC's Environmental Impact Statement concluded that the environmental effects were minimal and acceptable, a conclusion that has been strongly challenged by numerous environmental groups and the EPA. While the Connecticut Siting Council has little or no authority in interstate cases, Islander East filed for a site-specific review with the Council and was granted approval in September 2002.

Since this time, the Connecticut Department of Environmental Protection (DEP) has concluded that the proposal goes against the Coastal Zone Management Act (CZMA), and thus has refused to issue a water quality permit. DEP refusal essentially blocks any action by the Army Corps of Engineers, who's own review can not proceed without a water quality permit.

in May 2004 the U.S. Department of Commerce overruled DEP's determination, concluding that the proposal in fact does not go against the CZMA. This decision does not affect the water quality permit however, which means the project may still be far from complete. Should the Connecticut DEP maintain its refusal to give the water quality permit, Islander East may pursue judicial action. During the time of this debate, Connecticut legislators have continued to vote for a moratorium on Long Island Sound energy projects, with the third one-year ruling being approved by the Senate in April 2004 and by the House of Representatives in May 2004.

As a general matter the reasons for approval or denial of major energy facility infrastructure appears to have less to do with carrying out explicit national and state energy policies or with agency jurisdiction than with a combination of political support or opposition, choice of location, the strength and organization of local opposition, the quality of decisions and siting process execution on the part of project developers, regional market economics, and the rapidly changing nature of short-term reactionary politics. This mixed bag is a growing concern from the perspective of U.S. energy infrastructure development, because as our economy and energy needs grow, the cost, reliability impacts, and environmental and security risks associated with energy supply and use are becoming more acute. Addressing these issues will not only require paying closer attention to the development of rational energy policy, but also having the legal

and administrative capacity to successfully develop energy infrastructure that is critically needed to obtain national cost, reliability, environmental and security goals.

As will undoubtedly be true in future siting efforts, the success or failure of past infrastructure development projects has to do mostly with each project's site-specific circumstances – e.g., the timing of the proposal; local economic conditions; the host community's need for or interest in the additional tax revenues that would flow from development; the composition of local and state political bodies responsible for project review; the suitability of the site for the proposed project; the history of development in the area, and density of local populations; and the statewide and site-specific environmental conditions that influence site suitability and determine the required mitigation and control technologies. It is a fundamental, unavoidable characteristic of major facility siting that these specific local circumstances will play the most important role in determining the success or failure – and cost – of infrastructure siting proposals. Successful developers understand this very well, carefully review these circumstances, and conduct their development efforts in a manner dictated largely by these conditions. There may be little that can or should be done to overcome, override, or diminish the importance of site-specific project attributes.

Siting Example 4:
LNG: Long Beach, California & Harpswell, Maine

Two recent attempts from opposite corners of the U.S. to obtain siting approval for the construction of land-based LNG facilities demonstrate the potential jurisdictional roadblocks to such efforts, and the fundamental barrier of local concerns and opposition.

In Long Beach, CA, a proposal to site a LNG terminal has stirred up a jurisdictional debate between FERC and the California Public Utilities Commission (CPUC). While FERC has claimed sole jurisdiction over LNG terminal siting and construction, using Section 3 of the Natural Gas Act as legal backing, the CPUC has argued that the responsibility rests with them under the California Environmental Quality Act, since California is the sole state within which commerce would take place.

Sound Energy Solutions (SES), a Mitsubishi subsidiary, initially gained local approval for the LNG proposal in May 2003. Since that time the process has ground to a halt as the CPUC and FERC have engaged in a jurisdictional struggle. SES has filed for approval with FERC, but the CPUC has threatened to stop construction unless SES also files with the CPUC as a state utility. SES has sided with FERC, claiming that the CPUC has no jurisdictional authority.

FERC's claim of sole jurisdiction over LNG siting and construction followed the CPUC's statement that SES must file for state approval. Since then, the struggle has been heated, with FERC rejecting a rehearing appeal by the CPUC and numerous environmental groups that are worried about federal jurisdiction of such a volatile product as LNG. In August 2004, the CPUC filed a lawsuit in the US Court of Appeals for the District of Columbia.

Contrary to the Long Beach example, a proposal to construct a LNG facility in Harpswell Maine never made it past attempts to obtain local approval; many believe the proposers of the Harpswell project (a joint venture between TransCanada and Conoco Phillips) simply failed to develop an understanding of local values and concerns, and never obtained the trust of local residents.

The Harpswell proposal was a $350 million LNG terminal to be sited at a former US Navy fuel depot that was now owned by the town of Harpswell. This terminal would be serviced approximately once a week by 1000-ft tankers that would unload the LNG at the terminal, from where it would be piped throughout the Northeast and Canada. An information campaign to receive feedback and educate the town about LNG was not begun until after the initial September proposal.

The town's concerns ranged from viewing the facility as a possible terrorist target, to obstruction of local fishing important to the community, to degradation of aesthetic value of the coastline. Often heated debate ensued between those opposing the project and others who viewed the project as a significant economic and employment benefit to the town. A vote was postponed multiple times to allow residents longer to debate the issue, since many felt they didn't fully understand the many facets of the plan and didn't trust the information given to them by the TransCanada and Conoco Phillips partnership. On March 9, 2004, Harpswell rejected the proposal by a 56% to 44% margin. Discussion was heated leading up to the debate, with a bomb threat being called in on the day of the vote. A second vote was proposed, but this was rejected by the town council, who stated in its resolution that the first vote was satisfactory.

The challenge, then, is how to successfully and more quickly develop *critical* energy infrastructure whose outcome is made difficult or significantly lengthened by local conditions. The review of successful siting projects reveals important features to consider in this regard, related to the power and role of local, state and federal authorities, the practices of agencies involved in siting reviews, and the effort and attitudes of project developers that can significantly influence the success of projects. These features include the following:

- While it has not guaranteed success in the siting of any infrastructure project, strong federal jurisdiction (as in the case of natural gas pipelines) may ease and reduce the cost of energy facility siting;
- Clear and accessible agency rules, timelines, policies and precedence facilitate the filing and administration of complete and viable siting proposals;
- For the development of public utility infrastructure projects, the administration of clear resource planning procedures and practices to demonstrate infrastructure needs and compare them with alternatives can facilitate subsequent public and administrative siting efforts;
- Up-front, pre-filing efforts by developers in the local communities including contact with political and public interest groups, community education and issue flagging are critical to identifying fatal flaws and information/education needs, and to reducing the time and cost of regulatory/administrative siting procedures; and
- State and federal siting agencies must have sufficient resources (personnel, expertise and funding) to efficiently guide the proposal through the siting process, including educating developers on the rules and potential pitfalls; assisting and educating the public and political representatives within host communities; facilitating meetings with relevant groups/officials and hosting public meetings; and posting complete and timely project and process information on agency websites.

Conclusions

As discussed in above, virtually every region, and the country as a whole, has looming energy infrastructure needs that are, in some cases, being thwarted in the context of local or state siting processes. Examples include

- electricity transmission bottlenecks in the Northeast and elsewhere that have specific and well documented cost and environmental impacts, and that threaten the reliability of regional electricity systems;
- inability to site LNG import facilities in order to mitigate gas prices, reduce carbon emissions and other environmental impacts, and address the widening gap between U.S. consumption of natural gas for heating, industrial processes and electricity generation, and the supply available from U.S. and Canadian sources;
- impediments to the siting of large wind-power sources despite clear carbon-reduction and other environmental benefits and the need to promote renewable power and electricity supply diversification; and
- delays in finding a suitable permanent repository or monitorable, retrievable interim storage for nuclear waste, despite the existence of a large and growing quantity of spent nuclear fuel and other high-level nuclear wastes dispersed throughout the country, that represents a major concern from the perspectives of public health, environmental, security, and nuclear proliferation risks;

The need for this critical infrastructure is primarily driven by regional or national interests, but approval of infrastructure proposals to meet these needs may be held up or rejected in part due to local considerations. This is particularly true in cases where the primary siting authority is the state (e.g., transmission lines, power plants), but it is also true that local opposition has delayed or blocked projects even when the primary siting authority is federal (e.g., LNG and gas pipelines, nuclear waste). Consequently, there is value in considering the current authorities, standards and processes for siting critical energy infrastructure, and ask whether these processes can be improved to better capture the critical regional and national needs and goals. In effect, there needs to be a better understanding of energy infrastructure issues as one of "common interests and equal burdens" – as the coordination between and interdependence of all U.S. states and regions grow in the case of energy supply and delivery, so must the ability to incorporate regional and national perspectives and needs in the context of state and local siting procedures.

Large infrastructure projects can impose extraordinary changes on the communities in which they are located, including visual, noise, and traffic impacts, and local air and water quality. The local impacts need to be recognized and comprehensively addressed, and the review processes within towns, cities and the state are the best forums for addressing these concerns. But the importance of infrastructure for regional and national needs must also be more completely addressed within state reviews, and the procedures within state review processes should be reformed to facilitate these considerations and incorporate best practice improvements from the procedures implemented in other states. Consideration should also be given to in increasing federal authority in areas where it is clearly necessary within the context of energy infrastructure needed for interstate commerce, and for achieving national reliability, environmental and security priorities.

ADDITIONAL RECOMMENDATIONS OF THE NATIONAL COMMISSION ON ENERGY POLICY: LONG-TERM INVESTMENT CHALLENGES FOR THE ELECTRICITY AND NATURAL GAS SECTORS

[APPROVED BY THE COMMISSION: AUGUST 2004]

The Problem: In the electricity sector, major new grid enhancement, energy efficiency and generation projects often require long-term financial commitments. For natural gas customers, a portfolio of multi-year and short-term supply contracts are needed to diversify supply portfolios and hedge risks of exposure to spot market volatility. As supply portfolio managers for many customers, distribution companies play a crucial role in assembling these diverse portfolios. Yet distribution companies making long-term supply commitments create stranded cost exposure and raise their own cost of capital by taking on additional risk, inviting negative reactions from a skittish financial community. An inherent element of that risk is the possibility that customers will seek other suppliers, and avoid paying for all or part of the resources purchased earlier to meet system needs. Another inherent element of risk is that long-term commitments may provide to be more costly than spot market supplies at some point during the commitments, which creates pressure for regulators to disallow cost recovery.

But without some long-term supply commitments by distribution companies, it may be difficult or impossible to finance new infrastructure. The question then is, how can distribution companies entering into long-term supply commitments secure reasonable assurances of cost recovery and opportunities for appropriate shareholder reward?

Commission Recommendations for State Regulators and Legislators:

1. The resource portfolio for electric and natural gas distribution companies that provide systemwide or last resort service should be a mix of short, medium and long-term commitments, with long-term commitments held at or below the fraction of the system load at lowest risk of migration to retail competition (i.e., residential and small business customer loads). Assuming that a resource portfolio has been presented for regulators' review and has secured their approval, these regulators and/or their legislators should provide firm assurances that any associated long-term investments will not later be second-guessed and disallowed based on changes in electricity or gas prices. Similarly, local distribution companies who enter into an auction or RFP process to secure capacity and energy to meet their load obligations in accordance with an approved regulatory process should be assured cost recovery for all costs incurred in procuring necessary capacity and energy and conducting and/or backstopping the process, including particularly any costs incurred as a result of supplier default.

2. Legislatures should explicitly authorize regulators to create dedicated distribution rate components covering the cost of approved long-term resource acquisitions over the contract terms, allowing for the securitization of the payment streams and

the shift of risk of nonpayment to buyers of the securities (analogous to securitization of stranded cost recovery arrangements in several states).

3. Performance-based incentives should be established for distribution companies' resource portfolio management, tied to objective benchmarks established in the regulators' review and approval of the companies' resource procurement plans.

NATIONAL COMMISSION ON ENERGY POLICY

REVIVING THE ELECTRICITY SECTOR

Findings of the National Commission on Energy Policy

Fall 2003

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REVIVING THE ELECTRICITY SECTOR

Findings of the National Commission on Energy Policy

The National Commission on Energy Policy was founded in 2002 by the William and Flora Hewlett Foundation, and its partners—the Pew Charitable Trusts, the John D. and Catherine T. MacArthur Foundation, the David and Lucile Packard Foundation and the Energy Foundation. It is currently developing comprehensive recommendations for long-term national energy policy to be released in December 2004.

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Electric-industry restructuring has derailed. The massive blackout of August 14, 2003 certainly was not needed to underscore the point, but it adds urgency to the effort to find solutions. Wholesale markets continue to evolve slowly and erratically but are impeded by state-federal conflict, regulatory and legislative uncertainty, malfeasance, poor credit and outright collapses, of which Enron is only the most notorious. FERC's efforts to promote more efficient markets through regional transmission organizations and a wholesale market platform offer promise, but have generated confusion and opposition. In the last five years, increased generation competition has elicited more than 100,000 megawatts of gas-fired peaking and baseload capacity, which has contributed both to a period of relatively low wholesale prices in many regions and increased exposure to gas price volatility across the system. But competitors' losses have created substantial uncertainty about how quickly and on what terms capital markets will support additional investment throughout this sector. Indeed, investment in all categories of electricity infrastructure is down significantly, in part because of surplus capacity conditions in certain regions, but also because of uncertainty concerning which entities have the responsibility for identifying and making investments in the transmission and distribution networks, and uncertainties about how the associated costs will be recovered. A challenge in reviving these capital flows is to clarify prospects for cost recovery and reward: for example, when and on what terms will distribution utilities have the ability to enter into long-term contracts with generation service providers; how will distribution utility responsibilities interact with the opportunities created for competitive retail suppliers in states with retail competition; who has the responsibility for identifying needed enhancements to the transmission network; how will they be paid for securing them; and who will pay? The August 2003 blackout is a reminder of how much hinges on finding practical answers promptly.

Individual states have varied greatly in their willingness to introduce retail electricity competition, and their enthusiasm for federal policies designed to promote wholesale competition. Even in states that have opted for retail competition, efforts to expand it have generally halted in the wake of the Enron collapse and the California disaster. Large industrial customers often have benefited from retail competition, effectively exercising their ability to "buy wholesale" whenever prices are lower than the "safety net" of regulated rates that such states typically provide. These customers seldom seek "value-added" electricity service; rather, they seek the cheapest commodity prices and the shortest contractual commitments. Large customers contend that their continued exposure to some utility charges impedes the further development of these markets. Utilities contend that continued safety nets for the industrials have the same effect.

Small customers sometimes have benefited from rate guarantees in restructuring legislation, but they have received little direct benefit from retail competition itself. Because the pocketbook advantages have been insubstantial, many consumers find the choices associated with retail competition to be more of an annoyance than an advancement over past service offerings. Retail marketers have lost some billions in capital without developing a profitable, sustainable and distinct value-added product, although a few pioneers have made intriguing efforts to market products based on environmentally preferred generation sources.

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At the same time, it is often unclear who is responsible for assembling a diversified mix of short- and long-term resource commitments and other risk management tools, in order to sustain the economical and reliable electricity services that a healthy economy requires. Competitive models assume that decisions by market participants will replace resource planning by utilities or regulators. In practice, however, competitive models have retained -- whether in utilities, in regional transmission organizations or in the states themselves -- some residual responsibility for ensuring that electricity supplies remain adequate. In some restructuring models, customers unwilling or unable to choose a supplier have been provided with default options that influence the evolution of the market. These "carrier of last resort" options also fail to address either the real relationships between wholesale and retail markets or the complex issues involved in resource planning. Indeed, in California, events evolved such that from 1998-2001 utilities were required to supply power to retail consumers at frozen rates after losing the ability to enter into forward contracts for the power that they were obligated to deliver..

In states with traditional regulatory regimes, the regulated utilities that provide most resource procurement and management services generally do so based on longstanding cost recovery principles, with abundant downside risk and little or no prospect of gain regardless of the quality of their performance. In states with retail competition, the retail suppliers view long-term procurement by distribution companies as unfair competition, and the distribution companies face potential stranded cost problems or prudence reviews from regulators if they do make resource commitments. Yet failures to make such commitments may force expensive purchases in volatile short-term markets, which may result in adverse treatment by regulators.

Even in states that do not have retail competition programs, the threat of their introduction and stranded costs deters long-term commitments by investor owned utilities, even as risks of regulatory review make the alternative of short-term purchases look dangerous for utility shareholders. Utilities, regulators and wholesale suppliers alike are struggling with how states can regulate retail electric service provided by companies that operate in wholesale power markets that cross state lines. All parties are stuck between uncertain regulatory regimes, with no assurance about the rules that will determine commercial survival and success.

Finally, the electric industry's environmental footprint is significant, and a wide range of technologies and technology vintages means widely varying emissions and other impacts from the competitors for generation and grid investments. While there have been important reductions in some power generation pollutants, the sector's greenhouse gas emissions have been increasing more rapidly than those of the rest of the economy. National policy on greenhouse gases and other key pollutants remains uncertain, and states are beginning to act on their own initiative to reduce these emissions. This continuing policy struggle and growing jurisdictional tension creates an additional source of uncertainty for the industry, with serious implications for different technology options, electricity service costs, and environmental consequences of electricity production and transmission.

Overcoming these formidable challenges requires a balancing of the extent to which electricity is a commodity and a public service. Also needed are an evaluation of the benefits of

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competition and other mechanisms for achieving public utility goals, and an integration of the flexibility of spot markets with the increased certainty of planning. To complicate matters further, key decision-makers at different levels of government are at odds over who should make these decisions and how.

The Commission sees an urgent need to address and help resolve these issues. Both state and federal regulators have vital and complementary roles to play in providing consumers with the benefits of properly structured electricity markets. Within the context of pending regulatory and legislative proposals at both federal and state levels, we aim to help define those roles and to offer a vision for revitalizing both wholesale electricity markets and broader electricity-resource procurement and management responsibilities. In the process, we will explore the most promising ways to encourage appropriate electricity-resource and grid investments.

Absent the prospect of retail competition, of course, this would be an easier problem to solve.[1] Under regulatory oversight, distribution companies could have relatively well defined retail supply obligations, met through some combination of wholesale contracts, demand-side investments and ownership of generation assets. A crucial issue, then, is how to think about retail competition: if we are going to have it, how can we make it work and speed the transition? If instead we prefer to reject retail competition, how do we make that decision credible enough for distribution companies and others to take it to the bank? If different states and regions choose different models, how will those variations intersect with national policies that favor more standardization for wholesale power markets and the role of transmission systems (and regional transmission organizations) in enabling them?

Finally, no assessment of our electricity challenges would be complete without careful attention to the system's vulnerability to terrorist attack. Much of the electricity infrastructure is in private hands, so protecting that infrastructure will require a strong government-private sector partnership. Although the grid is more resilient than many may appreciate, some equipment has long replacement lead-times and constant vigilance is essential to guard against potential disruption of the grid control systems. Attacks could be either cyber-based or physical, or some combination of the two. These issues deserve, and are getting sustained attention from, institutions like the Department of Homeland Security, the Department of Energy, the Federal Energy Regulatory Commission, the National Academies, numerous state agencies, and the North American Electric Reliability Council. The Commission's recommendations below reflect and reinforce their vital work. At the same time, although it has not been linked to sabotage, the August 2003 blackout is a reminder that reliability concerns demand strong enforcement of mandatory reliability standards as a replacement for today's overburdened voluntary system; the Commission adds its voice to those who have been urging Congress to take specific action here.

[1] Other important questions include whether load serving entities should be generation owners or not, and whether distribution companies will retain ownership of transmission. A central and still unresolved issue is whether wholesale competition can flourish (or flourish enough) in a world that includes vertically integrated utilities (i.e., utilities that own generation, transmission and distribution assets).

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THE COMMISSION'S INITIAL RECOMMENDATIONS

The Commission supports an energy policy that recognizes both the quarter-century march toward increased competition in electric generation and wholesale markets and the value of traditional modes of regulatory authority. A fundamental assumption is that the wholesale electricity business is largely a competitive commodity business. So too is the retail supply of electricity to very large customers, including industrial customers and some national chains. However, the retail supply of electricity to other customers is, for the foreseeable future, likely to remain a service-oriented business with major public policy implications. In this context, electric distribution and transmission companies have both special opportunities and special obligations. As the federal government and the states attempt to resolve the tensions inherent in promoting competition and customer choice, multiple paths may be found to widely shared equity, environmental and economic objectives.

These recommendations constitute a framework that the Commission presents as a prototype for progress in accommodating diverse needs and goals:

FOR STATE REGULATORS AND BOARDS OF CONSUMER-OWNED UTILITIES:

1. Retail distribution should remain a responsibility of utilities under state and local regulation, along with electric energy resource portfolio management for residential and small business customers (and any larger customers who choose regulated portfolio services).[2] If customers, especially large users of electricity, are permitted to opt out of regulated portfolio service and to make their own choices in retail electric markets, they should be allowed to return to regulated service only on terms that hold harmless other customers and the regulated portfolio manager. For small customers in states that opt for retail electricity competition, schedules should be established to allow for orderly provision of retail choice opportunities in phases across service territories, with all small customers having opportunities to choose alternative portfolio managers no less than every five years.

2. Large customers who choose regulated portfolio service should be required to execute long-term contracts with the utility portfolio manager. Large customers who do not opt for regulated portfolio services should make their own way in the competitive retail markets.

3. State regulators and boards of consumer-owned utilities need to focus more on incentives for good portfolio management service. Options include systems of performance-based regulation for regulated portfolio management (and other) services provided by retail distribution companies, based on objective benchmarks, and incentives for managers and

[2] As indicated in the introductory section, by "electric resource portfolio management" the Commission means "assembling a diversified mix of short- and long-term resource commitments and other risk management tools, in order to sustain the economical and reliable electricity services that a healthy economy requires."

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(where applicable) shareholders reflecting reasonable measures of net benefits delivered to customers. Regulated distribution companies can be compensated independently of increased electricity sales (for example, utilities' fixed-cost recovery can be made independent of retail electricity use, through the mechanism of small periodic upward or downward adjustments in distribution rates). For purposes of meeting portfolio management responsibilities, reliable load reductions and reliable generation, including small-scale "distributed" generation at or near load centers, should all be investment candidates. The goal should be to hold regulated portfolio managers accountable but also to avoid complex regulatory review processes.

FOR THE FEDERAL ENERGY REGULATORY COMMISSION:

4. The Commission supports FERC's efforts to ensure nondiscriminatory transmission operations and nondiscriminatory access to grids and wholesale markets, with appropriate deference to the needs of states that have not adopted retail competition and states' crucial role in ensuring resource adequacy. Congress should authorize the extension of those requirements to all transmission regardless of who owns it. The Commission believes that these policies are needed to revitalize competitive wholesale electricity markets. Wholesale market participants should win or lose based on their ability to maximize operating efficiencies under a deregulated price regime untainted by exercises of market power

5. To improve system security and reliability, the national electricity system needs to maintain dispersed and well guarded stockpiles of critical equipment with long replacement lead-times, and to standardize such equipment wherever feasible. Prompt attention should also be given to ensuring the security of Supervisory Control and Data Acquisition (SCADA) systems. Also important are joint government-private sector efforts to complete the studies necessary to mitigate the effects of and accelerate recovery from terrorist attacks. The costs of these efforts, and other costs involved in improving grid security, should be shared system-wide on a competitively neutral basis, through uniform charges on transmission use administered by the FERC. In view of the national importance of this objective and its relatively modest cost when spread across the nation's electrical grid, Congress should provide for the collection of these charges notwithstanding state-mandated retail rate freezes.

FOR CONGRESS:

6. Both societal and generation-sector interests would benefit substantially from more coordination and greater certainty regarding targets and timetables for achieving long-term environmental objectives. Accordingly, for all categories of power plant emissions that it considers appropriate subjects of regulation, Congress should establish an integrated regulatory structure that (1) establishes a firm multi-year schedule of phased emission reductions that accommodates both environmental and system reliability needs;

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and (2) uses market-based mechanisms to the maximum extent feasible to minimize compliance costs and encourage innovation.

7. Congress also should tighten energy efficiency standards wherever practicable and cost-effective, in view of the substantial environmental and economic costs associated with unnecessary use of energy.

8. The August 2003 blackout was a terrible reminder that the system of voluntary compliance with non-binding reliability rules for electricity grids is breaking down across North America. Congress should approve widely supported proposals to make such reliability rules mandatory and enforceable, when promulgated by a FERC-approved North American electric reliability organization working with regional bodies accountable to all owners, operators and users of bulk power systems, and with ultimate oversight responsibility vested in the Federal Energy Regulatory Commission. See also item 5 above.

FOR ALL DECISION-MAKERS:

9. Wholesale electric markets work best when they are liquid and transparent, for real time, day ahead and long-term products. The Commission supports FERC's proposals for real-time and day-ahead wholesale markets, along with state-level policies designed to ensure that such price signals are much more effectively communicated to large customers or aggregators at the retail level. More transparency for spot market prices and volumes of electricity trading, with reporting as close as possible to real time, are urgent priorities.

10. While the Commission is encouraged by the emergence of innovative technological solutions to transmission reliability and congestion problems, we agree that inadequate investment in transmission infrastructure is a significant and growing national problem. Transmission owners should be challenged to identify and consider all potentially cost-effective solutions to congestion and reliability problems, including targeted demand reductions, replacements of existing facilities with better equipment and new technology, and new facilities. No single solution will suffice; we need a portfolio that includes using new technology as well as constructing new transmission lines. FERC should also clarify which entities are responsible for identifying and making transmission investments, how they will be paid, and who will pay the associated costs. Options for encouraging cost-effective investment include higher rates of return for approved measures, increased certainty of recovery, and performance-based rewards that share system savings between shareholders and users. In addition, confusion and controversies created by FERC's interest in merchant transmission investment, and ambiguities about the practical meaning and application of the "participant funding" concept, are discouraging investment and must be clarified and resolved.

11. Congress, FERC and state regulators should encourage interconnected electricity systems to undertake more regional resource and grid enhancement planning.

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12. Urgent action is needed to revive the electricity sector's research and development investments, always low by any reasonable standard and down by more than three-fourths in real terms over the past two decades. The Commission favors supplementing the federal budgetary contribution with a combination of federal tax incentives and state-approved utility investments, recovered as small charges on electric distribution, such as those that created the Electric Power Research Institute.

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The following Commissioners join in support of the recommendations stated herein:

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**** Special Concurrence from Commissioner Sharon Nelson***

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I respectfully concur. The commission's statement is a committee work product on a complex subject. Like all such collegial efforts, the paper suffers from compromises and code words. I worry that some of the less obvious compromises will be used in Congressional and other policy debates for purposes not intended by any commissioner. However, the report contains many meaningful recommendations which advance the policy debate currently underway in the nation's capital and in other policy venues.

The electricity sector provides an essential infrastructure for assuring the public safety, health and welfare. This report recognizes this practical reality and the significant need to re-establish some semblance of predictability for the electricity sector. It also encourages important efforts to address national security concerns, promotes coordinated regulation of all power plant emissions, encourages greater emphasis on energy efficiency and supports much needed technology R & D. The report also recognizes that other values besides market values still vitally affect the electricity industry and are affected by it. For these reasons, I support the report, despite the concerns described below.

I reside in a region of the country which has suffered from "market designs" we sought to avoid. In my view, markets are not designed. They may evolve, they may be influenced by public policy but they are not the product of legislative or regulatory mandates. This report should be understood as merely early input on a still fitfully evolving "competition" policy in electricity.

The report refers to the nation's quarter century trend toward competition in markets formerly viewed as de jure or de facto monopolies and implies that this forward march should not be interrupted by "inappropriate" state retail competition policies. In my opinion, there were good reasons for the electricity industry to be the last of the network industries to experience "restructuring." As opposed to the transportation, banking, or telecommunications industries, the preconditions which characterized the other sectors' reformations (such as ease of access to capital markets, freedom of entry, well understood rules about interconnection) did not exist in the vertically integrated electricity industry. Indeed, one major difference here is the ownership structure of the industry. As opposed to the natural gas industry or wireline telecom industry, the electricity industry is characterized by suppliers which are not investor owned. For example, in Washington State, two thirds of retail electricity sales are provided by customer or municipally owned providers. Traditional institutional oversight for this complex industry is not the same as the parallel natural gas or telecom markets "enjoyed," making legislative and regulatory initiatives even more complicated. The phrase "ensuring a level playing field" is a hackneyed one, but this common sense goal is practically not achievable for the entire electricity industry in the nation's current electoral-political environment. In my view, in 2003, the nation needs a far more thoughtful analysis of why the experiments in Pennsylvania, California, the United Kingdom and Texas are succeeding or failing. Once we draw some lessons from empirical studies, then maybe some more far reaching and sensible policy reforms would flow.

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I have specific concerns with recommendations 9 and 10. I am concerned that they provide too much deference to the Federal Energy Regulatory Commission which at this point does not manifest the institutional competence to warrant such trust, do not recognize regional differences or operational differences between thermal and hydro-electric systems, and are at once vague and overly prescriptive.

Despite these concerns, I support a significant majority of the paper's recommendations. The debate over the future direction of our nation's electricity system is fundamentally stymied. The hard work and significant agreements reached by our expert and diverse Commission causes me to conclude that the overall report advances the national policy debate. For this reason I concur.

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SPECIAL NOTICE – Leo Gerard, President of the United Steelworkers of America (USWA)

Leo Gerard joined the National Commission on Energy Policy after the bulk of work on this paper was completed. As a result, Mr. Gerard takes no position on the paper's content or recommendations. The issues raised in this paper are of significant interest to Mr. Gerard and to the USWA. Mr. Gerard will work actively in the coming months to ensure that the NCEP enjoys the benefit of the labor perspective when crafting its final recommendations.

Toward a Consumer-Oriented Electric System

Assuring Affordability, Reliability, Accountability and Balance After a Decade of Restructuring

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National Association of State PIRGs
for
The National Commission on Energy Policy

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The state Public Interest Research Groups (PIRGs) are a national network of state-based, nonprofit, nonpartisan public interest advocacy organizations working on consumer, environmental and good government issues. The National Association of State PIRGs provides research and policy development assistance to state PIRGs nationwide.

Cover photo: Nathan Sudds

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EXECUTIVE SUMMARY

America's electric system is on the verge of a crisis. After more than a decade of rapid structural change – characterized by the deregulation of parts of the industry – the reliability of the electric system has been degraded, rates in many parts of the country are going up, and events such as the California energy crisis and the August 2003 blackout have cost consumers and businesses billions of dollars.

There is strong disagreement among policy-makers and experts as to the way out. Federal regulators continue to push for increased liberalization of wholesale electric markets at the same time that officials in many states are pulling back from the deregulation of retail electric sales. The electric industry and some policy-makers speak of the need for massive ratepayer investment in new capacity for the transmission of electricity, despite the acknowledged potential of improved energy efficiency and local generation of electricity to ease current transmission constraints.

Unfortunately, much of the current discussion glosses over the impact that restructuring of the electric industry has had – and will have – on ordinary consumers. In this paper, we present a consumers-eye view of the current regulatory structure of the electric industry, the experience of the past decade of restructuring, and the critical problems facing the industry today. We also propose a series of guiding principles and policy options for protecting the interests of electricity consumers, and map out a long-term vision in which a shift to a more balanced mix of cleaner energy options leads to long-term cost savings for consumers.

America's electric system is in a state of limbo – caught between the traditional regulatory structure that has governed the industry for the last century and increasingly tentative moves toward market-based structures.

- The framework of laws and regulations that has delivered affordable and reliable electric service for decades remains largely in place – even after a decade of industry restructuring. Federal law and statutes in many states still require government to uphold the public interest in the provision of electricity and assure "just and reasonable" rates for electricity service.
- The 17 states that adopted retail restructuring allowed electricity suppliers to compete for the business of small consumers. The western energy crisis of 2000-2001, however, stalled the drive toward retail restructuring and many states are now reconsidering their restructuring policies amid a persistent lack of competition for residential customers.
- Nearly a decade after the opening of wholesale markets to competition, federal officials continue to struggle to develop and implement regulations to ensure a fair, efficient wholesale market in electricity.

A decade of electric industry restructuring has led to few benefits for the majority of consumers, and any benefits consumers have experienced are likely to be short-lived.

- Retail electricity rates for residential consumers declined by 18.3 percent in inflation-adjusted terms between 1993 and 2002 – a decline broadly consistent with long-term historical trends. In 2001 and 2003, however, residential rates increased in inflation-adjusted terms – the first such year-

to-year increases in nearly two decades.

- Declining real energy prices – particularly for coal – appear to have played a major role in causing the rate decline. Coal prices declined by about 40 percent in real terms between 1993 and 2002. Natural gas prices were at their lowest point since the mid-1970s for several years during the 1990s, before spiking in 2000.
- States in which consumers may choose their retail electricity provider experienced greater reductions in residential electricity rates than states without retail choice (21 percent vs. 16 percent) between 1993 and 2002. But the restructured states experiencing the greatest decreases were those in which very few consumers chose competitive suppliers, leading to the conclusion that other factors – including the imposition of mandatory rate reductions that accompanied restructuring in most states and the fact that most restructured states had higher rates to begin with – are responsible for the greater rate of decrease in restructured states.
- The gap between the rates paid by residential customers and those paid by industrial customers has been rising. In 1993, the average residential customer paid 71.5 percent more per unit of electricity than the average industrial customer. By 2002, residential customers were paying 74.9 percent more for each unit of electricity they used.

The average American household's electricity use increased over the last decade, while funding for utility- and state-supported energy efficiency programs was slashed – leading to increased energy consumption and strain on the electric grid.

- The size of the average residential consumer's monthly electric bill declined by 10 percent between 1993 and 2002 in inflation-adjusted terms. The decrease in the average bill was lower than the decrease in average rates (18.3 percent), meaning that the amount of electricity used by the average consumer increased significantly over the last decade.
- Spending on energy efficiency programs has a significant impact on residential electricity usage. On average, for every $10 spent on efficiency programs per capita from 1996 to 2000, the average state reduced residential electricity usage by 0.3 percent. This does not include savings from industrial or commercial efficiency programs.
- Between 1993 and 2000, spending on state- and utility-sponsored energy efficiency programs decreased by approximately 38 percent, as many utilities – in states both with and without retail restructuring – scaled back their energy efficiency investments.

Restructuring has also been accompanied by the degraded reliability of the electric grid and greater reliance on increasingly expensive natural gas. These developments – along with the impending removal of rate caps in some states that have undergone retail restructuring – will likely lead to higher costs for consumers in the years to come.

- The increase in wholesale electricity trading that resulted from industry restructuring is placing unprecedented strain on the nation's electric grid. The average number of

reported disturbances (service interruptions and other "unusual occurrences") in the interstate transmission system during the 1998 to 2001 period was double the average number reported from 1992 to 1996.

- Federal officials and the electric industry have proposed tens of billions of dollars worth of upgrades to make the transmission system – which was never designed to accommodate wholesale markets – an appropriate platform for the restructured industry. Ratepayers would likely pay the vast majority of the costs of such an upgrade.
- Natural gas prices have doubled since the mid-1990s, due in part to the restructuring-fueled boom in the construction of natural gas power plants during the 1990s. Prices are likely to remain well above historic levels for at least the next two years, and may lead to persistently high rates for customers of utilities that are heavily dependent on natural gas.
- Mandatory rate reductions and rate caps that benefited consumers in many states with retail deregulation are scheduled to be removed over the next several years. The removal of rate caps in New Jersey in 2003 led to an immediate 19 percent increase in rates. Utilities in Michigan and Maryland are already predicting double-digit rate increases when rate caps are removed in those states. In addition, many state rate caps allow utilities to recover the expense of complying with the rate caps (with interest) once the caps expire – providing further upward pressure on rates in the years to come.

The past decade of restructuring has created or exacerbated seven critical problems that must be resolved in the coming years if consumers are to be well-served by the electric system.

- **The failure of retail competition –** One of the most highly touted benefits of restructuring was to be consumers' ability to choose an electricity provider. But in no state that deregulated retail sales of electricity is there currently an active, competitive market for the business of residential consumers. In most restructured states, less than 5 percent of consumers have switched electricity providers. Even in states that experienced a greater amount of switching – such as Pennsylvania – the number of consumers receiving electricity from competitive suppliers has been going down, not up. States face the option of prioritizing competition – likely at the expense of higher rates – or protecting consumers from rate increases and volatility by requiring the provision of a regulated electricity product.
- **Failures in the wholesale market –** The scarcity of transmission capacity at times of peak demand impairs the workings of the wholesale market in fundamental ways. The two main solutions proposed by the electric industry and the federal government – the expansion of transmission capacity and market-based (as opposed to flat-rate) pricing of transmission – both have the potential to negatively impact ratepayers. Meanwhile, the scarcity of generation or transmission at peak periods continues to provide wholesale electric suppliers with incentives to withhold capacity in order to achieve higher profits, as occurred during the western energy crisis.
- **Lack of effective and coordinated planning –** Smooth operation of the electric grid requires extensive plan-

ning, and responsible operation of the grid requires planning that is responsive to public needs. Yet, system planning too often neglects less-expensive solutions to problems (such as energy efficiency); fails to provide for long-term stability in electricity costs; fails to coordinate the activities of various parts of the system; ignores resource, environmental and political constraints; and increasingly takes place out of the public domain.

- **Failure to account for external costs and impacts** – Decision-making in the electric industry often fails to take into account the costs imposed on society by electricity generation – including impacts on the environment, public health and other sectors of the economy. As a result, resource options that might provide the greatest aggregate benefits to society, such as the expanded use of renewable fuels and improved energy efficiency, are routinely ignored.
- **Financial instability** – The restructuring of the electric industry – together with the loosening of traditional financial controls over public utilities – has led to bankruptcies and bond rating downgrades for a variety of players in the industry. These developments may make it more difficult for some utilities to obtain credit, resulting in delayed capital expenditures and higher rates for consumers, who ultimately pay for utility debt service.
- **Lack of attention to traditional regulation** – The resources devoted to developing, implementing and correcting rules for industry restructuring have diverted time, energy and focus away from the task of protecting consumers through traditional regulation.
- **Lack of accountability** – Critical decisions for the future of the industry – including transmission planning and the rules governing the operation of wholesale markets – are increasingly being made by organizations with no direct accountability to the public. Both federal regulators and those in many states have given increasing deference to independent system operators and regional transmission organizations which, in most cases, have no explicit obligation to protect the public interest.

To address these challenges, the states and the federal government should govern the electric industry in keeping with a series of principles that put the interests of ordinary consumers first.

Specifically:

- States should acknowledge that retail deregulation is unlikely to ever provide significant benefits to small consumers, and should consider terminating their deregulation experiments. States that opt to retain retail deregulation should give consumers the ability to choose a reasonably and stably priced, regulated electricity product and allow communities to negotiate electric service on behalf of their citizens through municipal aggregation.
- The federal government should firmly guide wholesale markets toward solutions that benefit consumers, while not intruding on the prerogatives of the states. Specifically, the federal government should impose mandatory reliability standards on operators of the electric grid, clamp down on market manipulation through mandated refunds and fines, and assert its authority to set "just and reasonable" rates whenever wholesale markets are not truly competitive.

- All levels of government should adopt policies that maximize cost-effective energy efficiency and clean distributed generation and encourage the development of renewable sources of energy. Some of these policies may result in higher short-term costs, but the long-term benefits dwarf those costs.

As the attached analysis by Synapse Energy Economics demonstrates, a policy that emphasizes the development of efficiency, distributed generation and renewables would:

- Save money compared with a business-as-usual scenario that relies on construction of new fossil fuel-fired generation capacity and transmission lines. Savings would begin within just a few years, with annual savings reaching $36 billion by 2025.
- Reduce greenhouse gas emissions from electricity generation to below 1990 levels by 2025 – or 45 percent below what emissions would be under a business-as-usual scenario.
- Lead to additional savings in other areas, such as reduced expenditures for environmental compliance, reduced public health costs due to air pollution, and reduced price volatility and pressure on fossil fuel supplies.

Consumer Principles for the Electric System

1) Preserving universal access to safe, reliable, affordable electricity service should remain a national goal.

2) The public interest must guide all decisions with regard to the electric system.

- The goal of electricity regulation should be to provide adequate, reliable service to consumers at the lowest cost – including "external" costs such as environmental, public health, and social and economic impacts. Ratepayers must only be required to pay for investments that serve a legitimate public need and that could not otherwise be met through lower-cost means.
- Electricity rates should be designed to promote economically efficient and socially responsible outcomes – including energy efficiency, rate stability and the protection of low-income consumers.
- The public interest can only be preserved through an open, accountable regulatory system that is explicitly charged with safeguarding the public.
- An effective regulatory system must guarantee due process and freedom of access to relevant information, allow and encourage the participation of all stakeholders, and preserve a right of appeal.
- An effective regulatory system must balance the long-term and short-term needs of consumers, as well as the interests of various classes of consumers. To balance long- and short-term needs, system planning must take place in the public sphere, include ample opportunities for public participation, and explicitly consider resource, political and environmental constraints. To balance the interests of various consumer classes, regulators must encourage broad participation in decision-making and ensure that the views of small consumers are adequately represented in the process.

(continues on next page)

3) Market mechanisms should be employed when they benefit the public interest and supplanted by regulatory decision-making when they do not.

- The conditions for effective and fair markets in the electric industry – particularly in the transmission and distribution of power and the sale of electricity to small consumers – do not currently exist and are unlikely to exist in the foreseeable future. Regulation of rates and terms of service in these areas of the industry (and perhaps others) is necessary to protect the public interest.
- Where market mechanisms are established, consumers' basic rights must be protected. These include the right to choose an electricity provider, to switch providers in a timely and convenient manner, and to receive accurate and timely information about rates and service.
- Where market mechanisms are established, government retains a role in ensuring that markets operate fairly. This includes the need to prevent the accumulation and exercise of market power and to safeguard consumers' collective investments in the electric grid.
- The interests of consumers cannot be abandoned during any "transition" from regulated to open markets. Consumers should not be subjected to higher-than-warranted rates in order to encourage the entry of competitive suppliers to the market.
- Consumers must retain the ability to pool their resources through cooperatives or municipal governments in order to negotiate better rates and service or to provide power themselves.
- Private, unregulated entities must not be permitted to shift costs or risks to the regulated entities that serve consumers. Similarly, ratepayers must not be forced to make infrastructure investments that primarily serve private interests.

4) Decisions with regard to the electric system should be made at the level of government most accessible and responsive to the public, keeping in mind the need for broader coordination across jurisdictional boundaries.

- Ideally, decisions should be made at the lowest level of government possible in order to maximize the public's ability to participate in the decision-making process and hold decision-makers accountable to public interest goals.
- All levels of government must engage in comprehensive energy and electricity planning that establishes a long-term vision for the nation's energy future. Such plans should be developed in public and invite participation from all stakeholders.
- New structures may be required to allow democratic governance of regional energy pools and markets in order to bridge the gap between national and state decision-making.

5) Improved energy efficiency and increased use of renewable resources are in the long-term national interest and often have short-term benefits for consumers. Government policy should actively promote the development and use of these resources.

- Market and regulatory barriers that deter the use of energy efficiency, renewable energy, or distributed generation technologies should be removed.
- The long-term benefits of these technologies must be considered in system planning, ratemaking and other regulatory decisions.

A System Adrift

America's electric power system is one of the foundations of the nation's long-term economic prosperity. Built over the course of a century through private and public initiative, America's network of generating plants, transmission wires and local distribution facilities – along with the systems for governing and operating them – have generally worked well and are partially responsible for the high standard of living many of us enjoy today.

Over the past decade, however, the American electric power sector has undergone massive change. Based on the notion that markets could succeed where traditional regulatory systems have fallen short, policy-makers launched an effort to restructure the industry in order to allow more opportunities for competition and consumer choice – altering the terms of traditional relationships among utilities, regulators and consumers.

Restructuring has taken place on two levels. In about one-third of the states, *retail restructuring* has allowed consumers to choose their suppliers of electricity and allowed companies that generate electricity to compete for consumers' business. Across the country, *wholesale restructuring* has changed the way utilities and other firms produce, trade and sell power by opening the wholesale power system to market competition.

The transition to a restructured electric system has not gone smoothly. While consumer prices for electricity have declined in real terms since the onset of restructuring in most of the country (following the long-term historical trend), it is not at all clear whether restructuring or other factors – such as reduced fuel prices – are primarily responsible. What is clear is that other developments in the system have seriously damaged the interests of consumers and society in general. Consider:

- The reliability of the electric system has been degraded. The northeastern U.S. blackout of August 14, 2003 was just the most severe of a number of major system disturbances that have occurred in the decade since restructuring began.
- Retail consumers in most states that have opened themselves to competition enjoy little more choice than they did before restructuring. In some states, less than 1 percent of residential customers have switched electricity providers.[1]
- The electric system in some regions of the country has become dangerously over-reliant on natural gas. The proportion of America's electricity generated by gas doubled between 1988 and 2002.[2] The increasing use of gas – coupled with increasing strains in domestic supply – has led to price impacts for natural gas use in electricity, home heating, and industry. The overall economic cost of the natural gas crisis over the last four years has been estimated at as much as $111 billion.[3]
- Two events that have occurred since the onset of industry restructuring – the California energy crisis of 2000-2001 and the 2003 northeastern blackout – have imposed tens of billions of dollars of costs on consumers and the economy. The costs of the California energy crisis have been estimated to be as much as $45 billion.[4] Economic losses from the northeastern blackout have been estimated at approximately $6 billion to $10 billion.[5] The cost of these two events is large compared to the estimated $13 billion annually that federal officials

claim is saved by consumers annually through wholesale transfers of electricity (including transfers that were already occurring prior to restructuring).[6]

- Price caps in many states that have engaged in retail restructuring are scheduled to come off within the next few years. The lifting of rate caps in San Diego in 1999 – which caused rates for some consumers to triple the following year – was one of the first manifestations of the California energy crisis. In New Jersey, the expiration of price caps in August 2003 led to immediate rate hikes of more than 15 percent for many consumers.[7] Moreover, many of the state rate caps came with a provision requiring ratepayers to *pay back* the money saved during the rate cap period, with interest, once the caps expire.
- Proposals by government and industry to ease reliability concerns by spending tens of billions of dollars on additional transmission capacity could, if approved, saddle ratepayers with most or all of the additional cost, driving rates upward.
- In the wake of restructuring, many utility-based energy efficiency programs that had sought to reduce electricity consumption – often at a cost savings for consumers – have had their funding slashed. Between 1993 and 1997, spending on state- and utility-sponsored energy efficiency programs declined by 43 percent, before rebounding somewhat in the late 1990s.[8]
- Electric power plants continue to pose undue threats to the environment and public health. Emissions of carbon dioxide (the leading gas responsible for global warming) from fossil fuel power plants increased by 18 percent between 1993 and 2001.[9] Tighter environmental controls have led to reductions in power plant emissions of acid rain-causing sulfur dioxide and smog-forming nitrogen oxides, but many older power plants continue to release dangerous pollutants at levels that would be illegal if the plants were built today. Meanwhile, the prospect of financial gain has created pressure to draw even more power out of existing nuclear plants – generating additional nuclear waste and potentially creating safety problems.[10]

These developments and others have led policy-makers to take a second look at electric industry restructuring. In some cases, state officials have stopped the process of retail restructuring dead in its tracks, while others have altered the terms of restructuring to extend rate protections for consumers. At the regional and federal level, regulators, grid operators and others have scrambled to come up with fixes for the system reliability and market manipulation problems that have developed in the transition to competition. Federal efforts to restore momentum to restructuring have encountered significant opposition. And at some levels of government – particularly the federal level – the desire to create markets in electricity appears itself to have become the central goal, regardless of the ultimate impacts on consumers or other stakeholders.

The result is a system adrift – one in which neither investors, nor consumers, nor government officials have a clear idea of what the future shape of the industry will look like. Virtually every observer of the process has called for the restoration of certainty and clarity to the process – yet, there is little agreement as to what such a "certain" or "clear" regulatory structure should look like.

This document revisits the question of the future structure of the electric industry from the bottom up – that is, from the perspective of consumers, primarily small consumers. With all the attention that has been given to designing workable wholesale and retail electricity markets, it is easy to lose track of the attributes and values consumers seek from the electricity system. What do consumers want and need from the electric system? And what market and regulatory structures will most effectively deliver those values?

In this paper, we attempt to arrive at answers to those questions by first reviewing the nature of how consumers relate to electricity. We then review the current status of electric industry regulatory structures and the recent performance of the industry under restructuring. We propose a series of consumer-oriented principles for the future operation of the electric system and a series of regulatory changes to fulfill those principles. And finally, we present one view of how a new electricity industry that maximizes the efficient use of clean resources can provide tangible economic benefits for consumers and society.

To begin the task of crafting an effective regulatory structure for the electric industry, it is first necessary to examine the unique attributes of electricity within society, to identify the key requirements of various classes of consumers in the electricity marketplace, and to note some of the important tensions that have historically arisen in society's attempts to develop an electricity system that best serves the needs of consumers.

Unique Attributes of Electricity

The physical nature of electricity and the systems used to create and distribute it – coupled with traditional social assumptions about electricity – set the boundaries under which the system must operate. At least five basic attributes or tendencies deserve mention.

Electricity Is Both a Service and a Commodity

Imagine the following: A friend asks you if you would like two months' worth of electricity at half price. The only catches are that you have to take delivery within the next month, and you won't be able to receive electricity again for the following month.

Most of us would turn such a bargain down without hesitation. There is no cost-effective way to store two months' worth of electricity. And there is only so much electricity one can "spend" in a certain period of time in a beneficial way. Having electricity available for two months – even if one has to pay a premium for it – is generally preferable to being without it for any significant length of time.

The most attractive aspect of electricity for most consumers is that electricity is available on demand: 24 hours a day, 365 days a year. For most residential and other small consumers, therefore, electricity is primarily seen as a service.

While the provision of reliable electricity is of very clear value to consumers, the provision of electricity at the lowest price-per-unit is of less clear value. Electricity itself has little value to most small consumers; *rather, it is the services that electricity can provide* – heat, cooling, time savings (through the use of labor-saving appliances), and access to information and entertainment – that are important. If consumers have access to products that use less electricity, they may be able to pay higher rates for the electricity those products consume and still emerge with lower overall bills. There are many well-documented market barriers that prevent consumers from taking advantage of these efficiency opportunities (including information barriers; split incentives between builders and homeowners and landlords and tenants; and the need to pay for improved energy efficiency up-front versus over time). Fortunately, effective public policies exist that can reduce these barriers, but these policies have frequently been undermined by utility opposition or indifference and the loss of direction that has accompanied restructuring.

Efficiency improvements are equally, if not more possible for most larger consumers, such as industrial facilities. Large customers vary in their demands for reliability – for some, electricity is considered more of a commodity and price is of paramount concern. For others, particularly high-tech companies, service reliability may be of primary value.

Any regulatory system must prioritize quality service for small consumers, while striking an appropriate balance between reliability and price. To the extent possible, that system can provide industrial and other large consumers with fair opportunities to pursue either lower prices or ultra-reliable service – as long as those efforts do not shift undue burdens onto other consumer classes or saddle small consumers with unnecessary costs.

Finally, while it is convenient to think of the large, centralized electric system that has developed in the U.S. over the last century as a given, there are actually myriad ways to provide electric service to consumers. There is no inherent reason why consumers could not generate their own electricity, create new ownership structures for the industry, or demand that electricity be generated in ways that do less harm to the environment or public health – if these changes can be shown to be more economically or socially beneficial. The massive amount of capital invested in the existing system may limit opportunities for such changes in the short run, but in the long run, electricity's nature as an energy carrier permits great flexibility in how it can be created and delivered to consumers.

Electricity Service Tends Toward Monopoly

The provision of electricity service has long been recognized as a "natural monopoly," which is defined as a situation in which "a single firm can provide all of the output of all of the products at lower total cost than could be achieved by more than one firm."[11] Electricity has typically been thought of as a natural monopoly because the costs of stringing competing sets of poles and wires and building competing generating plants to serve local consumers have been greater than any economic benefits that would result from competition.

There is much debate about how far "up the line" tendencies toward natural monopoly persist. A few critics have suggested that not even the distribution of electricity is truly a natural monopoly, while others contend that the entire electricity system – from generation to distribution – is a natural monopoly due to the interdependence among various actors in the system and the need for tight coordination among those actors to operate the system effectively. It may be the case that some segments of the system – for example, distribution – tend toward monopoly while others do not. The tendency toward monopoly may even vary depending on location.

The experience of restructuring has not provided a definitive answer to the question of where natural monopoly within the industry begins and ends – advocates and opponents of market competition interpret the experience in vastly different ways. Wherever the line is drawn, however, companies within those sectors of the industry that are characterized by monopoly would possess almost unmitigated power to dictate prices and terms of service to their customers in the absence of regulation.

Thus, almost from the beginning of the industry, government regulation of rates and terms of service has been seen as essential to protect the public interest. In the beginning, regulatory power was largely held at the local level, exercised through the ability of local governments to grant franchises to investor-owned utilities or to provide power themselves. As utility systems consolidated and became more financially and physically interconnected, state governments – and eventually the federal government – exercised increasing regulatory control over the provi-

sion of electric power. At virtually all levels of government, the regulatory mandate was to provide "just and reasonable" rates and guarantees of reliable service to consumers, while allowing utilities the opportunity to earn a fair return on investment free from competitive pressures.

The Electric Grid Is a Dynamic and Tightly Coupled System

The electricity system that serves hundreds of millions of Americans can be thought of as three extraordinarily large machines: the Eastern, Western and Texas Interconnections. Each of these three electric grids operates, in a sense, as a very large unit with millions of interconnected parts. A failed power line or software problem on one portion of the grid can have repercussions hundreds of miles away – as millions of residents of the Northeast and Midwest discovered on the afternoon of August 14, 2003.

Moreover, each of these three giant machines must be controlled to create equilibrium between supply and demand under all possible conditions at every second of the day. The rotation of generators thousands of miles apart must be synchronized to within 1/60 of a second. As a result, successful operation of the grid requires a complex choreography involving the dispatch of generation, the maintenance of optimal levels of flow along transmission lines, and the accurate ascertainment of load in many different locations.

Vast, dynamic and tightly coupled systems such as the electric system are so complex in their day-to-day operation as to defy comprehensive human understanding. Changes to the system can have unpredictable effects. For example, the North American Electric Reliability Council (NERC) notes that increased bulk transfers of electricity and other changes resulting from restructuring have subjected the transmission system to "flows in magnitudes and directions that were not contemplated when it was designed and for which there is minimal operating experience."[12]

These aspects of electricity production and distribution have five effects on the structure of the system. First, within any substantial portion of the system, there must be a working system of communication and control designed to ensure reliable operation of the system on a second-by-second basis. The more pervasive the interconnections between portions of the system, the greater the need for overall coordination.

Second, the dynamism and interdependence of the electric system requires strict limits on individual behaviors that may compromise reliable operation. If transmission capacity in an area is constrained, for example, an economically beneficial transfer of power may not be permitted to go forward, or the price of such a transaction may have to increase. Participants in the system must adhere scrupulously to engineering and operating standards or risk damage to others far away. In short, there must be rules and the rules must be vigorously enforced.

A corollary to this point is that users of the grid – taken as a whole – have incentive to encourage individual behaviors that benefit reliability. Thus, it is acceptable and often prudent to pay individual consumers to reduce their load at peak hours of the day, to encourage them to adopt energy efficiency measures, or to defer power transfers on the grid, if these measures contribute to short- or long-term grid reliability. Determining how to allocate fairly the costs and benefits of these measures is not

easy. A poorly designed system can create perverse incentives, but a well-designed system can improve reliability, reduce environmental costs and lower rates.

Fourth, the need for all parts of the system to operate as a single unit creates the opportunity for individual actors or groups of actors to disrupt or manipulate the system for financial benefit. In conditions of scarcity, individual generation or transmission owners (or small groups of owners) can effectively hijack the system by withholding capacity that the system needs in order to meet demand – allowing them to charge exorbitant prices for their services. The opportunities for such manipulative and anti-competitive practices in such a system are rife.

Finally, maintaining reliable operation of a vast, dynamic and tightly coupled system requires that emergency systems, backups and redundancies be built into the system. These resources are expensive and rarely used, thus individual actors will have a strong incentive to avoid paying for them. As a result, some system must be developed to ensure that costs of these reliability measures are shared out equitably to all those who benefit from the reliable operation of the system.

Access to Electricity Is a Social Entitlement

Universal access to reliable electricity has long been enshrined as a goal of social policy in the United States. The desire to achieve universal access has been manifested in a host of policies with regard to electricity over time – from rural electrification efforts during the Great Depression to the obligation to serve written into utility franchises.

The ethic of universal access also relates to the provision of electricity service to low-income individuals. Through the rate-setting process and other means, states have often sought to insure that even the poorest individuals have a reasonable opportunity to obtain electric service.

Electricity Has a Large Societal Footprint

Like other elements of the economy, electricity has significant economic, environmental, safety and public health impacts. But the sheer size and scope of electricity's impacts set it apart.

Access to reliable electricity is a cornerstone of the American economy. Economic losses from the August 14, 2003 blackout that interrupted electric power for 50 million people for as long as two days have been estimated at approximately $6 billion to $10 billion. A single event, therefore, triggered by problems in one small part of the electric grid, caused damages representing about six-hundredths of a percent of the U.S. gross domestic product in 2002.[13]

In 2001, the generation of electricity consumed 40 percent of all energy used in the U.S., including 92 percent of all coal consumption, 25 percent of natural gas consumption, and 2 percent of petroleum consumption.[14] The consumption of fossil fuels for electricity generation has a measurable effect on domestic and world energy markets and could conceivably contribute to resource depletion as efforts to develop new gas and oil supplies struggle to keep pace with growing demand.

Generators of electricity emitted 39 percent of the global warming-inducing carbon dioxide resulting from fuel combustion in the U.S. in 2001, 22 percent of all smog-forming nitrogen oxides released to the air, 8 percent of all health-threatening small particulates, and 69 percent of all sulfur dioxide.[15] The depo-

sition of mercury from coal-fired power plants, the consumption of vast amounts of water by steam generators, and the destruction of land and water resources by coal mining are just a few of the other environmental impacts of the use of fossil fuels to generate electricity.

More than 100 commercial nuclear reactors are currently in operation nationwide. A major accident at any one of these facilities (along the lines of Three Mile Island or Chernobyl) could cause massive public health damage, societal dislocation and economic harm. In addition, tons of spent nuclear fuel and other radioactive wastes have been produced as a result of nuclear power plant operation, creating an expensive, long-term obligation on society to protect against human exposure and environmental contamination.

As a result of all these factors, society has an intense interest in minimizing the economic, environmental and public health risks posed by power generation. The economic transactions made by buyers and sellers in the electricity marketplace, therefore, do not occur in a vacuum, but are integrally related to the health and well-being of individuals who do not directly take part in those transactions.

Conclusion

The inherent and social attributes of the electricity system set the boundaries for appropriate regulation. Based on the above discussion, it is possible to arrive at several conclusions:

1. Society has a strong interest in the effective operation of the electric system in keeping with overall social and economic goals.
2. Reliable operation of the electric system depends on effective communication, coordination and cooperation among all participants in the system.
3. Electricity is unusually prone to anti-competitive (and therefore, anti-consumer) practices, due to its tendency toward monopoly and the ability of many individual actors to have significant impacts on the overall system.
4. In the short run, the electricity system is very inflexible – characterized by large sunk costs and intricate patterns of operation. Small changes in one segment of the system can have significant and unpredictable effects elsewhere in the system.
5. In the long run, the electricity system is very flexible. The resource mix used to generate electric power can be adapted to achieve economic, environmental and/or social goals. And there is ample opportunity for change on the demand side as well, through energy efficiency and other measures that can improve reliability and reduce cost to consumers and society.

Consumers' Needs in the Electric System

Thus far, we have discussed the inherent and social constructs that define the electric system. But what of consumers? What rights and protections do they need and deserve in order to protect their long- and short-term interests?

Electricity consumers are a diverse lot: from homeowners and small businesses to large industries and institutions. Often, the interests of these consumers collide – as a result, all consumers need fair and equitable rules to sort out conflicts.

However, on a surprising number of issues, the interests of all consumers within the system are consonant. Every user of the electric system, for example, has an interest in system reliability, stability, environmental quality, and the efficient provision of electricity – although individual consumers might prioritize these interests differently.

Due to electricity's large societal footprint, however, consumers also have interests in the operation of the electric system that go beyond their interests as customers of one particular utility. All consumers, for example, have an interest in ensuring that the electric system does not produce pollution that harms public health, or engage in over-consumption of scarce commodities, driving up prices in other segments of the economy.

The needs of consumers can be divided into three categories: service-related needs, procedural protections, and societal needs.

Service-Related Needs

It is likely that most consumers would rate the following concerns – in some order – as being their primary demands of the electric system.

- **Cost** – All other things being equal, consumers want their electricity to cost less, rather than more. But to focus solely on rates – the traditional gauge of cost – is to oversimplify. The size of the total monthly bill (rate times usage) as well as the volatility of prices from month to month and year to year are also major concerns.
- **Reliability** – Consumers want electricity to be available when they need it. Elements of reliability include a low number of outages as well as the speedy restoration of service after an outage.
- **Customer service** – Customers desire prompt, friendly service in billing, initiation or cancellation of service, restoration of power after outages, and other interactions.
- **Other** – Many consumers in restructured markets have shown a willingness to spend extra money for "green" electricity products – generally, those that are generated with a certain percentage of renewable resources or have other environmentally appealing characteristics. Some consumers might have other goals that are important to them in evaluating the provider of their electric service, such as the use of organized labor, support of charitable causes, or general reputation within the community.

The relative priority given to each of these qualities would likely vary from consumer to consumer, and most consumers would likely wish to see an effective balance between them – for example, the achievement of maximum reliability at a reasonable cost. In a market-oriented system, various products might spring up tailored to segments of the market; indeed, this has already occurred (to a very limited extent) in several states with retail restructuring. In the traditional regulatory system, such niche products have generally not been made available. Instead, regulators – advised by utilities and consumers – attempt to develop a small set of products for small consumers that balance these various interests.

Procedural Protections

Regardless of whether they are served by regulated or deregulated systems, individual consumers are entitled to certain procedural safeguards to ensure that they are able to adequately protect their own interests.

In a regulated monopoly, decisions regarding the allocation of resources and benefits are typically based on the rigorous, public evaluation of information using specific criteria. Because such decisions are made on the basis of protecting the broader public interest, however, those decisions are inherently political, and political constructs must be developed that guarantee that all stakeholders have a role in the process.

The following are among the procedural safeguards that are necessary to ensure that regulatory decisions are made in a fair and open manner:

- **Standards of evaluation** – Regulatory decisions must be based on a clear standard (for example, "just and reasonable" rates; "prudent" incursion of costs, etc.) established through a democratic process. The meaning of the standard must be fleshed out over time through case history and the use of precedent. Regulatory decisions must be based on the facts as established in the public record.
- **Due process** – Regulatory proceedings must follow a set of rules that are established in advance and treat all parties to the proceeding equally and fairly. Meetings must be conducted with adequate public notice and, ideally, at times and locations that are convenient to members of the public.
- **Participation** – Regulatory proceedings must be open to participation by all affected stakeholders. Any individual must be permitted to provide testimony for the public record.
- **Access to information** – All participants in the regulatory process must have access to all the information relevant to the issue at hand. Moreover, all participants must have equal access to the information – no participant should be able to gain advantage by keeping relevant information secret.
- **Right of appeal** – All parties must have the ability to appeal regulatory decisions that are not supported by the public record.
- **Independence** – Regulators making the decision should be free of financial or other ties to participants in the regulatory process that might create the impression of a conflict of interest.

In the classical conception of a free market, the broader public interest is arrived at subconsciously, through the individual actions of consumers acting rationally in their own best interests. However, firms within free markets do not always willingly provide consumers with the information they need to make "rational" decisions. Nor do free markets in some commodities or services allow for levels of competition that provide opportunities for consumers to voice their desires through their choices. (The tendency of electricity service toward monopoly has already been noted above.)

Thus, consumers acting in a market-based system – such as that intended for retail consumers in a restructured electric industry – require procedural safeguards to protect their interests. Among them are the following:

- **Access to information** – Consumers can only fulfill their responsibilities within a free market if they have access to accurate information about the products and services they buy. Information with regard to pricing, product content (in this case, the energy sources used to generate electricity), and terms of service must be explicitly described to consumers in terms that they understand, and gov-

ernment must have the authority to ensure that such information is accurate.

- **Protection of open, competitive markets** – Consumers can only make choices that serve their interests when they have a real choice. Government must protect the ability of competitors to enter the marketplace, primarily through antitrust laws as well as prohibitions against price-fixing and other anti-competitive behavior. In addition, government must be prepared to step in if competition fails to develop, either through more aggressive regulation of the services provided by companies in a position of monopoly or oligopoly, or through actions to encourage new competitors to enter the market.
- **Protection of consumer mobility** – In order to protect their interests, consumers must have the ability to change their behavior when it suits their needs. For example, the recent decision to allow portability in numbers for cellular phone users has sparked a new round of competition among telecommunications companies, bringing benefits to consumers. While there may be some circumstances in which consumers should not be permitted to change providers immediately, these should be the exception rather than the rule, and the time period during which consumers are "locked in" with a provider should be minimized.

In markets for goods and services that are essential to individual or societal well-being, even these procedural safeguards may not be enough. Consumers may require other protections – such as the right to appeal the discontinuation of service and protections against "redlining" (the refusal to offer service or assessment of discriminatory rates to particular classes of consumers) – to ensure that market participants are not permitted to victimize the least fortunate.

Societal Protections

Finally, as noted above, decisions with regard to the electricity system have broad societal implications. Failing to include the societal impacts of electricity generation, transmission and distribution within the regulatory process would lead to distorted decision-making. The impetus for consideration of these impacts may not come from participants in the rate-making decision – and indeed, the impacts may be addressed outside of the rate-making process entirely – but they must be considered.

Among the major external effects of electricity are:

- **Environmental externalities** – The generation of electric power produces air and water emissions that can damage the environment and public health. The production of fossil and nuclear fuels used in electricity generation also causes negative impacts. Regulations at various levels of government attempt to protect the environment and public health from the most egregious of these impacts, but regulatory systems must also account for these impacts by developing tools that seek to prevent pollution before it occurs.
- **Economic impacts** – The decisions made with regard to the electric system have far-reaching economic consequences. For example, the frequent choice of natural gas for new electric generating capacity over the past decade has led to tighter supplies that have increased prices for both residential users of natural gas and industries that use natural gas as a

feedstock (for example, fertilizer manufacturers). The long- and short-term economic impacts of a given decision should be considered intelligently within the regulatory process.

Consumers, therefore, have a variety of needs and desires with relation to the electric system. Different classes of consumers may have different needs, but all have an interest in the development of consistent procedural safeguards. In any event, the desires and needs of consumers extend far beyond the desire for low rates in the short term.

Tensions in Electricity Regulation

Given the unique nature of electricity, the complexity of the electricity system, and the wide variety of consumer needs that the system must serve, it is no surprise that the regulation of electricity produces its share of tensions and trade-offs. We identify six of those trade-offs here; there are likely many more.

Markets vs. Regulation

Advocates of free markets argue that the market is the most effective mechanism available for achieving the optimum distribution of resources within an economy. Others believe that democratic political systems tend to yield socially optimal results, particularly in the provision of essential public services such as electricity. This theoretical debate often obscures how markets and regulatory systems operate in reality.

In fact, there is no such thing as a perfect market or a perfect regulatory system. Both systems pose significant risks, while each has potential advantages. Experience in advanced economies such as those in the United States and Europe demonstrates that a mixed system of market and public decision-making is essential for long-term success – especially for important systems such as electricity.

Market Systems

The recent restructuring of the electric industry is predicated, in part, on the notion that the various interests of consumers can be balanced through the interplay of the free market. With competition, it is believed, consumers can choose electricity products that better fit with their individual needs and desires. At the same time, competition will serve to weed out inefficient operators and shift market risks to suppliers – both developments with potential benefits for the broad mass of consumers.

However, markets have several potential drawbacks:

- **Inequities –** Markets ideally work to create an economically efficient outcome; that is, the maximum aggregate good. However, an economically efficient outcome is not necessarily an equitable one. A free market might, for example, give substantially greater rewards (in the form of lower prices) to large industrial users of electricity. In contrast, low-income consumers, those who live in areas that are costly or difficult to serve, or those served by only a small number of competitive suppliers, might experience few, if any, benefits.
- **Volatility –** Energy is well-known for its price volatility. Prices for gasoline, heating oil, natural gas and other fuels can swing widely from season to season and even day to day based on fluctuations in supply, storage, demand and other market conditions. With regard to electricity, this prob-

lem is compounded. In addition to fluctuations in prices for the fuels used to generate electricity, scarcity in generation or transmission capacity can allow market actors to charge – and receive – exorbitant rates for power at periods of high demand. An electricity market in which suppliers were free to set market-based prices would subject consumers to this same type of volatility, with prices increasing and decreasing dramatically – perhaps even on a minute-by-minute basis.

- **Threats to reliability** – Markets can be a double-edged sword with regard to system reliability. On one hand, market operations allow individual consumers to truly express their interests in reliability through the prices they are willing to pay, and create opportunities for providers to offer new products that guarantee very high levels of reliability to those who need it most. As long as these market forces do not degrade the reliability of the electric service available to the broad cross-section of consumers, the result may be a net positive for reliability.

  On the other hand, the efficient operation of the electric grid depends on both the effective day-to-day management of the system and accurate long-term planning. Markets are often characterized by instability and turmoil – companies come and go, capital flows shift, plans for new construction are delayed or canceled. In other industries, such instability would not be especially damaging; in electricity, it has the potential to threaten the reliable operation of the entire system. If one considers system reliability to be a societal goal, rather than a priority of individual consumers, this situation would be of very great concern.

- **Competition vs. cooperation** – On a similar note, the maintenance and operation of the electric grid requires extraordinary cooperation among a variety of entities. In the past, cooperation was often voluntarily given, since electric utilities did not typically engage in direct competition with one another. In a market, such cooperation must be compelled, either through rules or through pricing scenarios that encourage cooperative behavior. However, in so doing, the system must walk a tightrope – as cooperation and integration increase among firms, so do the opportunities for collusion and other forms of anti-competitive behavior. Devising market systems that encourage the right kind of cooperation while preventing the wrong kind of cooperation is extremely difficult.

- **Market boundaries** – Very few individuals, even among those who support industry restructuring, believe that there will be no role for government price regulation in the electricity system of the future. At the very minimum, distribution service to small customers is likely to remain regulated. Under such a structure, consumers who turn on a light switch will be simultaneously buying a regulated product (transmission and distribution service) and a deregulated product (energy).

  There will be a strong incentive, therefore, for sellers of deregulated energy products to shift as much of their costs and risks as possible onto the regulated portion of consumers' electricity bills. And, due to the common ownership of many regulated and deregulated players in the electricity market, the opportunity for such cost-shifting is very real. To the extent that those costs and risks are

no greater than what would have been incurred under a vertically integrated, regulated utility, consumers may be no worse off. But if unregulated entities are permitted to engage in risky activities – and directly or indirectly make the regulated services assume the costs and risks – consumers could be greatly hurt.

- **Market power and manipulation** – The ability of monopolies or oligopolies to set exorbitant prices for goods and services is well known. In an industry that arose from regulated monopoly, and even now is largely controlled by a small number of entities, the threat that market participants might exert "market power" – the abuse of a party's control of essential facilities to unreasonably drive up prices – is a very real concern. But in the electric industry, not only is this traditional type of market power a concern, but under certain conditions (especially high demand), even very small actors can exercise market power by withholding generation needed to serve consumer needs. The western energy crisis provided numerous examples of the type of market manipulations that can occur in a market-oriented electricity system.
- **Lack of choice** – A market can only effectively reflect consumers' desires if consumers have a variety of products and suppliers to choose from. The experience of retail restructuring in the states that have tried it is not encouraging, with very few consumers having opted to switch providers. The math is discouraging as well. A consumer paying 10 cents per kilowatt-hour (kWh) for power who uses 700 kWh per month would spend approximately $70 per month on electricity. Assuming that 60 percent of the bill is subject to competition, the consumer would need to see a roughly 17 percent reduction on the competitive portion of the bill in order to achieve a 10 percent reduction in his or her total bill – about the level of savings required to convince many customers to switch providers. Given that would-be competitive suppliers also face increased costs (such as marketing), such a company would need to produce or obtain power at far lower cost than incumbent providers in order to have an incentive to enter the retail market. The elimination of retail price regulation, therefore, would likely result in few choices for consumers, and reduced protection against unjustified increases in price. This is not to say that there are not some segments of the market in which competition could arise – merely that such a prospect is unlikely to develop in large segments of the residential market and could arise in other market segments as well.

Regulatory Systems

Whereas the market approach to electricity attempts to sort out social interests in the hurly-burly of the marketplace, the traditional regulatory approach attempts to resolve them in the hurly-burly of the rate-setting process. Unlike the market, all consumers – regardless of how much electricity they use – theoretically have equal rights within the process and an equivalent ability to influence the outcome. A well-run regulatory system can ensure rate fairness and equity and seek to achieve broader economic and social goals in ways that pure market systems simply cannot.

Regulatory systems are only as successful as the authority on which they are based, the integrity of the process under which they are run, and the qual-

ity and independence of people who make the decisions. There are numerous examples of utility regulators who have intelligently and courageously defended the public interest, and many other examples of those who have made decisions that cost the public dearly. All regulatory systems – no matter how well-run – pose several potential drawbacks to consumers.

- **Perverse incentives** – Unlike market systems, in which incentives and disincentives for individual actions are set in the economic arena, incentives and disincentives in regulatory systems are largely set by regulators. Sometimes these incentives can be perverse: rate structures that provide utilities with additional profits based on increases in energy consumption, for example, inherently discourage utilities from aggressively pursuing energy efficiency opportunities that might be socially beneficial.[16]
- **Regulatory capture** – Any individual consumer has little direct stake in the rate-setting process, with most consumers standing to gain or lose a few dollars per month at most on the outcome of a rate case. For utilities, however, the stakes in rate cases are incredibly high, as they are for industries that consume large amounts of electricity. As a result, utilities and large consumers have strong incentives to influence all aspects of the regulatory process. Without provisions to ensure that consumer interests are voiced and heard in the process, this can lead to a situation in which regulators are "captured" by the interests they are supposed to regulate, putting the broader public interest second.
- **Socialization of risk** – When participants in competitive electric markets make bad decisions, they (as well as their stock- and bondholders and potentially their creditors) pay the price. When regulators or regulated utilities make bad decisions, all ratepayers usually pay the price. Consumers are given some measure of protection through the power of regulators to review the prudence of utility investments and refuse cost recovery to those deemed imprudent, but this process is not frequently used. As a result, consumers have been forced to pay billions of dollars, for example, for poor investments in nuclear power plants – investments that continue to cast their shadow over the industry today.
- **Lack of choice** – There is no fundamental reason why regulators could not require regulated utilities to offer a variety of products to consumers. In practice, however, this has been attempted very infrequently. As a result, most consumers in regulated systems must use "plain vanilla" products, regardless of whether a more customized product would better fit their needs.

State vs. Federal Authority

Beyond the question of how much to regulate is the question of who should do the regulating. The system of government in the U.S. is defined by federalism, with federal and state governments sharing interlocking responsibilities.

Yet, the federal/state breakdown of responsibilities does not tell the full story on at least two counts. First, within many states, local governments play a very important role, often negotiating utility franchises, deciding whether to participate in market aggregation programs on behalf of their citizens, or sometimes acting as suppliers of elec-

tricity themselves. From the very beginning of the industry, there has been a strong local prerogative, and that prerogative continues to exist today.

Second, many important decisions with regard to the electric system are made at the regional level. Regional bodies such as regional transmission organizations (RTOs), independent system operators (ISOs), and regional electric reliability councils are largely responsible for issuing and enforcing the rules that govern the day-to-day operation of the electric grid. While these organizations are not governmental entities, and are subject to regulation by the Federal Energy Regulatory Commission, they do play a pseudo-regulatory role in effect – a role that has become increasingly important over time as wholesale interstate markets for electricity have developed. In addition, these entities tend not to operate under the same rules for open decision-making along public interest criteria as federal or state regulators.

Both the federal government and the states have legitimate roles in utility regulation and will likely retain those roles for the foreseeable future. Only the federal government could effectively regulate the finances of multi-state utilities or create a national energy policy. The states, meanwhile, tend to be more attuned and responsive to the needs of local consumers, and the apparatus of decision-making is far more accessible to consumers and their advocates.

All other things being equal, a consumer-friendly electric system would appear to be more likely to arise from a level of government in which citizens are able to participate personally in the decision-making process and in which decision-makers can be held most directly accountable for their actions. This would suggest that, where possible, decisions on the shape and functioning of the electric system should be made at the local or state levels.

There is a fine line, however, between being responsive to local concerns and engaging in parochialism. The interdependence of the electric grid demands that an effective source of authority operate at the regional and national levels. Should states exercise primary authority over the industry (or at least that part of it that most directly affects consumers), they will also need to find effective ways to work together regionally – or risk ceding authority to the federal government or to regional organizations that are outside of their control. Given that federal regulators have a mixed record (at best) as effective watchdogs for consumers, retaining authority at the state level is quite important. However, there are many regulatory tasks that states simply cannot perform effectively. A federal authority that is both respectful of state prerogatives and aggressive in carrying out its own mandates is a necessary part of any strategy to improve the electricity system.

Centralization vs. Decentralization

Technological and policy changes over time have resulted in the creation of an electric system in which power is generated at large, central-station power plants and transmitted across a network of high-voltage wires to local distribution systems, which then serve end users. The current physical and regulatory structure of the system can constrain ways of thinking about the future of the system. A centralized electric grid is not the only way to supply electricity to consumers, nor do the forces of evolution move in only one direction – toward increased centralization.

In recent years, some have suggested that a different physical structure of the

system is possible, one in which the centralized electric grid plays a far less important role. In this decentralized structure, power is generated close to the point of use and is controlled by much smaller entities – individual homeowners and businesses. The regulatory structure that would ideally govern such a system is obviously significantly different from that which governs the centralized system in place today.

Both centralization and decentralization have inherent benefits and costs. A centralized system is characterized by the following:

- **Economies of scale** – For much of the history of the electric industry, there were significant economies of scale to be gained from the generation of electricity at large centralized power plants. Those economies of scale dissipated with the advent of efficient gas turbines in the 1990s, but could become more important given the recent upsurge in proposals for new coal-fired power plants. Economies of scale manifest themselves in other ways as well. Most consumers and businesses, for example, have never run a power plant of any size, but utilities and generation companies have years of experience in doing so – experience that may enable them to perform more efficiently.
- **Interdependence** – The centralized power system allows electricity to be shifted from locations where it is not currently needed to areas in which it is in demand. It also allows for consumers in one area to gain access to power generated far away. These aspects can improve the efficiency and reliability of the overall system at lower total system cost. On the other hand, interdependence also allows for problems in one sector of the grid to affect consumers far distant, posing a potential threat to reliability, as we learned in the August 2003 blackout.
- **Transmission and distribution losses** – It is estimated that about 9 percent of power generated at central power plants is lost in transmission and delivery, decreasing the functional efficiency of centralized power systems.[17]
- **Large sunk costs** – The construction of centralized power plants and transmission systems is extremely capital-intensive and expensive to those who bear the costs. The construction of a large power plant, therefore, is a very risky endeavor that must be undertaken based on projections of future demand and market conditions that may or may not be accurate. The capital intensive nature of the centralized system also locks in costs for long periods of time, reducing the adaptability of the system to future needs.

A decentralized system, on the other hand, would have similar – if converse – costs and benefits. Characteristics of a decentralized system include:

- **Modularity** – Smaller power generators are able to be sized and operated in closer proximity and scale to sources of demand. Enterprises operating smaller scale systems, however, may not be able to assemble the balanced load profiles that would enable them to operate at peak efficiency. In this way, they may face a disadvantage compared to larger systems.
- **Independence** – Small power systems can be isolated from problems occurring on the larger grid, enabling them to provide power even in the midst of a major grid disturbance.
- **Efficiency** – Small power systems are not inherently cleaner or more energy efficient than larger systems, but they do present some opportunities for

improved efficiency. In combined heat-and-power applications, for example, waste heat from the generation of power is used to heat buildings, improving the overall efficiency of the system.

- **Reliability** – The provision of backup and redundancies is an area in which large-scale systems benefit from significant economies of scale. Owners of small-scale systems must make provisions for how to obtain power when the system is not functioning due to maintenance or an outage. This requires either the purchase of an additional backup system or standby service from the electric grid – both of which can be expensive.

Like the differentiation between state and federal authority, centralization is a matter of degrees. It is possible to combine aspects of centralized and decentralized power production that help realize the benefits of each approach. Such a hybrid approach would maintain a central backbone of generators and transmission lines, but encourage the development of smaller-scale distributed resources that can meet an increased share of the demand within a given area. But such a result can only be achieved if it is an explicit goal of regulation. Otherwise, the inertia caused by decades of investment in the current structure will distort decision-making.

Public vs. Private Ownership

The debate over whether essential public services should be publicly owned or provided by the private sector stretches back more than a century. In some cases – such as water and sewer service – public ownership predominates. In others, such as telephone and natural gas service, private ownership is most common.

Ownership of electricity assets in the U.S. is split between public and private ownership. Publicly owned entities (including municipally owned utilities, cooperatives and federal power agencies) generated 21.5 percent of all power in the U.S. in 2002.[18] These entities were also responsible for 27.5 percent of electricity sales to ultimate consumers.[19]

Public ownership in the U.S. takes four predominant forms:

- Publicly owned utilities are typically established by one municipality or a group of municipalities. Publicly owned utilities may own generation, transmission and distribution equipment, though they may also purchase power from investor-owned utilities.
- Cooperatives are generally organized in rural areas. They typically do not own generation facilities or transmission lines (although some take part in generation and transmission cooperatives), but rather purchase power from investor-owned utilities, publicly owned utilities, or the federal government.
- Federal power agencies have traditionally been used to distribute power from federal hydroelectric projects, although some – such as the Tennessee Valley Authority – also own other forms of generation. These federal authorities own generation and transmission facilities, but do not generally distribute power to end-use consumers. Rather, the power is sold to investor-owned or publicly owned utilities or rural cooperatives, which then distribute the power to consumers.
- Several states have established state power authorities (such as the New York Power Authority) roughly on the model of the federal power agencies.

Advocates of public ownership of utilities point to greater accountability to the public and lower rates to justify their support. Indeed, advocates going all the way back to Franklin D. Roosevelt have viewed the performance of publicly owned utilities as a "yardstick" against which citizens could measure the performance of investor-owned utilities.

Opponents of public power suggest that private ownership provides a better fit with the American economic system and claim that implicit subsidies for public power systems create an unlevel playing field.

Traditionally, the choice of whether to adopt public ownership of utilities has been left to citizens at the local level, where it should remain. In some cases, several communities may wish to work together to pursue public ownership, while states may wish for various reasons to pursue public ownership of generation capacity. But public power does not exist in a vacuum – it must often use the same transmission network as investor-owned utilities to deliver its electricity to consumers. While publicly owned utilities are not subject to the jurisdiction of the Federal Energy Regulatory Commission or many state public utilities commissions, the decisions made by those entities regarding the conduct of investor-owned utilities can have a strong influence on whether public power can continue to serve its mission.

Resource, Environmental and Political Constraints

The electric system operates within boundaries set by society and the natural environment. These boundaries cannot be wished away. Instead, they must be recognized and dealt with squarely in any effective regulatory or market system.

Resource Constraints

As an energy carrier, electricity can be generated from a variety of fuels and energy sources – many of which are inherently limited in their availability. When, for example, supplies of oil or dammable streams run low, it is not possible to create more. To the extent that the construction of generation or transmission facilities is designed to take advantage of one specific fuel, the existence of resource constraints could make long-term, capital-intensive investments in those facilities less attractive.

Resource constraints are very likely to affect two fuels used in generating electricity within the near- to mid-term.

- **Natural gas** – Production of natural gas in the U.S. has not kept up with increased demand – particularly from electric power plants. Between 1989 and 2002, natural gas consumption in the U.S. increased by 17 percent. During the same period, domestic production of natural gas increased by only 10 percent, while the number of producing gas wells in the U.S. increased by 40 percent.[20] The electric power sector was responsible for the vast bulk of the increase in domestic consumption, with the consumption of gas for power production increasing by 79 percent between 1989 and 2001.[21] In short, more wells are being drilled, each well is producing less gas, and consumption – particularly in the electric sector – continues to increase.

  Unlike petroleum, which can be easily imported from overseas, imports of natural gas to the United States have been limited to pipeline ship-

ments from neighboring countries and overseas shipments of liquefied natural gas (LNG). LNG shipment is expensive and potentially dangerous. In the wake of the September 11 attacks, communities near LNG terminals and shipping lanes have expressed strong concern about the potential damage that would result from terrorist attack. And the opportunities for a dramatic increase in domestic supply are limited: even if natural gas drilling is expanded to even more environmentally sensitive areas, it would be unlikely to change the overall equation, and could cause serious harm.

The supply situation is likely to become even more tenuous in the years to come. While plans for new natural-gas fired power plants have dropped sharply, about 184 gigawatts of natural gas-fired capacity are still planned to come on line over the next several years.[22] Most observers believe there will be no return to the low natural gas prices that fueled the power plant construction boom of the 1990s. For example, Federal Reserve Board Chairman Alan Greenspan told a U.S. House committee in June 2003, "Today's tight natural gas markets have been a long time in coming, and futures prices suggest that we are not apt to return to earlier periods of relative abundance and low prices anytime soon."[23] The result is that consumers will end up paying more for both natural gas used for heating and for electricity, and utilities will seek to increase generation from coal – posing severe environmental problems.

- **Petroleum** – Petroleum provides only a small portion of America's electric power – less than three percent – but it is disproportionately important in certain areas of the country (e.g. the Northeast) and as a substitute for natural gas in dual-fuel generators. The history of price spikes and supply disruptions in petroleum is well-known and some observers predict that increases in global consumption, coupled with the depletion of oil reserves, could result in a worldwide peak in oil production sometime within the next decade, bringing sharply higher prices and shortages.

Natural gas and petroleum are not the only fuels that face resource constraints. Over the past several decades, for example, imports have overtaken domestic production as the primary source of uranium for nuclear reactors.

Environmental Constraints

The electric power system has a massive environmental footprint. Water pollution and land destruction from strip mining of coal, threats to marine environments posed by offshore drilling and the transport of oil, the discharge of hazardous air pollutants from coal-fired power plants, the constant environmental and public health threat posed by the operation of nuclear power plants and storage of spent fuel, and the contribution of fossil fuel consumption to global warming are among the many impacts – too numerous to mention – of electric power generation.

Traditionally, environmental regulation has been treated as an unknown (and often unknowable) factor in the planning of electric power systems. In the long term (which is the frame through which most major capital investments in the electric system are viewed) this view betrays a lack of foresight. While one cannot predict exactly what forms environmental regulation

might take, one can reasonably anticipate that future environmental regulations might serve to limit the use of certain fuels – such as coal and nuclear power – with serious unsolved environmental problems. A wise regulatory system would recognize and anticipate these constraints, and integrate pollution prevention as a primary operating principle. In addition, including the consideration of future environmental compliance and public health costs in regulatory decision-making would reduce the artificial advantage polluting energy sources such as coal currently possess.

Political Constraints

Finally, it is important to recognize that all facets of the electric system – regulated or not – are influenced by political decisions at a variety of levels. Siting, for instance, is one area in which political constraints must be recognized. For example, even if the construction of a generation of new nuclear plants were shown to make economic sense on its own terms (an unlikely prospect, given the industry's history of high costs and massive taxpayer subsidies), the chances of finding communities willing to host such facilities are slim – absent a significant curtailment of the right of the public to participate in democratic decision-making.

Similar problems also crop up around the siting of transmission lines, natural gas pipelines and other energy facilities. A prudent regulatory system based on democratic principles would seek to minimize the need for controversial facilities, while creating appropriate mechanisms for those beyond the local community who might benefit from the construction of a particular facility to also have a say.

Transition Issues

Lastly, it is important to recognize that we are not building an electric system from scratch. A vast and capital intensive infrastructure has been created to generate and provide electricity. Any transition within the industry – whether it be from regulated to market-based provision of electricity services or from centralized to decentralized generation – must take into account the needs not only of those who are taking part in the transition, but also those who continue to be served by the existing system.

The central issue in any transition is how to recover costs for infrastructure that has been built to service a particular customer once that customer decides to leave or curtail his or her use of the system. Without some provision to recover those costs, an individual could choose to provide his or her own power, or seek a better deal on the market, leaving other consumers to cover the costs of investments that have been made on that individual's behalf.

States have grappled with the issue of "stranded costs" recovery with respect to deregulation and we will not reopen that debate here, other than to note that utilities also bear some responsibility for past uneconomic investments in infrastructure and should be required to bear some of the burden in paying off those investments. But the stranded costs issue is not limited to deregulation proposals – it also appears in discussions surrounding distributed generation, with the key question being whether to assess exit fees or other charges to consumers who leave the electric system entirely or dramatically scale down their use of power from the grid.

Transition issues also appear in the move toward competition in wholesale and retail markets. In most cases, there are not a fleet of competitive generation

companies or retail electricity marketers ready to enter a market at the drop of a hat once deregulation takes effect. How will consumers' interests be protected in a "competitive" market during the period in which vigorous competition does not yet exist? And if consumers should be protected during this period, how do those protections influence the willingness of new firms to enter the market?

Transition issues present among the most difficult "chicken and egg" problems in electricity regulation. It is possible to imagine that higher costs or other negative impacts during a transition period may be justifiable from the consumer point of view if a) the transition period is relatively short, b) the ultimate new form of the system guarantees benefits for the vast bulk of consumers that significantly outweigh any costs incurred during the transition, and c) no group of consumers is disproportionately harmed. Such determinations of long-term costs and benefits need to be made with a hard-headed, realistic view of the benefits and costs of various models of the electricity system and from the perspective of ordinary consumers. And, perhaps most importantly, they need to be made with the full participation of affected consumers in the decision-making process.

Conclusion

Creating an efficient electricity system that provides reasonably priced, reliable service to consumers with minimum negative external impacts is a challenge. Consumers' interests in the electricity system are far more complex than just a desire for low rates – indeed, for many consumers, reliability of service, rate stability, environmental responsibility and the size of their overall electricity bills are likely to be of as great concern as the per-kilowatt-hour charge on their electric bills. Similarly, the unique attributes of electricity and structure of the electric system mean that approaches that might work in other areas of the economy – such as large-scale deregulation – may have significantly less effectiveness if applied to electricity. The national scale and importance of the electricity system – along with its major social impacts – demand participation in decision-making from citizens and governments at all levels. Finally, all must recognize that the electricity system cannot be turned on a dime – the transition to a system that better serves the needs of consumers must occur in line with well-established goals and implemented with both the short- and long-term needs of consumers in mind.

THE ELECTRIC SYSTEM TODAY

The past decade has seen a series of sweeping changes in the governance, structure and day-to-day operation of the electric industry. In general, these changes have moved electricity away from its century-long status as a closely regulated monopoly and toward greater reliance on markets to set the direction of the industry.

Despite the significance of these changes, for many Americans, the fundamental aspects of electricity service remain as they have been for decades. Most consumers continue to obtain their electricity from the same utility that has always provided it to them (even if, perhaps, the name has changed), and at roughly the same price as before.

Indeed, by looking at the state and federal statutes that supposedly govern the electric industry, it is easy to come to the impression that not much has really changed. Both the federal government and the vast majority of states retain the core responsibility to set "just and reasonable" rates for electricity – a responsibility that has traditionally justified rate-setting on the basis of the cost of providing electricity service.

Nonetheless, the electric industry today is far different than it was five, 10 or 20 years ago. To understand how the industry has (and has not) changed – and what impacts those changes have had on consumers and society – it is first necessary to look at the legal and regulatory framework that governs the industry. Then, we will examine recent trends in the cost of electricity service to consumers and identify emerging trends that may affect consumers in the years to come. Finally, we will identify several key problems facing the electric system today, and begin to arrive at some conclusions about the steps that will be necessary to create an electric system that puts the needs of consumers, and the broader public interest, first.

The Current Status of Electric Industry Regulation

Overview of Regulatory Authority

Authority over the electric industry is held at many levels of government, and there is great variety in how the industry is governed across states and regions of the country. In general, however, levels of government have the following areas of responsibility:

- **Local governments** are responsible for choosing investor-owned utilities to serve their communities or establishing municipally owned utilities to provide service.
- **State governments** set rates for the retail sale of electricity to consumers and regulate the activities of local utilities. State governments generally also have responsibility for determining the sites on which electricity facilities can be built, ensuring the protection of low-income consumers and setting policy on energy and environmental issues.
- The **federal government** regulates the interstate wholesale transfer of electricity and has the power to set rates for wholesale transactions. Federal agencies also regulate the corporate structure and activities of multi-state utility holding companies. Other federal agencies also set broad policy on energy and environmental issues.
- **Regional bodies** are created by either the federal government, state govern-

"Restructuring" Defined

In general, "restructuring" can be defined as any substantial change to the traditional structure of the electricity industry: namely, the provision of power by vertically integrated, largely investor-owned utilities, whose rates are determined by regulators on the basis of the cost of providing electricity service to consumers. Over the past decade, restructuring has taken place at two levels:

- **Wholesale restructuring** has been characterized by the opening of markets for the sale of power to traditional utilities and other end-use suppliers and, in some cases, directly to large industrial users. Under wholesale restructuring, any generator of electricity is able (in theory, at least) to send their power over the transmission system on non-discriminatory terms – regardless of who actually owns the transmission wires. Moreover, the rates generators can charge for such sales are primarily determined by markets. The existence of wholesale restructuring does not change the relationship between consumers and the utilities that serve them, but it does change the way utilities secure power to satisfy consumer demand. It is also important to understand that changes in the ownership of generation fleets and the restructuring of wholesale power relationships has occurred across the nation to a much greater degree than has retail restructuring.

- **Retail restructuring** is characterized by efforts to allow consumers to choose their suppliers of electricity. Under retail restructuring, individual consumers may purchase electricity from any licensed supplier at market rates. The task of transmitting and distributing that electricity remains a regulated function, with rates fixed by state regulators. In retail restructuring, vertically integrated utilities are required to either functionally separate their generation and distribution functions or to divest themselves of their generators, in order to eliminate any unfair advantage their ownership of generation may give them in the market.

ments or utilities themselves to manage regional wholesale electric markets and facilities. They do not have governmental powers, but have been delegated important regulatory responsibilities.

Local Regulation

The role of local governments in electricity regulation has often been overshadowed – particularly in the recent era of sweeping changes to state and federal regulatory mandates. Yet, for more than a century, local governments have largely had the power to decide the most basic questions related to electricity service: who provides it and under what terms.

The power of local governments over electricity service is derived from their control over the use of the public rights of way over which electricity distribution lines must be built. Municipalities can choose to extend the right to use those public rights of way to one utility or many, and can require compensation for that use. The basic agreement between the municipality and the utility is called the franchise agreement, and lo-

cal governments can attach a variety of conditions to that agreement – requiring, for instance, the connection of electricity service to anyone within the defined service territory who requests it.

Local governments also possess another option: to provide electricity to their citizens directly through ownership of a municipal utility. Municipal utilities own and operate the distribution system for the community, and may either generate their own power or purchase it from other private or public entities.

Franchise agreements with investor-owned utilities are typically long-term contracts – limiting the opportunities for the community or the utility to renegotiate the agreement. At the expiration of a franchise, municipalities may do one of several things: renew the agreement (perhaps with revisions), terminate the agreement and seek another provider (although this may be difficult in practice), or purchase the utility's facilities and offer itself as a provider of electricity service.[24] The threat of "municipalization" of electricity service is one of the major points of leverage communities have to achieve better terms of service from investor-owned utilities – a power Franklin D. Roosevelt famously likened to a "birch rod in the cupboard."[25]

Local governments may also possess other roles in regulation beyond the extension of franchises or establishment of municipally owned utilities. For example, in at least 14 states, according to the Edison Electric Institute, no state agency has siting jurisdiction over power plants.[26] In these states, county or local governments have primary jurisdiction over where power plants and other energy facilities may be located. In some other states, such as Florida, state agencies may have exclusive jurisdiction over siting, but power plant owners must also comply with local land use laws.

The extent of local authority over the electric system varies from state to state. Some utility franchises and state laws limit the flexibility of municipalities to take over utility assets. Clearly, however, local governments have significant powers to shape the utility services they receive – if they choose to use those powers.

Local governments have even greater powers when they own municipal utilities. Many state utility regulatory schemes grant more autonomy to municipally owned utilities – exempting them from the normal process of rate-setting and other regulations. While state, regional and federal decisions – particularly over the operation of the transmission system and wholesale electricity markets – can have profound effects on publicly owned utilities, the basic decisions regarding how electricity service is provided are made at the local level.

Local Regulation Under Restructuring: Municipal Aggregation

Many states that have implemented retail restructuring have explicitly preserved a role for municipalities to negotiate the provision of power to their consumers through the process of municipal aggregation.

Aggregation is the process by which a group of consumers join together to shop for electricity as one entity – in effect, forming a buying pool to allow collective negotiation of lower rates. In the 24 states that passed legislation to restructure their electricity markets (several of which have since delayed or reversed the transition to retail competition), 21 specifically provided for aggregation. The other three (Dela-

ware, New Hampshire, and Oklahoma) did not specifically prohibit it, but made no provisions for it.[27]

Depending on the state law, an aggregator can be a municipal government, county government, or any group of consumers. Both non-governmental and municipal aggregators generally operate under an "opt-in" system, in which they must receive written approval from electricity users before bargaining on their behalf. This provision tends to undermine the effectiveness of aggregation by increasing the cost and difficulty of assembling blocs of consumers that will be attractive for competitive suppliers to service.

In a growing minority of states, municipal aggregation is permitted on an "opt-out" basis. Under opt-out aggregation, municipal governments negotiate for electricity service on behalf of their residents, much as they once had through franchise agreements with vertically integrated utilities. Consumers are automatically included in the aggregation unless they choose to remove themselves.

Opt-out municipal aggregation has provided some of the few success stories in retail restructuring. In Ohio's successful Community Choice program, for example, municipalities that have been authorized by a majority vote of their resident citizens can develop aggregation plans. Consumers are notified that they will be automatically enrolled in the program unless they specifically choose not to participate.[28] Through 2002, 93 percent of consumers who chose alternate electricity suppliers in Ohio in the wake of retail restructuring did so as part of an aggregation program.[29]

California, Massachusetts, New Jersey, Ohio, and Rhode Island all have provisions to allow some form of opt-out aggregation.[30]

State Regulation

State governments have traditionally held the preeminent role in the regulation of electric utilities. Through their broad powers to regulate retail rates and terms of service, to determine the extent to which the public can own electricity infrastructure, and to pass judgment on the siting of energy facilities, state officials have long held significant power to shape the future of the industry.

The restructuring of the electricity industry has not diminished the importance of the states' role. While a number of states have ceded the ability to set retail rates for electricity generation to the market – and while many states defer to regional bodies, such as independent system operators and regional transmission organizations, on issues such as planning for the transmission system – most states retain retail rate-setting authority and all states continue to possess important tools for protecting the rights and well-being of consumers.

State authority exists in at least five important areas of electricity regulation:

- Rate setting (or the setting of market rules for retail competition)
- Resource planning
- Facility siting
- Low-income assistance
- Energy and environmental policy setting.

In most states, some or all of these authorities are vested in the state public utilities commission (PUC).

State Public Utilities Commissions

State PUCs generally operate according to similar rules and principles, many of which can be traced back to the origins of public utility regulation in the

late 19th and early 20th century. But in some important ways, states have taken different approaches in designing their PUCs.

Composition

Most PUCs consist of three to five commissioners, whose terms vary from two to six years. In 12 states, public utility commissioners are elected, while in 38 states they are appointed. (See Table 1.) At least one empirical study has found that states with elected commissioners set lower rates of return for utilities and produce a lower ratio of residential-to-industrial rates than states in which commissioners are appointed.[31]

The choice of commissioners may also be limited to those who meet certain qualifying criteria, for example:

1) **Residency for a specific time period or in specific area of the state.** For example, Delaware requires commissioners to come from certain counties.

2) **Independence.** Many state statutes place restrictions on commissioners' current, past or future affiliations with the entities they regulate. This restriction may apply to the duration of a commissioner's service or to a time period prior to or after service on the commission. For example, Texas requires that for two years prior to their appointment, the commissioners may not have served as officers, directors, owners, employees, partners, or legal representatives of any public utility or affiliated interest, and may not have owned stocks or bonds worth $10,000 or more in a public utility, affiliated interest, or direct competitor of a public utility.

Some states have revolving-door clauses, restricting what role commissioners (and in some cases, their staff) can play after serving their term. For example, these clauses may prohibit former commissioners from repre-

Table 1. Elected vs. Appointed Public Utilities Commissioners[32]

Elected	Appointed	
Alabama	Alaska	Missouri
Arizona	Arkansas	North Carolina
Georgia	California	New Hampshire
Louisiana	Colorado	New Jersey
Mississippi	Connecticut	New Mexico
Montana	Delaware	Nevada
North Dakota	Florida	New York
Nebraska	Hawaii	Ohio
Oklahoma	Iowa	Oregon
South Carolina	Idaho	Pennsylvania
South Dakota	Illinois	Rhode Island
Virginia*	Indiana	Tennessee
	Kansas	Texas
	Kentucky	Utah
	Massachusetts	Vermont
	Maryland	Washington
	Maine	Wisconsin
	Michigan	Wyoming
	Minnesota	West Virginia

** Elected by General Assembly for six-year terms*

senting clients before the commission, or in some cases, any state agency.

3) **Nonpartisanship.** A minority of states place restrictions on the partisan affiliation of a commissioner while in office. Commissioners can be restricted from serving on the committee of any political party or from campaigning for any political candidate.

4) **Expertise.** Because utility regulation is a complex, technical field, some statutes authorizing PUCs require commissioners to have specific expertise or experience – for example, a degree or work experience in fields of engineering, finance, economics, accounting, business administration, or public administration. Ohio, for example, requires at least one PUC commissioner to be an attorney-at-law.

   PUC commissioners can obtain statutorily required experience in the field in a number of ways. PUC staff sometimes work their way up through the commission's ranks to become commissioners.

Jurisdiction

All state PUCs have jurisdiction over the operations of investor-owned utilities. PUCs have varying degrees of authority over publicly owned utilities. Although state commissions may regulate various safety and service issues, PUCs in many states have almost no oversight over municipal utilities.[33] In a few states, including Indiana and Wisconsin, public power systems' electricity rates are regulated by state utility commissions. In another set of states, only areas outside of the municipal or city limits are subject to state regulation. This includes Kansas, Mississippi and Wyoming.[34]

State regulators also frequently have little to no jurisdiction over consumer-owned electric cooperatives. States have authority to regulate rates of electric co-ops in 25 states (though in nine of these states, co-ops may opt out of or into state regulation).[35]

Funding of PUC Activities

The three primary ways in which PUCs are funded are by utility assessments, the state general fund, and a mix of the two – roughly one-third of the states fall into each category. In Colorado, for example, the PUC is funded entirely with fees paid by the regulated companies, not by general tax revenue.[36]

The ideal funding system to ensure the vitality and independence of a commission is a system in which revenue from utility assessments directly funds the commission, and any surplus from year to year stays with the commission. In addition, it is crucial that commissions have the authority to assess additional charges on utilities to cover the reasonable and necessary expenses of expert witnesses and independent analysis on specific complex cases that impose special burdens on the regulatory process.[37]

Consumer Advocacy

Decisions about the rates and terms of electricity service impact a wide variety of stakeholders. Some of those stakeholders – such as distribution utilities, generators and large industrial consumers – have a great deal to gain or lose in state PUC decisions. But to many individual stakeholders – such as residential consumers – a PUC decision in a rate case may cost only a few dollars more or less per month on their electricity bills – even though consumers in the aggregate have a great deal to gain or lose. Without the presence of some

countervailing force to ensure balance in the process, the large, concentrated interests of major customers would inevitably have a great advantage over the even larger, but diffuse, interests of small consumers.

To preserve fairness in the process, most states have an appointed office or commission that is expressly charged with advocating on behalf of ratepayers in rate cases and other decisions before the public utilities commission.

Consumer advocate offices exist in 42 states and the District of Columbia.[38] In some states, this office is located within the attorney general's office. In other states, it is established as an independent agency or commission. And in some states, the consumer or ratepayer advocate is housed within the PUC itself. Generally, the state governor or attorney general appoints the lead consumer advocate for the state with the advice and consent of the legislature.[39]

By presenting evidence to PUC commissioners in support of lowering profit margins for utilities and disallowing imprudent expenses, consumer advocates play an important role – most states have due process requirements that ensure that PUCs cannot ignore such evidence in their decision-making.

Most state consumer advocate offices are funded through utility assessments. A 2002 analysis by the Missouri Office of Public Counsel found that, excluding states that utilize their attorneys general to represent utility consumers, 92 percent of state consumer advocate offices around the country are funded through utility assessments.[40] Missouri is one of the few states that depends on general funding to maintain its consumer advocate position. This arrangement leaves the position vulnerable to changing state budget circumstances.

Other Forms of Consumer Advocacy

Some states have created intervener funds to ensure that municipalities or public interest representatives are supported in their efforts to challenge or participate in public utility commission decision-making. For example, the New York Public Service Commission requires those seeking a permit to construct and operate new generation facilities to pay a fee of $1,000 per megawatt of capacity, up to $300,000, into an intervener fund. This funding can then be awarded to municipalities or other local interests to defray their expenses in hiring expert consultants and witnesses.[41]

California's landmark intervener compensation program, established in state code in 1985 and revised in 1993, allows interveners to recover their expenses, including attorneys fees and expert witness fees, if the California PUC determines they couldn't otherwise afford to participate. In 2002 alone, the public intervener program awarded more than $3 million for 21 separate interventions.[42]

A different approach has been the formation of dues-funded citizens' utility boards (CUBs). These grassroots organizations, run by democratically-elected boards accountable to ratepayers, were originally funded by memberships solicited through inserts in utility bills. CUBs continue to operate in Oregon, Illinois, Wisconsin, and the city of San Diego.

Illinois CUB estimates that it has saved consumers more than $5 billion by blocking rate hikes and winning consumer refunds. After receiving $100,000 in seed money from the state (which was subsequently repaid, with interest), the Illinois CUB has been funded solely by consumers and nongovernmental foundations.[43] Similarly, the Oregon CUB,

funded by 6,000 members, estimates it has saved ratepayers over $1 billion in the 20 years of its operation.[44]

Rate Setting

The power to set retail electricity rates is the greatest power held by state PUCs. The amount and structure of rates – and the process for establishing those rates – creates a system of financial incentives and disincentives from which utilities and consumers will take their cues.

States can be broken into two categories depending on their approach to rate-setting: those who engage in traditional regulation and those that administer retail choice programs. In all states, charges for transmission and distribution service continue to be set through traditional rate-setting, while, in restructured states, the price of generation is set by the market.[45]

Traditional Rate-setting

In traditional rate-setting, PUCs evaluate rate requests by utilities (and sometimes by consumers or government officials) according to specific standards and on the basis of the cost of providing electric service to customers. Utilities invest in the necessary generation, transmission and distribution equipment needed to deliver electricity to consumers (a determination often made with the guidance of PUCs), and then seek to recover those costs through rates.

Standards

Just and Reasonable Rates

Almost every state requires that rates be demonstrated to be "just and reasonable." Such requirements may be outlined in further detail, depending on the statute. For example:

- The burden of proving that a rate increase is just and reasonable may be placed explicitly on the utility.
- Some states specify that any doubt as to reasonableness should be resolved in favor of the consumer.
- "Just" may be defined to mean that states may limit the revenues obtained by electricity generators to levels justified by a competitive market; or ensuring that all types of customers are served in an equitable fashion.

Utah law, for example, explicitly sets criteria for "just and reasonable" rates that:

> shall include, but shall not be limited to, the cost of providing service to each category of customer, economic impact of charges on each category of customer, and on the well-being of the state of Utah; methods of reducing wide periodic variations in demand of such products, commodities or services, and means of encouraging conservation of resources and energy.[46]

Maine law describes criteria for determining "just and reasonable" to include whether the utility is operating "as efficiently as possible" and "utilizing sound management practices, including the treatment in rates of executive compensation."[47]

Other considerations that are commonly included either in the definition of "just and reasonable" or in addition to that standard are:

- **Environmentally Sound:** Many states have specific clauses specifying that the commission shall set rates to encourage energy conservation and/or renewable energy use in order to minimize environmental harm from electricity production.

- **Ensure Safe, Adequate, Efficient Service:** Most states require that, in fixing rates, the authority shall take into account the safety, adequacy and efficiency or lack thereof of the service provided by the public utility. Maine, for example, supplements the just and reasonable standard described above with a statutory clause requiring that utilities "shall furnish safe, reasonable and adequate facilities and service."[48]

Cost-Based Rates

In traditional regulation, rates are based on the cost incurred by utilities to provide electricity service. "Cost" includes the cost of invested capital, including interest payments on bonds and fair profit to shareholders.[49] Operating expenses are collected through rates on a dollar-for-dollar basis; capital costs are depreciated over the useful life of the equipment.

Cost is also an important factor in determining the rates set for various classes of consumers. Under cost-based rate-setting, rates for various classes of consumers are set based on the cost of serving those consumers. As a result, large consumers (who are often less expensive to serve) frequently receive lower rates than small consumers. However, cross-subsidization among consumer classes (with a few exceptions, such as low-income consumers) is generally prohibited.

In order to recover costs in rates, the investments made by regulated utilities generally must meet certain standards. One such standard is the "prudence" test.

Regulators conduct quasi-judicial administrative reviews to determine whether costs have been "prudently incurred" incurred by the utility. Prudence has always been a standard for review of utility costs, but the concept came into prominent use in the 1980s, as regulators began to identify a growing number of electric utility industry decisions that seemed to violate basic standards of care in investment decision-making. The prudence standard is a necessary safeguard, since the cost-based rate-making system provides few incentives for utilities to avoid excessive risk.[50]

The concept of prudence is not always explicitly established in state utility legislation, but instead may be grounded in judicial and case law developed over the past century. Robert Burns of the National Regulatory Research Institute identified four general principles underlying the process by which states determine prudence:[51]

1) Utility investments are to be presumed prudent until substantive evidence proves otherwise.
2) The investment must be judged to have been reasonable under the circumstances that were known or could have been known at the time the decision was made.
3) Hindsight should not be used in determining prudence – therefore, outcomes cannot be used to determine that an investment was imprudent.
4) Staff investigation or other factual inquiry, though time-intensive and expensive, should be used to investigate how an investment decision was made.

Not all states follow these exact guidelines for determining recoverable costs. For example, some states supplement or supplant the prudent investment test with the consideration of investment outcomes, and other states set caps on project costs in advance that may make no reference at all to the prudence test.

A second test that utility investments must pass in order to be eligible for cost

recovery through rates is the "used and useful" test, which prevents utilities from recovering the cost of investments in plants that

- are not yet operable;
- are no longer used; or
- provide benefits to parties other than consumers of regulated services.

Many companies have claimed cost recovery for abandoned nuclear plants on the basis of prudence, while being denied reimbursement for failure to meet the used and useful test.[52]

States have different approaches in assigning costs of facilities that fail to be used and useful. In Massachusetts, the costs of prudent investments that fail the "used and useful" tests have generally been shared equally by the company stockholders and the ratepayers. New Mexico code specifies that the rate base only includes "the value of utility property used and useful in rendering the public utility service."[53]

Process

The formal process for setting utility rates is generally an adversarial process similar to litigation. Any individual or group can intervene in the process, which takes place in public view. The PUC sits as the "judge," examining evidence, facilitating the process, and passing judgment based on the facts established in the case.

The steps in a typical rate-setting case include:

- Public filings of the rate request and notices of participation by any interveners.
- Public hearing.
- Formal written questions, filings, discovery and cross-examination.
- Sometimes a tentative decision, followed by additional briefs.
- Sometimes oral arguments.
- Decision.
- Post-decision motions.
- Filing by utility to comply with decision.
- Appeal (if necessary).[54]

Not every decision made by PUCs goes through this formal process. In some cases, utilities and other participants can engage in negotiation and mediation to arrive at mutually beneficial agreements, which are then subject to approval by the PUC. The principles of such negotiations are similar to the principles in formal rate-setting – anyone may file to intervene in the negotiations and any participant can withdraw from negotiations, returning the matter to the formal rate-setting process.

Retail Deregulation

Deregulation of retail rates changes the role of state PUCs in rate-setting. The PUC is still responsible for setting rates for transmission and distribution service according to traditional regulatory imperatives. For generation service, PUCs (and often legislatures) define and enforce the rules and limitations affecting newly created retail markets. In every restructured state, the PUC and legislature have also created "default" or "standard offer" service packages for customers who do not choose another retail provider. The majority of customers, and the vast majority of small customers, remain on these default service packages, which have now become the *de facto* franchises of the restructured era.

Over the past decade, 17 states and the District of Columbia have moved ahead with some form of retail restructuring. An additional half-dozen or so states enacted restructuring legislation,

but have since pulled back. California, which had engaged in retail restructuring, suspended its program in September 2001 in the wake of the state's energy crisis (although the state has not repealed its retail restructuring law.) (See Table 2.)[55]

Several rate-related issues have tended to come before legislatures and state PUCs in the course of retail restructuring, including how to protect consumers during the transition to competition, how to recover "stranded costs" for utility investments that may not be economical in an open market, and how to establish rules for the fair and open operation of retail markets.

Rate Caps/Standard Offer Service

All states that have established retail competition have also established a regulated standard offer service – available to consumers who do not choose a competitive electricity supplier – with limitations on the rates utilities may charge consumers. These rate limitations had two purposes: 1) to protect consumers who "refuse to choose" during the transition to competitive retail service, and in many cases, 2) to deliver consumers an immediate benefit from restructuring prior to the anticipated benefits that would result from competition.

States have differed in their strategies for setting rates for standard offer service. Some have opted to "stack the

Table 2: Status of Retail Restructuring

Adopted Retail Electric Competition	Delayed or Halted Retail Electric Competition	Have Not Adopted Retail Electric Competition	Adopted Retail Electric Competition Since 2000
Arizona	Arkansas	Alabama	None
Connecticut	New Mexico	Georgia	
Delaware	Nevada*	Florida	
Maine	California	North Carolina	
Massachusetts	Oklahoma	South Carolina	
New Hampshire	Montana (6)	Mississippi	
New York*		Missouri	
Pennsylvania		Louisiana	
Rhode Island		Indiana	
New Jersey		Kentucky	
Maryland		Kansas	
Virginia		Tennessee	
District of Columbia		Iowa	
Michigan		North Dakota	
Texas		South Dakota	
Illinois		Minnesota	
Ohio		Wisconsin	
Oregon* (18)		Wyoming	
		Washington*	
		Idaho	
		Utah	
		Colorado	
		Nebraska	
		Vermont	
		Hawaii	
		Alaska	
		West Virginia (27)	

** New York has implemented retail competition through a series of decisions by the Public Service Commission, not through legislative mandate; Oregon allows only commercial/industrial customers to choose an alternate supplier; Nevada allows only very large commercial/industrial customers to choose an alternate supplier; Washington allows only very large commercial/industrial customers of Puget Sound Energy to choose an alternate supplier.*

deck" in favor of competition by setting standard offer rates higher than they would have been under traditional cost-based regulation. Others have chosen to maximize the benefits to consumers in the short run by setting standard offer rates low (although often with a provision that consumers pay back the savings achieved under rate-capped standard offer service after the rate caps expire). Pennsylvania is an example of the former approach, California (prior to its energy crisis) the latter. PUCs may also be empowered to determine when utilities may increase standard offer rates. For example, in Massachusetts, where the state imposed mandatory rate reductions as part of restructuring, the state's Department of Telecommunications and Energy later approved utility requests to pass through rising wholesale electricity prices to consumers – wiping out much of the savings from the mandatory rate reductions.[56]

In virtually all cases, the setting of rate limitations and guaranteed availability of standard offer service are phased out at a particular date that is either established by statute or determined by the PUC. In some cases – such as in Connecticut and Maryland – PUCs or legislatures have already acted to push back the date on which standard offer service is withdrawn in an effort to protect consumers.[57]

Stranded Cost Recovery

States deregulating their retail markets have authority over how utilities' "stranded costs" will be recovered.

Stranded costs are those investments that utilities have historically made in generation assets (investments that may have been approved by state PUCs or included in historic rates), but which may no longer be profitable in an open market. To prevent utilities and their remaining customers from being stuck with these costs once some consumers switch to competitive suppliers, states have frequently sought to make all consumers pay off some or all of these costs through a standard charge on the electricity bill. While estimates vary, states may have experienced up to $200 billion in stranded costs as a result of deregulation, largely from poor utility investments, particularly in costly nuclear plants.

Stranded costs typically fall into three categories:[58]

- Assets: Expensive power plants and excess generating capacity whose electricity cannot be sold at a high enough price to pay off the initial investment.
- Liabilities: Expensive contractual commitments to buy power or fuel at a certain price above competitive market rates, or the costs of decommissioning nuclear power plants.
- Regulatory assets: Expenses or costs that regulators allowed to be deferred for future recovery from ratepayers, instead of paid for up front.

Stranded costs can be calculated in one of two ways:

- Administratively, using forecasting and modeling methodologies similar to those used in traditional rate cases to estimate the market value of utility assets and obligations, or
- Through market valuation, which generally requires divestiture (sale) of generating assets to determine the fair market value of those assets.

In many states, a non-bypassable surcharge on all ratepayer bills was used to recover stranded costs. California's deregulation statute calls for full recov-

ery of utilities' stranded costs over a five-year period through a "non-bypassable competitive transition charge" – a charge to all ratepayers, regardless of which utility they choose to provide their electricity. Similarly, New Jersey allowed recovery of stranded costs through a "market transition charge."

Massachusetts, like California, created a non-bypassable charge over a 10-year period; however, Massachusetts regulations explicitly denied utilities a legal right to full stranded cost recovery, requiring "all reasonable actions to mitigate" stranded costs before any recovery of benefits would be permitted.[59] Massachusetts also required divestiture – sale or transfer of generation assets – as a prerequisite for full stranded cost recovery for those assets. However, settlement agreements reached between regulators and the states' utilities guaranteed virtually full recovery of the utilities' stranded costs.

In Maryland, the commission chose to allow recovery of "verifiable, prudent and fully mitigated stranded costs."[60] In contrast, New Hampshire ruled that only utilities with rates at or below average New England rates would be permitted to recover the full amount of their stranded costs.[61]

While some states sought to recover stranded costs through lump sum payments by consumers switching to a different utility (called exit fees), other states, like New Jersey, specifically avoided this strategy, arguing it would discourage rather than encourage retail competition.

Changes in Market Valuation and "True-Ups"

One potential problem with stranded cost recovery is the potential that consumers will end up paying utilities more than they should, because the economic value of investments changes over time. For example, a nuclear plant designed to run for 40 years at 80 percent capacity is worth substantially more if it generates power for 60 years at 90 percent capacity instead.

Nuclear stranded costs are an example of costs that might be calculated differently now than in the late 1990s, when markets were deregulated. At that time, the market valuation of nuclear power plants was low – many of the plants had had huge capital cost overruns during construction, ran below capacity, produced expensive power, and had a limited number of years remaining of future productivity. Therefore, during restructuring, much of the capital invested in these plants could not foreseeably be recouped by electricity sales over the plant's projected lifetime in a competitive market, and portions of these generation assets were identified as "stranded costs."

However, more recently, nuclear power plants have been given a new lease on life by the Bush administration, with license extensions commonly granted for 20 years of additional operation, and uprates that allow the plants to run at higher output levels (though arguably, closer to safety margins). As such, these plants will be generating more power for longer than was anticipated in the late 1990s, and will be significantly more profitable. Furthermore, electricity generated by these plants is now being sold into the electric wholesale markets at higher rates than the cost-of-service rates that prevailed before deregulation.

This raises the possibility in deregulated states that ratepayers are paying off stranded costs for "unprofitable" nuclear investments, while paying high rates to nuclear power producers who are now reaping significant profits.

Some state restructuring acts required PUCs to periodically revisit the amount

of stranded costs initially awarded to each utility, comparing this against empirical evidence gained over time to determine if stranded cost estimates were inflated. In this case, resulting profits would be returned to consumers.

This process of adjusting stranded costs estimates, sometimes called a sanity check or "true up," may be required annually or at specific intervals. In Maine, for example, "true ups" are required every three years. In Massachusetts, they were mandated by state restructuring legislation at years two, five, and 10 post-restructuring.[62] Considering the changes in valuations experienced in just the past five years, it is fair to conclude that these "true-up" provisions do help to achieve a better balance between ratepayer and utility interests, compared with a "once and for all" attempt at valuation.

Market Policies and Rules

Finally, PUCs in many cases have the authority to set the rules for how consumers and electricity suppliers interact in a competitive market: for example, what types of information suppliers are required to disclose about their products, how consumers may voice their desire to choose a particular supplier, how frequently consumers can switch suppliers, etc.

More than 20 states require electricity sellers to disclose their generation mix (fuel sources) on customer's bills or in some other manner. Such information disclosure is commonly required in restructured states, but also required of some utilities in Florida, Washington and Colorado, which have not restructured their retail electricity markets.[63] In addition, at least 15 states require disclosure of air emissions associated with electricity production.

In some cases (such as Pennsylvania), PUCs have attempted to spark competition by allowing utilities to assign blocs of consumers to competitive suppliers. In other cases, states have imposed conditions – such as renewable portfolio standards – that directly or indirectly affect generators seeking to sell power into a market.

Resource Planning

Traditional cost-based rate-making puts PUCs into a reactive posture – passing judgment on utilities' investments after the fact. During the 1980s and 1990s many states sought to shape utilities' decision-making (and enhance the interests of the public and consumers) by requiring utilities to develop long-range plans for the adequate provision of reasonably priced electricity with minimal impacts on the environment or public health. Under the practice of integrated resource planning (IRP), utilities would focus on identifying the "resources" – both additional generation and improved efficiency and conservation – that could be harnessed to meet an area's electricity needs, and then seek to assemble a portfolio of those resources in an integrated resource plan.

State requirements for long-term resource planning vary substantially. Some planning requirements cover all aspects of electricity generation, delivery, and demand management, while others focus on just one aspect, such as generation or transmission.

Of 21 states surveyed thus far by the Regulatory Assistance Project, 15 require integrated resource planning (IRP) by utilities or by a state energy or regulatory agency. Six surveyed states do not require IRP: Illinois, New Jersey, New York, Ohio, Connecticut and Maine; all of which have active electric industry restructuring.

The majority of states that require IRP do so through plans submitted by each

utility. Of the states surveyed by the Regulatory Assistance Project, only in Florida and Wisconsin do the PUCs write a long-term energy plan, based on submissions from the utilities.

Most states grant the PUC or its equivalent the power to reject the plan, require modifications and resubmission, or accept the plan. Georgia's PUC has substantial leeway to accept or reject the proposed plan, or even to recommend options not considered by the utility in its proposed plan. Washington's and Arizona's PUCs are more limited in their actions: Arizona's PUC can accept the plan with conditions but cannot require resubmission of the plan; Washington's PUC can recommend changes, but those changes do not have to be incorporated until future plans.

The surveys show wide variation in the span of time that must be covered by integrated resources plan – ranging from as little as three years in Wisconsin to a 40-year planning horizon in Colorado. Ten- and 20-year time-spans are most common. In addition, state laws vary in how often they require new plans to be developed and submitted. Massachusetts and Arizona require new plans annually, while Colorado requires new plans only every four years. Most states require plans be submitted every two to three years.

IRP requirements vary in comprehensiveness. The most complete require consideration of future generation options, transmission capacity, projected demand, demand reduction through efficiency and load management, and the environmental impacts of various options. Some, however, focus on just one area, such as transmission.

IRP requirements are more than plans. Among other things, they provide state regulatory agencies with information necessary to judge whether proposed projects are prudent and necessary, and help agencies determine the best way to achieve Clean Air Act compliance.[64]

Almost all plans are evaluated on their ability to provide power at the lowest cost to consumers while maintaining reliability. Environmental impact is included by some states as a broad aspect of evaluation, but it is just as often excluded or considered only if it does not affect costs. Arizona's IRP guidelines give substantial weight to environmental factors – indeed, these guidelines have led to the cancellation of several projects.[65] In reviewing proposals for new generation capacity, Arizona's Corporation Commission is expressly charged to "balance the project's environmental impact on Arizona with the state's need for adequate and reliable electricity at a reasonable cost."[66]

Generally, interested parties and the public have some opportunity to comment upon a proposed integrated resource plan, but rarely are their comments binding. States most often rely upon public hearings to allow interested parties an opportunity to recommend changes. Nevada allows perhaps the most involvement by admitting formal interveners. Georgia also acknowledges outside parties of record whose comments carry greater weight. Washington and Montana employ stakeholder processes but not public hearings.

Integrated resource plans may range from being advisory in nature to being strictly enforceable in siting and permitting decisions. The states with stronger plan enforcement (Idaho, Oregon, Washington, New Mexico, and Georgia) look more favorably upon new generation or transmission proposals if the project is included in the plan. These states also review the utility's behavior relative to its plan when it applies for a rate change. No state surveyed automatically rejects proposals not included

in the plan. Other states, such as Massachusetts and Colorado, have not developed clear procedures for ensuring that utilities adhere to their plans.

Resource Planning in Restructured States

Most states that have adopted retail restructuring have removed requirements that utilities engage in long-term resource planning. Because generation is technically no longer regulated under state law – and is subject to competition – the notion has been that the workings of the free market will bring about the optimum mix of resources for satisfying an area's electricity needs. However, even in states that have restructured, the vast majority of consumers continue to purchase standard offer service from their incumbent electricity provider (or have a standard offer provider chosen for them through competitive bidding). With no requirement to engage in long-term planning to secure adequate generation or conservation resources, these suppliers often find themselves overly reliant on short-term markets for electricity, which are notoriously volatile. As long as standard offer service remains the norm for consumers, rather than the exception, it makes sense for states to require long-term resource planning for those providers. (For more on this issue, see "Lack of Effective and Coordinated Planning," p. 106.)

Facility Siting

The authority to determine whether and where energy facilities may be constructed is an important power states possess in determining the future structure of the electric industry. Policies that allow for the unfettered construction of generation facilities and transmission lines will tend to favor supply-side responses to problems in the electric system, while policies that place limits on construction and force the consideration of alternative strategies for meeting electricity demand will tend to produce alternative responses.

States vary significantly in where primary jurisdiction for facility siting is housed and the criteria that must be met to achieve siting approval.

Jurisdiction

In the majority of states, state utility commissions or other state bodies have authority over decisions to locate new generation or transmission facilities in a given location. In Arizona, California, Florida, Minnesota, New Hampshire, and New York, several state entities share siting responsibility.

Many states have siting boards or commissions. In some cases, as in Oregon and Montana, this board is comprised of appointed citizen volunteers.[67] In other cases, siting boards are comprised of government officials and may have access to professional staff. The members of the California Energy Commission, for example, are full-time paid professionals with much broader policy responsibilities than siting, and Washington's Energy Facility Site Evaluation Council is comprised of state agency representatives and one public member. Local government representatives sit on the Washington Council and have a vote in siting facilities within their jurisdiction.[68]

More than half the states (28 in total) have some authority over the siting of transmission facilities.[69] There is no state oversight on transmission line siting in Alabama, Georgia, Indiana, Louisiana, Oklahoma and Tennessee.

Determination of Need

The results of resource planning efforts typically form the basis for PUC

decisions to authorize or prohibit construction of major transmission or generation facilities. Such construction generally requires PUC approval in the form of a certificate of need (sometimes called a certificate of public convenience and necessity).

Many states have a statutorily defined "need" requirement: developers proposing to build a new generation or transmission facility must document the need for the facility to meet projected consumer demand.[70]

The definition of need varies greatly from state to state. Variations exist in several areas:

- **Regional vs. in-state need** – Traditionally, the need standard has been interpreted as the need of in-state consumers. In some cases, this is specified in the statute. Mississippi and Florida are among the states that define need strictly with respect to in-state consumers. However, a number of states include a regional basis for the consideration of need. Ohio, for example, considers whether "the facility is consistent with regional plans for expansion of the electric power grid of the electric systems serving this state and interconnected utility systems and that the facility will serve the interests of electric system economy and reliability."[71] Rhode Island requires that those proposing a facility demonstrate that the facility is "necessary to meet the needs of the state and/or region."[72] Connecticut takes a more lenient approach to need, requiring only that new generation is needed to promote either reliability within the state or "a competitive market for electricity."
- **Consideration of alternatives** – Many states require that proposed facilities be the least-cost option available for addressing a particular need. Florida, for example, requires that the state public service commission "shall also expressly consider the conservation measures taken by or reasonably available to the applicant or its members, which might mitigate the need for the proposed plant."[73] In Vermont, it must be demonstrated that a facility "is needed to meet the future demand for energy that could not be more cost effectively provided by conservation."[74]
- **Environmental impacts** – States take sharply different approaches to defining the environmental criteria facilities must meet. Some states, such as New York, require that "the facility's construction and operation is in the public interest and that it minimizes adverse environmental impacts."[75] Others, such as New Hampshire, require the demonstration that "the facility will comply with pertinent state public health, environmental, economic, and safety standards."[76] Other states construe environmental impacts more broadly. Massachusetts' environmental review covers a broad range of issues, including air quality, water resources, water supply, and visual, noise, safety and land use impacts.[77] Several northwestern states require an environmental impact analysis modeled after the federal National Environmental Policy Act that requires that the proposed project have an "acceptable environmental impact."[78]
- **Planning requirements** – Some states require or give preference to proposals that fit within long-range plans or utilize previously identified sites.
- **Other** – New Hampshire requires utilities seeking a certificate of need to demonstrate appropriate, sound

financial management practices and resources.

Public Participation

Many state statutes governing siting afford the public opportunity to weigh in on these decisions. For example, Minnesota law requires a hearing in order to receive comments from the public. After the hearings, the department issues a final environmental report and an administrative law judge issues findings, conclusions, and a recommendation to the commission. The commission then deliberates before making its final decision.

Low-Income Assistance

In the United States, electricity is broadly recognized as a basic need to which everyone must have access. As such, state and local governments have often stipulated that utilities have an obligation to serve anyone who wants electricity within the utility's defined service territory and an obligation to provide assistance to low-income individuals.

Many states have laws that recognize the need for universal electric service, as demonstrated by these statutory references compiled by the Consumer Law Center:[79]

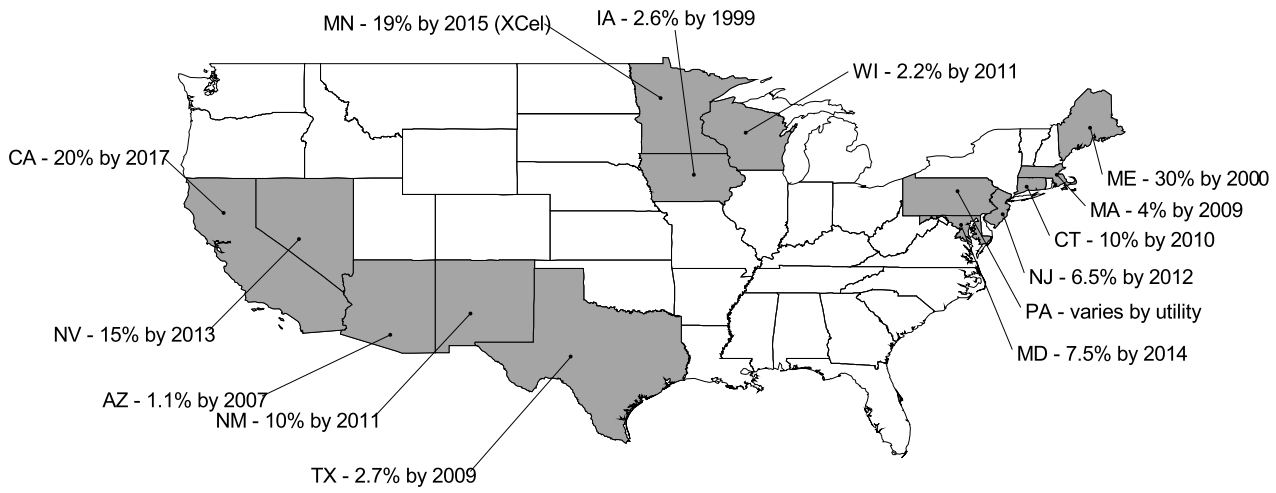
- **Maine**: "Electricity is a basic necessity to which all residents of the State should have access, …"
- **Massachusetts**: "Electricity service is essential to the health and well-being of all residents of the commonwealth...Affordable electric service should be available to all consumers on reasonable terms and conditions…"
- **New Hampshire**: "Universal Service …electric service is essential and should be available to all customers…"
- **Oklahoma**: "Mechanisms that enable …consumers with limited incomes to obtain affordable essential electric service" shall be ensured.

Low-income assistance takes several forms:

- **Affordability programs** that provide discounts to low-income consumers. Discounts can be based on a percentage of the utility bill, a fixed amount, or vary by usage, with discounts applying only to "lifeline" consumption (consumption below a certain number of kilowatt-hours per month).
- **Consumer protections** including bans or restrictions on deposit requirements, late charges, and excessive reconnection fees. Protections can also require the provision of levelized monthly bills on request, and moratoriums on the disconnection of electric service in periods of extreme weather or when electricity is medically necessary or needed for the health of the elderly or infant children.
- **Education programs** to help consumers pay their electricity bills and to use electricity more efficiently.
- **Efficiency and weatherization programs.**[80]

In traditionally regulated states, low-income assistance programs emerge from state requirements established by statute or through the regulatory process. Most states that have undergone retail restructuring have preserved low-income protections, including rate discounts. Many of these states have also established systems benefit charges (SBCs) – charges assessed on a kilowatt-

Fig. 1. States with Renewable Portfolio Standards[83]



hour basis on electric bills – to support low-income programs. These programs are administered either by utilities or by state agencies.[81]

Massachusetts' restructuring law, for example, requires utilities to maintain programs for low-income customers "comparable to the low-income discount rate in effect" prior to deregulation. California requires utilities to collect a mandatory charge that finances energy efficiency and rate assistance programs for low-income customers.[82] Pennsylvania has established more specific guidelines for utilities: they must help low-income customers maintain electric service through assistance programs, limits on disconnection, and energy conservation programs.

Environmental and Energy Conservation Issues

PUCs and other arms of state government often play a role in attempting to reduce the environmental impacts of power production. In recent years, states have acted to achieve this goal by promoting the use of renewable sources of energy, encouraging energy efficiency, and bolstering the use of clean, small-scale distributed generation technologies.

Renewable Energy

Many states operating under both traditional regulation and retail competition have taken action to encourage the development of renewable resources. The first major attempt to promote the use of renewable energy was the passage of the Public Utility Regulatory Policies Act (PURPA) of 1978, which required utilities to buy electricity from qualified renewable and cogeneration facilities at avoided cost. Today, a large portion of the effort toward promotion of renewables is taking place at the state level, through policies such as renewable portfolio standards (RPS), systems benefit charges for renewables, and green pricing requirements.

Renewable Portfolio Standards

To date, at least 14 states have adopted renewable portfolio standards (RPS), requiring that a certain portion of electricity generated for sale in the state come from renewable energy sources. Fig. 1 documents states with renewable portfolio standards.

In traditionally regulated states and most restructured states, RPS requirements are imposed on those selling power in the state. There are various approaches to compliance: in Minnesota, for example, electricity suppliers must demonstrate that they have made a "good faith effort" to achieve the state's non-mandatory RPS goals.[84] Most states allow for compliance through the accumulation of credits, which can be obtained from in-state or out-of-state generation. Others allow for the payment of a fee to support state renewables development funds in lieu of meeting the RPS requirement – although this fee is typically set higher than the marginal cost of bringing new renewable resources online and functions in effect as a penalty for noncompliance.

The percentage of renewable resources required in an RPS is important, but can be deceiving. One key issue is whether the RPS applies to all electricity sales in the state or exempts large amounts of generation. Connecticut's original RPS, for example, exempted standard offer providers, which supply the vast majority of the state's electricity. This loophole has since been fixed. Other states exempt municipal utilities or other non-investor owned entities from compliance with the RPS.

States also take different approaches in defining the resources allowed to gain credit as "renewable." On the surface, Maine's RPS requirement of 30 percent renewable generation is the strongest in the country. However, Maine's RPS allows the combustion of municipal solid waste (under certain circumstances) and certain cogeneration facilities to count toward the achievement of RPS goals – even though these sources may produce significant amounts of pollution and are not truly "renewable."[85] In addition, Maine's RPS does not set a specific requirement for *new* renewable generation. Because Maine has historically generated more than 30 percent of its electricity from renewables (mostly hydroelectric power and biomass in the paper industry), the state's RPS effectively requires no additional renewable generation in the state. To address this problem, some states – including Massachusetts and Connecticut – set specific requirements for the development of new renewable resources.

Systems Benefit Charges for Renewables

In addition to these RPS policies, at least 14 states have adopted systems benefit charges (SBCs) to promote the development of renewable resources.[86] Funds collected through SBCs are managed either by state agencies, utilities, or a nonprofit entity to promote research and development on renewable energy sources, subsidize the installation of renewables, or promote the development of renewables through public education.

The size of systems benefit charges dedicated to renewables varies greatly from state to state, from roughly 2 cents per megawatt-hour in Pennsylvania to 80 cents per megawatt-hour in California and Massachusetts.[87]

The duration of the programs also varies. In roughly half of the 14 states with SBC funds for renewables, state law has established the SBC for a set amount of time, slating it to be in effect through 2007 or 2011, for example. In the other half, the SBC has been established to last indefinitely.[88]

Green Pricing

In states that have undergone retail restructuring, consumers have sometimes had the option of purchasing "green" electricity products from competitive electricity suppliers. In recent years, a number of states that have not permitted retail choice – including Oregon, Washington, Minnesota and New Mexico – have required utilities to offer consumers a "green power" option, allowing consumers to opt to pay higher rates in exchange for supporting the development of renewable energy. In some places, utilities have proposed green power options without a mandate from the regulator.

Several key issues arise with regard to green pricing:

- The degree to which the higher rate for renewables is regulated in keeping with traditional regulatory principles – ensuring that consumers pay only the additional cost of the renewable power and no more.
- The minimum standards set for the types of generation and percentage of the total power mix in "green" products.
- The intersection of green pricing with other regulatory policies such as RPSs. In theory, consumers paying extra to purchase "green power" should not be subsidizing power producers for compliance with RPSs or other regulatory requirements.
- The allocation of costs between consumers of "green" products and other consumers. One common limitation of green pricing programs is that the customer who pays extra for the greener power rarely sees the benefits of that choice. If the cost of the renewable energy is calculated simply as a premium above the regular tariff, then the "green" customer is still paying 100% of the risks of the traditional power supply (for example, nuclear plant outage costs, or gas price increases). Green power customers should at least get the benefits of the premium they are paying, and be exempted from a portion of the cost increases in the underlying mix.

Green pricing requirements are relatively new and states will need to consider these issues as they consider implementing similar programs.

Energy Efficiency

For many years, state regulators have required utilities to take steps to promote energy efficiency among their customers, under the theory that doing so would allow utilities to serve their mission at the lowest aggregate cost by reducing the need for expensive peak generation and additional transmission capacity.

However, over the last decade, utility spending on energy efficiency programs dipped dramatically. Between 1993 and 2000, spending on state- and utility-sponsored programs to promote energy efficiency and reduce electricity demand was cut by 38 percent.[89] The decline occurred in both restructured and non-restructured states, but the decline was particularly dramatic in several states that had opened their retail markets. In Maryland, for example, per capita spending on efficiency programs dropped from approximately $13 per capita in 1996 to less than $1 per capita in 2000.[90]

In an effort to reverse this trend, a number of states – both regulated and restructured – have now moved to bolster their efficiency efforts through systems benefit charges and other programs to encourage efficiency (aside from efficiency efforts required as part of resource planning). While efficiency

spending increased significantly in the late 1990s and early 2000s thanks to these programs, in several states – such as Connecticut and Wisconsin – efficiency funds have been raided by legislatures to plug holes in state budgets. This trend threatens to reverse the momentum of energy efficiency activities in these states and signals a shift away from trends toward increased efficiency spending.

Systems Benefit Charges for Efficiency

At least 20 states now assess systems benefit charges to support energy efficiency programs.[91] As with SBCs for renewables and low-income programs, efficiency SBCs vary widely from state to state in their size and method of implementation. In fact, the largest SBC (Connecticut, at $3 per megawatt-hour) is 100 times higher than the smallest (Illinois, at approximately 3 cents per megawatt-hour).[92] Funds raised through efficiency SBCs are administered either by utilities, by state agencies, or in the case of Vermont, through a contract with an "energy efficiency utility" selected through competitive bidding.

Pay-as-You-Save Programs

Systems benefit charge funds are frequently used to provide rebates encouraging consumers to purchase more energy efficient appliances or equipment. Yet, even with financial assistance, significant barriers remain in the way of consumers' adoption of cost-effective energy efficiency improvements. New Hampshire (a restructured state) has implemented a pilot pay-as-you-save program to encourage residential and other consumers to adopt cost-effective efficiency measures.

In a pay-as-you-save program, the utility (or in this case, distribution company), pays the upfront cost of purchasing and/or installing the efficiency measure. Prior to undertaking the project, the utility must verify that the benefits to the consumer will exceed the costs. The consumer then pays the cost of the measure over time on his or her utility bill. If the consumer should happen to move before the full amount is paid, he or she either pays off the remaining cost (if the equipment is taken from the residence) or the charge on the utility bill continues for the next resident.

Pay-as-you-save removes two major barriers to the adoption of efficiency measures: the high upfront cost and the prospect that a consumer will not live in a residence long enough to fully benefit from the investment. Instead, consumers begin to receive savings immediately upon installing the measures.

Distributed Generation

Not all energy is generated from large, centralized plants. Indeed, many states have come to see distributed generation (small, modular power-generating technologies that can be combined with energy management and storage systems) as a key strategy for both improving the efficiency of power production and enhancing the reliability of the electricity system.

Traditionally, however, many utilities discouraged the installation of distributed generation capacity for small consumers. As a 2000 report from the Regulatory Assistance Project noted:

> Distributed resources located on the customer side of the meter almost always hurt utility profits. This is true for both demand-side and supply-side resources. From the utility's perspective, demand- or supply-side

> resources installed on the customer side of the meter produce the same effect: sales go down and as a result revenues and profits go down.[93]

As a result of this perverse incentive, utilities have often thrown up roadblocks in the path of distributed generation – including refusing to respond to requests for interconnection in a timely fashion, assessing exorbitant fees for interconnection, and imposing onerous technical and insurance requirements.[94] In addition, utility and regulatory policies with regard to rates can reduce the viability of distributed generation – for example, by charging excessive rates for the provision of "standby" access to the grid (use of the grid when the distributed generator is offline), low returns on the sale of excess power into the grid, and high "exit fees" assessed to pay off utility investments made over time to benefit the customer.

The tricky part of removing barriers to distributed generation is that many of the barriers have some basis in reasonable regulatory imperatives. For example, it is theoretically legitimate to assess an exit fee for a consumer who seeks to disconnect from the grid, since the utility has made expensive investments on the assumption that it will continue to serve that consumer and it is unfair to shift those costs to others. The problem arises when utilities or regulators look at only part of the picture (ignoring, for example, the cost savings that would result from not having to serve a given consumer at a time of peak demand) or when utilities use the assessment of such fees as a deliberate tool to dissuade consumers from installing distributed generation technologies.

A number of states (in some cases, following the leadership of the Federal Energy Regulatory Commission) are moving forward with the adoption of standardized rules for interconnection of distributed generators and have begun to address rate-related issues as well. One area that has received much attention is the concept of "net metering."

Net Metering

Owners of rooftop solar photovoltaic panels or other small generation systems generally do not have the luxury of storing the excess power they produce over and above their needs at any given moment. In addition, because renewable resources such as solar and wind power are intermittent resources, consumers often must maintain a connection to the grid to obtain power when their own generator supplies insufficient power to meet their demand.

Thirty-seven states and the District of Columbia have adopted rules that allow for "net metering" – enabling consumers to sell excess electricity from distributed generators back into the grid.

Every state that has a net metering policy allows photovoltaic systems to be net metered, and most states also allow wind. Other technologies that sometimes qualify include solar thermal, biomass, hydroelectric, geothermal, and municipal solid waste. Most states allow all customers to take advantage of net metering, but some states limit it to certain customer classes. For example, Maryland law only provides for net metering by residential customers and schools, while Vermont allows it for residential, commercial and agricultural customers.

Most states also limit the size of a given generation system that qualifies for net metering (the only exceptions are Iowa, Ohio and Connecticut, which place no limit). One utility region in Colorado only allows net metering for systems smaller than 3 kW – about the

size of a typical residential rooftop solar PV system; California has the most generous limit, encompassing systems as large as 1,000 kW. Some states place limits on the total net metering enrollment mandated, often as a percentage of the utility's peak load. This potentially restricts the total number of customers that utilities permit to have net-metered systems.

In some states, such as Hawaii, net-metered systems are connected to the same electricity meters through which power from the grid flows, so that the meter will actually run backward when the consumer uses less electricity than they produce. Thus, each month's electric bill is only for the net power drawn from the grid (power drawn minus power supplied).

Other states require small generators to be reimbursed for the extra power they generate after the fact. The utility may be required to purchase this surplus, called net excess generation (NEG), each month at "avoided cost." Usually, this means at wholesale electricity prices, which are less than the retail prices that consumers pay. In many states, credit for the NEG is rolled forward to the next month, to balance out months when the consumer might generate less than they use. Often, at the end of the annual billing cycle, unused credits are granted to the utility with no compensation to the consumer, or they are purchased at avoided cost. In Indiana and most utilities areas in Oklahoma and Pennsylvania, the monthly NEG is simply granted to the utility.[95]

Summary

The scope and diversity of issues facing state regulators – both in PUCs and associated agencies – is immense and growing. Several decades ago, state PUCs mainly had to deal with the mundane – if challenging – task of setting rates and monitoring the activities of vertically integrated utilities. Today, PUCs must often not only continue to fulfill their basic responsibilities, but must also resolve issues driven by technological change (distributed generation) and environmental concern (development of renewables), as well as deal with the effects of sweeping regulatory changes made by federal agencies. At the same time, PUCs in states that have restructured their retail markets must also devise ways to structure those markets to the ultimate benefit of consumers.

It is no surprise, then, that state officials have appeared willing to allow other entities to take the lead on certain issues of importance to the electric system. One set of organizations that has arisen to assert leadership are the regional grid operating organizations.

Regional Regulation

There is no regional government regulation of the electric power industry in the United States *per se*. The main reason for this is that there is no regional government in the United States – at least not in the sense of duly constituted governmental bodies that are directly accountable to the people.

There is, however, regional regulation of the industry – but it is the industry itself, and not governmental agencies, that do the regulating. Independent system operators (ISOs), regional transmission organizations (RTOs), and regional reliability councils are among the organizations that set and enforce rules regarding system reliability and grid and market behavior, while also engaging in long-term system planning and other pseudo-regulatory activities.

These self-regulatory organizations, particularly the ISOs and RTOs, are

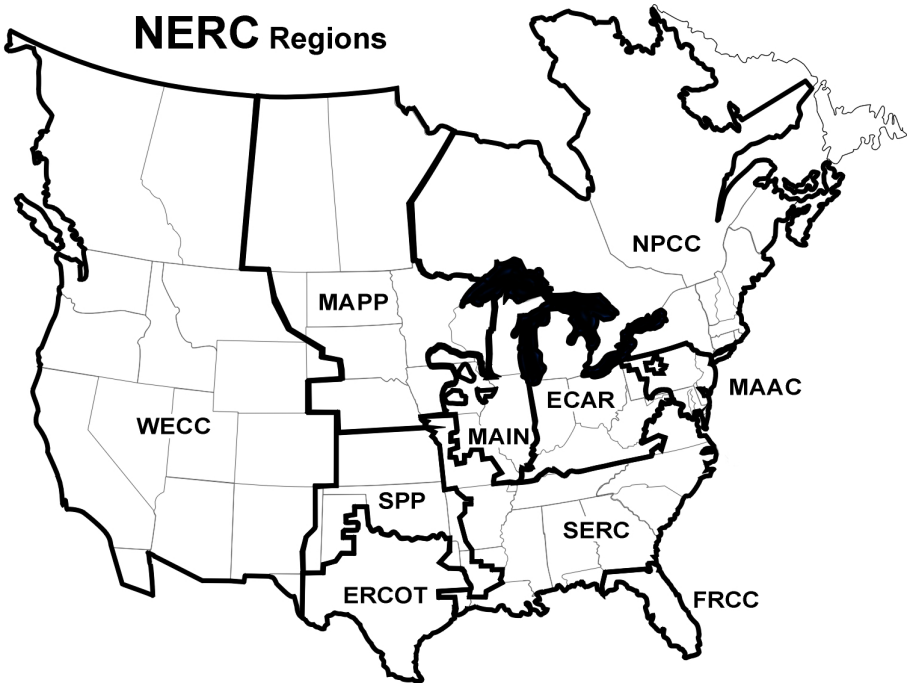
strange creatures – part traditional utility, part independent nonprofit organization, and part regulator. While "independent" in name (and sometimes in deed), these organizations generally arise out of the efforts of electric utilities and do not make their decisions based on the same public interest standards that govern state and federal regulation.

Origins and Evolution of Regional Regulation

Regional regulation of the electric power industry has its roots in the 1965 Northeast blackout. The blackout resulted, in part, from the increasing interconnection of utility systems that had been proceeding over the previous half-century. In the wake of the blackout, utilities and public officials in the region sought to bring transmission systems under increased centralized control, while government officials demanded that steps be taken to ensure the reliable operation of the system.

From these efforts emerged two sets of organizations: power pools and reliability councils. Power pools are voluntary associations of interconnected utilities that coordinate their operations. While regional power pools had existed since the formation of the Pennsylvania-Jersey-Maryland (PJM) pool in 1927, the momentum to establish power pools accelerated in the late 1960s and early 1970s. In contrast to previous (and many ensuing) power pool arrangements, the pools that emerged in the northeast following the 1965 blackout were both extensive – covering entire states – and tight, in that the pool was

Fig. 2. North American Electric Reliability Council Regions[98]



ECAR- East Central Area Reliability Council
ERCOT- Electric Reliability Council of Texas
FRCC – Florida Reliability Coordinating Council
MAAC – Mid-Atlantic Area Council
MAIN – Mid-America Interconnected Network
MAPP – Mid-Continent Area Power Pool
NPCC – Northeast Power Coordinating Council
SERC – Southeastern Electric Reliability Council
SPP – Southwest Power Pool
WECC – Western Electricity Coordinating Council

operated similarly to a single system, with the New England Power Pool – NEPOOL – the tightest of them. Utilities participating in tight power pools gave up a substantial share of their autonomy, ceding to the pool important responsibilities such as control over which generating units operated at which times, coordination of maintenance scheduling, the setting of rules for maintenance of reserve capacity (the amount of extra capacity needed to guard against the sudden loss of a generator), and emergency procedures.[96]

In 1968, the organization that would become the North American Electric Reliability Council (NERC) was formed to design and implement rules to ensure the reliable operation of the electric grid. NERC is a voluntary organization, with no enforcement powers of its own. Much of the work of ensuring system reliability is accomplished through the operations of regional reliability councils, of which there are 10 in the continental U.S. and Canada.[97] In some cases, power pools or other regional organizations also serve as reliability councils.

NERC defines reliability of the wholesale electric system with regard to "adequacy" (the availability of sufficient generation and transmission capacity to satisfy consumer needs) and "operating reliability" (the ability of the system to withstand sudden disturbances).[99] NERC establishes detailed standards for both aspects of reliability, which it expects utilities to follow.

Independent System Operators/ Regional Transmission Organizations

In 1996, the Federal Energy Regulatory Commission (FERC), which regulates the interstate transmission of electricity in the U.S., issued its landmark Order 888, which required that the owners of transmission lines provide open, non-discriminatory access to their lines in order to facilitate the development of wholesale electric markets. The order (which had its roots in the passage of the Energy Policy Act of 1992) represented a dramatic shift. Prior to the issuance of the order, transmission owners could, with some exceptions, control who transmitted power over their lines and under what terms – all subject to the authority of the FERC, which regulated wholesale rates much as state PUCs regulate retail rates. (For more on the FERC and federal regulatory authority, see the next section.)

The problem was this: while the letter of the law required transmission owners to provide open, nondiscriminatory access to their lines, transmission owners (which in many cases also owned generation and/or distribution systems) faced inherent financial incentives to operate their lines in keeping with their own interests or those of their affiliate companies.

Thus, as part of Order 888, the FERC encouraged investor-owned utilities to join independent system operators (ISOs). ISOs were intended to operate similarly to tight power pools (and indeed, ISOs in New England, New York and the PJM region were built off of existing power pools), but with one important difference. Whereas power pools operated for the collective benefit of their members, ISOs were to act independently of the interests of any particular company or group of companies.

In 1999, the FERC went a step farther when it issued Order 2000, which set the criteria for regional transmission organizations (RTOs). The goal set by Order 2000 was that all transmission owners would "place their transmission facilities under the control of appropriate RTOs in a timely manner."[100] RTOs were to be

similar to ISOs in their functional characteristics, except that they were to have regional scope. The initial concept was that as few as four RTOs would emerge to cover the entire country.

Characteristics and Responsibilities of ISOs/RTOs

The FERC required ISOs/RTOs to exhibit four basic characteristics:

- Independence – ISOs/RTOs should not be dominated by or linked financially to any market participant or group of participants.
- Regional scope and configuration (for RTOs) – RTOs should be of sufficient size and include the majority of transmission facilities within a given region.
- Operational authority over the transmission systems under its control.
- Responsibility for the short-term reliability of the electric system, in keeping with standards established by NERC and regional reliability councils.[101]

In addition, the FERC has defined the minimum functional responsibilities of RTOs, which generally apply to ISOs as well:

- Administer and design tariffs and hold sole decision-making authority on interconnections.
- Manage congestion using market-based mechanisms.
- Resolve parallel path flow problems stemming from the fact that electricity travels along any path connecting two points, not just a specific contracted path.
- Act as a supplier of last resort for ancillary services (the scheduling, control and reserve maintenance services needed to maintain reliable operation of the system) and determine what levels of ancillary services are required.
- Administer real-time information systems.
- Monitor for the exercise of market power (the ability of one or more market participants to manipulate electricity supplies in order to achieve excessive profit).
- Take primary responsibility for studying and planning for future transmission expansions.
- Coordinate with neighboring regions.[102]

Criticism of the FERC's initial RTO proposal – and the withdrawal of several proposed RTOs – has caused the commission to backtrack on some of the particulars. In its White Paper on Standard Market Design, issued in 2003, the FERC stated that it would maintain requirements that all investor-owned utilities join an ISO or RTO, but allowed greater flexibility in the regional scope of ISO/RTO operations, provided that ISOs/RTOs work with neighboring regions to coordinate their efforts and work to eliminate the payment of multiple access fees ("pancaked" rates) that increase the cost of transactions that cross regional boundaries.[103]

Where do ISOs/RTOs Operate?

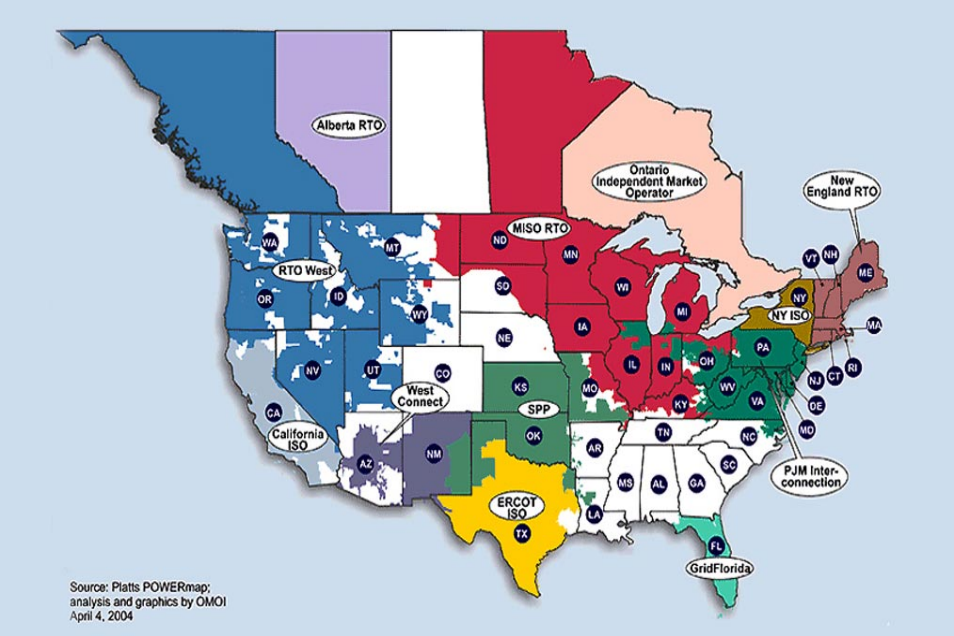
Following the commission's original 1996 ruling in Order 888, ISOs were established in New England, New York, the PJM Interconnection, the Midwest, California and the Electric Reliability Council of Texas (ERCOT) region. Because the territory covered by ERCOT lies entirely within the state of Texas, and is not substantially interconnected with transmission systems outside the state, it falls under state, not FERC, jurisdiction, and will not be discussed in detail here.

In some cases – such as in the Northeast – ISOs were a direct outgrowth of long-established tight power pools. In other cases, ISOs were largely the outgrowth of state requirements imposed as a result of restructuring. The PJM and Midwest ISOs have since made the transition to RTO status.

In addition to the five federally regulated ISOs/RTOs, several other RTO proposals have come before the FERC for approval. Two RTOs – GridFlorida and GridSouth (which would have covered North and South Carolina) – were provisionally approved by the FERC.[104] The GridFlorida proposal as originally designed, however, was rejected by state regulators, while the utility sponsors of GridSouth have suspended their efforts toward establishment of an RTO.[105] GridFlorida continues to pursue state and FERC approval. The Southwest Power Pool (SPP) – which operates in six southwestern states – was conditionally approved as an RTO in early 2004, but has yet to begin operation.[106] ISO-New England's RTO proposal was conditionally approved in March 2004.[107] Two groups in the western United States are continuing the process to achieve RTO status, but have yet to receive FERC approval.

Three of the RTOs – ISO-New England (ISO-NE), New York ISO (NYISO) and California ISO (CAISO) – operate within contiguous areas that roughly adhere to state borders. The PJM and Midwest ISO (MISO) RTOs do not serve contiguous areas and the PJM RTO territory crosses boundaries

Fig. 3. Existing and Proposed RTO Configurations[108]



Source: Platts POWERmap; analysis and graphics by OMOI April 4, 2004

of electric system control areas and reliability regions. The MISO and PJM RTO service territories also overlap in five midwestern states.

Despite the emphasis placed on the creation of ISOs and RTOs by the FERC over the past decade, much of the nation remains unserved by either type of entity. In these locations, individual owners of transmission facilities – perhaps engaged in power pooling arrangements – manage all facets of transmission provision in keeping with FERC orders on open, non-discriminatory access to transmission lines.

Characteristics of Current ISOs/RTOs

Governance

Most ISOs/RTOs are governed in a two-tier structure. Ultimate decision-making responsibility is housed in a board of directors, none of whose members may have a substantial ongoing business relationship with any participant in the market.

Selection of board members is done by ISO/RTO members (Midwest, PJM), by board members themselves (NY, NE), or, in the case of California, by gubernatorial appointment. Membership in an ISO/RTO, where it exists, is generally self-selecting, but typically includes transmission owners, generators, distribution utilities and (in some cases) end-use consumers or other interested parties who apply for membership.

With the exception of California, all ISOs/RTOs are advised by one or more standing committees consisting of members and/or other stakeholders. (California allows the ISO's board of governors to appoint advisory committees as needed.) In most cases, members of advisory committees are selected by sectors of ISO/RTO members representing various interests (e.g. owners, end users, etc.). In the case of ISO-New England, the advisory committee is appointed by the ISO board, however, the associated New England Power Pool includes a participants committee selected by members.

Decision Criteria

All ISOs/RTOs are responsible for making decisions that provide open and non-discriminatory access to the transmission system and protect the reliable and efficient operation of the grid. In implementing these core responsibilities, however, ISOs/RTOs must sometimes make difficult planning and operational decisions that create winners and losers. In a theoretical case in which two proposals with equal impacts on access, reliability and efficient operation were to come before an ISO/RTO, what criteria would guide the decision? Maximization of profit for owners of transmission lines? Minimization of cost for users? Protection of the broader public interest? Some other factor?

For most ISOs/RTOs, there are no such clear criteria. The Midwest ISO, in its agreement with transmission owners, states that "It shall be the duty of the Midwest ISO ... to maximize transmission service revenues .. so as to most efficiently utilize the Transmission System as it exists at any given time ..."[109] The PJM RTO describes the responsibilities of its board as including the promotion of a "robust, competitive and nondiscriminatory electric power market."[110] In other ISOs/RTOs, there is no explicit fiduciary responsibility, other than to protect the equipment of the transmission owners. With no specific public interest/private interest criteria to evaluate decisions – and virtually no direct connection with, or accountability to, end-use customers – the tendency will be for ISOs/RTOs to make decisions based on the views of their board members, the market participants and other stakeholders who participate in the ISO governance

process, and the anticipated reactions of regulators at the federal and state levels.

Functions

All ISOs/RTOs either currently undertake – or are moving toward undertaking – all of the minimum functions laid out by the FERC in Order 2000. In addition, ISO-NE, NYISO and PJM operate central power markets. (California had operated a Power Exchange separate from the ISO, but it collapsed in the wake of the state's energy crisis.) All ISOs/RTOs (except for Midwest ISO) now administer congestion pricing systems and administer the distribution/auction of transmission rights, which allow market participants to hedge against increased costs from congestion prices. The Midwest ISO is planning to launch a wholesale electricity market with congestion pricing and the allocation/auction of transmission rights during 2004.[111]

Multi-State Entities/Regional State Committees

The emergence of regional wholesale markets for electricity – and the growing importance of ISOs/RTOs in regulating those markets – has exposed a gap in regulatory oversight of the industry. As noted above, there is no regional government regulation of the industry – currently, regulation of regional issues is provided by the FERC or the states (or sometimes both), depending on the particular issue. However, many states have claimed in the past that FERC decisions and oversight are not sufficiently sensitive to regional concerns. Meanwhile, the assertion of state jurisdiction over issues of regional concern (such as transmission siting) leads to the potential for parochialism to undermine projects or policies that might be beneficial for a region as a whole.

In 2002, both the states and the FERC moved to create institutions that could bridge this regulatory gap. The National Governors Association proposed the creation of "multi-state entities" that would allow states to coordinate policy on issues falling within traditional state jurisdiction. In addition, the FERC proposed, as part of its Standard Market Design notice of proposed rulemaking, the creation of regional state committees (RSCs) to play a role in shaping policy on matters that traditionally fall within federal jurisdiction. The consolidation of both functions within a single entity appears to be the most prudent course, and the regional state committees we refer to in the rest of this section are assumed to fill both roles.

Currently, the dominant organization in regional issues is the ISO/RTO (in locations where they exist). Unlike ISO/RTO governing boards – which are intended to be "independent" and may or may not be accountable to a self-selecting group of stakeholders – RSCs would be creatures of the states, providing a forum for state regulators to consider issues from a regional perspective. In some areas of the country where ISOs/RTOs do not currently exist, but are planned, a regional state committee formed at the outset of the planning process could ensure that the eventual form of the ISO/RTO best serves regional needs. In other cases, in which ISOs/RTOs are contained within a single state's boundaries, a formal RSC may not be needed, since its function could be performed by a state public utilities commission that is fully integrated into the decision-making structure of the ISO/RTO. To the extent that ISOs/RTOs engage in inter-regional cooperation through the establishment of common markets and efforts to reduce "seams" issues (differences in operational and market structures across ISO/RTO boundaries),

it may make sense for individual states or RSCs to create some forum for the discussion of inter-regional issues.

RSCs could fulfill a number of functions, including:

- Determining the allocation of costs for investments made to relieve transmission constraints.
- Setting resource adequacy requirements.
- Planning for the future expansion of the transmission grid.
- Resolving interstate transmission siting issues.
- Monitoring the markets for evidence of the use of market power.
- Coordinating the development of electricity generation with the availability of natural gas supplies.
- Developing policy on issues such as rate design, market power monitoring, demand response, energy efficiency and the environment.
- Overseeing RTO operations.[112]

There is no formal directive from FERC on how RSCs should be structured or developed. The FERC has declined to create a formal regional regulatory structure, instead leaving it to the states to determine the ultimate form and functions of RSCs.

Regional organizations that bring together state utility commissioners have existed for many years. However, it is unusual for these organizations to conform to the irregular boundaries of many ISOs/RTOs. (For example, the Mid-Atlantic Conference of Regulatory Commissions – MACRUC – and PJM Interconnection have established formal channels of communication through a memorandum of understanding. However, the expansion of PJM's service territory to Ohio – a state that is not a member of MACRUC – leads to a disconnect between PJM's service territory and the corresponding body of state officials.)[113] Thus, while some regional state committees could be formed from existing organizations, many would have to be created from scratch.

New organizations along the lines of regional state commissions have been formed in the Midwest ISO territory and proposed for New England.[114]

The effectiveness and importance of RSCs depends greatly on the degree to which RSCs are able to reach decisions that present a clear vision for the industry, and the degree to which the FERC, state commissions and ISOs/RTOs take those decisions into account. The FERC is explicitly counting on RSCs to provide direction on a number of important RTO-related issues. Should the RSCs fail to follow through on their promise, those decisions would be left (as they largely are now) to ISOs/RTOs to resolve.

However, RSCs – no matter how they are established and directed – will always face the essential problem of being unmoored from direct accountability to any specific governmental entity. If an individual dislikes a decision made by a state PUC or the FERC, he or she could always hold the chief executive (governor or president) responsible for appointing those commissioners accountable (or, in the case of elected PUC commissioners, the commissioners themselves). Such lines of accountability become attenuated when related to regional bodies such as RSCs with real decision-making power. To ensure that regulators are held accountable for their decisions, states (or the federal government) must remain the ultimate authority, with the RSC in a strong, yet essentially advisory role. In addition, RSCs would ideally be funded independently – and not through allocations from ISO/RTO budgets.

Federal Regulation

The federal government imposes numerous regulations that affect the generation, transmission and distribution of electricity. Environmental policy, tax policy, appliance efficiency standards, and subsidies for energy production, consumption and conservation all have a dramatic impact in shaping how electricity is produced and used in the United States. To attempt to capture the entire impact of federal policy on electricity would go well beyond the limits of this report (although we do touch on some of these issues, particularly taxpayer subsidies for energy production, elsewhere). Thus, we will focus mainly on federal regulation that specifically relates to electricity generators and utilities.

The federal government's primary role in electricity regulation is to oversee the nation's bulk interstate transmission system and the transactions that occur through that system. These are the transfers of power between utilities (and increasingly, in the wake of restructuring, among independent power producers, utilities and end-use consumers) that form the wholesale electricity market in the United States. In addition, the federal government regulates the corporate and financial structure of electric utilities.

Origins and Evolution of the Federal Role

The federal government's role in electricity regulation dates from the 1930s, when serious flaws in the state regulatory system began to make themselves apparent. Electric utilities created a system of holding companies that allowed them to shift and conceal expenses and revenues in order to gain favorable treatment in state rate-setting. In addition, these financial structures allowed for speculative activity and the shifting of regulated revenues to support non-utility investments – threatening the stability of the electricity system. Meanwhile, the increasing interconnection of power systems over state lines required that authority be asserted at a level higher than individual states.

The Federal Power Act (FPA) and Public Utilities Holding Company Act (PUHCA) – both enacted in 1935 – established the basic framework for the federal role in utility regulation. Under the two laws, states retained the central mission of establishing retail electric prices, determining the amount of money the utility will be permitted to collect, and deciding how prices can be set among residential, commercial, and industrial consumers. The federal government was given jurisdiction over and charged to regulate *interstate* transactions, wholesale rates, interconnection and transmission (wheeling) of wholesale electricity.

The Federal Power Act established the forerunner of today's Federal Energy Regulatory Commission (FERC) with the mission of ensuring adequate and reliable service by regulating the terms, conditions and rates for the sale in interstate transmission of wholesale electricity, as well as mergers, acquisitions, and dispositions of facilities used for interstate wholesale transactions.

PUHCA charged the Securities and Exchange Commission (SEC) with regulating electric utilities' corporate structure and business ventures. PUHCA eliminated the many-tiered structure of holding companies that utilities had used to consolidate control over the industry and manipulate their finances, requiring that holding companies could be no more than twice removed from their operating subsidiaries.[115] In addition, PUHCA required that multi-state utilities provide detailed financial information to the SEC, similar to the financial information that had long been

required under state public utility regulation. Finally, PUHCA required holding companies to receive approval from the SEC before purchasing holdings from other companies and limited the ability of regulated utilities to participate in non-related business ventures.[116]

The basic regulatory structure created by the Federal Power Act and PUHCA remains in place today. But, beginning in the late 1970s, federal law – and the application of the law by federal agencies – began to shift the emphasis of federal regulation away from aggressive regulation of utilities' day-to-day affairs and toward a new model of the wholesale electric system driven by competition.

In 1978, Congress enacted the Public Utility Regulatory Policies Act (PURPA). PURPA was passed largely in response to the energy crisis in an attempt to increase the amount of efficiently produced electricity in the country. A central goal of PURPA was to encourage electricity production from relatively efficient cogeneration (a process that harnesses byproducts of electricity production, such as steam and heat, as secondary sources of fuel) and renewable fuels.

PURPA identified cogeneration and small generators as "qualified facilities" and required utilities to purchase the power they generated at "avoided costs" – the price it would have cost them to generate the electricity otherwise. This was the first mandatory purchase requirement ever enacted for public utilities, requiring them to purchase power from outside sources.[117] In addition, qualified facilities were exempted from reporting regulations under PUHCA and the FPA.

In establishing the price on the basis of avoided costs, PURPA also was the first federal law to move away from cost-of-service pricing, in which costs were set by FERC on the basis of seller's costs to generate and transmit the power.[118] PURPA left the precise methods of determining avoided costs to the state PUCs, leading to various definitions of avoided costs.

PURPA had two long-term philosophical ramifications. First, it established the idea that the generation of electric power did not have to take place within a structure of vertically integrated utilities, but that independent power producers could sell power into the grid. Second, PURPA set important precedents for how such producers could be treated in the regulatory system, by exempting them from some of the regulations facing traditional utilities and creating an exception to the traditional calculation of rates based on the cost of providing service.

In 1992, Congress built upon the precedents set by PURPA by enacting the Energy Policy Act (EPAct). EPAct created entities called "exempt wholesale generators" (EWGs), that can generate and sell electricity at wholesale without being regulated as utilities. To further open up markets to EWGs, the title assured them access to transmission (wheeling) of their wholesale power. However, under EPAct, states maintain jurisdiction over transmission of power to retail consumers – FERC cannot mandate that utilities transmit EWG power to retail consumers, although FERC can mandate utilities, on a case-by-case basis, to allow competitors to use their transmission lines for wholesale sales of electricity.[119]

In 1996, the FERC's Order 888 required investor-owned utilities to allow competitors to use their transmission lines for interstate commerce. Through this order, FERC asserted its jurisdiction over rates, terms, and conditions of unbundled retail transmission in interstate commerce by public utilities:

> Based on an analysis of the relevant legislative history and case law under the Federal Power Act (FPA), the Commission concludes that it has exclusive jurisdiction over the rates, terms and conditions of the unbundled transmission in interstate commerce, by a public utility, of electric energy to an end user. This is also known as retail wheeling in interstate commerce. [120]

In addition, utilities were allowed full recovery of stranded costs – costs that were prudent investments before wholesale competition but now are uneconomic or "stranded" – by passing the costs for revenues lost from these unprofitable investments to customers who are deciding to leave the utility system. (Order 888 only applies to wholesale stranded costs, leaving retail stranded costs to state public utilities commissions to regulate.)

The Federal Energy Regulatory Commission

Composition

The FERC is composed of five commissioners, who are appointed by the president to five-year terms. The president also appoints the chair of the commission. No more than three of the five commissioners may be members of the same political party.

Jurisdiction

FERC's authority is largely limited to investor-owned utilities – the FERC does not have jurisdiction over publicly owned utilities or most electricity cooperatives. FERC also has no explicit authority over system reliability – which has largely been the responsibility of electric utilities, and, since its creation in 1968, of the North American Electric Reliability Council and member organizations.

Mandate

Rate Regulation

The Federal Power Act of 1935 requires that all rates related to the sale and transmission of electric power under FERC's jurisdiction be "just and reasonable and not unduly discriminatory or preferential." [121]

> All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates and charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.[122]

The Federal Power Act authorizes the FERC to investigate electric power prices that appear to violate the just and reasonable standard, and *obligates* the FERC to take remedial action to control prices and reverse any violations of the standard that are identified. In fact, the Federal Power Act requires that the FERC order refunds for any payments by consumers for prices found to exceed just and reasonable levels.

Traditionally, FERC has met its obligation to ensure just and reasonable rates by setting rates at levels sufficient to recover the costs of generation and transmission, plus a margin of profit. In this cost-recovery approach, if the seller's costs increased, the FERC authorized higher rates; if seller's costs decreased, the FERC set lower rates.

However, the FERC has recently supplanted this cost-recovery approach with a different methodology to set rates: market-based pricing or "proxy pricing." This methodology was adopted in the hope that allowing competitive markets to determine pricing would lead to more efficient production of electricity and ultimately lower the cost of electricity to the consumer. The depth of this hope is illustrated by the FERC's strategic plan for fiscal years 2004 through 2008, which sets as a major goal "foster(ing) competitive energy markets as a substitute for traditional regulation."[123]

The tension between the FERC's statutorily defined role in assuring just and reasonable rates and its interest in promoting competitive markets was clearly demonstrated during the California energy crisis, when the FERC failed for months to recognize the exercise of market power – even issuing a report in February 2001 that generating companies in California were not withholding power in an effort to increase prices – and failed to implement effective price caps in western transmission markets for another several months.[124] The FERC remains embroiled in the process of sorting out the refunds that must be made by those who unjustly benefited from the market crisis.

It must be noted that the California crisis thrust the issue of market power before the FERC and state regulators in a very dramatic way, bringing new attention to the issue and means of addressing it. Yet, the inherent characteristics of the electric system – the inability to store power, the need for minute-by-minute equilibrium between supply and demand, and the ability of individual actors to disrupt a dynamic and tightly coupled system – create myriad ways in which markets can be manipulated, some of which are extremely difficult to detect. The California experience raises the question of whether the FERC – or any regulator – explicitly committed to encouraging open market transactions in electricity as an end in and of itself will have the wherewithal to recognize market power as it is being exercised and take action to stop it.

Mergers

The Federal Power Act grants the FERC the authority to review proposed mergers and consolidations of public utilities to determine whether they are consistent with the public interest. In evaluating proposed mergers, the FERC takes into account three factors: the effect on competition, the effect on rates, and the effect on regulation.[125]

Between 1995 and 2002, the FERC received 66 applications for merger approval, approving 56 and conditionally approving an additional four.[126] The wave of mergers has led to rapid consolidation within the industry. Whereas, in 1992, 70 electric holding companies owned 78 percent of all generation capacity owned by investor-owned utilities, by 2000, 50 companies owned 86 percent of the generating capacity. By the end of 2000, the 20 largest investor-owned utilities owned about 72 percent of generating capacity, compared to 58 percent in 1992.[127] Industry consolidation has continued since then.

Securities and Exchange Commission PUHCA Enforcement

One major piece of utility regulation – enforcement of the financial and business restrictions contained in PUHCA – is left to the Securities and Exchange Commission (SEC). The SEC has long been lackluster in its enforcement of the law, has argued that other laws duplicate the functions of PUHCA, and has

conditionally recommended that the law be repealed.

PUHCA itself also includes two exemptions that are often used to evade the law's restrictions – exemptions for holding companies that are "predominantly intrastate in character" and those "whose operations as such do not extend beyond the State in which it is organized and States contiguous thereto."[128]

In recent years, however, the SEC and Congress have carved out a number of other exemptions to PUHCA that allow companies that own utilities to avoid regulation under the Act.

Among the exemptions are:

- Exemptions for foreign owners of U.S. utilities.
- Exemptions for "exempt wholesale generators," removing restrictions on utilities' ownership of generation-only assets.[129]
- Exemptions for power marketers (such as Enron), allowing them to be owned by regulated utilities.[130]
- Exemptions for PUHCA-regulated utilities who purchase certain telecommunications firms.[131]

The increasing number of exemptions from PUHCA regulation has opened the field for regulated utilities to participate much more actively in non-utility businesses. We will address the consequences of these changes later in this report.

Summary

The framework for public interest regulation of electric utilities at the federal level largely remains in place as it has since the 1930s. While changes in federal law have opened the door for competition in the wholesale power sector, federal agencies retain the statutory authority to set and enforce just and reasonable rates for wholesale electricity transfers and to limit the risks regulated utilities can impose on their customers and shareholders through dalliance in non-regulated business ventures. The major issue with regard to federal authority is not whether sufficient authority exists, but how that authority is used. The performance of the FERC and the SEC in recent years suggests that the two agencies have refrained from exercising their authority to the benefit of retail consumers.

Recent Trends in Consumer Costs and Service

From the perspective of consumers, the success of the electric power system can be measured in the reliable provision of quality electricity service at stable, reasonable prices, and with minimal damage to the environment and public health. Advocates of various structures for the electric industry often claim that their favored approach will provide the greatest consumer benefits.

In this analysis, we examine consumer cost trends over the past decade from a variety of perspectives. As yet, nearly a decade into the restructuring of the industry, restructuring has led to little apparent benefit for the majority of consumers.

Electric Rates

Rates are the traditional measure by which electricity costs are evaluated. Rates are an imperfect measure of consumers' electricity costs – a system in which power is consumed more efficiently could yield lower overall costs for consumers (in terms of bills), even if

consumers pay higher rates per kilowatt-hour. However, because electricity usage patterns differ significantly from region to region and state to state, rates present one way of drawing meaningful comparisons.

Rate Trends

Electricity rates have been on a long-term downward trend in real, inflation-adjusted terms for the last four-plus decades – a trend that has been interrupted only by higher energy prices in the 1970s and early 1980s and by the impact of nuclear power plant construction in that same period. (See Fig. 4.)

Overall, from 1993 to 2002, average nationwide electricity rates decreased by approximately $0.014 / kWh – or 16.4 percent – in real terms (2003 dollars). However, the trend in recent years has been less positive. In 2001, inflation-adjusted electricity rates increased for the first time in nearly two decades, due in part to the California energy crisis and high natural gas prices. Rates increased again in 2003, with the average rate for all sectors up by 2.6 percent (in nominal terms) from 2002.[133]

Industrial customers have received slightly greater benefits from rate reductions than other classes of consumers. Between 1993 and 2002, industrial consumers saw a 19 percent decrease in their real, inflation-adjusted electricity rates, compared to an 18.3 percent decrease for residential consumers and an 18.5 percent decrease for commercial consumers. (See Table 3.)

Not every state saw equal reductions in rates. Seventeen states experienced re-

Fig. 4. Overall Trend in Inflation-Adjusted Electricity Rates, 1960-2002[132]

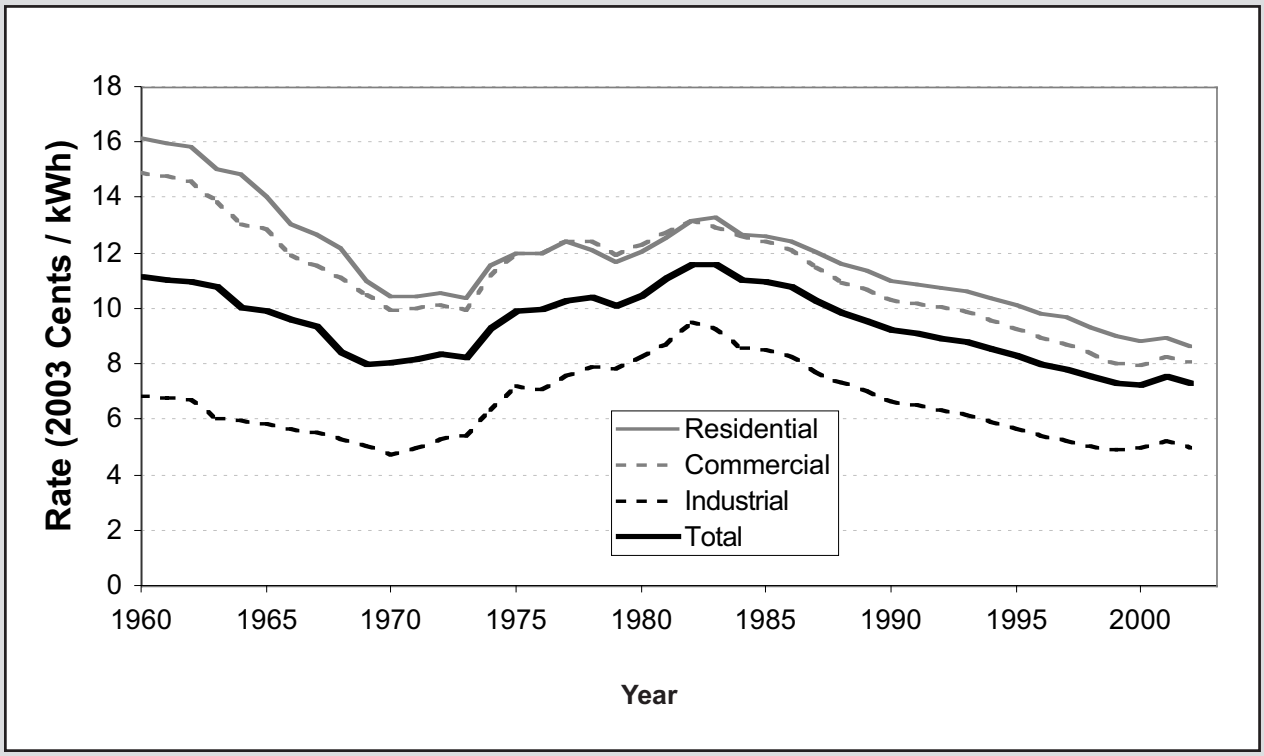


Table 3. Change in Rate by Customer Class in Real Terms, 1993 to 2002[134]

Customer Class	Change in Average Rate, 1993-2002 (2003 cents / kWh)	% change
Residential	-1.9	-18.3%
Commercial	-1.8	-18.5%
Industrial	-1.2	-19.0%
Total*	-1.4	-16.4%

* Difference in percentage reduction in total rate is lower than the percentage reduction in any single sector due to differences in the share of each sector in total electricity consumption between 1993 and 2003.

Table 4. States With Greater Than 20 Percent Decrease in Inflation-Adjusted Residential Rates, 1993 to 2002

State	Change in Real Residential Rate (1993-2002)
Illinois	-34%
Arizona	-31%
Arkansas	-30%
Rhode Island	-28%
New Jersey	-27%
Louisiana	-26%
New Mexico	-26%
Maryland	-25%
Oklahoma	-24%
New Hampshire	-23%
Connecticut	-23%
Delaware	-22%
Missouri	-22%
Kansas	-22%
Georgia	-21%
West Virginia	-21%
Kentucky	-21%

ductions in their inflation-adjusted average residential rates of greater than 20 percent between 1993 and 2002. (See Table 4.) Meanwhile, seven states saw real increases in residential rates over the same period. (See Table 5, next page.)

There has been little change over the last decade in the geographic disparity in rates among the various states, athough the number of states with extremely low or extremely high rates has declined. In 1993, among the 50 states, there were 11 states with residential rates more than 25 percent above the median rate and seven states with rates more than 25 percent below the median. By 2002, the number of high-rate states had dropped from 11 to nine, and the

Table 5. States Experiencing an Increase in Inflation-Adjusted Residential Rates, 1993-2002

State	Change in Real Residential Rate (1993-2002)
Montana	1%
Hawaii	2%
Vermont	4%
Idaho	6%
Washington	10%
Oregon	14%
Nevada	16%

number of states with rates more than 25 percent below the median had dropped from seven to three.

Overall, residents of the Northeast, California and Hawaii continue to pay the nation's highest electric rates. Residents of the Pacific Northwest, the Plains states, and most of the Southeast enjoy low rates. This situation is virtually unchanged from a decade ago.

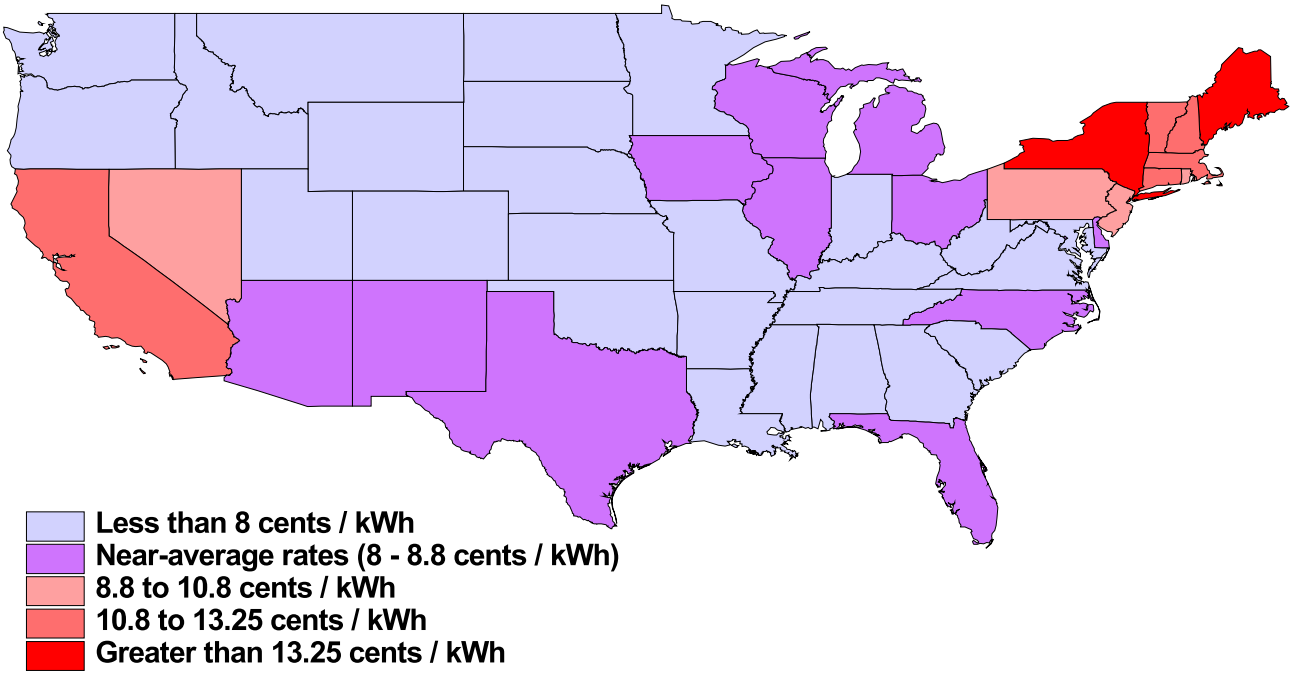
Factors Influencing Rates

Energy Prices

The steep decline in the real cost of fossil fuels during the 1990s is likely responsible for at least some of the real declines in rates over that period. The subsequent increase in natural gas prices since the turn of the century is likely responsible for the uptick in average rates in 2001 and 2003.

The cost of fuel can have a significant impact on rates. From 1990 to 2002, the cost of fossil fuels represented an average of 22 percent of residential consumers' electricity rates, although this percentage varies significantly from region to region based on the fuel mix of the generators serving a particular area.[136]

Fig. 5. Residential Electricity Rates in 2002[135]



The 1990s saw steep declines in the cost of all major fuels used to power electric power plants. From 1993 to 2002, for example, the cost of coal – the most commonly used fossil fuel in the electric power industry – declined by 25 percent in nominal terms. In real (inflation-adjusted) terms, coal costs declined by 40 percent.[137]

For much of the 1990s, natural gas prices were also low in historic terms. By 1995, natural gas prices had dropped to their lowest level in inflation-adjusted terms since the mid-1970s.[138] However, beginning in 1999, the increased demand for natural gas sparked by the construction of numerous gas-fired power plants began to strain natural gas supplies. Between 1999 and 2001, the nominal price of natural gas in the electric power sector increased by 76 percent, before easing somewhat in 2002. (See Fig. 6.) Natural gas prices in the electricity sector increased by approximately 51 percent over 2002 levels during 2003, partially explaining the higher electric rates faced by many consumers.[139]

These same trends appear in utility expenditures on fuel for power generation over the last decade. The cost of fossil fuel per unit of energy produced declined in real terms through the late 1990s, with an increase in 2000 and 2001 – likely due to increased natural gas demand. From 1994 to 2002, utility expenditures for fossil fuels declined by 0.4 cents/kWh in real terms, or 19.5 percent. Similarly, utility expenditures for nuclear fuel declined by 0.24 cents/kWh, or 33.7 percent. (See Fig. 7, next page.)

Thus, if one assumes that fuel savings are passed through directly to consumers in their rates, reductions in fuel costs would be responsible for about one third of the reductions in electric rates that consumers experienced during the 1993 to 2002 period.

Energy Sources

States in which the generation mix is heavily reliant on coal and hydropower tend to have the lowest electric rates.

Fig. 6. Nominal Costs Per Unit of Fuel[140]

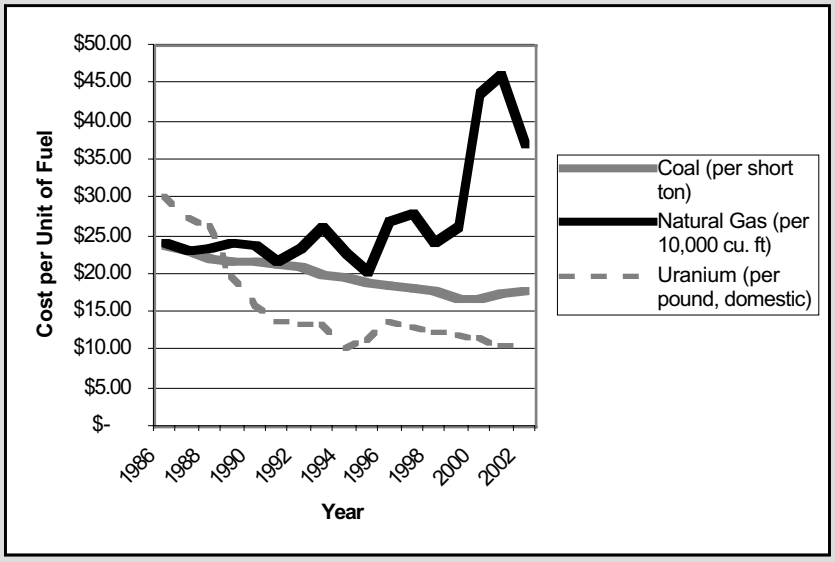
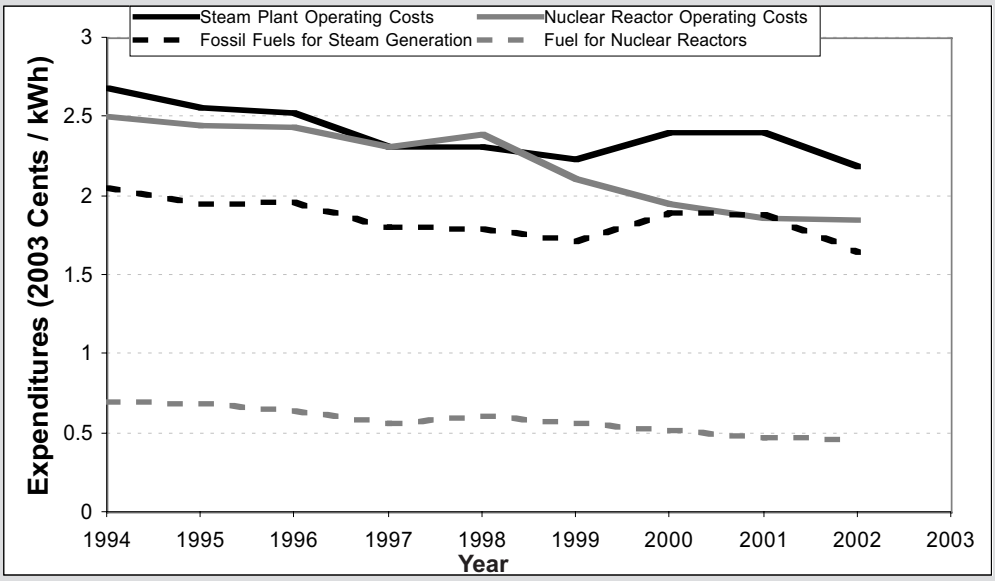


Fig. 7. Inflation-Adjusted Trend in Utility Expenditures for Fossil and Nuclear Fuels, per kWh Produced[141]



States in which the majority of generation is from nuclear power, natural gas, or petroleum tend to have higher rates. However, when external costs – such as environmental and public health impacts – are factored into the mix, cheap forms of power such as coal-fired generation do not appear to be such a bargain.

With the onset of wholesale – and in some cases, retail – restructuring, it is much more difficult to draw a clear link between the cost of electricity for consumers and the sources of generation that supply that electricity. Consumers, utilities or standard offer service providers may choose to purchase electricity from out-of-state generators, sometimes in distant regions.

Despite this fundamental shift in the industry, the rates consumers in various states pay for electricity appear to be strongly correlated with the sources of energy used to generate electricity within their states.

Fig. 8 shows the average residential rate paid by consumers, with the shading of the bars indicating the percentage of net generation within each state provided by each fuel source. The figure shows that consumers in states with heavy reliance on petroleum, natural gas and nuclear power pay significantly higher rates for electricity than consumers in states that are heavily dependent on coal and hydroelectric power.

This trend is even more clear if one simplifies the comparison by grouping states based on their primary source of electricity generation. Fig. 9 shows the states again, with this simplified breakdown.

There are two important points that bear noting. First, electric rates do not include external costs – such as impacts on the environment. Environmental costs resulting from air emissions from modern integrated gas combined cycle coal plants have been estimated to be as much as 4 to 5 cents per kilowatt-hour – not counting the myriad land and water pollution impacts of coal mining. External costs from older, less-efficient coal-fired power plants that are not re-

Fig. 8. Residential Electricity Rates and Fuel Dependence (2002)[142]

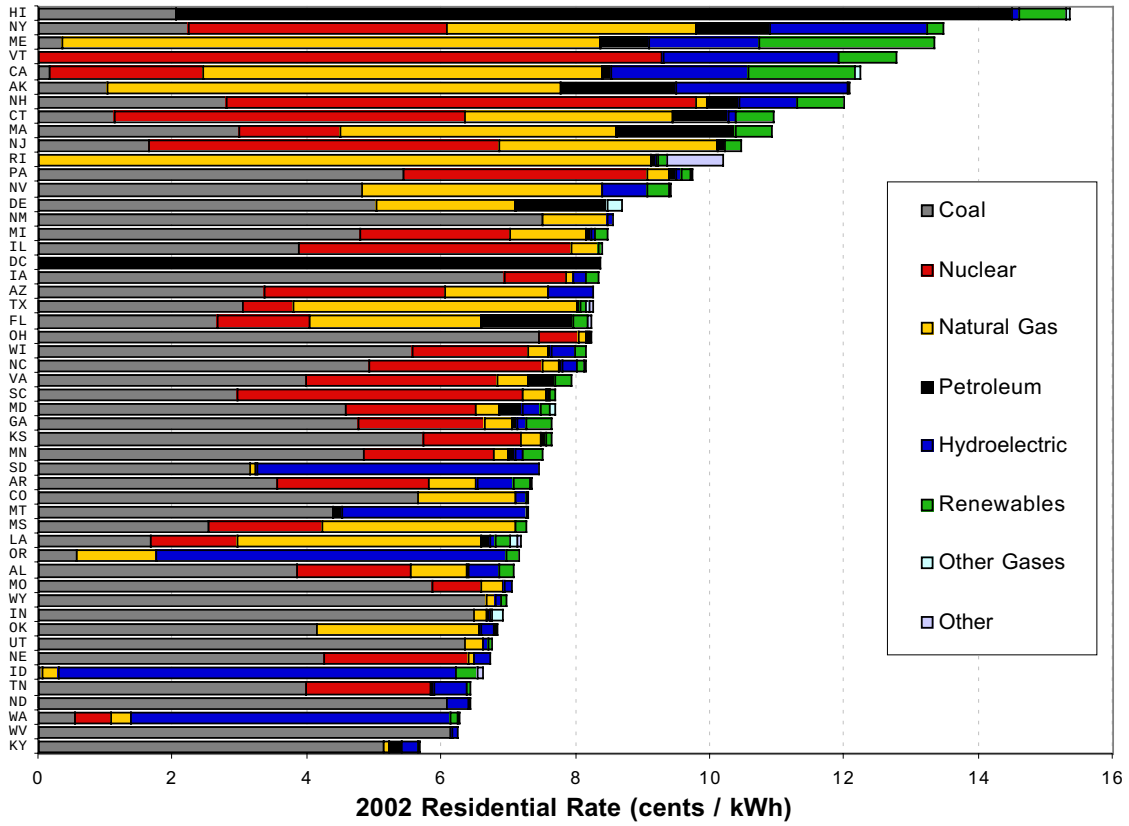


Fig. 9. Residential Electricity Rates and Primary Fuel Dependence for In-State Generation (2002)[143]

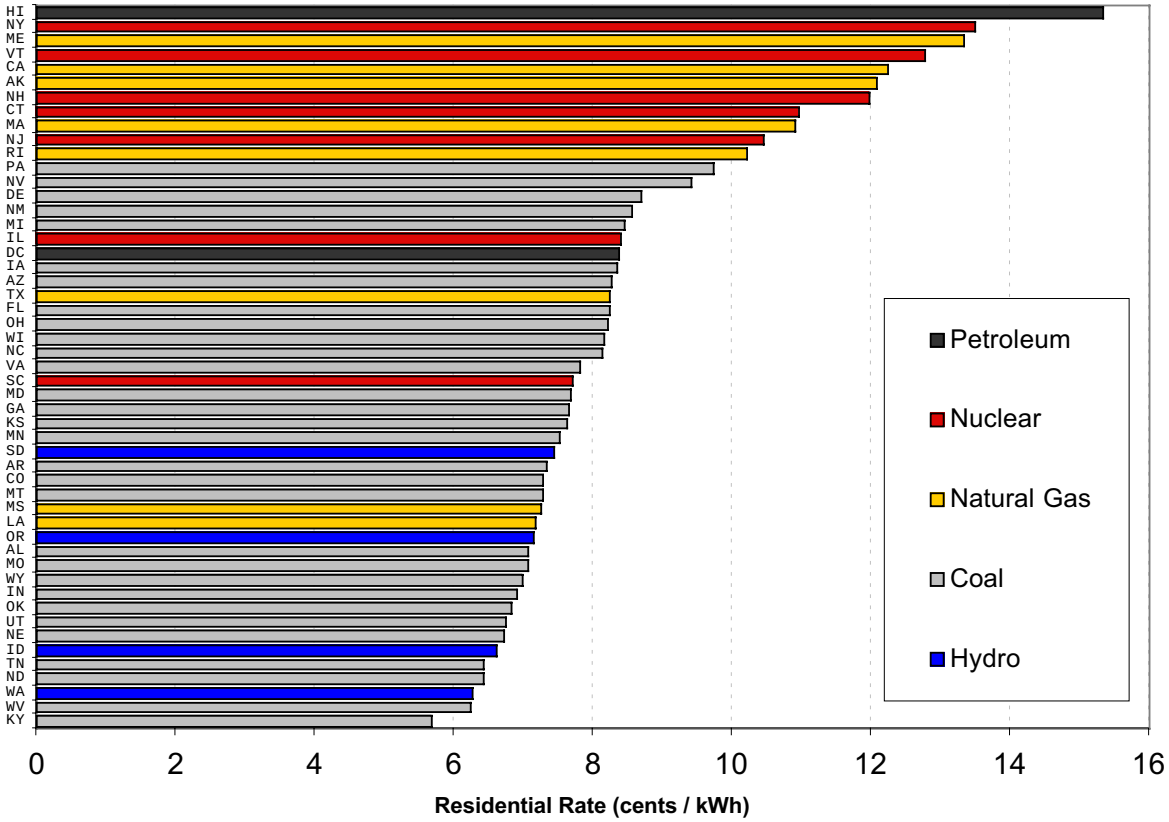
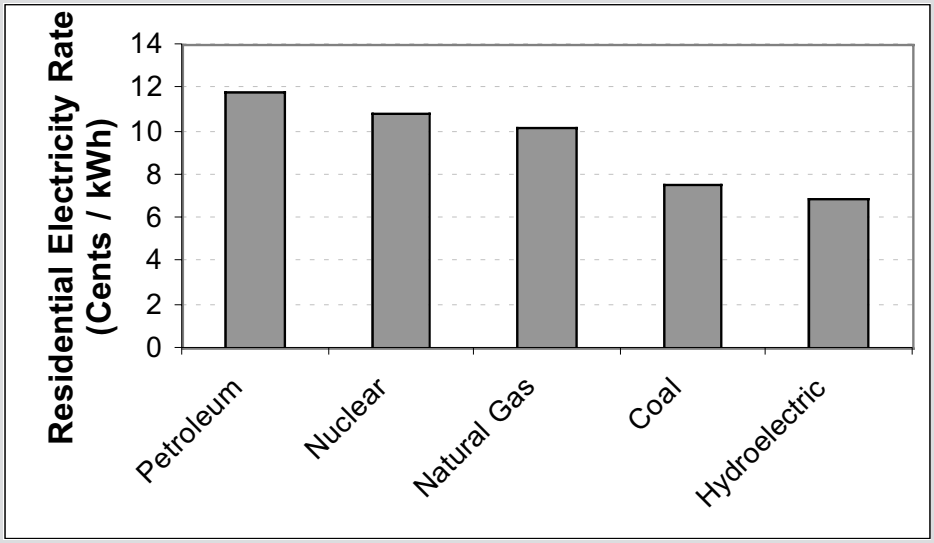


Fig. 10. Average Residential Electricity Rates in States Based on Primary Source of Energy for In-State Generation, 2002[144]



quired to meet updated environmental standards are estimated at more than double that amount.[145] Including the costs of environmental and other impacts in consideration of rates – costs that are currently "externalized" and borne by others in society – would remove much of the perceived economic benefits of coal as an energy source. (For more on this issue, see "Environmental Externalities," page 91.)

Second, states with heavy reliance on natural gas are generally among the states with the highest rates. This result would not have been predicted at the outset of restructuring, when promises of new markets for electricity, combined with low natural gas prices and efficient new plant designs, spurred the construction of numerous new natural gas-fired power plants. The increased demand from those plants is among the causes of the recent spike in natural gas prices. The natural gas experience demonstrates the problems posed by over-reliance on a single, nonrenewable fuel, as well as the weaknesses created when short-term market forces are permitted to dictate long-term investments in infrastructure.

Public Power Penetration

States in which publicly owned utilities (municipal utilities and cooperatives) provide a large share of the state's electricity tend to have lower average residential rates than states in which service is provided primarily by investor-owned utilities. Of the 16 states in which more than 40 percent of electricity was supplied by publicly owned power companies, only one – Arizona – had average electricity rates that were greater than 8 cents per kilowatt-hour in 2002. (See Fig. 11.)

Indeed, the percentage of power supplied by publicly owned entities is directly correlated with rates. This correlation is statistically significant at a 99 percent confidence level. (See Fig. 12.)

Fig. 11. 2002 Residential Electricity Rates and Market Penetration of Public Power[146]

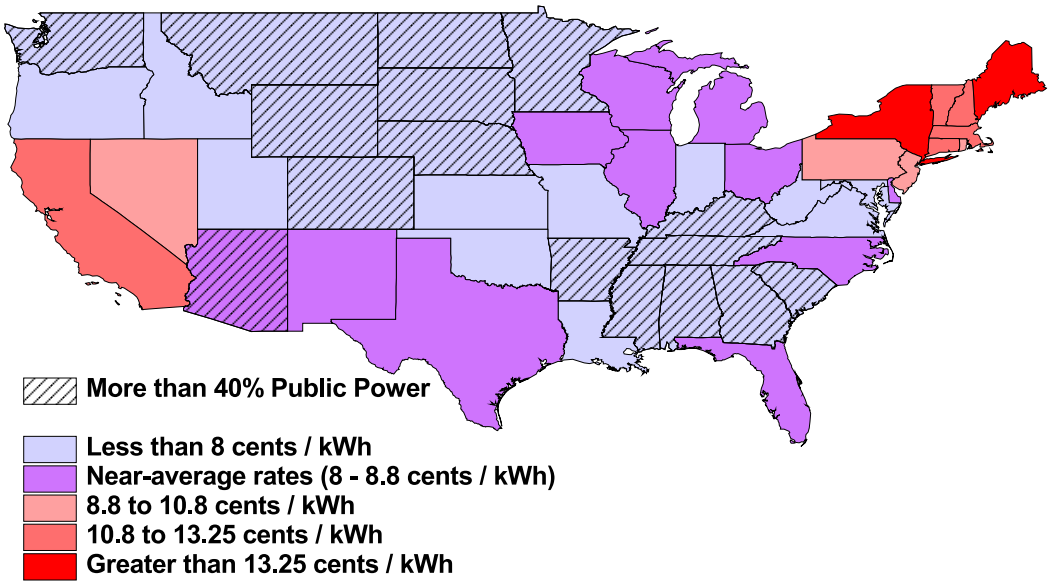
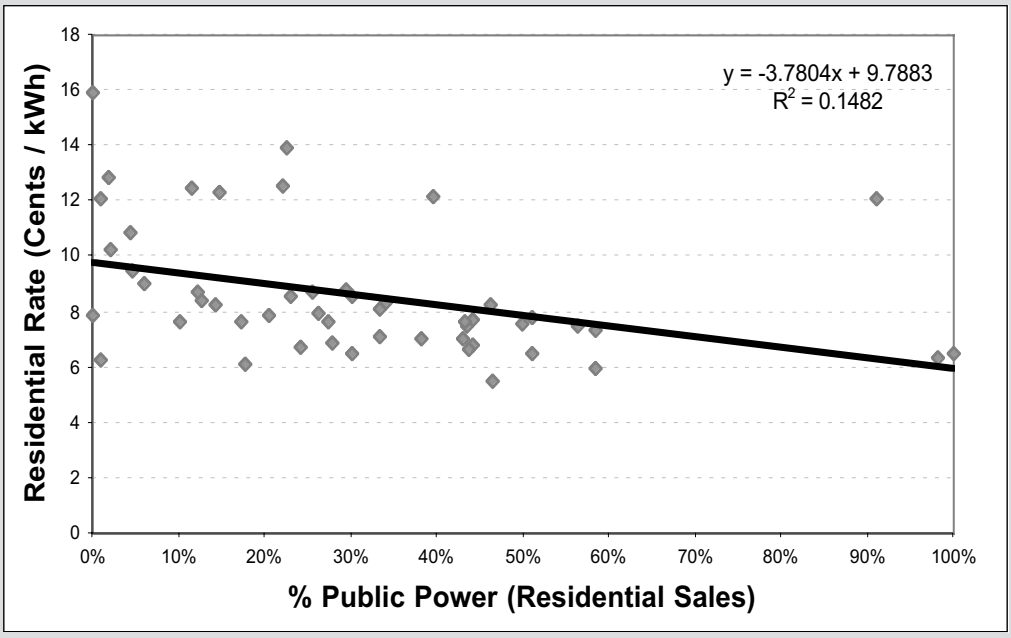


Fig. 12. Residential Electricity Rates by Public Utility Ownership Levels, 2002[147]



Restructuring Status

Retail restructuring appears to have had little effect on overall electricity rates. It is unclear whether the modest additional rate declines that have occurred in states with retail choice are

the result of competition, state-imposed rate caps or reductions, rates that were high to begin with, or a combination of all of these factors. It is likely that wholesale restructuring has had both positive and negative impacts on consumers – the net impact is unclear.

Fig. 13. Inflation-Adjusted Trends in Residential Electricity Rates by State Restructuring Status in 2003[148]

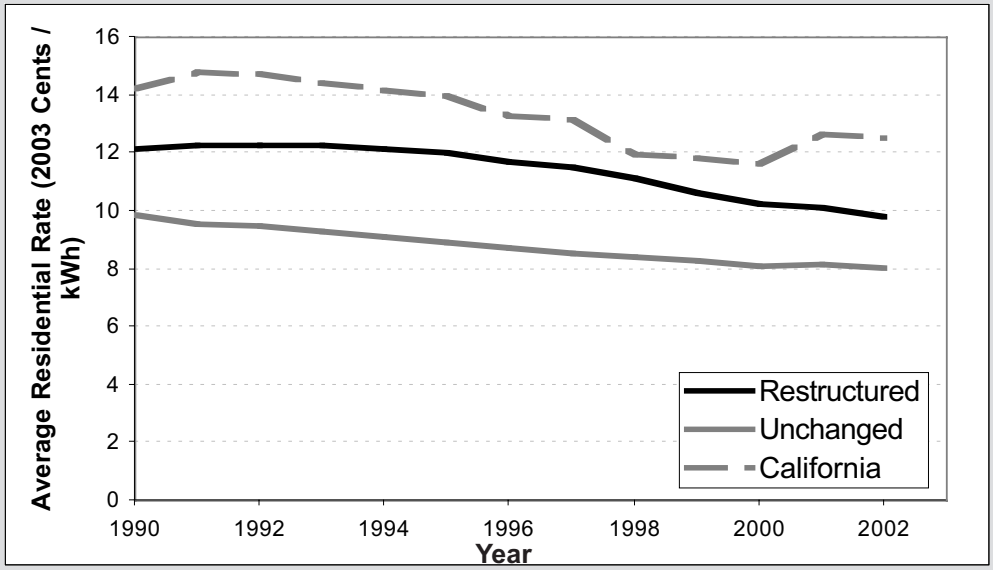


Fig. 14. Rate Changes by Customer Class and Restructuring Status, 1993 – 2002[149]

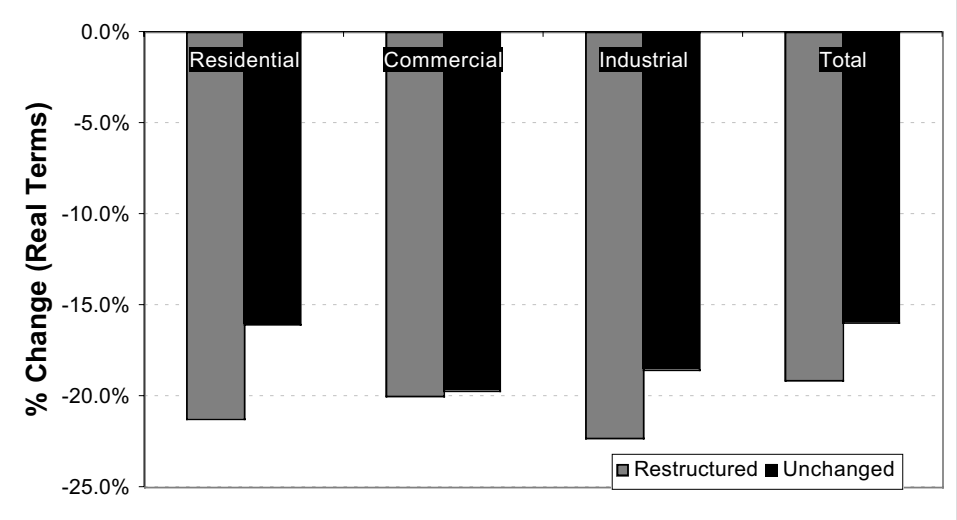


Table 6: States with the Largest Residential Rate Decreases 1993-2002, in Real Terms (2003 dollars)[151]

State	% change in rate, 1993-2002	1993 rate ranking	Rate reduction/ freeze required in restructuring?	Reduction/freeze expires
Illinois	-34.5%	11	reduction	2007
Arizona	-31.1%	13	reduction	2004 / 2008
Arkansas	-29.6%	18		
Rhode Island	-28.0%	7	reduction	2009
New Jersey	-26.9%	5	reduction	2003
Louisiana	-26.5%	27		
New Mexico	-25.6%	15		
Maryland	-24.6%	19	reduction	2004 / 2008
Oklahoma	-24.3%	33		
New Hampshire	-23.2%	2	reduction	2006

Retail Restructuring

The 17 states (not counting California) that have engaged in retail restructuring have adopted a wide variety of strategies – from extremely limited retail choice in states like Oregon to aggressive pro-competition policies in states like Pennsylvania. To lump these various experiments together in a single category runs the risk of oversimplification.

With that caveat in mind, here is what we do know: From 1993 to 2002, residential rates declined an average of 21 percent in real terms in restructured states, and declined an average of 16 percent in states that did not change regulatory policy. (California, which terminated retail choice following the state's energy crisis, is a special case and is treated separately.) Overall, rates declined 19 percent in real terms in restructured states, and 16 percent in states without restructuring policies active in 2003.

These results, however, do not suggest that retail restructuring has *caused* residential rates to fall.

First, many of the states that engaged in retail restructuring were already high-rate states. It is therefore somewhat more likely that – in an atmosphere in which rates were falling across the board during the 1990s – these states may have seen their rates fall faster than states with lower rates, even without the influence of restructuring.

Second, it is likely that the policies designed to provide benefits to consumers during the "transition" to competition – rather than competition itself – are mainly responsible for any rate decreases attributable to restructuring. Of the 10 states that experienced the largest decreases in residential rates between 1993 and 2002, six engaged in retail restructuring. However, in each of those six states, mandatory rate reductions ranging from 1 percent to 15 percent were included as part of the states' restructuring plans.[150] Moreover, the restructured states that appear on this list have experienced little meaningful competition in residential markets – indeed, states that have seen significant numbers of consumers switch provid-

ers, such as Ohio and Pennsylvania, are conspicuous by their absence.

Wholesale Restructuring

The impact of wholesale restructuring on rates is unclear. The U.S. Department of Energy, in its 2002 National Transmission Grid study, estimated that wholesale electricity markets lower consumers' electricity bills by approximately $13 billion annually versus rates that would have been paid without wholesale market transactions.[152] However, this estimate includes wholesale trades that would have been made under the regulatory regime that preceded restructuring.

The DOE figure also does not include additional costs imposed by wholesale restructuring. If the system reliability and natural gas crises that have emerged in the past several years are included in the cost of wholesale restructuring, the benefits of restructuring would be reduced, if not eliminated entirely. For example, the economic cost of the California/western energy crisis has been estimated to be as much as $45 billion.[153] Economic losses from the northeastern blackout have been estimated at approximately $6 billion to $10 billion.[154]

The argument that wholesale restructuring contributed to these incidents has merit, but is difficult to prove. On one hand, it seems clear that the efforts to restructure power markets in California led to the energy crisis. Whether the conditions contributing to the outage in August 2003 resulted from restructuring, or were just a more typical case of inadequate planning and human error, is less clear.

Summary

- Electricity rates have declined over the last decade in keeping with the long-term historic trend. However, in 2001 residential rates increased in real terms for the first time in 20 years, and they increased again in 2003.
- Industrial consumers have seen their rates fall slightly faster than other consumers over the last decade.
- Coal prices declined sharply during the 1990s, contributing to lower rates. Prior to 2000, natural gas prices were also low in historical terms.
- When external costs (such as environmental and public health impacts) are not factored in, states where the generation mix is dominated by coal and hydropower tend to have the lowest rates. States in which natural gas, petroleum and nuclear power are dominant tend to have the highest rates.
- States that have engaged in retail restructuring have seen rates fall slightly faster than non-restructured states. However, it is likely that other factors (including high rates at the beginning of the period and mandatory state-imposed rate reductions) are responsible for the declines, not retail competition.

Rate Equity

The past decade has seen a trend toward increased disparity in the rates charged to industrial consumers versus residential and commercial consumers. The trend toward increased differences in rates is greater in states that have adopted retail restructuring.

"Equity" is a value-laden term. Within the cost-based framework of electricity rate-setting however, some amount of inequity is permissible. If a class of consumers (for example, industrial consumers) is less expensive to serve, they may legitimately enjoy lower rates for electricity service. The shifting of costs from

one class of consumers to another, however, is usually unjust, and there are ample opportunities for such cost-shifting to take place in both regulated and restructured systems. In regulated systems, regulatory authorities can extend special rates to larger customers (e.g. economic development rates) in an effort to gain or keep their business. In states with retail restructuring, large industrial consumers can use their clout to negotiate better deals than smaller consumers.

Across the nation as a whole, the 1990s saw a trend toward increasing disparity between the rates paid by industrial consumers and those paid by residential consumers. Whereas the gap between industrial and residential consumers had narrowed considerably in the 1960s and 1970s, since 1980, the trend has been toward increasing rate disparity. (See Fig. 15.)

The disparity between industrial and residential rates appears to have increased more rapidly in restructured states than in fully regulated states. Interestingly, rate disparities are similar in restructured and non-restructured states for most of the year, but they spike in the summer, at times of peak demand. (See Fig. 16, next page.) This suggests that industrial consumers may be somewhat insulated from seasonal fluctuations in rates to account for increased demand.

Again, as noted above, the experience of restructured states varies widely. In New York, there is a large gap in rates between residential and industrial consumers that has increased over the past decade. In addition to the increasing difference between industrial and residential rates, industrial rates demonstrated much greater stability over time than residential and commercial rates.

Fig. 15. Ratio of Average Residential to Industrial Rate, 1960-2002[155]

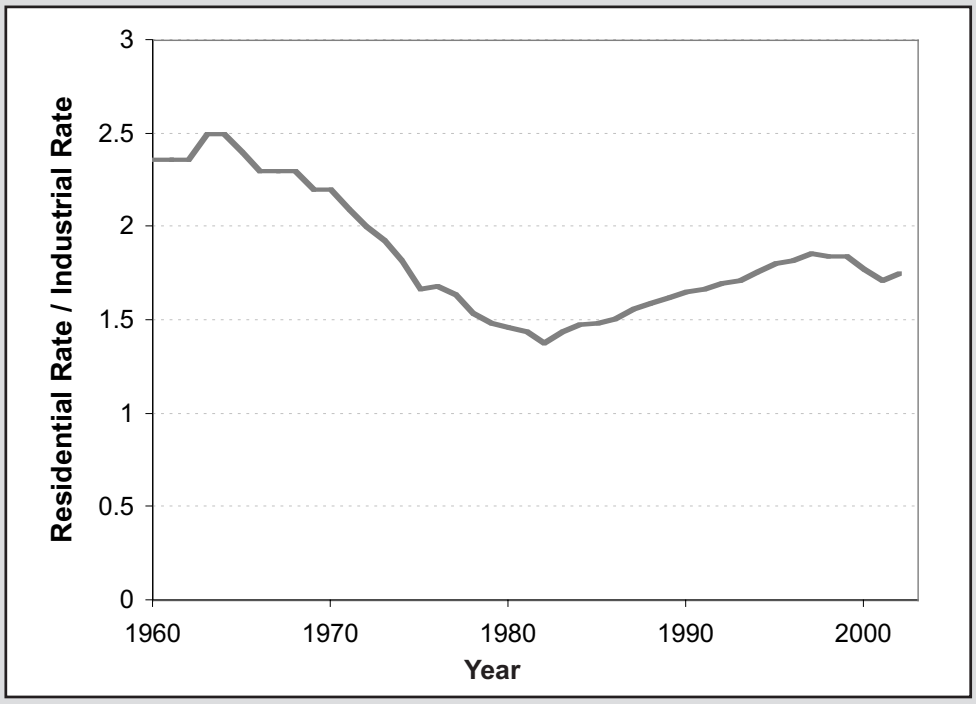


Fig. 16. Rate Disparity Between Industrial and Residential Customers in Restructured vs. Non-Restructured States

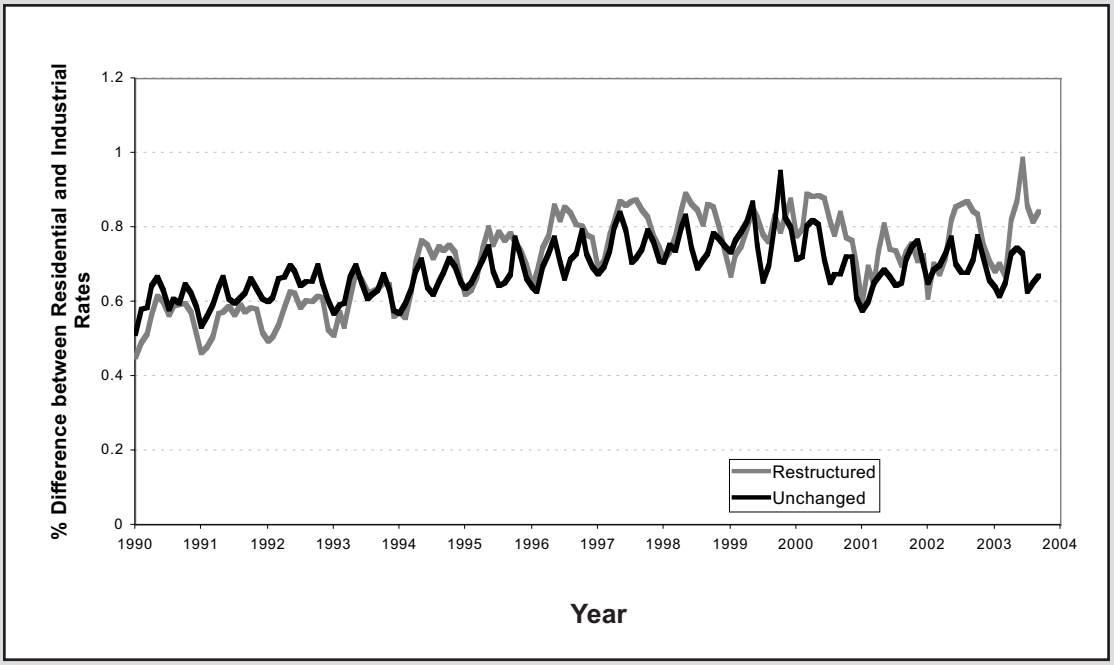
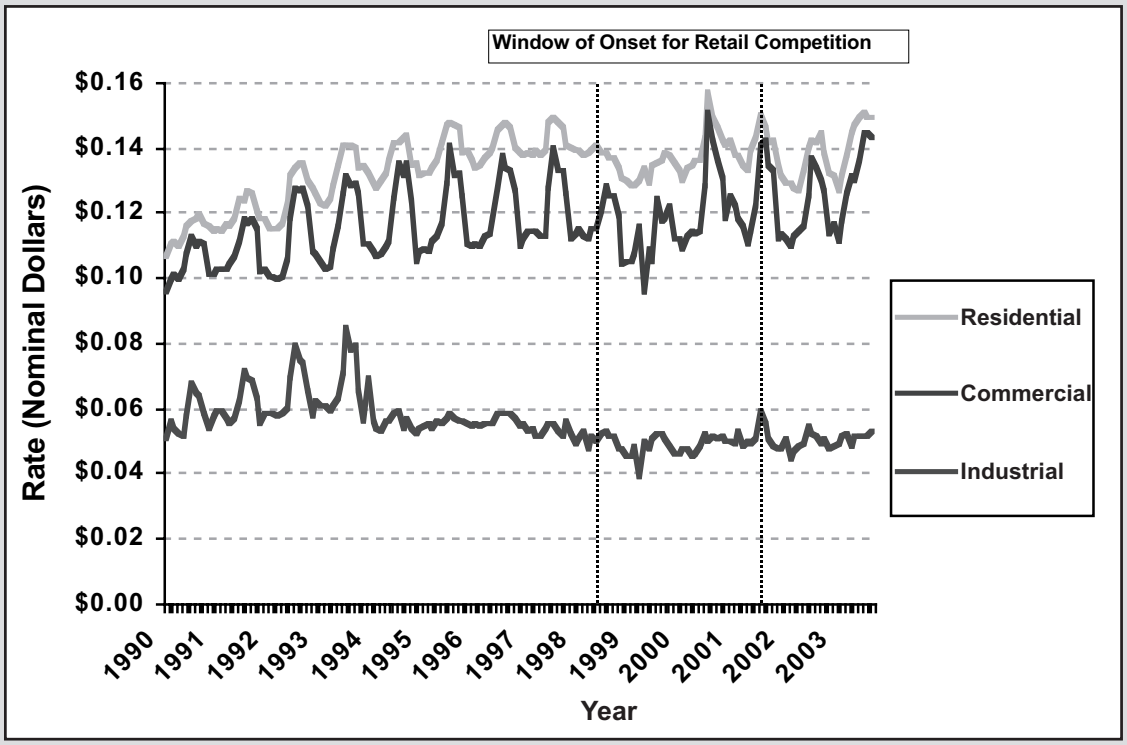


Fig. 17. Retail Electricity Rates Before and After Restructuring, New York[156]



This effect does not appear to be connected with retail restructuring, however, since the trend began in 1995, prior to the onset of restructuring.

In Massachusetts, by contrast, far greater equity existed between residential and industrial rates prior to restructuring – and while rate disparity has increased somewhat since the onset of restructuring, the difference in rates still remains relatively low.

The above data suggest that, at least

Fig. 18. Disparity Between Residential and Industrial Consumers in New York

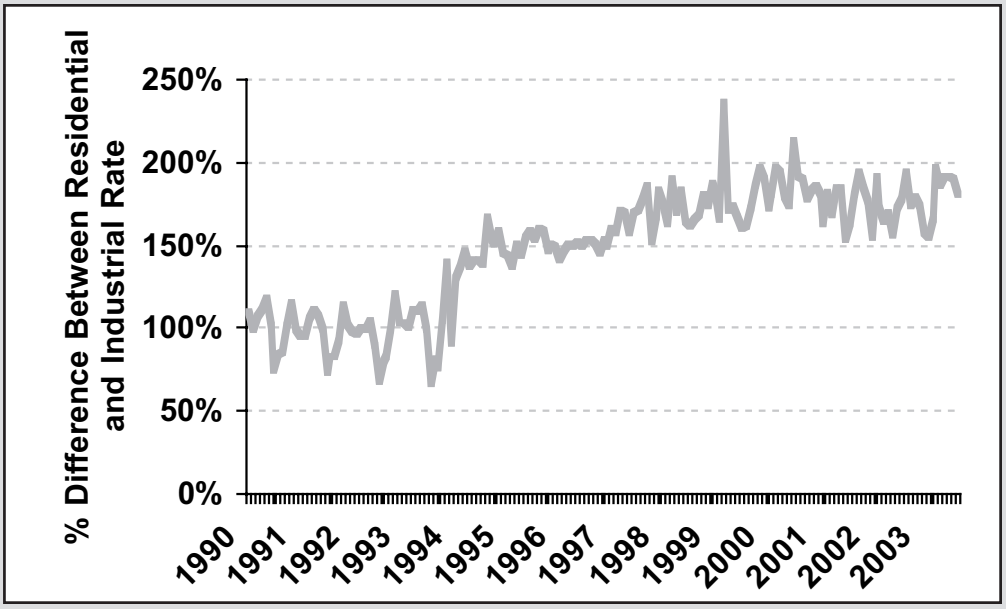


Fig. 19. Disparity Between Residential and Industrial Customers in Massachusetts

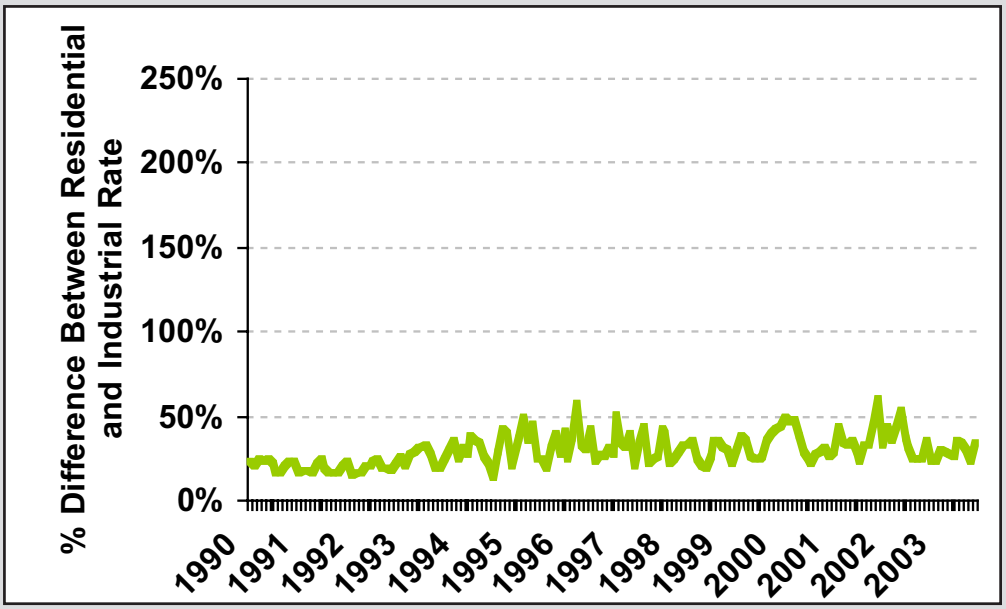
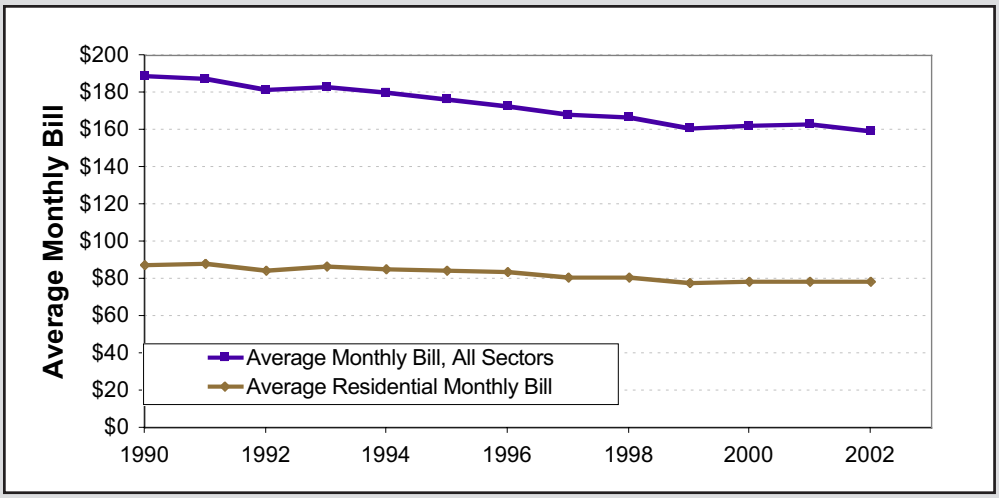


Fig. 20. Inflation-Adjusted Trend in Monthly Electricity Bills[157]



in some cases, industrial consumers have benefited disproportionately from restructuring. In addition, residential consumers tend to experience somewhat greater volatility in their rates than industrial consumers post-restructuring. But the degree of rate disparity varies a great deal from state to state, suggesting that market and regulatory policies can be designed that will protect the interests of residential consumers.

Electricity Bills and Usage

Average monthly electricity bills have declined over the past decade (in inflation-adjusted terms), but not to the same extent as rates. States vary greatly in their patterns of electricity usage based on a variety of factors including climate, market penetration of electric space heating, and spending on efficiency programs.

Monthly electricity bills are – in theory, at least – a much better measure of the cost of electricity than rates. Consumers who use energy more efficiently may experience lower monthly bills, even if their per-kilowatt-hour rates are higher.

Efficiency is not the only factor that influences electricity bills. Electricity usage varies from place to place – and even from year to year – based on climate. In addition, consumers in certain areas of the country are much more likely to rely on electricity to heat their homes.

From 1993 to 2002, overall nationwide average monthly electricity bills decreased by 13 percent in real terms. Bills for residential customers declined by about 10 percent, commercial bills by about 6 percent, and industrial bills by an average of 25 percent. (Because there are relatively few industrial customers, each of whom uses a great deal of electricity, the data on average bill reductions are likely to be very volatile and may not provide an accurate picture of the industrial cost of electricity.) (See Fig. 20.)

The reduction in average bills (13 percent) is significantly lower than the reduction in average rates – 16.4 percent. This means that the average consumer used more electricity per month in 2002 than in 1993.

States that had the steepest declines in residential rates from 1993 to 2002 also tended to have the steepest declines in residential bills. Maine, however, was

Table 7. States with the Largest Residential Bill Decreases (Inflation-Adjusted)[158]

State	% Change in Avg. Residential Bill, 1993-2002	% Change in Residential Rate, 1993-2002
Illinois	-22.8%	-34.5%
Rhode Island	-20.5%	-28.0%
Arizona	-20.2%	-31.1%
Maryland	-19.8%	-24.6%
Maine	-19.6%	-15.8%
Arkansas	-19.6%	-29.6%
New Hampshire	-19.2%	-23.2%
New Jersey	-18.1%	-26.2%
New Mexico	-17.7%	-25.6%
Louisiana	-15.8%	-26.5%

Table 8. States with Residential Bill Increases or Small Decreases (Inflation-Adjusted)

State	% Change in Avg. Residential Bill, 1993-2002	% Change in Residential Rate, 1993-2002
Nevada	16.7%	16.3%
Hawaii	7.8%	2.3%
Oregon	0.9%	13.9%
Wisconsin	0.5%	-6.6%
Vermont	-0.7%	4.3%
California	-2.7%	-8.3%
Alabama	-2.8%	-16.2%
Washington	-2.8%	9.9%
Nebraska	-3.1%	-13.5%
Montana	-3.1%	0.6%
Wyoming	-3.2%	-6.1%

the only state in the top 10 for bill decreases that saw bills decrease faster than rates. All other states experienced increased residential usage from 1993 to 2002. (See Table 7.)

The 10 states that saw the greatest increases (or smallest decreases) in residential bills show no consistent trend. Two states (Nebraska and Alabama), saw substantial decreases in their inflation-adjusted residential rates, yet did not see any decrease in their average monthly bills. By contrast, Idaho, Oregon, Washington and Vermont all experienced significant increases in their real residential electricity rates, yet saw only minor increases or slight decreases in their average monthly bills. (All four states invest relatively heavily in energy efficiency programs.) (See Table 8.)

Fig. 21. Residential Monthly Bills vs. Usage by State[159]

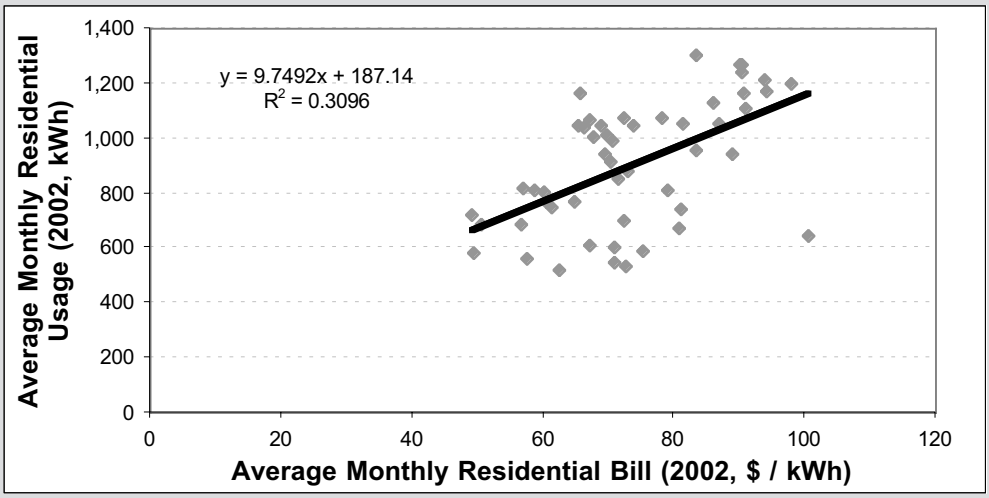
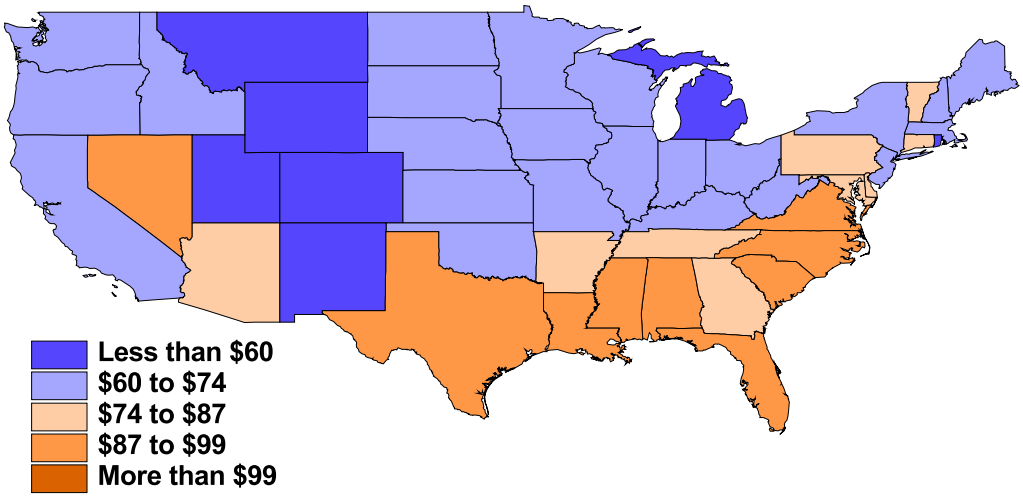


Fig. 22. Residential Bills, 2002[160]



Statistically speaking, the average electricity bill a consumer pays has much more to do with usage patterns than with the per-kilowatt-hour rate. Even consumers in states with very low rates can run up large monthly bills depending on their usage patterns. Looking at rates and bills for the 50 states, there is no significant correlation between rates and bills in the residential or industrial sectors. There is, however, a strong correlation between bills and usage. (See Fig. 21.)

Fig. 22 shows average residential electricity bills by state for 2002. The highest monthly bills are in the Southeast – an area characterized by relatively low electricity rates. Meanwhile, most states in the high-rate Northeast pay only moderate electric bills.

On the basis of electricity bills, America can roughly be broken into five categories by state, which roughly correspond to the regions of the country:[161]

Table 9. Ranking of States by Avg. Monthly Residential Bill and Avg. Electricity Rate, 2002 (Continental U.S.)[163]

State	Avg. Residential Monthly Bill	Population Weighted Cooling Degree Days 2002	Avg. Residential Rate, Cents (2002)	Avg. Residential Monthly Usage Calculated (2002, KWh)	Rank - Efficiency Spending (1996-2000) Per Capita (2000)
Florida	$97.95	3,668	8.23	1,201	17
Texas	$94.06	2,717	8.25	1,168	27
South Carolina	$93.88	2,054	7.72	1,215	24
North Carolina	$90.98	1,626	8.15	1,110	26
Virginia	$90.78	1,261	7.82	1,166	44
Alabama	$90.43	2,142	7.07	1,270	25
Mississippi	$90.34	2,229	7.26	1,241	48
Louisiana	$90.17	2,738	7.17	1,269	46
Nevada	$88.87	2,279	9.41	943	43
Arizona	$86.87	3,241	8.25	1,050	32

1) Hot, low rate, low efficiency states – (FL, TX, SC, NC, AL, MS, LA, NV, AZ, GA, TN, AR, OK, KS) These states are among the hottest states in the country (as indicated by the number of "cooling degree days" each year – a measure of the need for air conditioning) and, surprisingly, among those with the lowest residential rates. They also generally have a high market penetration of electric space heating and, as a general rule, tend to spend very little on energy efficiency. They are largely in the South and many have among the nation's highest average monthly electricity bills. (See Table 9.)[162]

2) Temperate, high rate, high efficiency states – (DE, CT, VT, NY, NJ, CA, NH, MA, ME, RI) These states, which include California and much of the Northeast – have among the highest residential rates, but hover toward the middle of the pack in bills. Rhode Island, for example, had the 11th-highest residential rate in 2002, but ranked 46th for average monthly bill. In addition to a climate that does not require frequent air conditioning use and (in the Northeast) relatively low penetration of electric space heating, these states also spend more than the average amount on energy efficiency programs.

3) Cold/temperate, low rate, low usage states – (IL, WI, MN, MT, WY, MI, CO, NM, UT)[164] These states, largely in the upper Midwest and Mountain West, tend to have low electricity rates and low usage. However, as compared to other states, particularly in the Pacific Northwest, their use of electricity is relatively low. (Several states in this category are also among the top spenders on energy efficiency.) These states make up eight of the 10 states in the lower 48 with the lowest monthly electricity bills.

4) Cold/temperate, low rate, high usage states – (VA, MD, MO, OR, IN, SD, ID, NE, WA, ND, KY, WV) These states – mostly in the upper Plains, Pacific Northwest and Mid-Atlantic – have low to moderate demand for air conditioning and have lower-than-average electric rates. But they also use more than

Fig. 23. Residential Electricity Usage With Respect to Rates[166]

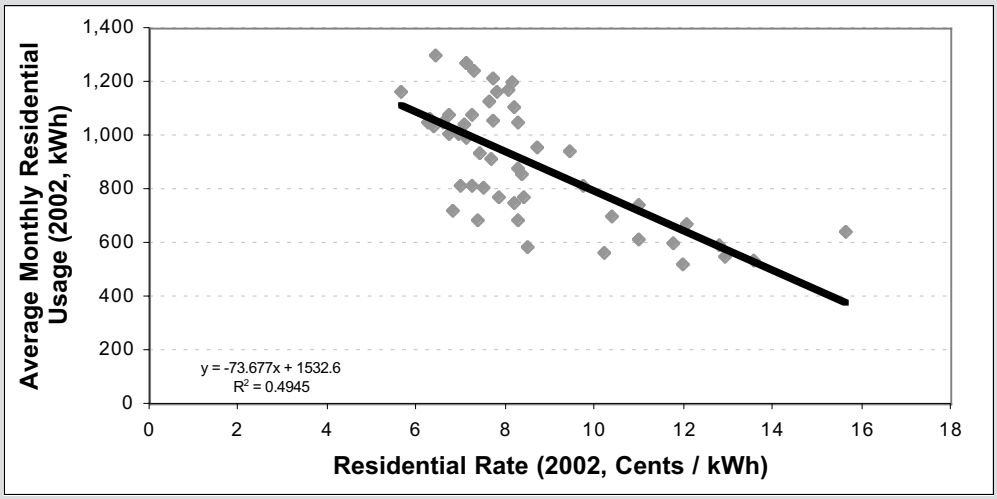
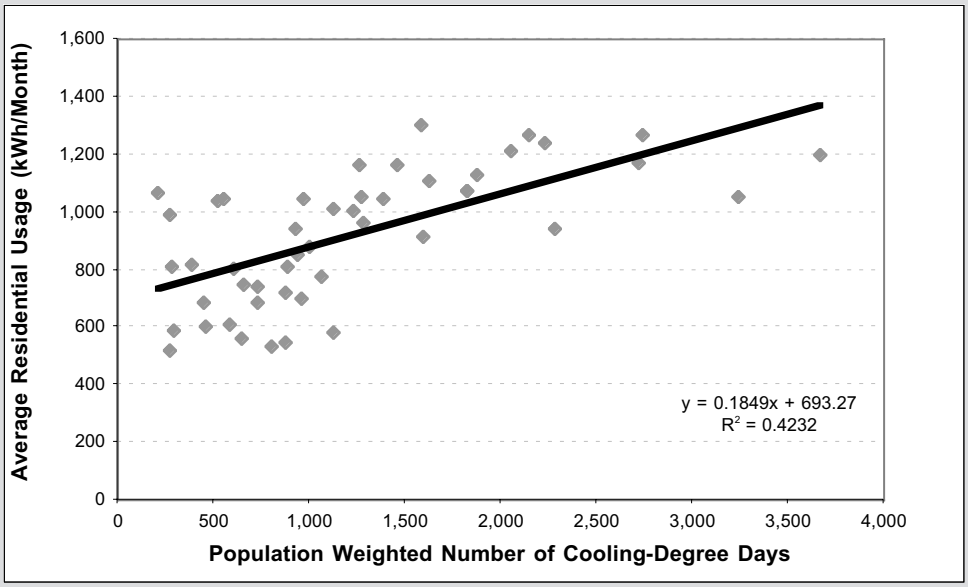


Fig. 24. Average Monthly Residential Power Usage versus Annual Population-Weighted Cooling Degree Days, 2002[167]



the average amount of electricity, suggesting that electric space heating may have made deep penetration into some of these areas. They generally have lower-than-average monthly bills, with the exception of states such as Virginia, Maryland and Missouri that have warmer summertime temperatures.

5) **Everyone else** – (PA, OH, IA) These states have near-average rates, near-average demand for air conditioning and near-average electricity consumption.

As evidenced by the above description, several factors – climate, efficiency investments, rates and the use of electricity for space heating – can influence

electricity usage, which is the primary determinant of the size of the monthly bill. To begin to disentangle these influences, we will look at each of these factors separately, with relation to actual electricity usage.

Factors Influencing Bills and Usage

Electric Rates

The law of supply and demand states that when the price of a commodity drops, consumption will increase (and vice versa) along a demand curve unique to that commodity. With regard to electricity, it is generally recognized that demand is inelastic (i.e. does not change much) in relation to price in the short run.[165] In the long run, however, consumers' patterns of electricity use appear to be molded to a certain extent by price.

The residential use of electricity is clearly correlated with the average residential rate. (See Fig. 23.) This would seem to suggest that residential consumers adjust their consumption of electricity based on its price. But, because electric rates on a state-by-state basis have remained relatively stable over the past decade, it is possible that this is more of a long-run phenomenon. Many of the investments consumers make in electrical appliances are in durable goods such as heating and cooling systems and refrigerators. The expectation of low electric rates likely shapes those decisions – making a long-term impact on consumption patterns.

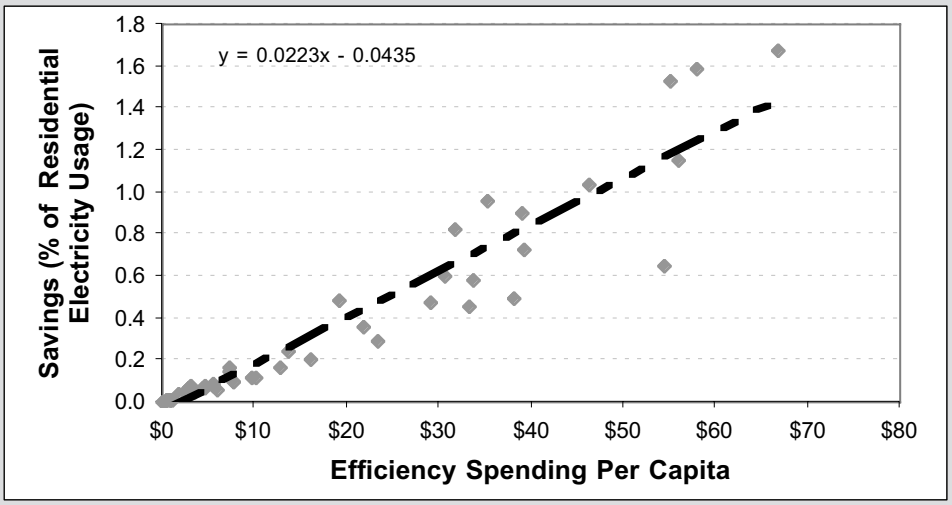
Climate

Electricity bills are also clearly correlated with the assumed demand for air conditioning as defined by the number of "cooling degree days" registered in each state each year. A cooling degree day is the number of degrees that the daily mean temperature exceeds a certain baseline, weighted by population. (See Fig. 24.)

Efficiency

Spending on energy efficiency programs – both utility-based and state-run – appears to be correlated to reduced electricity usage over time.

Fig. 25. Calculated Efficiency Savings, as a Percentage of 1996 Usage, Compared to Efficiency Spending Per Capita, 1996-2000[170]



The American Council for an Energy Efficient Economy issued a report in 2002 that tallied spending on efficiency programs from 1996 to 2000, including both utility programs and programs funded by system benefits charges.[168] States with greater efficiency spending per capita in this report tend to show a decrease in residential electricity usage from 1996 to 2002, when the influence of changes in climate and in residential electricity rates on usage are accounted for.[169]

On average, for every $10 spent on industry-wide efficiency programs per capita from 1996 to 2000, the average state reduced residential electricity usage during the 1996 to 2002 period by 0.2 percent. (See Fig. 25.) In other words, residential efficiency programs saved roughly 20 billion kWh over this seven-year period. This estimate does not include any savings from efficiency efforts targeted at commercial or industrial consumers.

Efficiency spending is not the only state policy that can affect electricity consumption. The adoption and enforcement of commercial and residential building energy codes, appliance efficiency standards, and other policies can also contribute to improved efficiency.

Use of Electric Space Heat

Regions of the country vary widely in the market penetration of electric space heating. (See Table 10.) This likely accounts for higher electricity usage even in some parts of the country (such as the Pacific and Mountain West states) that have cold or temperate climates and do not experience extreme heat in the summertime.

One final note: the section of the nation that consumes the most electricity – the Southeast – also invests the least in energy efficiency programs. During the course of a year (if consumption rates are similar to those in 2002), the average Virginia resident will consume more than twice the amount of electricity as the average Californian.[172] But, in 2000, Virginia barely invested at all in energy efficiency, while even pre-energy crisis California had robust programs in place to promote energy efficient products and

Table 10. Market Penetration of Electric Space Heat by Census Region[171]

	Pct. of Households Using Electric Space Heat	Average Monthly Residential Bill, 2000
New England	9.3%	$66.01
Mid-Atlantic	12.2%	$70.03
East North Central	10.5%	$59.92
West North Central	12.2%	$62.35
South Atlantic	55.7%	$75.78
East South Central	50.0%	$72.99
West South Central	42.4%	$79.82
Mountain	31.8%	$56.50
Pacific	30.8%	$67.36

practices. To the extent that power to serve these low-efficiency states causes negative environmental, public health, and system reliability issues, the federal government should play a role in solving the problem – for example, by enacting energy efficiency standards and efficiency programs supported by small charges on electricity bills that can complement existing programs in states like California while improving efficiency nationwide.

Summary

- Average monthly electricity bills declined between 1993 and 2002, but the rate of decline was less than the rate of decline in electricity rates, suggesting that per-consumer energy consumption increased over the decade.
- States that experienced the greatest reduction in monthly residential bills tended to be those that experienced the greatest reduction in rates. However, several states that saw their electric rates increase over the decade were able to avoid large increases in their monthly bills – presumably through improved efficiency.
- The states with the highest electricity rates tend not to be those with the highest monthly bills.
- At least four factors appear to play a role in affecting electricity usage patterns:
    - Electricity rates (likely over the long term)
    - Climate
    - Market penetration of electric space heating
    - Investment in efficiency programs

Costs Not Captured in Rates

Not every cost of power production is reflected in the bills consumers pay for electricity service. Additional costs are imposed by the environmental consequences of power production, the reliability (or lack thereof) of electric service, and taxpayer subsidies.

Environmental Externalities

The production of electric power – particularly from fossil and nuclear sources – causes a wide variety of environmental and public health problems. Air pollution, global warming, water pollution and land disruption from fossil fuel extraction, as well as potential exposure to radiation from nuclear power plants or nuclear waste are among these impacts.

A variety of studies – mostly conducted in the 1980s and 1990s – have attempted to develop dollars-and-cents estimates of the costs of various types of environmental emissions and methods of generating electric power. In addition, seven state PUCs developed estimates of the monetary costs of externalities for use in their planning processes in the late 1980s and early 1990s.[173] Few estimates have been compiled since the mid-1990s, however.

One externalities study, conducted by Pace University in 1989, estimated the cost per pound of sulfur dioxide emissions at $2.03, nitrogen oxide emissions at $0.82, and carbon dioxide emissions at $0.0068.[174] Using figures for emissions from the electric power sector from the Energy Information Administration, and applying them to the Pace estimates (adjusted for inflation), it can be estimated that externalities resulting from the emission of these three pollutants caused $127 billion in economic impacts in 2002; down 17 percent from $153 billion in 1993.[175]

These figures are presented merely as a means of comparison and to give a sense of the magnitude of the economic

impacts of power plant pollution. They do not include myriad other external impacts of resource extraction and electricity production. Still, it is fair to conclude that electricity production continues to impose significant environmental and public health costs that are not accounted for in electricity rates. While these costs may be declining (thanks to more aggressive environmental regulation), they remain significant and must be considered in assessing the economic merits of various fuel and technology choices.

It is difficult to determine whether changes in regulation of the electric industry over the past decade have imposed greater environmental costs than would have been imposed otherwise or have reduced those costs. A 2002 study by Resources for the Future, however, estimated that nationwide retail restructuring would lead to significant increases in smog-forming nitrogen oxide emissions.[176] Clearly, these potential impacts should be considered as states debate whether to engage in retail restructuring, and similar analyses should be completed of the environmental impacts of wholesale market measures, such as the creation of regional transmission organizations.

Reliability

Reliable electric service is of great value to all classes of consumers and the American economy as a whole. The economic cost of unreliable electric service can be steep. One recent study estimated the cost of power outages to business alone at between $104 billion and $164 billion per year.[177]

There is little doubt that the reliability of the electric system – particularly the interstate transmission grid – has been significantly degraded since the onset of open transmission access and wholesale competition in the mid-1990s. The economic costs of this reduced reliability are difficult to estimate, but they are certainly significant.

In recent years, the North American Electric Reliability Council (NERC) has repeatedly warned that the increase in long-distance electricity transactions across the grid is challenging the reliability of the system. In its 2003 Long-Term Reliability Assessment, NERC noted that "As customer demand increases and transmission systems experience increased power transfers, portions of these systems are reaching their reliability limits. Coincident failures of critical equipment, while highly improbable, can degrade bulk electric system reliability."[178]

Since the onset of restructuring, the number of serious system disturbances on the North American grid reported to NERC and the U.S. Department of Energy has increased significantly. Because many disturbances are caused or initiated by natural events (such as hurricanes, ice storms and wildfires), the number of such disturbances – and their severity – varies from year to year.

System disturbances are broken into several categories – those that interrupt service for customers, "unusual occurrences" (which do not result in service interruptions), demand reductions, voltage reductions, and public appeals for conservation. The average number of such major disturbances during the period 1998-2001 was more than twice the annual average of disturbances for the period 1992-1996. (See Table 11.)

Changes in the use of the transmission system are not the only restructuring-related developments that threaten the reliability of the grid. The voluntary system of compliance with reliability rules that worked well when utilities did not directly compete with one another may not work well in an era of increased

Table 11. System Disturbances Reported to NERC[179]

Year	Service Interruptions	Unusual Occurrences	Other	Total
1992	14	8	0	22
1993	15	9	0	24
1994	17	10	1	28
1995	13	5	3	21
1996	16	4	9	29
1998	51	5	7	63
1999	24	13	4	41
2000	37	17	4	58
2001	25	21	4	50
Average 1992-96	**15**	**7**	**3**	**25**
Average 1998-2001	**34**	**14**	**5**	**53**

competition. As NERC's 2002 long-term reliability assessment noted:

> Since 1968, NERC has relied on voluntary efforts and "peer pressure" to ensure compliance with its standards. This voluntary arrangement is no longer adequate. The users and operators of the electric systems who used to cooperate voluntarily on reliability matters are now competitors without the same incentives to cooperate with each other or comply with voluntary reliability standards. Little or no effective recourse exists today under the current voluntary model to correct such behavior — not a single bulk electric system reliability standard can be enforced effectively today by NERC or the Federal Energy Regulatory Commission (FERC).[180]

Indeed, in its investigation of the August 14, 2003 blackout, NERC found that "several entities violated NERC operating policies and planning standards, and those violations contributed directly to the start of the cascading blackout." The sharing of key information and communications among system operators were also found to be lacking.[181]

These concerns go to the heart of the current market-based, competitive structure for wholesale electricity markets. While a range of fixes – including expansions of the current grid or reductions in load – could alleviate the technical problems brought on by restructuring, only additional regulation is likely to solve the structural and coordination problems that precipitated the August 14 blackout.

Taxpayer Subsidies

Taxpayers subsidize various forms of energy production and use, both directly (through government spending) and indirectly (through the tax code).

Over the past several decades, federal energy subsidies have been overwhelmingly tilted toward the support of nuclear and fossil fuels. The Renewable Energy Policy Project has documented that, between 1947 and 1999, the

nuclear industry received more than $145 billion in federal subsidies (in 1999 dollars), while solar and wind power received just $5.6 billion in subsidies.[182] A 2002 report by the Green Scissors Campaign estimated that subsidies for coal already written into federal law would cost an additional $3.37 billion over the next decade.[183]

Various versions of the federal energy bill that has been debated in Congress over the past several years would layer additional federal subsidies atop those that already exist – again, with fossil and nuclear energy receiving the bulk of the funding. These subsidies negatively influence the competitiveness of energy efficiency and renewable energy technologies. A year-to-year comparison of government subsidies is well beyond the scope of this report, but they must be considered in any discussion of the cost of electricity to consumers.

Emerging Trends

Looking toward the future of electricity costs for consumers, several ominous trends lurk. The impending removal of rate caps in states that have undergone retail restructuring, the continued high price of natural gas, and the proposed construction of tens of billions of dollars worth of transmission facilities to support the drive toward more vigorous wholesale markets for electricity could all have serious negative impacts on consumers' electricity rates in the years to come.

Expiration of Rate Caps

States that adopted retail restructuring preserved a regulated electricity product – standard offer or default service – for consumers who did not choose competitive electricity suppliers. Most states imposed mandatory rate reductions on standard offer service at the outset of restructuring in order to provide some immediate benefits for consumers (although several of the states allowed utilities to defer the cost of complying with the rate caps and recover the cost from consumers once the caps had expired). Standard offer service was originally intended to be a temporary phenomenon – once vigorous, competitive retail markets were established, the thinking was, consumers would choose their electricity supplier from the open market.

Now, as many states are nearing the end of their "transition" periods, the vast bulk of consumers remain on some variant of standard offer service. Competitive markets have not yet developed. And yet, the potential exists for standard offer service – and the regulated rates that come with it – to be withdrawn.

Several states, including Connecticut and Maryland, have recently extended the life of rate-capped standard offer service. Others have not. In New Jersey, for example, rate caps imposed on standard offer service were lifted in August 2003. Rates immediately increased by about 19 percent and have remained above 2002 levels since. (See Fig. 26.)

The rate increases experienced in New Jersey may even be mild compared with the removal of rate caps elsewhere. The removal of rate caps in San Diego in 1999, for example, allowed electricity rates to more than double during the wholesale electricity price spikes of the following year.[185] In addition, consumers in several states will be required to *pay back* the savings they have received during the rate cap period – perhaps for many years to come. In New Jersey, for example, utilities have run up about $1 billion in "deferred balances," which consumers will likely have to pay back – with interest – in their rates. A recent

Fig. 26. Average Revenue Per Kilowatt Hour (Cents), All Sectors, New Jersey[184]

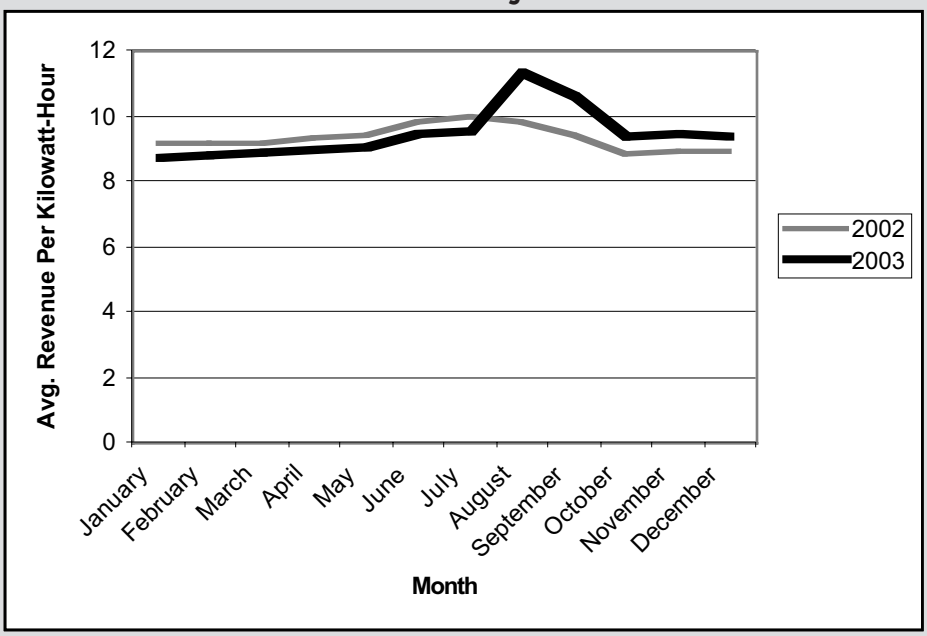
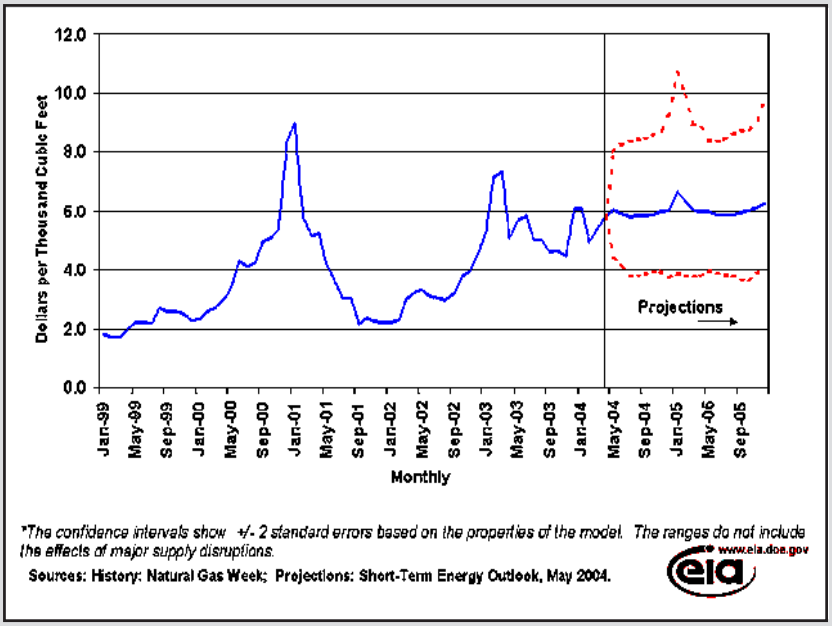


Fig. 27. U.S. Natural Gas Spot Prices (Base Case and 95 Percent Confidence Interval)[189]



report by a New Jersey state task force summed it up this way: "Consumers have a right to know that under [the state's restructuring law] they have not benefited from true rate reductions; rather, they have been purchasing electricity on credit, and it is now time to repay the loan, with interest."[186]

Rising Natural Gas Prices

The dramatic increase in natural gas generating capacity during the 1990s was predicated on the notion that natural gas – then relatively inexpensive – would remain so indefinitely. As noted earlier, things have not turned out that way: natural gas prices have shown incredible volatility over the last three years and have remained well above the prices that predominated during the 1990s.

Relief will likely not be coming soon. On June 10, 2003 Federal Reserve Chairman Alan Greenspan told the House Energy and Commerce Committee that "we are not apt to return to earlier periods of relative abundance and low prices anytime soon."[187] The Department of Energy predicts that natural gas prices will remain high at least through the end of 2005.[188] (See Fig. 27, previous page.)

The long-term picture is even more hazy. Unlike petroleum – which can be easily shipped from overseas – natural gas is largely transported by pipeline, tying U.S. utilities to supplies of natural gas from North America. Shipping of liquefied natural gas (LNG) from overseas is very expensive and poses safety concerns for citizens living near LNG terminals. Opening up environmentally sensitive lands for natural gas extraction would likely provide only a short-term boost, while resulting in long-term damage to the environment.

The rate spikes of 2001 and 2003 demonstrate clearly the degree to which electricity prices have become tied to the price of natural gas. Further increases in gas prices could continue to have rate impacts for consumers – in the form of electric rates and the cost of home heating – for years to come.

Transmission Investment

In the wake of the blackout of August 14, 2003, numerous organizations – from the electric industry, to the federal government, to independent system operators (ISOs) and regional transmission organizations (RTOs) – have stepped forward to bemoan the lack of investment in the transmission grid and propose multi-billion dollar upgrades. Immediately after the blackout, Energy Secretary Spencer Abraham suggested that upgrades to the grid could cost as much as $50 billion, noting that "[r]atepayers, obviously, will pay the bill because they're the ones who benefit."[190]

The perceived need to invest large amounts of ratepayer funds in transmission upgrades – and to do it quickly – has led to a number of radical proposals. FERC, for example, has proposed a system of bonuses for utilities for joining an RTO, spinning off transmission to separate companies and investing in transmission pursuant to an RTO process. Synapse Energy Economics has estimated that the bonuses would cost consumers in New England alone between $40 million and $70 million annually, on top of the hundreds of millions of dollars charged to ratepayers for new transmission investments.[191]

Investment programs and incentives of this scale would certainly have a significant impact on electricity rates. The trend in electricity rates over the past decade suggests that residential consumers have benefited marginally – if at all – from wholesale restructuring, and it is unlikely that the cost of such a massive investment in transmission upgrades would bring sufficient benefits to outweigh the costs.

Summary

From the point of view of consumers, the past decade of increasing emphasis on markets in the electricity industry has brought mixed results. Rates in real terms are lower. So are average monthly bills. But the increase in system reliability problems, higher natural gas prices in other sectors of the economy, and episodes of market manipulation such as those that took place during the western energy crisis have canceled out many of those benefits. In addition, it is far from clear what would have happened had restructuring not taken place – indeed, residential electricity rates were already in decline well before the onset of restructuring, and the rate of decrease has not accelerated appreciably. Lower costs for key fuels such as coal may have caused rates to decrease even in the absence of any change in regulatory strategy (although some suggest that the threat or reality of competition has helped force coal prices down).

The future of electricity costs, however, looks anything but rosy. Average residential rates increased in 2001 for the first time in nearly 20 years and increased in 2003 as well. System reliability problems have been on a steady upward trajectory. Rate caps that had protected consumers in states with retail restructuring are about to come off. Energy efficiency programs and resource planning requirements that had once provided cost-effective energy savings to consumers and attempted to shield consumers against volatile prices have been scaled back or eliminated. Natural gas prices are high and are likely to stay that way. And the massive investments in transmission capacity proposed by many in the electric industry could saddle consumers with higher rates for years, if not decades, to come.

Critical Problems in the U.S. Electric System

There is little doubt that the U.S. electric power system is facing a crisis. The reliability of the system is in doubt as it has not been in decades. Consumers face the possibility of substantially increased electricity costs in the near future. Environmental challenges are growing. Interested parties at all levels disagree strongly as to the way out.

If consumers are to be well-served by the electricity system in the years to come, at least seven critical problems in the electric industry must be solved.

1. The Failure of Retail Competition

States face a fundamental decision about the future of retail competition. The half-decade since the onset of retail restructuring has demonstrated that the transition strategy of offering retail choice alongside regulated "default" or "standard offer" service has been a failure in spurring the entry of new competitors to the retail market (even if rate caps on standard offer service have resulted in significant – if temporary – savings for many consumers). The question facing legislators and regulators is whether to go forward with competition, go back to full regulation of retail prices, or continue under some variant of the current system. For small consumers, a strong argument can be made that the downside risk posed by retail competition is far greater than the potential benefits.

In no state is there currently a vigorous competitive market for individual small customers. Consider Pennsylvania, once considered a poster child for the benefits of retail deregulation.

Pennsylvania's restructuring law encouraged consumers to choose alternate suppliers of electricity by setting an artificially high "price to compare" rate for customers remaining with incumbent suppliers. This essentially forced consumers who stayed with their utility to subsidize those who switched to competitive suppliers. Initially, alternative power suppliers enthusiastically entered the market and a significant numbers of consumers switched providers. But, as wholesale electricity prices spiked in 2001, competitors became unable to offer prices below the "price to compare," which was subject to a cap. As a result, large numbers of consumers found their way back to regulated electricity suppliers.[192] (See Table 12.)

The percentage of consumers choosing alternate energy producers in other states with retail restructuring has been similarly low. As of December 2003, 4 percent of Massachusetts residential customers had switched to alternative providers.[194] In New Jersey, about 3 percent of residential customers have switched providers.[195] In New York, about 4 percent.[196]

With rate cap protections set to expire in several states over the next few years, consumers could experience significantly higher electricity prices. As noted above, the removal of rate caps in New Jersey led to an immediate increase in rates of greater than 15 percent. In states such as Maryland and Michigan, utilities are already warning of double-digit rate increases once price caps are removed.[197]

But even the prospect of significantly higher rates may not be sufficient to attract new competitors seeking to sign up individual residential electricity customers. A 2003 survey found that two-thirds of Maryland consumers would require lower prices to switch to a competitive electricity supplier. Of these consumers, more than half would require a price discount of more than 10 percent off their total electricity bill.[198] Because about half of the average electricity bill pays for regulated services (transmission and distribution), this would mean that a discount of around 20 percent on the generation side of the bill would likely be needed to induce large numbers of consumers to switch. In addition, competitive electricity suppliers must spend significant sums on marketing to sign up new consumers, which further eats into potential profits. Barring a technological breakthrough that would enable a competitive supplier to provide power far more cheaply than other actors in the market (or the sale of value-added

Table 12. Percent of Pennsylvania Residential Customers Served by Alternative Power Suppliers[193]

	April 2001	January 2004
Allegheny Power	0.4%	0.1%
Duquesne Light	33.4%	24.9%
MetEd/Penelec	3.9%	0.2%
PECO Energy*	34.1%	20.4%
Penn Power	6.3%	0.3%
PPL	1.6%	0.1%
UGI	3.1%	0.1%

* Includes PECO Energy customers who were assigned to competitive suppliers.

products such as "green" electricity), the business model of competitive suppliers competing for the business of individual residential consumers does not appear to make economic sense.

Other options exist for preserving some competition in retail electricity supply through the aggregation of consumers into larger blocs. Several states that have deregulated their retail markets now bid out the right to serve blocs of residential consumers as standard offer providers. Such competitive bidding may – as it has in New Jersey – dampen the short-term rate impacts of the removal of price caps. But it also depends for its success on the presence of numerous bidders willing to compete on the basis of price for providing the service. In an era of increased consolidation in the electric industry, it is questionable whether such a competitive atmosphere will continue to be present in some areas of the country. Moreover, competitive bidding for short- and medium-term contracts of one to three years will do little to encourage sound, balanced long-term planning for electricity supply – planning that is necessary to protect consumers against price volatility and ensure the most cost-effective operation of the system as a whole. Finally, assigning or bidding out the business of consumers who have no ability to influence that decision undermines the very notion of consumer choice. With no real choice of supplier and greater exposure to price volatility over time, such a system would appear to be a poor substitute for properly implemented regulation.

The few real success stories of retail competition are in states that have allowed opt-out municipal aggregation, in which consumers – through their municipal governments – bid out the right to serve them as a bloc. (Consumers who do not wish to be served by the municipally chosen provider may choose their own provider.) In Ohio, for example, hundreds of thousands of residents of northern Ohio have taken part in aggregation programs.[199] Ohio regulators estimate that aggregation is responsible for 93 percent of the residential customers who have switched electricity providers under restructuring.[200]

In a sense, opt-out aggregation is a "back to the future" strategy, since it has traditionally been municipal governments that have had the authority to negotiate franchises with utilities. As opposed to involuntary aggregation at the statewide level, municipal aggregation allows communities to negotiate for electric services that best fit their local needs. Opt-out aggregation, however, has only been tried in a few places and depends for its success, again, on the existence of competition among prospective suppliers.

The ideal course for states appears to be to limit the further expansion of retail competition for small consumers and to return to some variant of traditional cost-based regulation through local utilities in places where retail competition has occurred. States in which significant numbers of consumers have switched providers can allow consumers to retain those providers, or develop an orderly and equitable plan for "detransitioning" those customers back to regulated services. In all cases, though, consumers would retain the right to purchase a regulated "standard offer" electric service, provided according to traditional regulatory imperatives, and supplied either by traditional vertically integrated utilities or by purchases from wholesale markets, secured through contracts of various lengths to protect consumers from price volatility.

It is important to recognize, however, that the failure of retail competition

does not impugn the goals of retail competition: improved efficiency and consumer choice.

Regulatory systems can be redesigned to promote more economically efficient behavior by utilities. Performance-based regulation can allow regulators to adjust the allowable revenue for utilities based on a set of objective standards to encourage operating efficiency, customer service or other desirable traits. Caps on revenue per customer can encourage utilities or distribution companies to reduce costs. Other types of performance-based regulation may also promote consumer-oriented goals, but with a major caveat: direct incentives to utilities contained within rates should only be used to reward exceptional performance – not to provide extra rewards for providers to do the job they are already being paid to do.

Of particular importance is the need to design systems of incentives and disincentives that promote economically beneficial improvements in energy efficiency. Currently, cost-based rate structures give utilities an incentive to encourage power consumption. Because electric rates are set to allow utilities to recover their costs based on *projected* levels of power consumption, growth in power consumption beyond projected levels generates a windfall profit for utilities. As a result, utilities have little incentive to promote efficiency improvements that would reduce net costs to the consumer.

Several measures could be employed to redirect incentives to support cost-effective improvements in efficiency. Per-customer revenue caps – such as those mentioned above – would eliminate the incentive to sell more electricity to consumers, while periodic "true-ups" in rates would restore any windfall profits created by demand growth to consumers (or vice versa). The Natural Resources Defense Council and the Edison Electric Institute recommended the use of "modest, regular true-ups in rates" to "eliminate a powerful disincentive for energy efficiency and distributed-resource investment" and "to ensure that any fixed costs recovered in kilowatt-hour charges are not held hostage to sales volumes."[201] The state regulatory community has more than two decades of experience with such mechanisms, which involve a simple comparison of actual sales to predicted sales, followed by an equally simple determination of actual versus authorized fixed cost recovery during the period under review. The difference is then either refunded to customers or – if sales are below projection – restored to the utility.

Just as utilities should not have a financial incentive to sell more electricity, consumers should not have a financial incentive to consume more. Efforts to shift portions of the electricity bill from per-kilowatt-hour charges to flat, monthly fees that do not vary based on consumption should be resisted. Maintaining volume-based charges for electricity will preserve consumers' incentive to implement energy efficiency improvements in their homes and businesses when it is cost-effective to do so.

While the vast majority of consumers have stayed with their default service providers throughout retail restructuring, some have moved to other providers. For at least some small segment of consumers, therefore, the ability to choose among a variety of electricity products appears to have some appeal. Opportunities do exist to achieve some of the same goals desired from competition through the regulatory structure. In Oregon, for example, the state's restructuring law allows small consumers to choose from a variety of electricity

products, including several "green power" options, a time-of-use option, and a market-based option.[202] Again, however, a series of caveats are in order. First, assurances must be in place that consumers choosing a "premium" electric product get what they pay for. Second, the opening up of options for choice must not be allowed to degrade the quality of the "plain vanilla" electricity product supplied to the vast majority of consumers. Finally, utilities should not be able to doublecount any additional renewable generation for both meeting regulatory requirements such as a renewable portfolio standard and supplying a premium-priced product to consumers.

It can be argued that retail competition has thus far been more successful for large consumers than it has been for small consumers. In states that have adopted retail competition, industrial and large commercial users have been far more likely to switch to competitive suppliers than small consumers.[203]

In theory, there is no reason why a competitive market for large consumers cannot exist alongside a regulated distribution system for small consumers. In practice, such a parallel system would create several challenges, not least among them the just allocation of costs for past and future investments in the electric grid. Such a system also depends on the existence of a deregulated wholesale market, which we will address in the next section.

Industrial and large consumers bear responsibility for investments made over the years in generation, transmission and distribution systems, and may bear responsibility for future investments as well. Large consumers who purchase power through competitive markets (or who leave the system entirely by generating their own power) must still pay their share of the costs for historic investments in the system and – to the extent that regulated investments are made to serve their load – future investments as well.

Finally, jurisdictional lines must be drawn such that states – and not the FERC – retain ultimate regulatory authority over retail sales of electric power to large and small consumers, regardless of whether consumers take power from local distribution systems or interstate transmission wires. States are the locations in which most discussions regarding the allocation of stranded costs and infrastructure investments will take place, and they must retain authority to ensure that all consumers pay their fair share of those costs.

2. Failures in the Wholesale Market

Most consumers have only an indirect relationship with wholesale power markets, but what happens in those markets has a powerful effect on the quality of electric service that individuals receive and how much they pay for that service.

In order to set the future course of the wholesale bulk electric system in the U.S., it is necessary to answer two threshold questions:

1) Is a competitive wholesale market in electricity compatible with the maintenance of system reliability at least cost?

2) Is a fair, competitive wholesale market in electricity possible at all?

Nearly a decade after the issuance of FERC Order 888 – which created the wholesale market as we know it today – both questions remain unanswered.

With regard to the first question – reliability – there is ample evidence that the current transmission grid, originally constructed to allow for bulk transfers

of power that improve efficiency and enhance reliability, has not responded well to the need to accommodate the increased wholesale bulk transfers of electricity caused by the deregulation of wholesale power markets. The North American Electric Reliability Council (NERC) notes that "the transmission system is being subjected to flows in magnitudes and directions that were not contemplated when it was designed or for which there is minimal operating experience."[204]

According to NERC, there are three long-term choices for how to respond to this situation: locate new generation close to demand centers, implement demand-side management procedures, or increase the capacity of the transmission system. The preferred option depends in large part on the answer to the second question above: specifically, whether a truly competitive wholesale market that provides economic savings for consumers can be called into being.

On this question, however, the track record of restructuring is also disappointing. As the California energy crisis demonstrated, the opportunities for the accumulation and exercise of market power in the electricity industry are numerous – particularly during periods of heavy load – and the windfall profits thus generated can wipe out the savings consumers could have garnered through competition. Transmission owners – who control the "bottlenecks" of the system – can give preferential access to favored providers. Generators can withhold power from the market to create a situation of scarcity. Small numbers of companies serving a particular market can collude on supply and pricing. These and other actions have the potential to distort the performance of wholesale markets in ways that undermine the overall economic efficiency of the system and harm consumers.

The years since the California debacle have seen much energy put forward to develop regulatory "fixes" to these problems. Fundamentally, however, the physical characteristics of the electric system (e.g. the inability to store electricity and need for minute-by-minute balance of supply and demand), create opportunities for mischief that are difficult to foreclose – or, in some cases, even detect.

Thus, deregulation of wholesale markets appears to be both incompatible with maintaining optimum system reliability and with preserving the best interests of consumers. However, unlike retail competition – which has been implemented in only about one-third of the states and has resulted in few obvious changes for most consumers – wholesale deregulation is a fact of life. Merchant generators – some without any ties to traditional, vertically integrated utilities – now provide a significant share of America's electric power. New institutions, such as ISOs and RTOs, have emerged to play a major role in facilitating wholesale markets. It may simply not be possible (or desirable) to return to the days of FERC regulation of bilateral transmission contracts between utilities.

It is possible, however, to create a new framework for the regulation of wholesale markets in keeping with public interest principles. Among the issues that must be dealt with in developing that framework are the future size and scope of the transmission grid, the means by which scarce transmission capacity will be allocated, and the ways in which the opportunities for the exercise of market power can be reduced or eliminated.

Transmission Capacity

The increase in wholesale bulk transfers of power that has resulted from restructuring has put the reliability of the grid – which was never designed to handle such transfers – in jeopardy. Undoubtedly, at least some investments must be made to improve the operation of the transmission grid – both the addition of capacity in a number of severely capacity-constrained areas as well as the modernization of equipment to improve system reliability. Before any plan for substantial long-term investment in transmission is undertaken, however, it is necessary to take a step back and ask a few questions: What do we need transmission for and how much do we need? What types of new generation and load are likely to arise and where will they be located? Will we need as much transmission in 20 years as we do today, or will we need more or less? And who should make the decisions?

On the national level, the only way to truly resolve these questions is through the development of a plan that creates an overarching vision for the nation's energy future – one created through a public process that involves ample public participation. The types of transmission required to serve an electricity system that relies on centralized fossil and nuclear plants is substantially different from that required to serve a system moving toward greater use of renewable energy sources and a more decentralized structure. Without a plan that sets broad national energy direction, changing the rules to encourage the development of large amounts of additional transmission capacity is a recipe for wasted investment and the imposition of long-term financial burdens on ratepayers.

Such a national planning effort will be difficult to pull off. Regional planning that takes into account all of the options (including demand-side options) for addressing transmission constraints and bases its decisions on public interest principles can create the sense of direction needed to navigate these issues and impart the legitimacy that current plans – such as the transmission expansion plans drawn up by ISOs and RTOs – lack. A regional planning process of this sort could be led by duly constituted regional state committees under the direction of state public utilities commissioners.

Siting authority for transmission lines and other energy facilities should remain with the states. Siting decisions have strong local impacts and shifting authority to the federal level will almost certainly ensure that the needs of local communities will not be heard. To reduce the influence of parochialism, nonresidents who might benefit from a facility should be given a voice in the process and their needs should be considered.

Siting conflicts would be much reduced if the number of controversial facilities were kept to a minimum. Additional transmission lines should only be authorized if they serve a legitimate public need, and if there are no alternatives that are less costly in economic and social terms. The hypothetical benefits of a free and open wholesale market may be considered in such a discussion, but must be extensively questioned – especially given the experience of the last decade.

The allocation of the cost of transmission upgrades based on causation becomes more complex when the grid is being used not just to serve local demands but also to facilitate the operation of the wholesale market. Ideally, those who are responsible for paying congestion costs – either utilities or generators – should also bear the responsi-

bility for the investments in transmission, efficiency or load response that would enable them to reduce those payments.

Ultimately, the public and government officials need to decide whether the principal purpose of transmission is to ensure the delivery of reliable service or to facilitate a vigorous wholesale market in electricity. The current system was designed largely to support the former goal. Before committing tens of billions of ratepayer dollars to building a grid that adequately supports the wholesale market, regulators must justify, in specific terms, how consumers and the public stand to benefit from the operation of that market, describe the long-term consequences of their decisions, and consider all possible alternatives. We believe that such an analysis would point to a less transmission-intensive alternative relying largely on energy efficiency improvements and the deployment of renewables and clean distributed generation as being of greater benefit to consumers. (Please see the attached analysis, *A Responsible Electricity Future*, for a description of the costs and benefits of such an approach.)

Transmission Pricing

Assuming the continued operation of a transmission system that is not radically different than it is today, the key issues then become how to allocate scarce transmission resources and who should do the allocating. The need to allocate scarce resources requires discrimination among various types of transactions – exactly the kind of situation that proponents of "non-discriminatory" access to the grid seek to avoid.

One proposed method to deal with this problem is to discriminate on the basis of price. In theory, by increasing the price of transmission at times of peak demand or at locations where transmission is constrained, economic signals will be sent that will result in increased supply of transmission (through new construction), reduced demand, or other adjustments.

Congestion pricing has numerous potential benefits. If designed properly, it can assign to long-range transfers of power something approximating their true cost – in turn, providing an additional incentive for load reductions and for the construction of generating capacity closer to the point of use. However, congestion pricing can also impose tremendous burdens on consumers and open the door to new types of exploitative behavior by market participants.

To protect the short-term and long-term interests of consumers, utilities (on behalf of their customers) must have the ability to hedge against congestion charges. One way to do so would be to allocate financial transmission rights (FTRs) to load-serving entities. The FTRs could then be sold or traded in a secondary market. Utilities that reduce their load (through demand-side strategies, purchase or generation of electricity generated closer to sources of load, or encouragement of distributed generation) could then gain the benefit of reselling their FTRs on the market, while those constructing new transmission lines could gain additional rights to sell. This type of system would ensure that the real cost of delivering wholesale electricity is factored into the price of power.

A second opportunity for hedging is through the development of balanced, long-term energy portfolios. We will discuss this issue further in the next section.

Where transmission pricing runs the risk of damaging consumers' interests is when congestion charges are passed through directly to end-use consumers.

In systems characterized by cost-based rates – and without either portfolio planning requirements or other incentives for utilities to protect their customers from price volatility – this is a tremendous risk. While time-of-use or real-time pricing may work for some small subset of consumers, it is unlikely that a pricing system can or will be developed that will allow consumers to adjust their power usage in keeping with fluctuations in the wholesale market for electricity. Such a system may not even be socially acceptable – consider, for example, the potential dilemma faced by a low-income household in the midst of a summer heat wave. A high price for power at a time of peak demand may be "economically efficient" in such a circumstance, but the consumption decisions that result could be damaging to the public health and welfare.

Finally, all policy-makers must remember that investments in the transmission grid have been made over the course of many years through ratepayer funds to enhance the reliability of the system. The preservation of system reliability must be the top priority, regardless of the method used to allocate access to transmission.

Market Power and Manipulation

Proposals to allocate what are, in effect, property rights to transmission capacity open up another potential avenue for the accumulation and use of market power. Should transmission rights become concentrated in too few hands, the potential exists for owners of those rights to withhold transmission capacity in order to gain undue leverage in the market.

Indeed, the current structure of wholesale electricity markets provides virtually unlimited opportunities for manipulation. Regulators and grid operators have created new rules designed to limit many avenues for manipulation. Such efforts are worthwhile, but are ultimately doomed as long as two conditions persist: scarcity at any point in the market during periods of peak demand, and the presence of limited numbers of players in the market.

In a truly open market, high prices at times of scarcity create incentives for suppliers to increase supply and/or consumers to reduce demand, thus restoring the system to equilibrium. In electricity markets, things are not so simple. Entry to the market is generally costly, demand varies widely from hour to hour and day to day, and demand is generally unresponsive to price signals, which are themselves expensive and extremely difficult to convey to a consumer base largely accustomed to paying a stable rate for electricity. These conditions deliver enormous incentives to those who own scarce resources (or wish to create artificial conditions of scarcity) to extract the maximum profits from those who are forced to pay – usually utilities with an obligation to serve the public (and often, by extension, consumers). The potential for manipulation is magnified when large percentages of generation or transmission capacity in an area are owned by a single firm or a small group of firms, who can then assert monopoly or oligopoly control over prices.

Breaking the grip of market power and stamping out manipulation require a variety of measures. First, as noted above, regulators must force utilities to hedge against market volatility through long-range portfolio planning and by securing rights to transmission capacity. Second, concentration in the ownership of generation or of rights to transmission capacity must be severely limited. Firms that dominate the mar-

ket in a given region should be required to divest or be subjected to cost-based rate regulation, and the FERC should not approve utility mergers unless it can be conclusively demonstrated that they pose no threat of the accumulation of market power in a given area. Third, safety nets such as generation rate caps should be implemented to protect consumers from the worst market abuses. And finally, market manipulation must be monitored for and violations severely punished.

On this last point, it is necessary that the FERC serve as "watchdog in chief," with grid operators serving as the day-to-day eyes and ears monitoring the markets. The lackadaisical response the FERC demonstrated in response to the obvious manipulation of markets in California must be replaced with an aggressive program of enforcement. Punishments for the exercise of market power should include, but not be limited to: the refund of excessive charges from all recipients of windfall profits (not just "bad actors") dating back to the time at which such charges began, reimposition of cost-based rate regulation on the offending parties, and potentially federal prosecution. It would not take the imposition of many such penalties to deter potential violators from engaging in opportunistic behavior.

One further note: the use of market power also applies, in more subtle ways, to the development and deployment of new technologies. For years, providers and consumers of distributed generation technologies have complained about utility practices that deter the deployment of those technologies. A 2000 survey by the National Renewable Energy Laboratory, for example, found that "some utilities generally oppose interconnection of distributed power, with varying explanations. Some utility representatives told customers that interconnection was not possible. In some cases, utilities knowingly or unknowingly chose not to follow state commission regulations, forcing the customer to pursue legal remedies."[205] Obviously, the creation of standard rules for interconnection – and the vigorous enforcement of those rules – is needed to ensure that new technologies can compete on a level playing field with those favored by utilities.

If the exercise of market power cannot be stamped out through regulation (a distinct possibility), it may become necessary to reinstate cost-based ratemaking for transmission at the federal level or to vest control of scarce transmission resources with a single firm: one under public control. The notion of a publicly owned transmission company stretches back to the New Deal and may prove to be the most effective way to ensure that the public interest is protected while enabling a wholesale market in electricity.

3. Lack of Effective and Coordinated Planning

The concept of "planning" may appear to be anathema to notions of a free market in electricity. But even within market-based wholesale and retail systems, the delivery of reliable electric service requires effective planning. Historically, individual utilities planned for their future needs separately (or, in a few cases, through cooperation in a voluntary power pool), but the onset of competition has required new venues for planning. Planning is currently carried out by RTOs/ISOs, individual utilities, merchant generators and other system participants.

Planning within a market-based system is inherently difficult. Any indi-

vidual participating in the market must make decisions based on the presumed behavior of all other participants. Investors in a generating company want to know who will buy the power being produced and how it will be transmitted. Individual consumers choosing among retail electricity suppliers may want to know whether the supplier has a diversified energy portfolio that will reduce the chance of price volatility. Generation, transmission and distribution operators alike need to have accurate assessments and projections of load – both on a minute-by-minute basis for effective system operation and over the long haul for infrastructure-related decisions.

There are several problems with planning as it is currently carried out. They include:

- Failure to examine/consider all cost-effective means to solve a given problem
- Failure to develop balanced, long-term energy portfolios
- Lack of coordination among generation, transmission and load aspects of planning
- Planning that takes place outside the public arena
- Failure to include resource and other constraints in plans.

Failure to Consider Alternative Options

A lack of transmission capacity to serve a given load can be addressed in one of two ways: by adding capacity or reducing the load. Yet, load management, energy efficiency and the deployment of distributed resources are often considered only cursorily – if at all – in long-term plans for development of the electric system. For example, a 2001 survey by the American Council for an Energy-Efficient Economy found that, of 21 states that reported reliability problems or "close calls" during 2001, only seven had attempted a demand-side management strategy aimed at solving the problems.[206]

To ensure that alternatives are considered in the planning process, the Regulatory Assistance Project has proposed an "Efficient Reliability" standard. Under the standard, costs for regulated investments designed to enhance reliability could be shared out to consumers only if the investment meets a three-part test:

1. The market is fully open to demand-side as well as supply-side resources.
2. The proposed investment or standard is the lowest-cost, reasonably available means to correct a remaining market failure.
3. Benefits from the investment or standard will be widespread, and thus appropriate for support through broad-based funding.[207]

Such a standard – if implemented by the FERC, RTOs/ISOs, and individual state commissions – would ensure that alternative approaches are explored and consumer interests protected in the planning and development of the electric grid.

Failure to Develop Balanced Long-Term Energy Resource Mixes

A related problem is the failure of utilities to develop long-term plans for the provision of electricity to consumers at reasonable, stable prices. The onset of retail restructuring (or the near-term potential of restructuring) left many entities within the industry gun-shy about committing to long-term contracts and engaging in planning processes with

long time horizons. Short-sighted legislative and regulatory decisions contributed to this problem.[208] The result, particularly in states with retail competition, has been to rely too heavily on spot markets for electricity, which are notoriously volatile, particularly at periods of heavy load.

Regulated or standard offer service providers should be required to produce plans for procuring energy for their customers that incorporate all cost-effective resources, with provisions for limiting the risk of price volatility. If states with retail competition guarantee access to a regulated standard offer service product for small customers, this would result in some form of long-range portfolio planning in every state.

An effective portfolio plan will, in addition to taking advantage of demand-side resources, manage risk by balancing long-term power supply contracts with participation in short-term markets. In a regulated environment with vertically integrated utilities, portfolio planning will take the form of long-range plans for the construction of new generation and transmission capacity, perhaps augmented by purchases of power from short-term markets. In a state with retail competition, default service providers may or may not own significant amounts of generation. In these cases, a portfolio of long- and short-term power supply contracts will likely be needed to provide price stability while allowing for the purchase of power on spot markets when it is economically advantageous to do so.[209]

All portfolio plans should be subject to public and regulatory input in keeping with traditional regulatory principles of open participation, access to information, and guarantees of due process rights.

Lack of Coordination Among Generation, Transmission and Load

The electric system, while separated into market-based and regulated components, must act as a seamless whole. In the days of vertically integrated utilities, coordination among various portions of the industry was never an issue. The experience of restructuring has shown that the decisions of market actors do not always mesh well with the decisions of the regulated components of the industry.

The boom (and subsequent bust) in the construction of new generation capacity in the initial wave of industry restructuring is a prime example. Over the past decade, new generation capacity has increasingly been built in locations far away from load centers, straining the ability of the transmission system to deliver the electricity. For example, the North American Electric Reliability Council's (NERC) 2003 10-year adequacy assessment notes that, if current projections hold, installed generation capacity in Mississippi by 2007 will be more than double what it was in 1998. "This capacity," NERC notes, "exceeds what is needed to serve local demand, and the transmission system is not currently capable of moving this electricity to other areas."[210] Investments in new generation in other parts of the country, meanwhile, have not been as swift, and many plans for new generating capacity have been shelved in the wake of the industry's recent economic difficulties.

One of the dangers of such a situation is that the decisions of merchant generators create "facts on the ground" that then shape the decisions made in the regulated portions of the industry. Consumers did not ask for, nor do they need, Mississippi's glut of power plants.

Yet, if upgrades are made to the transmission system to support the wholesale market – allowing the power from those plants to be widely marketed – it is likely consumers who will pay the costs.

To prevent such a situation from arising again in the future, states should restore the requirement for a determination of need in siting decisions, and ensure that it applies to the construction of merchant generation. State and regional authorities should also ensure that the cost of providing transmission for such facilities is borne by the generator and not shared out to ratepayers.

Planning Outside the Public Arena

Decisions over the future of the electric system affect more than just "market participants." They also affect consumers and society as a whole.

Currently, the effective locus of planning for the future of the wholesale electric grid is with RTOs/ISOs, individual utilities, and, to some extent, the federal government. While the ultimate decision-making over regulated investments in transmission and generation does take place within the public interest sphere – largely in state regulatory commission rate decisions – regulators are often placed into a reactive posture, passing judgment on plans that have been developed elsewhere.

RTOs and ISOs, while intended to be independent from the specific interests of any individual market participants, tend to be guided by the general interests of those who take part in the RTO/ISO governing process, which is dominated by major market participants. Public interest representation in RTO/ISO decision-making is typically limited to participation as "stakeholders." While state regulators have, in some cases, formed regional organizations to attempt to coordinate their activities and inject public interest considerations into the process, they are typically not in the drivers' seat.

The National Governors Association and the FERC have proposed the creation of regional state committees to facilitate regional planning for transmission and act as a forum for the resolution of disputes among states over facility siting. With proper goals, protections for the rights of individual states, and provisions for participation by citizens and nongovernmental organizations, such entities could provide a good mechanism for improved regional planning and impose a measure of accountability on regional transmission organizations. Because such bodies would not be responsible to any one government, ultimate jurisdiction must continue to rest with the federal and state governments. The creation of regional state committees, however, has the potential to bring regional planning issues back into the public arena.

Failing to Include Resource and Other Constraints in Planning

Any plan for the future of the electricity system must take into account real-world constraints such as the availability of fossil and other fuel resources. As the natural gas crisis has shown, short-term market signals aren't always the best indicator of the wisdom of investments when it comes to fossil fuel resources, which are notoriously volatile in price and limited in supply.

Similarly, planning must also include not only current, but also prospective environmental constraints. Environmental legislation and regulation is a key factor in planning, but future changes in environmental regulations are often

chalked up as unknowable. In reality, while it is difficult to know the exact format of future environmental regulation, it is relatively easy to project which activities will be the focus of future regulation. For example, efforts to reduce emissions of carbon dioxide and other global warming gases will inevitably have to address emissions from coal-fired power plants. And, regardless of one's opinions of nuclear power, it is difficult to envision a dramatic expansion of nuclear generation without a significant political backlash on siting decisions.

Such constraints have impacts not only on what types of generation should be encouraged or discouraged, but on the shape of the grid itself. The transmission investments needed to, for example, supply wind power from the Plains states (known as the "Saudi Arabia of wind") will be vastly different from the systems needed to supply power from large-scale nuclear plants, and both will be different from a system that supplies power from small scale wind turbines, solar installations and fuel cells.

Prudence dictates that future plans for the electricity system take these factors into account, and steer a course that will minimize the use of scarce resources and prevent pollution before it occurs. Doing so will require a certain amount of crystal ball gazing, but is far preferable to the alternative of wasted investment and long-term dependence on unstable sources of energy. In addition, planning for the use of cleaner resources can produce long-term benefits for the environment, public health and consumers. (See Synapse Energy Economics, *A Responsible Electricity Future*, attached.)

Such considerations, while they should be the subject of discussion at the state and regional level, are truly national in scope. Only at the federal level can such questions be dealt with in a satisfactory manner. Unfortunately, previous efforts to develop such a national energy strategy – such as the Bush administration's National Energy Policy – have not only ignored potential resource and other constraints, but have also been the result of a policy development process that took place in private and excluded many key stakeholders.

4. Failure to Account for External Costs and Impacts

The societal costs of various methods of electricity generation are not necessarily reflected in the rates consumers pay for power. The nuclear industry, for example, has received more than $100 billion in federal subsidies since the end of World War II.[211] Fine particulate air pollution from power plants (largely coal-fired) causes an estimated 30,000 premature deaths each year as well as many illnesses, imposing health care and other costs on the economy.[212] The recent spike in natural gas prices – driven in part by increased demand from electric power plants – has had widespread economic ramifications beyond increases in electric rates. Environmental damage caused by the extraction of fossil fuel resources is extremely costly to remediate – and the potential economic damage that could be caused by global warming is incalculable.

In short, every form of energy imposes its share of external costs – whether they be environmental, health-related, economic or social. Just because these costs do not appear on consumers' electric bills does not mean they are not significant and should not be considered within the regulatory process. As noted earlier, the inclusion of environmental and public health costs in the cost of

operating coal-fired power plants would change the economics of coal completely.

Any regulatory process that is truly protective of consumers' interests should incorporate such external costs into all facets of planning and decision-making. Unfortunately, the opening up of wholesale power markets – coupled with retail deregulation in some states – has limited the opportunities of regulators to insist upon the factoring in of external costs.

Within the regulatory process, perhaps the best opportunities to bring true least-cost principles to bear are in long-term resource planning. Regulators could also choose to incorporate external costs into considerations of vertically integrated utilities' plans for generation investments and/or long-term contracts for purchases of power.

The most promising way to reduce external costs is to create systems that require or incentivize investments in energy efficiency and renewable power and internalize the external costs of fossil and nuclear sources. Strong efficiency standards for appliances and energy efficiency codes for buildings can maximize cost-effective efficiency in the broad range of products for sale in the market. Renewable portfolio standards and emission portfolio standards help to promote energy sources that pose reduced threats to the environment and public health. Systems benefit charges to support energy efficiency and renewable energy development – if properly implemented – can achieve a similar goal. So too can efforts to price pollution, such as carbon taxes and cap-and-trade programs. (Any cap-and-trade program, however, must be designed carefully so as to provide real, surplus and verifiable reductions in pollution.) Finally, state and federal governments must realign their spending priorities and eliminate subsidies for polluting and dangerous sources of energy. Federal subsidies for fossil fuel development alone have been estimated to be as much as $5 billion annually, and could increase significantly if Congress adopts a version of the Energy Bill debated during the last two congressional sessions.[213]

In recent years, a number of states have moved to adopt these and similar policies. At least 14 states have adopted some form of renewable portfolio standard, while at least 20 states and the District of Columbia assess or plan to assess systems benefit charges to support efficiency and/or renewable energy programs. There remains, however, a great disparity in support for efficiency programs from state to state and region to region – no southeastern states, for example, possess either an RPS or a systems benefit charge and utility efficiency spending lags in many states within the region, despite the fact that per capita demand in the region is very high. A national RPS and systems benefit charge program – overlaid atop existing state programs – would help bring the benefits of renewables and efficiency to new regions of the country, and could reduce the external costs of electricity generation for all Americans.

One potential criticism of an approach that relies heavily on renewables and public support for efficiency is that it will raise rates for consumers in the short term. However, as noted above, a narrow focus on short-term rates does not give due credit to the wide range of interests consumers possess. In addition, consumers who benefit from efficiency improvements supported through systems benefit charges and other programs may well experience lower bills in the short term. Finally, as the attached analysis by Synapse Energy Economics demonstrates, a long-term shift toward

increased efficiency and increasing generation of power from renewable sources is likely to yield lower consumer costs in the long term, due in part to the reduced need for infrastructure investments to serve increases in load.

5. Financial Instability

One of the great benefits of electric restructuring was to have been the influx of dynamic, innovative new enterprises into what had once been a stale, regulated industry. Proponents of restructuring promised that these new actors would create new efficiencies that would in turn provide ample benefits to investors and customers alike.

Indeed, during the 1990s, the electricity industry saw the dramatic growth of merchant generation investment as well as the development of new trading enterprises – such as those operated by Enron – designed to participate in the evolving wholesale market for electricity. For much of the decade, stock prices of these enterprises skyrocketed.

But the California energy crisis, the pull-back from retail restructuring that followed, the rise in natural gas prices, and the Enron collapse brought about a dramatic reversal of fortune for the industry. Companies that had invested in these new enterprises saw their stock prices and bond ratings pummeled; some were forced into bankruptcy. By 2002, energy companies that received less than 75 percent of their revenue from regulated assets (in both electricity and natural gas) experienced a five-year annualized rate of return to stockholders of only 1.1 percent. By contrast, energy companies that received more than 75 percent of their revenue from regulated assets posted an average rate of return of 3.7 percent.[214]

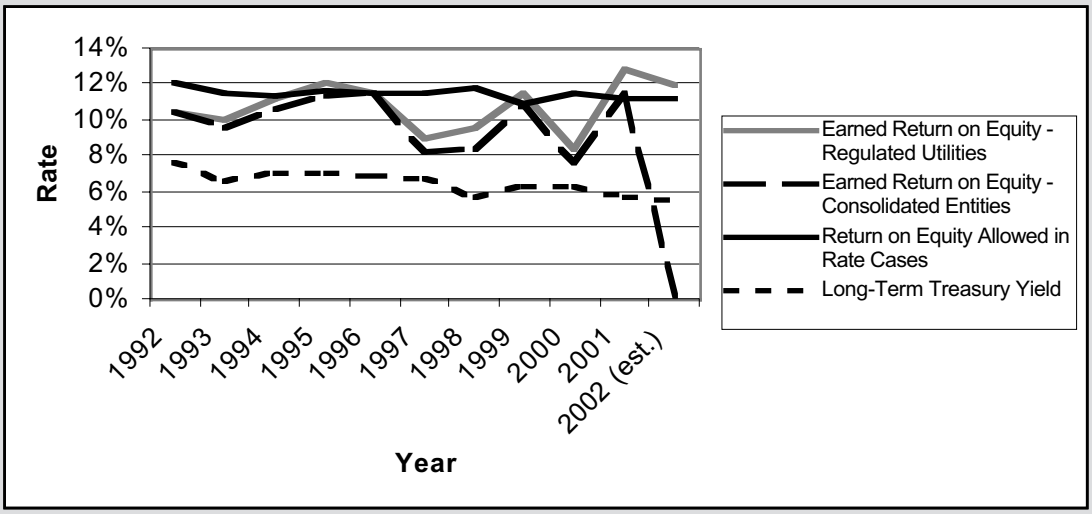
The financial problems of non-regulated power producers can bleed over into the operations of regulated utilities. The exemptions to the Public Utilities Holding Company Act of 1935 (PUHCA) described earlier for owners of non-regulated generation companies and power marketers have allowed some regulated utilities to get into financial hot water. For example, XCel Energy, which serves more than 3 million customers in the Midwest and West, saw its bond rating downgraded two notches due to the bankruptcy of its non-regulated generation subsidiary.[215] The higher costs that XCel Energy will incur for credit in the future may well be passed on to consumers of the company's regulated products through their rates.

Despite recent experience, some suggest that the most effective way to bring new vitality and investment to the industry is to free utilities from current regulations that limit their geographic spread and ownership. The proposed solution is to repeal PUHCA.

Advocates claim that repeal of PUHCA would allow new types of investors to own public utilities, pumping needed capital into the system. However, the repeal of PUHCA is an exceedingly risky step. Among the potential downsides of PUHCA repeal are:

- Greater industry consolidation, reducing the potential for meaningful competition in both retail and wholesale markets.
- Greater leeway for holding companies to manipulate (and conceal) their finances in order to gain favorable regulatory treatment in rate setting.
- Greater financial instability for utilities along the lines of the instability facing merchant generators and other unregulated energy companies.

Fig. 28. Return on Equity vs. Long-Term Treasury Bond Yield[219]



Indeed, far from increasing the flow of capital into regulated utilities, repeal of PUHCA would likely make utility capital acquisition far more expensive by stripping utilities of their status as a safe, regulated investment. Standard & Poor's Rating Services, for example, recently concluded that the SEC's relaxation of PUHCA enforcement in recent years has not benefited investors and that, "[i]f PUHCA is repealed, companies would have a greater ability to increase deregulated investment. If these companies choose to pursue those options, we could see deterioration in credit quality for utilities whose corporate parents have an appetite for greater risk if PUHCA is repealed."[216]

Because the cost of securing capital is typically passed through to consumers in cost-based rate-setting, any measure that increases utilities' cost of capital is likely to have a detrimental effect on the prices consumers pay for electricity. Moreover, the further industry consolidation that repeal of PUHCA would spark could have a negative impact on competitiveness, again with potential rate impacts for consumers. Thus, repeal of PUHCA appears not to be in the best interests of consumers.

While the strong financial situation of regulated utilities is certainly a good thing for consumers who rely on those entities to provide their electricity service, it is also likely that financial conditions at present are *too good* for many regulated utilities. Average return on equity for electricity rate cases in 2002 has been estimated at 11.16 percent.[217] Indeed, return on equity (for regulated utilities) has remained relatively stable over the past decade, even as interest rates have declined significantly. (See Fig. 28.) Between 1992 and 2002, allowed return on equity (set by state regulators) declined by about 8 percent, while long-term Treasury bond yields declined by 28 percent. Earned rates of return for regulated utilities remained relatively stable, but rates of return for utilities that own non-regulated assets ("consolidated" entities) have not been as strong, due to the wave of poor investments made during restructuring.[218]

Given the relatively low level of risk inherent in investments in regulated utilities, it is likely that regulators are allowing utilities to benefit from rates of return that are significantly higher than they ought to be. State regulators should adjust utility rates of return to account for lower interest rates, ensuring that consumers are not supplying excessive profits to regulated entities.

6. Lack of Attention to Traditional Regulation

The move to create – and then impose effective conditions upon – competitive markets in electricity has absorbed a tremendous amount of intellectual and regulatory energy in recent years. For regulators who already, in many cases, struggle to marshal the resources to effectively defend the public interest, the burden of dealing with restructuring has made that essential task even more difficult.

If, as we conclude, the re-application of traditional regulatory principles to retail and wholesale markets is necessary to protect the interests of small consumers, then regulators must begin to focus attention on how to discharge their duties, given all that has occurred over the last decade and the availability of new technologies – such as cost-competitive renewable power and clean distributed generation technologies – that did not exist a decade ago. Attention must be paid to both the level of staffing and resources available to regulatory agencies, as well as the potential application of tools such as performance-based regulation. It may never be possible to design a "perfect" system of electricity regulation. But it is possible to develop a system that safeguards the essential interests of consumers while improving the overall efficiency of the electricity system and protecting the broader public good. Now is the time for academics, regulators, state and federal officials, and the public to turn their attention to this task.

7. Lack of Accountability

A regulatory system that protects the public interest must involve the public in all levels of decision-making and be accountable to the public for its performance. Unfortunately, the public is often unaware of – or has little ability to influence – the decisions carried out in its name.

The first step toward restoring public accountability to the electricity system is to ensure that essential decisions are made within the public arena. The reliable operation of the electricity system is too important a matter to leave to industry self-regulation. System reliability rules must be imposed at the federal level, be enforced by bodies with direct accountability to government agencies, and carry large penalties for non-compliance. Similarly, the day-to-day operators of the grid – the regional transmission organizations, independent system operators and others – must be held accountable for their performance as pseudo-regulators. Currently, these bodies operate either as private enterprises or nonprofits with only loose accountability to the FERC and to state regulators. Because wholesale markets are essentially regional in nature, the development of effective regional agencies – themselves accountable to the states and the public – to monitor and help guide the activities of regional grid operators could be beneficial.

However, the public must be brought inside the process of setting the future course of the electricity industry in a more fundamental way. Ratepayer advocates within state utility commissions have long played an essential role in

ensuring that the public interest is represented in rate decisions. In locations where the power of ratepayer advocates is limited, they should be permitted to participate in and initiate rate cases at their discretion, as well as to represent the interests of consumers in their states before regional and federal bodies. The activities of ratepayer advocates should also be explicitly geared toward defending the interests of small consumers, who generally lack effective representation in the process.

To supplement the work of ratepayer advocates, states should allow for compensation for public interest interveners – such as advocates for low-income consumers and environmental advocates – who represent important points of view and can contribute materially to rate cases before utility commissions.

Finally, there is an urgent need – at the federal, state and local levels and every level in between – to develop long-range energy plans that safeguard the interests of consumers, public health, the environment, and the broader economy and society. For these plans to have legitimacy and meaning, it will be necessary for governments to find new ways of including the public in the process, beyond the typical schedule of public hearings and comment periods. The interest is there; the number of consumers choosing "green" electricity products, purchasing hybrid-electric automobiles, or simply expressing concern about the nation's energy future proves it. But without a vehicle for expressing these concerns – such as through open, inclusive planning processes – energy policy will continue to be dominated by a fragmented approach that results from the clash of interests on an issue-by-issue basis.

We believe that an energy future that supports the diverse needs and desires of consumers is achievable. The attached analysis by Synapse Energy Economics describes, with relation to the electricity sector, what such a future might look like.

A New Vision for Electricity Regulation

In determining the future of the nation's electricity industry, America must make several fundamental decisions.

The first decision is whether we care to trust the production and delivery of electricity to markets or to regulated industries.

A decade ago, this was a matter for philosophical debate. Amid a political atmosphere that favored deregulation and market approaches, and with the backdrop of failed nuclear investments and other regulatory failures, the devil we didn't know – deregulation – appeared to many to be far more appealing than the more familiar devil of cost-based regulation.

Over the past decade, however, we have learned a great deal about the ways in which competition in electricity works – and doesn't work – to serve consumers and the public interest. From the California debacle, we learned that electricity markets are uniquely susceptible to manipulation. From the string of reliability episodes culminating in the August 14, 2003 blackout we learned the true cost of wholesale deregulation on the reliability of the nation's electric system. From the financial peril of the merchant generators, we have learned about the need to maintain a strong firewall around the finances of regulated utilities – and about the challenges posed by the boom-bust cycle of capital investment on system planning. And from the half-decade-long experience of retail restructuring, we have learned that new electricity suppliers will not rush to secure the business of individual consumers (at least not without substantially higher baseline rates against which to compete).

In short, a decade of efforts to rebuild the electric system around market principles has left us with electricity service that is less reliable and yet, in all probability, no less costly than it would otherwise be – at least for residential consumers.

The solution to the problems of deregulation is the re-regulation of the electric industry. But on what terms? Even the market-oriented FERC, for example, proposes or supports increased regulation with regard to enforcing reliability standards, preventing the exercise of market power, and assigning responsibility for transmission investments. Yet, the FERC's approach relies heavily on implementation through non-governmental agencies (especially RTOs) and the use of financial incentives to nudge markets in what the commission believes is the right direction.

This vision of re-regulation flows from the notion that electricity markets experience failures but can be fixed through artful regulatory design – administered by "independent" entities. But "fixed" to what end? Is the end the provision of electricity at the lowest possible cost to all consumers? The reduction of environmental and public health threats from power plants? The equitable distribution of costs and benefits among various segments of society? The maximization of revenue for electric utilities? The achievement of some vision of economic efficiency? Or some combination of all of these goals?

It appears to us that none of these goals – many of which are worthwhile – are the ultimate aim of restructuring. Rather, the creation of markets itself appears to have become the central goal.

The experience of the last decade has shown that there are inherent problems in market-oriented strategies for the electric industry. For example, it is difficult to create conditions in which firms

cooperate for the sound management of the grid and yet compete vigorously against one another to sell their services over the same set of poles and wires. Similarly, it is difficult to assure both reasonable prices for consumers and simultaneously create legitimate opportunities for profit by new competitors.

If effective, open markets in electricity – at least under today's technological conditions – are unattainable, what is the alternative?

The shape of that alternative depends on the goals we assert, as a society, for the electricity system. These goals cannot be divined by "independent" agencies or regulators whose default position is to leave markets alone to do their work. Rather, they must be asserted through the difficult process of politics. It is the public, in person or through their elected representatives, that should have the responsibility for establishing those goals. And because residents of different parts of the country have different needs and desires, those goals should be articulated and implemented (to the extent possible) from the bottom up.

The traditional system of public interest regulation of utilities – which produced reliable service at low and steadily declining prices – is a workable template for how such a regulatory system can be constructed. But the traditional system of regulation is far from perfect, both in its design and in its implementation. Public officials charged with the regulation of the electric industry must reach out to include the public in their decision-making and experiment with new tools to regulate the industry in a way that promotes efficient operation while preserving the interests of ordinary consumers. As long as the attention of federal, regional and some state regulators is distracted by the design and maintenance of brand-new regulatory structures to contain restructured markets, it is doubtful that this important task will receive the attention it deserves.

The question of markets-versus-regulation, however, is a question of process: a question of "how." America must also decide the "what" of its electricity system – that is, what sources of energy should be used in the future to provide our electricity, and what form should the transmission and distribution systems that supply that electricity take?

The advance of technology has created a new opportunity to re-envision the "what" of America's electric system. Renewable sources of energy such as wind power, small-scale distributed generation technologies, and advanced energy efficiency technologies provide an opportunity for us to reimagine the electricity system from top to bottom.

The attached analysis by Synapse Energy Economics makes a compelling economic case for why the United States should encourage the development of renewable resources, energy efficiency and distributed generation in its future strategy for the electricity system. The long-term results of this approach will not only be less pollution and fewer impacts on public health, but also consumer savings and enhanced economic competitiveness.

The promise of this long-term vision will require that we make capital investments in these technologies now, and that we commit to maintaining those investments over the long term. But it also requires us to understand the opportunity costs of other measures that might be taken to resolve the critical problems facing the electricity system. For example, the investment of tens of billions of dollars in transmission capacity or the outlay of billions in taxpayer subsidies to encourage new generation (as proposed in various versions of the Energy Bill before Congress) would nec-

essarily displace investments that could be made in efficiency, renewables and distributed generation.

Public interest regulation of the electricity industry can evaluate the long-term benefits of a clean electricity investment strategy – both for electricity consumers and the rest of society – in ways that market-based systems, with their short-term focus, cannot. In addition, publicly accountable bodies can achieve greater legitimacy in assigning the costs of making this transition in an equitable and socially acceptable way.

The challenges posed by the last decade of restructuring – combined with the potential economic and social benefits of a transformation to a more balanced portfolio of generating resources – argue for vigorous, thoughtful and accountable regulation of the electric system based on public interest principles. Below, we suggest a set of principles for the consumer-oriented regulation of the electric system.

Consumer Principles for Regulation of the Electric System

1) Preserving universal access to safe, reliable, affordable electricity service should remain a national goal.

2) The public interest must guide all decisions with regard to the electric system.

- The goal of electricity regulation should be to provide adequate, reliable service to consumers at the lowest cost – including "external" costs such as environmental, public health, and social and economic impacts. Ratepayers must only be required to pay for investments that serve a legitimate public need and that could not otherwise be met through lower-cost means.
- Electricity rates should be designed to promote economically efficient and socially responsible outcomes – including energy efficiency, rate stability and the protection of low-income consumers.
- The public interest can be preserved only through an open, accountable regulatory system that is explicitly charged with safeguarding the public.
- An effective regulatory system must guarantee due process and freedom of access to relevant information, allow and encourage the participation of all stakeholders, and preserve a right of appeal.
- An effective regulatory system must balance the long-term and short-term needs of consumers, as well as the interests of various classes of consumers. To balance long- and short-term needs, system planning must take place in the public arena, include ample opportunities for public participation, and explicitly consider resource, political and environmental constraints. To balance the interests of various consumer classes, regulators must encourage broad participation in decision-making and ensure that the views of small consumers are adequately represented in the process.

3) Market mechanisms should be employed when they benefit the public interest and supplanted by regulatory decision-making when they do not.

- The conditions for effective and fair markets in the electric industry – particularly in the transmission and distribution of power and the sale of electricity to small consumers – do not currently exist and are unlikely to exist in the foreseeable future. Regulation of rates and terms of service in these areas of the industry (and

perhaps others) is necessary to protect the public interest.

- Where market mechanisms are established, consumers' basic rights must be protected. These include the right to choose an electricity provider, to switch providers in a timely and convenient manner, and to receive accurate and timely information about rates and service.
- Where market mechanisms are established, government retains a role in ensuring that markets operate fairly. This includes the need to prevent the accumulation and exercise of market power and to safeguard consumers' collective investments in the electric grid.
- The interests of consumers cannot be abandoned during any "transition" from regulated to open markets. Consumers should not be subjected to higher-than-warranted rates in order to encourage the entry of competitive suppliers to the market.
- Consumers must retain the ability to pool their resources through cooperatives or municipal governments in order to negotiate better rates and service or to provide power themselves.
- Private, unregulated entities must not be permitted to shift costs or risks to the regulated entities that serve consumers. Similarly, ratepayers must not be forced to make infrastructure investments that primarily serve private interests.

4) Decisions with regard to the electric system should be made at the level of government most accessible and responsive to the public, keeping in mind the need for broader coordination across jurisdictional boundaries.

- Ideally, decisions should be made at the lowest level of government possible, in order to maximize the public's ability to participate in the decision-making process and hold decision-makers accountable to public interest goals.
- All levels of government must engage in comprehensive energy and electricity planning that establishes a long-term vision for the nation's energy future. Such plans should be developed in public and invite participation from all stakeholders.
- New structures may be required to allow democratic governance of regional energy pools and markets in order to bridge the gap between national and state decision-making.

5) Improved energy efficiency and increased use of renewable resources are in the long-term national interest and often have short-term benefits for consumers. Government policy should actively promote the development and use of these resources.

- Market and regulatory barriers that deter the use of energy efficiency, renewable energy, or distributed generation technologies should be removed.
- The long-term benefits of these technologies must be considered in system planning, ratemaking and other decisions made in the regulatory system.

Policy Recommendations

For the States

- In all states, retain or reimplement through statute the traditional imperatives of utility regulation, including the guarantee of "just and reasonable" rates, universal service, rate equity, preservation of the environment and public health, and the resolution of disputes through due process mechanisms.
- Do not move forward with retail competition in states where it is not already present. In states with retail competition, reform the system to protect consumers by:
  - Guaranteeing access to a regulated electricity product ("standard offer" service), with rates set according to traditional regulatory principles, including the principles of rate stability, resource diversity and least-cost management.
  - Establishing provisions to allow opt-out municipal aggregation.
  - Removing disincentives for small consumers to return to regulated service (possibly with some reasonable limitations on the frequency and/or periods of time during which consumers can change providers)
  - Establishing a builder of last resort to provide generation resources in the event that market forces do not provide adequate supply.
- Require full transparency and disclosure of the attributes of "premium" electricity products (such as "green" electricity) offered through retail competition or consumer choice programs.
- Adopt performance-based regulation as a layer atop traditional cost-of-service based regulation, through the imposition of per-customer revenue caps that promote cost savings and improved efficiency. Performance-based incentives should not be used to reward utilities for performing their basic functions of providing reliable electricity service.
- Require resource planning, and evaluate those plans based on least-cost principles. Plans should consider all possible options for meeting electricity needs (including efficiency and distributed generation), and must be revised periodically on a regular schedule. Determinations of least cost should be based on a) short- and long-term rate impacts, b) risk management, c) long-term costs and benefits, d) the possibility/likelihood of future environmental regulation, e) energy security and national security concerns, and f) social and environmental impacts.
- Require (along with regional grid operators and the FERC) the adoption of policies to encourage the use of cost-effective distributed generation while preserving equity in cost allocation for investments in electricity infrastructure and ensuring protection of the environment. A suite of such policies should include:
  - Uniform standards for interconnection
  - Net metering
  - Elimination of punitive standby power rates in favor of fair and cost-based rates
  - Standards for the speed of utility response to requests for interconnection, with penalties for utilities that fail to adequately respond to interconnection requests

- Emission standards for distributed generators to protect air quality
- Implementation of reasonable exit fees to avoid the shifting of costs to customers remaining on the grid.

- Assess systems benefit charges to support energy efficiency efforts and renewable power development. Such charges:
  - Should be used to support initiatives above and beyond efficiency and renewables projects adopted by utilities as part of least-cost resource planning or required through other regulation.
  - Should be administered outside of distribution utilities – either by a state agency, non-profit corporation, or independent contractor. Expenditure of funds should be reviewed annually by state PUCs.
- Adopt public policies – such as energy efficiency codes for buildings and appliance efficiency standards – that ensure that new buildings and infrastructure achieve maximum cost-effective levels of energy efficiency.
- Experiment with cost-effective time-of-use pricing for individual small consumers and real-time pricing for large consumers, while mitigating any undue burdens imposed on consumers with limited options for changing their use patterns. Educate the public about the effects of time-of-use pricing and about ways they can reduce their consumption of electricity during high-cost periods.
- Experiment with "pay as you save" programs and other innovative market structures to promote the installation of energy efficient equipment and distributed generation technologies.
- Provide protection for low-income individuals in both regulated and deregulated retail markets. Such protections must include:
  - Discounted rates
  - Protection against redlining in competitive markets
  - Fair disconnection procedures, including sufficient notice of disconnection, the availability of alternative payment options, and moratoriums on disconnection during winter months or when electricity is medically necessary or needed for elderly or infant residents
  - Programs for the forgiveness of payments in arrears
  - Weatherization and energy efficiency assistance.

  These protections should be required of all energy providers as a condition for doing business in a state. Energy efficiency and weatherization programs may be supported by systems benefit charges.
- Revise siting rules to restore the determination of need in the siting of generation and transmission (where it has been eliminated) and require any generation or transmission project to be judged against other alternatives that might be cheaper and less environmentally harmful. Allow for the consideration of projects with benefits outside the state in the determination of need. Assign authority for siting decisions to boards with adequate public representation and processes for the consideration of environmental, public health and ratepayer interests.
- Reinvigorate citizen participation in rate-setting and other regulatory processes by:

- Providing funding for citizens who can materially contribute to a rate case to intervene in cases.
- Establishing an office of ratepayer advocate with independent governance and funding and strong powers to initiate and intervene in rate cases.
- Aggressively reaching out to stakeholders to include them in the development and evaluation of all decisions, including issues related to performance-based regulations, resource planning, and investment strategies for energy efficiency and renewables funds.
- Provide an option for citizens to establish publicly funded, independent citizen utility boards to represent small consumers in the regulatory process.

- Provide state public utilities commissions with the staff and funding they need to do their jobs.

For Regional Bodies

- Require ample public interest and state representation on boards of regional grid operators, including the regional power pools, the regional independent system operators and the regional transmission organizations.
- Consider the creation of regional state committees (or "multi-state entities"), made up of government representatives from the participating states, with sufficient legal authority conferred by a regional compact among the states. These committees should be charged with undertaking regional transmission planning and facilitating the siting of transmission facilities. Such committees should be created in parallel to the service areas of ISOs/RTOs. The committees should engage in decision-making on public interest principles and encourage participation from stakeholders, including consumers. Ideally, these entities will assume the primary regional transmission planning responsibility now housed in ISOs/RTOs and their recommendations will have influence with both state and federal regulators. Regional state committees should not be beholden to ISOs/RTOs for their funding.
- ISOs, RTOs, transmission companies or other regional grid operators should be required to consider and analyze alternative approaches to proposed transmission investments and engage in least-cost planning. Demand-side approaches to transmission congestion should be considered on equal footing with supply-side approaches and be eligible for socialization of costs.
- Consumers must be insulated from the pass-through of excessive costs resulting from location-dependent congestion pricing of transmission capacity. Congestion pricing systems must distribute financial transmission rights to utilities to hedge against congestion costs, and utilities must be required to use these rights to protect their customers. Mechanisms must be established to prevent the exercise of market power in transmission and ensure that revenues from congestion pricing are used to benefit consumers and the system as a whole.
- Regional grid operators should aggressively monitor market power conditions and should, in consultation with the FERC, states and regional bodies:
  - Set generation rate caps in areas that are susceptible to the accumulation of market power.

- Have the authority to limit the percentage of power controlled by any one company.
- Have a mechanism for petitioning FERC to assert authority to refund "unjust and unreasonable" charges to purchasers by firms exercising market power.

- Federal and regional officials should study the benefits of establishing independent (or government-operated) transmission entities to assume the transmission assets of regulated utilities and the system operation responsibilities now undertaken by ISOs, RTOs and for-profit transmission companies.

For the Federal Government

- The federal government must establish a comprehensive, long-range energy plan for the United States that includes a plan for meeting the nation's electricity needs. The plan should consider all economically and socially feasible strategies, including energy efficiency, distributed generation and renewable power sources. Both long- and short-term impacts should be considered. The process for creating the plan must take place in public, include affected stakeholders, and allow and encourage public participation. The plan should be a living document, revised periodically to meet updated conditions.

- Federal officials must align public subsidies, tax incentives and regulatory policy to the nation's long-term energy goals. Specifically, subsidies and incentives should be shifted away from the production and use of energy sources that face significant resource constraints (such as petroleum and natural gas) or that pose unmitigable environmental or public health problems (coal, nuclear). The federal government should fund an effort to research and develop alternatives to these energy sources.
- The FERC should use its jurisdiction over ISOs and RTOs to ensure that the decision-making processes of these bodies reflect the public interest. Specifically, the FERC should require non-token representation of consumers and other constituencies on ISO/RTO boards and foster the creation of duly constituted regional state committees through which state public utilities commissioners can bring a public interest perspective to ISO/RTO decisions.
- The FERC and Congress should respect the jurisdiction of states with regard to utilities' decisions to join RTOs.
- The FERC, the Securities and Exchange Commission and the Justice Department should aggressively enforce antitrust protections in the electricity industry to prevent anticompetitive behavior and undue concentration of ownership in the generation and transmission of power.
- The FERC should exercise its authority to guarantee "just and reasonable" rates to require refunds in cases where the exercise of market power has occurred. Refunds must apply both to the "bad actors" who exercise market power and to any entities who reap windfall profits during the time in which market power is being abused.
- The FERC should facilitate and assist regional transmission siting coordination efforts undertaken by regional state committees. The fed-

eral government should not assert authority over facility siting.

- Congress should resist efforts to repeal or weaken the Public Utility Holding Company Act. Rather, the SEC should aggressively enforce the provisions of the act.
- Congress and the FERC should impose mandatory reliability standards for operation of the electric grid, with substantial penalties for entities that violate the rules. Regional bodies, such as reliability councils, could be charged with enforcing the rules, but must come under strict FERC oversight.
- The FERC should encourage ISOs, RTOs and utilities engaged in interstate commerce to implement interconnection rules and rate structures that remove market barriers blocking the expedited deployment of cost-effective, clean distributed generation technologies.
- The federal government should move aggressively to adopt energy efficiency standards for appliances that maximize the cost-effective energy efficiency of new products in the marketplace and bolster programs – such as Energy Star – that encourage consumers to purchase energy efficient equipment.
- The federal government should adopt a renewable portfolio standard requiring that 20 percent of the nation's electricity come from new, clean renewable sources by 2020 and establish a federal systems benefit charge to encourage deployment of energy efficiency, renewable technologies, and low-income assistance programs. The structure of programs financed through the systems benefit charge should not duplicate efforts already underway in the states.

METHODOLOGY - RECENT TRENDS IN CONSUMER COSTS AND SERVICE

Data Sources

Several sources supplied the information on trends in consumer costs and service:

1) The Energy Information Administration, *Electric Power Annual 2002*, released December 2003. This report contains spreadsheet files covering retail electricity sales, revenue and customer count information from 1990 through 2002, as well as long-term historical information on rates by customer class.

2) Database files from the Energy Information Administration:
   a. Annual Electric Power Industry Database, Form EIA-861. This database contains information on generation, sales, revenue, customers, and other information by utility.
   b. Monthly Cost and Quality of Fuels for Electric Plants Database, FERC Form 423. This database describes fuel purchases by energy generators.
   c. Monthly Electric Utility Database, Form EIA-826. This database presents retail sales and revenue by month.
   d. Monthly Utility Power Plant Database, Form EIA-906. This database presents generation data, ownership information, and fuel source information by utility.

3) Federal Energy Regulatory Commission, Form 1 Filings. These filings contain financial information from major investor owned utilities, FERC licensees, and others, including detailed information on revenue and expenses.

Inflation Correction

Dollar values for all years were translated to 2003 equivalent value using the Consumer Price Index (CPI), available from the Federal Reserve Bank of Minneapolis at minneapolisfed.org.

Definition of Trends

Average trends in the retail electricity sector were defined as follows:

- Rates: Retail revenue in 2003 dollars divided by retail sales in kWh.
- Bills: Retail revenue in 2003 dollars divided by number of retail customers, divided by 12 to obtain the average monthly bill.
- Usage: Retail sales in kWh divided by the number of retail customers.

Fuel Cost Trends

Fuel cost trends were examined in two ways. First, information on the cost of fossil fuels from FERC Form 423 over time was compared to retail sales to obtain fossil fuel cost per unit of energy generated. This value was then compared to overall revenue per kWh of electricity. Second, utility expenditures on fuel, including nuclear fuel, were extracted from FERC Form 1 filings, and reported relative to energy generation figures.

Energy Sources

State dependence on different fuel sources was determined using electricity generation data aggregated by state and fuel source from the *Electric Power Annual 2002*.

Public Power Penetration

Public power penetration in each state was defined using data from the Monthly Utility Power Plant Database, Form EIA-906. Utilities classified as "private" or "power marketer" in this database were considered private utilities, while municipal, cooperative, and federal suppliers were defined as public. Public power penetration was defined as the percentage of electricity supplied by public entities in each state in 2001.

Restructuring Status

States were divided into "restructured" or "unchanged" categories based on the status of electric industry retail competition policies in place as of February 2003. (See Energy Information Administration, U.S. Department of Energy, *Status of State Restructuring Activity as of February 2003*, viewed at www.eia.doe.gov on 2 February 2004.) The restructured category, as noted in the text, covers a range of policy experiments that may not all have the same or perhaps even similar effects on each state's electricity situation. The unchanged category includes both states that considered but did not act on restructuring policies, and those states that considered no action. California was treated as a special case, since it revoked its retail competition policy after the energy crisis of 2000-2001.

Rate Equity

Rate equity issues were examined in terms of the ratio or difference between average residential electricity rates and average industrial electricity rates. Trends in long-term historical data from the *Electric Power Annual 2002* were examined, as well as recent data from the Monthly Electric Utility Database, Form EIA-826.

Factors Influencing Bills and Usage

Trends in average residential electricity bills and residential electricity usage were examined against trends in electricity rates, trends in climate (measured as "cooling degree days," a proxy for demand for air conditioning), and trends in spending on energy efficiency programs. The National Oceanic and Atmospheric Administration regularly calculates cooling degree day data by state, and the American Council for an Energy Efficient Economy tracks trends in energy efficiency spending by state.[220] The effect of energy efficiency programs was determined by examining changes in residential electricity usage by state against total efficiency spending from 1996-2000 by state, controlling for the effect of changes in climate and in residential electricity rates using a multivariate least-squares analysis. The analysis was performed using ViSta, free visual statistics software written by Forrest Young, professor emeritus at UNC Chapel Hill. Using the results of the multivariate analysis, predicted usage trends in the absence of efficiency spending were calculated, and the difference between the actual usage trend and the predicted usage trend was defined as the calculated impact of efficiency spending, presented as a fraction of 1996 residential usage.

APPENDIX: RESIDENTIAL ELECTRICITY COST DATA[221]

Table A-1. Residential Electricity Rates, 1993 and 2002

Rank (2002 Residential Rate)	State	1993 Residential Rate (Nominal Cents/kWh)	2002 Residential Rate (Nominal Cents/kWh)	Change In Residential Rate, 1993-2002 (Inflation Adjusted)
1	HI	12.3	15.6	2.3%
2	NY	13.2	13.6	-17.2%
3	CA	11.3	12.9	-8.3%
4	VT	9.8	12.8	4.3%
5	AK	11.1	12.0	-13.2%
6	ME	11.4	12.0	-15.8%
7	NH	12.3	11.8	-23.2%
8	MA	11.0	11.0	-20.0%
9	CT	11.4	11.0	-22.7%
10	NJ	11.4	10.4	-26.9%
11	RI	11.4	10.2	-28.0%
12	PA	9.6	9.7	-18.3%
13	NV	6.5	9.4	16.3%
14	DE	9.0	8.7	-22.5%
15	NM	9.2	8.5	-25.6%
16	IL	10.3	8.4	-34.5%
17	IA	8.0	8.4	-16.3%
18	OH	8.4	8.3	-20.4%
19	MI	8.2	8.3	-18.5%
20	AZ	9.6	8.3	-31.1%
21	NC	8.2	8.2	-19.5%
22	WI	7.0	8.2	-6.6%
23	FL	8.0	8.2	-18.0%
24	TX	8.0	8.1	-19.2%
25	DC	7.2	7.8	-12.5%
26	VA	7.6	7.8	-17.4%
27	SC	7.3	7.7	-15.4%
28	MD	8.2	7.7	-24.6%
29	KS	7.9	7.7	-21.7%
30	GA	7.8	7.6	-21.4%
31	MN	7.1	7.5	-15.1%
32	SD	7.0	7.4	-15.6%
33	CO	7.2	7.4	-18.2%
34	MS	7.1	7.3	-17.9%
35	AR	8.3	7.3	-29.6%
36	MT	5.8	7.2	0.6%
37	AL	6.8	7.1	-16.2%
38	OR	5.0	7.1	13.9%
39	LA	7.8	7.1	-26.5%
40	MO	7.3	7.1	-21.9%
41	WY	6.0	7.0	-6.1%
42	IN	6.7	6.9	-16.8%
43	UT	6.8	6.8	-20.4%
44	NE	6.2	6.7	-13.5%
45	OK	7.1	6.7	-24.3%
46	ID	5.0	6.6	6.0%
47	TN	5.8	6.4	-10.6%
48	ND	6.3	6.4	-18.7%
49	WA	4.6	6.3	9.9%
50	WV	6.3	6.2	-20.5%
51	KY	5.7	5.6	-20.5%

* The Energy Information Administration (EIA) reports a discrepancy between annual data and monthly estimates for utility revenue and electricity sales for Maine. This issue should be resolved with the release of the Electric Power Annual 2003 in late 2004. For further information, contact Charlene Harris-Russell at EIA at (202) 287-1747.

Table A-2. Average Monthly Residential Bills, 1993 and 2002

Rank (2002 Average Bill)	State	1993 Average Residential Monthly Bill (Nominal Dollars)	2002 Average Residential Monthly Bill (Nominal Dollars)	Change in Average Residential Bill, 1993-2002 (Inflation Corrected)
1	HI	$74.89	$100.52	7.8%
2	FL	$82.48	$97.95	-4.6%
3	TX	$85.63	$94.06	-11.8%
4	SC	$83.95	$93.88	-10.2%
5	NC	$86.20	$90.98	-15.2%
6	VA	$83.92	$90.78	-13.1%
7	AL	$74.70	$90.43	-2.8%
8	MS	$75.67	$90.34	-4.1%
9	LA	$86.00	$90.17	-15.8%
10	NV	$61.15	$88.87	16.7%
11	AZ	$87.43	$86.87	-20.2%
12	GA	$78.28	$86.05	-11.7%
13	TN	$69.58	$83.50	-3.6%
14	DE	$76.68	$83.50	-12.5%
15	MD	$81.34	$81.23	-19.8%
16	CT	$76.68	$81.15	-15.0%
17	AK	$74.87	$80.88	-13.2%
18	PA	$69.44	$78.91	-8.7%
19	AR	$77.97	$78.09	-19.6%
20	VT	$60.94	$75.35	-0.7%
21	MO	$66.18	$73.78	-10.5%
22	OH	$67.38	$72.91	-13.1%
23	NY	$68.45	$72.63	-14.8%
24	OK	$68.08	$72.44	-14.5%
25	NJ	$70.94	$72.31	-18.1%
26	IA	$64.02	$71.38	-10.4%
27	CA	$58.52	$70.88	-2.7%
28	NH	$70.45	$70.85	-19.2%
29	OR	$56.18	$70.60	0.9%
30	KS	$62.32	$70.32	-9.4%
31	IN	$60.97	$69.80	-8.0%
32	SD	$62.07	$69.52	-10.0%
33	ID	$59.92	$68.99	-7.5%
34	NE	$56.15	$67.76	-3.1%
35	WA	$55.50	$67.16	-2.8%
36	MA	$61.05	$67.14	-11.7%
37	ND	$62.54	$66.28	-14.9%
38	KY	$58.73	$65.71	-10.1%
39	WV	$58.99	$65.25	-11.2%
40	IL	$67.42	$64.82	-22.8%
41	ME*	$62.48	$62.52	-19.6%
42	WI	$48.88	$61.18	0.5%
43	DC	$50.56	$60.33	-4.2%
44	MN	$50.23	$60.26	-3.6%
45	MT	$48.72	$58.77	-3.1%
46	RI	$58.10	$57.49	-20.5%
47	WY	$47.18	$56.85	-3.2%
48	MI	$48.15	$56.60	-5.6%
49	CO	$44.08	$50.59	-7.8%
50	NM	$48.31	$49.51	-17.7%
51	UT	$44.55	$49.14	-11.4%

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Table A-3. Average Monthly Residential Usage, 1993 and 2002

Rank (2002 Avg. Res. Usage)	State	1993 Average Residential Usage (kWh)	2002 Average Residential Usage (kWh)	Change in Average Monthly Residential Usage, 1993-2002
1	TN	1,209	1,303	7.8%
2	AL	1,095	1,270	16.0%
3	LA	1,108	1,269	14.5%
4	MS	1,062	1,241	16.8%
5	SC	1,145	1,215	6.1%
6	FL	1,033	1,201	16.3%
7	TX	1,070	1,168	9.2%
8	VA	1,108	1,166	5.2%
9	KY	1,030	1,164	13.0%
10	GA	1,004	1,128	12.4%
11	NC	1,054	1,110	5.3%
12	AR	943	1,077	14.2%
13	OK	953	1,077	13.0%
14	WA	1,207	1,067	-11.6%
15	MD	990	1,054	6.4%
16	AZ	906	1,050	15.9%
17	ID	1,200	1,047	-12.7%
18	WV	936	1,047	11.8%
19	MO	911	1,045	14.7%
20	ND	991	1,037	4.7%
21	IN	914	1,010	10.5%
22	NE	898	1,007	12.0%
23	OR	1,119	992	-11.3%
24	DE	851	960	12.8%
25	NV	939	943	0.4%
26	SD	882	939	6.5%
27	KS	793	917	15.7%
28	OH	806	880	9.2%
29	IA	799	855	7.1%
30	WY	792	816	3.0%
31	MT	844	813	-3.7%
32	PA	727	812	11.7%
33	MN	709	805	13.5%
34	IL	656	773	17.8%
35	DC	704	771	9.5%
36	WI	695	748	7.6%
37	CT	673	740	10.0%
38	UT	650	723	11.2%
39	NJ	622	697	12.0%
40	CO	609	686	12.7%
41	MI	590	683	15.8%
42	AK	672	671	0.0%
43	HI	610	643	5.4%
44	MA	555	612	10.4%
45	NH	572	602	5.2%
46	VT	619	590	-4.8%
47	NM	526	582	10.6%
48	RI	510	563	10.3%
49	CA	518	549	6.1%
50	NY	520	535	2.9%
51	ME	546	522	-4.5%

Table A-4. Differential Between Residential and Industrial Electricity Rates, 1993 and 2002

Rank (Rate Differential in 2002)	State	Percent Difference Between Residential and Industrial Rates, 1993	Percent Difference Between Residential and Industrial Rates, 2002	Change in Rate Differential, 1993-2002 (Absolute Percentage Point Difference)
1	NY	97.7%	163.1%	65.4
2	IA	104.4%	105.5%	1.1
3	SC	80.7%	100.6%	19.9
4	MD	50.8%	98.6%	47.8
5	WY	70.4%	96.5%	26.1
6	MT	85.9%	95.3%	9.4
7	GA	64.4%	93.2%	28.8
8	NM	88.7%	90.0%	1.2
9	VA	80.6%	88.4%	7.8
10	AL	57.3%	86.7%	29.4
11	WI	76.6%	84.7%	8.1
12	KY	72.9%	82.9%	10.0
13	AR	70.6%	80.7%	10.1
14	MN	61.2%	78.9%	17.7
15	OH	96.8%	77.2%	-19.6
16	UT	81.4%	77.0%	-4.3
17	OK	72.7%	76.8%	4.1
18	IN	71.8%	74.9%	3.1
19	NC	66.8%	74.5%	7.7
20	NE	54.8%	73.2%	18.5
21	TX	85.2%	72.9%	-12.3
22	DE	84.5%	70.1%	-14.4
23	KS	59.1%	69.2%	10.1
24	IL	88.7%	67.6%	-21.1
25	MI	52.8%	67.5%	14.6
26	MS	55.2%	65.5%	10.3
27	WV	59.0%	63.8%	4.8
28	SD	53.1%	63.0%	9.9
29	CO	60.1%	63.0%	2.8
30	VT	31.2%	61.8%	30.5
31	LA	74.9%	60.8%	-14.1
32	ND	30.1%	60.7%	30.5
33	PA	58.2%	60.4%	2.1
34	MO	54.1%	59.7%	5.6
35	AZ	66.2%	59.0%	-7.2
36	DC	21.4%	57.8%	36.5
37	AK	36.1%	57.5%	21.4
38	FL	51.8%	56.1%	4.3
39	TN	24.6%	54.4%	29.8
40	ID	77.6%	51.8%	-25.8
41	OR	50.9%	50.6%	-0.3
42	CT	37.5%	42.7%	5.2
43	HI	37.3%	41.9%	4.6
44	WA	91.9%	37.9%	-54.0
45	NH	36.2%	33.3%	-2.9
46	NJ	41.0%	32.6%	-8.4
47	NV	29.1%	30.1%	1.0
48	RI	26.1%	27.0%	0.9
49	MA	27.0%	25.1%	-1.9
50	CA	54.1%	19.1%	-35.0
51	ME*	64.2%	6.5%	-57.7

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170. Savings data are derived from a prediction of the average monthly demand in the absence of efficiency spending, using the relationship between efficiency spending, average monthly demand, and change in residential rate described earlier in the text, compared to actual 1996 average monthly usage. Usage Data: Energy Information Administration, U.S. Department of Energy, *Monthly Electric Utility Database, Form EIA-826*, 1990-2002. Values were calculated by dividing total electric industry sales by total industry number of customers for each month; Energy Efficiency Data: Dan York and Marty Kushler, American Council for an Energy Efficient Economy, *State Scorecard on Utility and Public Benefits Energy Efficiency Programs: An Update*, December 2002.

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THE FUTURE OF DISTRIBUTED GENERATION AND DISTRIBUTION UTILITIES

[Approved by the Commission, August 2004]

Substantial efforts are being made to develop environmentally sound and cost-competitive small-scale electric generation that can be installed at or near points of use in ways that enhance the reliability of local distribution systems or avoid more expensive system additions. Examples of these "distributed resources" include fuel cells, efficient small gas turbines, and photovoltaic arrays. Energy efficiency improvements are appropriately included in this category also, although the focus here is generation technologies (the Commission addresses strategies for promoting cost-effective energy efficiency improvements extensively in other sections of its report). An attractive feature of some distributed generation is the capacity to supply combined heat and power with total system efficiencies of 90% or more.

Our view is that even the best of the distributed technologies cannot prosper absent strong partnerships with the nation's distribution utilities, but that such partnerships are unlikely to emerge without substantial changes in the incentives that utility regulators typically provide through both pricing and policy regulations. Few if any distribution companies can earn any reward for effective management of distributed generation, let alone match the earnings potential of traditional investments. From the standpoint of electric distribution companies today, distributed generation too often looks like all hassle and no gain.

Also urgently needed is a more expansive view of the role of the distribution utility itself. Particularly in states that have moved to embrace retail choice, the local utility often is characterized narrowly as a "wires company" that should not own generation and is best excluded from decisions about where to site and build new generation. But obstacles to integrating distributed generation have emerged across the spectrum of electric industry regulatory approaches.

Regardless of the model chosen, distribution companies will have capital budgets for maintaining reliable distribution systems, for which distributed generation is a potential candidate. Nothing in the Commission's recommendations, here or elsewhere, is inconsistent with regulatory decisions to withhold or offer retail choice, or with the continued integration of generation, transmission and distribution functions within regulated utilities. This paper highlights potential benefits of generation and distribution system integration that deserve more attention from all participants in the nationwide debate over the future of the electricity sector.

The Commission notes also that many of the distributed energy devices now on the market fall short of full "technology readiness." They are not available in enough size classes and configurations to meet potential market needs. Improvement is widely needed in cost, reliability, durability and emissions performance. Small-scale packaged combined-heat-and-power systems for commercial and residential applications still face

significant research and development challenges, and R&D investment is needed more broadly to achieve a full range of marketable distributed energy products and services.

The Commission views the best of the emerging distributed technologies (including energy efficiency improvements) primarily as potential grid enhancements, not grid replacements, despite a history of tension between the distributed generation and utility industries. These technologies rely on the distribution grid itself to deliver much of their value, which centers on opportunities for both distribution companies and their customers to displace more costly and cumbersome solutions to congestion and reliability problems. In certain systems and for certain technologies, distributed resources may also be candidates for providing utility systems with cost-effective generation, ancillary services and reserves/standby power.

On the other hand, poorly sited and managed units can be grid congestors and confounders, not to mention local air polluters for technologies whose performance lags that of remotely sited alternatives. And proponents of distributed generation should not overlook sobering evidence on market expectations for analogous investments. If, as other Commission reports indicate, customers routinely impose two-year payback requirements on energy efficiency improvements, distributed generation faces a daunting challenge in mass markets based on the prospect of lower electricity bills alone, although some applications also offer improvements in power quality and service reliability.

Moreover, most customers choosing small-scale generation will continue to want support services from the integrated grid, including backup, power quality and wider market access for both purchases and sales. Facility managers also need reductions in the "hassle factor" of siting, permitting and interconnecting; this is one more reminder that the needs of these managers and their distribution utility partners are quite different in important respects, and both must be accommodated in order to achieve successful outcomes. Add all the near-term uncertainties and risks associated with electricity pricing in today's unsettled markets, and one conclusion seems inescapable: without involvement by highly motivated distribution utilities, supported by their regulators, near-term prospects for distributed generation are clouded. It is time for a partnership perspective to supplant a tradition of antagonism between distribution utilities and distributed generation. Indeed, without investment and support from a grid partner, distributed technologies could be stalled indefinitely in niche applications.

One of the keys to optimizing the use of distributed technologies is to reveal to both suppliers and consumers the values associated with deployment in different locations, to empower those who are in a position to direct or facilitate deployment (directly or through the distribution company as a proxy) and to reward those decisionmakers for appropriate choices. In short, those who deliver benefits should be paid for them and those who enjoy those benefits should pay for them. And to the extent that the distribution company is in the latter category, its cost recovery must not be held hostage to subsequent customer choices of retail electricity suppliers in states that permit it; cost recovery must be secured through nonbypassable charges on the users of the

distribution system that makes the investment or through charges assigned more directly to any departing customers on whose behalf the reliability investment was made

Given the grid enhancing potential of distributed generation, it is entirely appropriate for grid owners to have a significant role in integrating the best of these technologies at strategic locations in their service territories. Through partnerships with customers choosing to utilize efficiency, load management or distributed generation at their facilities, grid owners can begin to integrate distributed resources into their system planning and operations and customers can be compensated for the value they bring to the grid. Any such compensation must, however, be tied directly to distribution system value added, which is often modest and almost always time-limited; DG installation does not imply an exemption from customers' obligation to pay their share of the distribution services that almost all will continue to require.

As the distribution grid is modernized and automated, visionaries are predicting that its typical topology will shift from a unidirectional tree to an omnidirectional web, facilitating the efficient and graceful handling of power flows both to and from distributed generators. Distributed technologies could provide voltage support while helping to defer or avoid costly system expansions, although distribution companies will need to be able to exercise significant control over unit operation in order to realize these benefits. Pioneers in demonstrating the potential for realizing these benefits include PG&E, Commonwealth Edison and the Bonneville Power Administration. Deployment opportunities abound where multiple stakeholders would benefit and no stakeholder would be harmed. These occur when distributed energy resources serve specific customer needs, such as reduced energy costs, and simultaneously serve grid needs, such as peak energy supply, as long as the distribution company has reasonable assurances that it can recover such investments through nonbypassable (or directly assignable) charges on distribution system users, regardless of the extent of retail electricity competition.

But little of this promise will be realized unless grid owners see earnings potentials that are sufficient to induce them to become successful facilitators and integrators of cost-effective distributed resources, and few if any are in that position today. Not only do distribution system managers see no reward for optimizing integration of distributed resources, but typically the societal benefits come packaged with reduced recovery of costs as a result of the displacement of retail sales by on-site generators and efficiency improvements. This is true for both public and private power systems.

Inadequate and distorted incentive\structures are constraining distribution utilities from emerging as the distributed-resource partners (and co-problem solvers) that they can and should be. The good news is that no one really intended any of this, and remedies are readily available (see the Commission's Electricity Sector paper, for example, for illustrative ways to ensure that the recovery of distribution costs is independent of retail electricity volumes over distribution wires). The Commission also encourages state regulators to work with their distribution utilities to design fair mechanisms that reward sound distribution company investment in distributed resources (either directly or through customer partnerships), by letting the utilities share in any

independently verified savings that such resources create when they displace more costly infrastructure investment. Here as elsewhere, of course, mismanagement should carry appropriate penalties.

Some worry that new distributed-resource technologies may be overwhelmed by much more numerous diesel generators with vastly inferior environmental profiles, which share advantages of scale and proximity to electricity loads.[1] These ubiquitous "back-up" units have a place, at least temporarily, but only as the grid's last line of defense against blackouts; environmental consequences of substantially increased operation are unacceptable. Older diesel generators emit up to four times as much hazardous air pollution as even the dirtiest coal-fired power plants. If used routinely to reduce system peak needs, back-up diesels would often be pumping exhaust into populated areas when air pollution levels were already high. New diesel generators, using ultra-low-sulfur fuels, NOx adsorbers, and diesel particulate filters would be much cleaner, although local emissions loading would still be higher than for central station power plants and efficiencies (about 25%) lag well behind the best combined cycle gas turbines (60%). By comparison, to cite just one example, natural gas reciprocating engines with heat recovery have emerged as a much more efficient (up to 70%) on-site power source. Accordingly, the Commission believes that national and state policy should continue to restrict back-up diesel generators to emergency service. In addition, an air quality regulation policy that provided a fast approval process for onsite-systems meeting modern technology standards for criteria pollution emissions would send a clear and favorable signal to customers and manufacturers.

Finally, the Commission believes that the use of distributed generation solely to bypass gas and electric systems is typically not desirable from a societal perspective. Planning a distribution system on a long-term basis and recognizing the value of customer-sited resources has clear social value, but many of these benefits will stay on the table if distribution utilities must operate and invest with significant risk of sales erosion from their franchises and without reasonable assurances of cost recovery. This does not mean, of course, that grid owners can ever be insensitive to cost or efficiency considerations. Poor management conceivably could counter the grid advantages that we have identified driving some customers at least to what otherwise would be inferior alternative off-grid arrangements. That prospect is itself a useful antidote for complacency among grid owners.

THE COMMISSION'S RECOMMENDATIONS

FOR STATE REGULATORS AND BOARDS OF CONSUMER-OWNED UTILITIES:

1. The Commission views the best of emerging distributed technologies primarily as grid enhancements, not grid replacements, despite a history of tension between distributed generation and utility industries. These technologies rely on the distribution grid itself to deliver much of their value, which centers of

[1] At least 120,000 Megawatts of diesel generators are in service across the United States, compared to a few hundred megawatts in all the other small-scale "distributed generation" categories.

opportunities for both distribution companies and their customers to displace more costly and cumbersome solutions to congestion and reliability problems. The use of distributed generation solely to bypass gas and electric systems is typically not desirable from a societal perspective. Planning a distribution system on a long term-basis and recognizing the value of customer-sited resources has clear social value, but many of these benefits will stay on the table it distribution utilities must operate and invest with significant risk of sale erosion from their franchises and without reasonable assurance of cost recovery.

2. The Commission encourages state and local utility regulators to work with their distribution utilities to design fair mechanisms that reward sound distribution company investment in distributed resources (either directly or through customer partnerships) by letting utilities share in any independently verified savings that such resources create when they displace more costly infrastructure investment. Of course, such investment should be encouraged only for resources that meet reasonable tests of cost-effectiveness, emissions performance and reliability; poorly sited and managed units can be grid congestors and confounders, not to mention local air polluters for technologies whose performance lags that of remotely sited alternatives.

FOR STATE AND FEDERAL AIR QUALITY REGULATORS:

1. Continue to restrict back-up diesel generators to emergency service.

2. Send a clear and favorable signal to customers and manufacturers through an air quality regulation policy that provides a fast approval process for onsite-systems meeting modern technology standards for criteria pollution emissions.

FOR RESEARCH AND DEVELOPMENT FUNDERS:

1. Many of the distributed energy devices now on the market fall short of full "technology readiness." They are not available in enough size classes and configurations to meet potential market needs. Improvement is widely needed in cost, reliability, durability and emissions performance. Small-scale packaged combined-heat-and-power systems for commercial and residential applications still face significant research and development challenges, and R&D investment is needed more broadly to achieve a full range of marketable distributed energy products and services.