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Electricity: The Road Toward Restructuring

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Electricity: The Road Toward Restructuring

SUMMARY

The Public Utility Holding Company Act of 1935 (PUHCA) and the Federal Power Act (FPA) were enacted to eliminate unfair practices and other abuses by electricity and gas holding companies by requiring federal control and regulation of interstate public utility holding companies. Prior to PUHCA, electricity holding companies were characterized as having excessive consumer rates, high debt-to-equity ratios, and unreliable service. PUHCA remained virtually unchanged for 50 years until enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA, P.L. 95-617). PURPA was, in part, intended to augment electric utility generation with more efficiently produced electricity and to provide equitable rates to electric consumers. Utilities are required to buy all power produced by qualifying facilities (QFs) at “avoided cost.” QFs are exempt from regulation under PUHCA and the FPA.

Electricity regulation was changed again in 1992 with the passage of the Energy Policy Act (EPACT, P.L. 102-486). The intent of Title 7 of EPACT is to increase competition in the electric generating sector by creating new entities, called “exempt wholesale generators” (EWGs) that can generate and sell electricity at wholesale without being regulated as utilities under PUHCA. This title also provides EWGs with a way to assure transmission of their wholesale power to its purchaser. The effect of this Act on the electric supply system is potentially more far-reaching than PURPA.

On April 24, 1996, the Federal Energy Regulatory Commission (FERC) issued Orders 888 and 889. FERC believed these rules would remedy undue discrimination in transmission services in interstate commerce and provide an orderly and fair transition to com-

petitive bulk power markets. Order 2000, issued December 20, 1999, established criteria for forming transmission organizations.

Comprehensive electricity legislation involves three issues. The first is PUHCA reform. Some electric utilities want PUHCA changed so they can more easily diversify their assets. State regulators have expressed concerns that increased diversification could lead to abuses, including cross-subsidization. Consumer groups have expressed concern that a repeal of PUHCA could exacerbate market power abuses in a monopolistic industry where true competition does not yet exist.

The second issue is PURPA’s mandatory purchase requirement provisions. Many investor-owned utilities support repeal of these provisions. They argue that their state regulators’ “misguided” implementation of PURPA has forced them to pay contractually high prices for power that they do not need. Opponents of this legislation argue that it would decrease competition and impede development of renewable energy. The third is retail wheeling. It involves allowing retail customers to choose their electric generation supplier.

Comprehensive energy legislation has passed both the House and Senate. The House passed H.R. 6 on April 11, 2003. On July 31, 2003, the Senate suspended debate on S. 14 and inserted the text of H.R. 4 from the 107th Congress as a substitute and passed H.R. 6. H.R. 6 as passed by the House and Senate includes an electricity title that would, in part, repeal the Public Utility Holding Company Act, would prospectively repeal the mandatory purchase requirement under the Public Utility Regulatory Policies Act, and would create an electric reliability organization.

MOST RECENT DEVELOPMENTS

On April 30, 2003, the Senate Energy and Natural Resources Committee voted to report comprehensive energy legislation, S. 14. On July 29, 2003, Senator Domenici proposed S.Amdt 1412, which would have been a global replacement to the electricity title of S. 14 as introduced in the Senate. This Amendment was withdrawn on July 31, 2003. The Senate substituted the language of H.R. 4 that passed the Senate in the 107th Congress and passed H.R. 6 on July 31, 2003. On April 30, 2003, the Department of Energy issued its report to Congress on Federal Energy Regulatory Commission's (FERC) proposed Standard Market Design (SMD) proposal. FERC issued a White Paper on its SMD proposal on April 28, 2003. On April 2, 2003, the House Energy and Commerce Committee reported unnumbered energy legislation by a vote of 36-17; it, unlike omnibus energy legislation debated in the 107th Congress, included provisions pertaining to restructuring of the electric utility industry. This was merged into H.R. 6, introduced on April 7, 2003, and passed on April 11, 2003 by a vote of 247-175. On March 5, 2003, and March 13, 2003, the House Energy and Commerce Committee held hearings on draft comprehensive energy legislation.

On July 31, 2002, FERC issued a Notice of Proposed Rulemaking (NOPR) on Standard Market Design (Docket No. RM 01-12-000) [<http://www.ferc.gov/Electric/RTO/Mrkt-Strct-comments/nopr/Web-NOPR.pdf>]. The proposed rulemaking would create a new tariff under which transmission owners would be required to turn over operation of their transmission systems to unaffiliated independent transmission providers. (See also the CRS Electronic Briefing Book on electricity restructuring at [<http://www.congress.gov/brbk/html/ebele1.shtml>].)

BACKGROUND AND ANALYSIS

Historically, electricity service has been defined as a natural monopoly, meaning that the industry has (1) an inherent tendency toward declining long-term costs, (2) high threshold investment, and (3) technological conditions that limit the number of potential entrants. In addition, many regulators have considered unified control of generation, transmission, and distribution as the most efficient means of providing service. As a result, most people (about 75%) are currently served by a vertically integrated, investor-owned utility.

As the electric utility industry has evolved, however, there has been a growing belief that the historic classification of electric utilities as natural monopolies has been overtaken by events and that market forces can and should replace some of the traditional economic regulatory structure. For example, the existence of utilities that do not own all of their generating facilities, primarily cooperatives and publicly owned utilities, has provided evidence that vertical integration has not been necessary for providing efficient electric service. (For additional information on Public Power, see also the CRS Electronic Briefing Book on electricity restructuring at [<http://www.congress.gov/brbk/html/ebele12.html>].) Moreover, recent changes in electric utility regulation and improved technologies have allowed additional generating capacity to be provided by independent firms rather than utilities.

The Public Utility Holding Company Act (PUHCA) and the Federal Power Act (FPA) of 1935 (Title I and Title II of the Public Utility Act) established a regime of regulating electric utilities that gave specific and separate powers to the states and the federal government (see CRS Report RS20015). A regulatory bargain was made between the government and utilities. In exchange for an exclusive franchise service territory, utilities must provide electricity to all users at reasonable, regulated rates. State regulatory commissions address intrastate utility activities, including wholesale and retail rate-making. State authority currently tends to be as broad and as varied as the states are diverse. At the least, a state public utility commission will have authority over retail rates, and often over investment and debt. At the other end of the spectrum, the state regulatory body will oversee many facets of utility operation. Despite this diversity, the essential mission of the state regulator in states that have not restructured is the establishment of retail electric prices. This is accomplished through an adversarial hearing process. The central issues in such cases are the total amount of money the utility will be permitted to collect and how the burden of the revenue requirement will be distributed among the various customer classes (residential, commercial, and industrial).

Under the FPA, federal economic regulation addresses wholesale transactions and rates for electric power flowing in interstate commerce. Federal regulation followed state regulation and is premised on the need to fill the regulatory vacuum resulting from the constitutional inability of states to regulate interstate commerce. In this bifurcation of regulatory jurisdiction, federal regulation is limited and conceived to supplement state regulation. The Federal Energy Regulatory Commission (FERC) has the principal functions at the federal level for the economic regulation of the electricity utility industry, including financial transactions, wholesale rate regulation, transactions involving transmission of unbundled retail electricity, interconnection and wheeling of wholesale electricity, and ensuring adequate and reliable service. In addition, to prevent a recurrence of the abusive practices of the 1920s (e.g., cross-subsidization, self-dealing, pyramiding, etc.), the Securities and Exchange Commission (SEC) regulates utilities' corporate structure and business ventures under PUHCA.

The electric utility industry has been in the process of transformation. During the past two decades, there has been a major change in direction concerning generation. First, improved technologies have reduced the cost of generating electricity as well as the size of generating facilities. Prior preference for large-scale — often nuclear or coal-fired — powerplants has been supplanted by a preference for small-scale production facilities that can be brought online more quickly and cheaply, with fewer regulatory impediments. Second, this has lowered the entry barrier to electricity generation and permitted non-utility entities to build profitable facilities. Recent changes in electric utility regulation and improved technologies have allowed additional generating capacity to be provided by independent firms rather than utilities.

The oil embargoes of the 1970s created concerns about the security of the nation's electricity supply and led to enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA, P.L. 95-617). For the first time, utilities were required to purchase power from outside sources. The purchase price was set at the utilities' "avoided cost," the cost they would have incurred to generate the additional power themselves, as determined by utility regulators. PURPA was established in part to augment electric utility generation with more efficiently produced electricity and to provide equitable rates to electric consumers.

In addition to PURPA, the Fuel Use Act of 1978 (FUA, P.L. 95-620) helped qualifying facilities (QFs) become established. Under FUA, utilities were not permitted to use natural gas to fuel new generating technology. QFs, which are by definition not utilities, were able to take advantage of abundant natural gas as well as new generating technology, such as combined-cycle plants that use hot gases from combustion turbines to generate additional power. These technologies lowered the financial threshold for entrance into the electricity generation business as well as shortened the lead time for constructing new plants. FUA was repealed in 1987, but by this time QFs and small power producers had gained a portion of the total electricity supply.

This influx of QF power challenged the cost-based rates that previously guided wholesale transactions. Before implementation of PURPA, FERC approved wholesale interstate electricity transactions based on the seller's costs to generate and transmit the power. As more non-utility generators entered the market in the 1980s, these cost-based rates were challenged. Since non-utility generators typically do not have enough market power to influence the rates they charge, FERC began approving certain wholesale transactions whose rates were a result of a competitive bidding process. These rates are called market-based rates.

This first incremental change to traditional electricity regulation started a movement towards a market-oriented approach to electricity supply. Following the enactment of PURPA, two basic issues stimulated calls for further reform: whether to encourage nonutility generation and whether to permit utilities to diversify into non-regulated activities.

The Energy Policy Act of 1992 (EPACT, P.L. 102-486) removed several regulatory barriers to entry into electricity generation to increase competition of electricity supply. Specifically, EPACT provides for the creation of entities, called "exempt wholesale generators" (EWGs), that can generate and sell electricity at wholesale without being regulated as utilities under PUHCA. Under EPACT, EWGs are also provided with a way to assure transmission of their wholesale power to a wholesale purchaser. However, EPACT does not permit FERC to mandate that utilities transmit EWG power to retail consumers (commonly called "retail wheeling" or "retail competition"), an activity that remains under the jurisdiction of state public utility commissions. PURPA began to shift more regulatory responsibilities to the federal government, and EPACT continued that shift away from the states by creating new options for utilities and regulators to meet electricity demand. (For additional background on EPACT and PURPA, see CRS Report 98-419.)

The question now is whether further federal legislative action is desirable to encourage competition in the electric utility sector and if so at what speed this change would occur. Currently, 24 states and the District of Columbia have either enacted legislation or issued regulatory orders to implement retail access. Six states, Arkansas, Montana, Nevada, New Mexico, Oklahoma and West Virginia, have delayed implementation of retail access. The map later in this issue brief shows the current status of each state's restructuring efforts. Issues discussed in this brief include repeal or alteration of both PUHCA and PURPA; transmission access and FERC's Orders 888, 889 and 2000; environmental impact; and issues related to standard market design.

Transmission Issues

In addition to creating a new type of wholesale electricity generator, Exempt Wholesale Generators (EWGs), the Energy Policy Act (EPACT) provides EWGs with a system to assure transmission of their wholesale power to its purchaser. However, EPACT did not solve all of the issues relating to transmission access. As a result of EPACT, on April 24, 1996, FERC issued Orders 888 and 889. In issuing its final rules, FERC concluded that these Orders will "remedy undue discrimination in transmission services in interstate commerce and provide an orderly and fair transition to competitive bulk power markets."

Under Order 888, the Open Access Rule, transmission line owners are required to offer both point-to-point and network transmission services under comparable terms and conditions that they provide for themselves. The Rule provides a single tariff providing minimum conditions for both network and point-to-point services and the non-price terms and conditions for providing these services and ancillary services. This Rule also allows for full recovery of so-called stranded costs with those costs being paid by wholesale customers wishing to leave their current supply arrangements. The rule encourages but does not require creation of Independent System Operators (ISOs) to coordinate intercompany transmission of electricity.

Order 889, the Open Access Same-time Information System (OASIS) rule, establishes standards of conduct to ensure a level playing field. The Rule requires utilities to separate their wholesale power marketing and transmission operation functions, but does not require corporate unbundling or divestiture of assets. Utilities are still allowed to own transmission, distribution, and generation facilities but must maintain separate books and records.

On December 20, 1999, FERC issued Order 2000 that described the minimum characteristics and functions of regional transmission organizations (RTOs) [<http://www.ferc.gov/news/rules/pages/RM99-2A.pdf>]. The required characteristics of an RTO are: the RTO must be independent from market participants; it must serve a region of sufficient size to permit the RTO to perform effectively; an RTO will be responsible for operational control; and it will be responsible for maintaining the short-term reliability of the grid. The required functions of an RTO outlined in Order 2000 are: it must administer its own transmission tariff; it must ensure the development and operation of market mechanisms to manage congestion; it must address parallel flow issues both within and outside its region; it will serve as supplier of last resort for all ancillary services; it must administer an Open Access Same-time Information System; it must monitor markets to identify design flaws and market power and propose appropriate remedial actions; it must provide for interregional coordination; and an RTO must plan necessary transmission additions and upgrades.

Order 2000 does not require RTO participation, set out RTO boundaries, or mandate the acceptable RTO structure. RTOs will be able to file with FERC as an independent system operator (ISO), a for-profit transmission company (transco), or another type of entity that has not yet been proposed. Although RTO participation is voluntary under Order 2000, FERC built in guidelines and safeguards to ensure independent operation of the transmission grid. RTOs are required to conduct independent audits to ensure that owners do not exert undue influence over RTO operation.

FERC Order 2000 required the existing ISOs to submit to FERC by January 1, 2001, a plan to describe whether their transmission organization meets the criteria established in the RTO rulemaking. Electric utilities not currently members of an ISO had to file plans with FERC by October 1, 2000. The Order does not mandate RTO formation, but if an individual utility opts not to join an RTO, the utility is required to prove why it would be harmed by joining such an entity.

On July 12, 2001, FERC issued several orders requiring utilities to enter into talks to form four Regional Transmission Organizations. Even though FERC Order 2000 did not set out RTO boundaries, in effect the July 12, 2001, order does. On September 17, 2001, FERC's Administrative Law Judge Mediator H. Peter Young filed his report (Docket No. RT01-99-000) [<http://www.ferc.gov/Electric/RTO/rto/issuance/RT01-991-9-17.pdf>] that presented a blueprint for creating a single RTO in the Northeast.

FERC has granted RTO status to three entities. On December 20, 2001, FERC granted RTO status [Docket No. RT01-87-000] to the Midwest Independent Transmission System Operator (MISO). On September 18, 2002, FERC approved the RTO West proposal [<http://ferc.gov/Electric/rto/RT01-35-005-09-18-02.pdf>]. RTO West includes all, or part of, Washington, Idaho, Montana, Oregon, Nevada, Wyoming, Utah and a small part of northern California near the Oregon border. FERC granted PJM RTO status on December 19, 2002 [<http://ferc.gov/Electric/rto/pjm-12-19-02.pdf>]. PJM manages the grid in parts of Ohio, West Virginia, Pennsylvania, New Jersey, Delaware, Maryland, Virginia and the District of Columbia. Other RTOs have received conditional approval from FERC. Most recently, FERC conditionally approved SeTrans RTO and WestConnect RTO on October, 9, 2002 [Docket Nos. EL02,101-000, RT02-1-000 and EL02-9-000]. SeTrans includes utilities in Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, South Carolina and Texas. WestConnect RTO will operate in parts of Arizona, Colorado, New Mexico and Utah.

In the past, utilities and some state utility commissioners have argued against large RTOs, stating that currently the expertise is not available to integrate a large geographic region with multiple control centers and power pools. On February 26, 2002, FERC released a report [http://www.ferc.gov/electric/rto/mrkt-strt-comments/rtostudy_final_0226.pdf] that assessed the potential economic costs and benefits of RTOs. The study concluded the annual savings from RTO formation could range from \$1- \$10 billion. However, the study did not find significant differences in savings between larger and smaller RTOs. Those in favor of large RTOs argue that the most efficient operations of the transmission system would take place with large RTOs. On November 7, 2001, FERC issued an order (Docket No. RM01-12-000) [<http://www.ferc.gov/Electric/RTO/rto/issuance/RM01-12.pdf>] that stated FERC's goals and process for creating Regional Transmission Organizations.

On May 14, 1999, the U.S. Court of Appeals for the Eighth Circuit ruled in a case between FERC and Northern States Power. The court held that the Commission overstepped its authority when it ordered Northern States Power Company to treat wholesale customers the same as it treats native load customers in making electricity curtailment decisions. This decision raised federal-state jurisdictional questions, particularly a state's right to guarantee system reliability.

On October 3, 2001, the U.S. Supreme Court heard arguments in a case (New York et al. v. Federal Energy Regulatory Commission) that challenges FERC's authority under

Order 888 to regulate transmission for retail sales if a utility unbundles transmission from other retail charges. In states that have opened their generation market to competition, unbundling occurs when customers are charged separately for generation, transmission, and distribution. Nine states, led by New York, filed suit, arguing that the Federal Power Act gives FERC jurisdiction over wholesale sales and interstate transmission and leaves all retail issues up to the state utility commissions. Enron argued that FERC clearly has jurisdiction over all transmission and FERC is obligated to prevent transmission owners from discriminating against those wishing to use the transmission lines. On March 4, 2002, the U.S. Supreme Court ruled in favor of FERC and held that FERC has jurisdiction over transmission including unbundled retail transactions. The ruling is available at: [<http://a257.g.akamaitech.net/7/257/2422/04mar20021030/www.supremecourtus.gov/opinions/01pdf/00-568.pdf>]. H.R. 6, as passed by the House, would allow utilities that are not members of regional transmission organizations to give preferential treatment to native load customers.

Many groups assert that difficulty siting transmission lines is one reason that in the past decade, there has been less transmission capacity added than generation capacity. H.R. 6, as passed by the House, would provide for incentive-based transmission rates. In addition, H.R. 6, as passed by the House, and H.R. 1370 would allow transmission owners in certain instances to exercise the right of eminent domain to site new transmission lines

S. 14, S. 475, H.R. 6, as passed by the House and Senate, and H.R. 1370 would provide for an Electric Reliability Organization to prescribe and enforce mandatory reliability standards.

Standard Market Design. On July 31, 2002, FERC issued a Notice of Proposed Rulemaking (NOPR) on standard market design (SMD) (Docket No. RM01-12-000)[<http://www.ferc.gov/Electric/RTO/Mrkt-Strct-comments/nopr/Web-NOPR.pdf>]. FERC's stated goal of SMD requirements in conjunction with a standardized transmission service is to create "seamless" wholesale power markets that allow sellers to transact easily across transmission grid boundaries. The proposed rulemaking would create a new tariff under which each transmission owner would be required to turn over operation of its transmission system to an unaffiliated independent transmission provider (ITP). The ITP, which could be an RTO, would provide service to all customers and run energy markets. Under the NOPR, congestion would be managed with locational marginal pricing. The NOPR comment period originally was 75 days (November 15, 2002), but the comment period was extended to January 10, 2003, for the following issues: 1) market design for the Western Interconnection; 2) transmission plan in pricing, including participant funding; 3) Regional State Advisory Committees and state participation; 4) resource adequacy; and 5) Congestion Revenue Rights and transition issues.

Under the NOPR, FERC asserts jurisdiction over all power transmission, including service to bundled retail customers. Commissioners from 15 states (Alabama, Arkansas, California, Georgia, Idaho, Kentucky, Louisiana, Mississippi, New Hampshire, North Carolina, South Carolina, Oregon, South Dakota, Washington, and Wyoming) are planning to fight FERC's proposed changes on the grounds that FERC usurps state authority. On August 15, 2002, state regulators from 22 states and the District of Columbia (Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Montana, North Dakota, Ohio, Oklahoma, Texas, Wisconsin, Delaware, the District of Columbia, New Jersey, New York,

Pennsylvania, West Virginia, Connecticut, Maine, Massachusetts, New Hampshire, and Rhode Island) released a statement that “voiced support for FERC’s ongoing effort to remedy undue discrimination in the use of the nation’s interstate high voltage transmission system in order to create a truly competitive bulk power market.” In general, the industry has been in favor of FERC’s SMD proposal, but some industry groups have voiced concerns about the implementation of SMD.

On April 28, 2003, FERC staff issued *Wholesale Power Market Platform*, a White Paper that intended to clarify FERC’s SMD proposal [http://ferc.gov/Electric/RTO/Mrkt-Strct-comments/White_paper.pdf]. The White Paper responds to approximately 1000 sets of formal comments submitted FERC. In the White Paper, FERC states its intention to eliminate a proposed requirement that utilities join an Independent Transmission Provider. Instead, the final rule will require utilities to join an RTO or ISO. In the NOPR, FERC proposed to assert jurisdiction over the transmission component of bundled retail service. The White Paper reverses this position and states that the final rule will not assert new FERC jurisdiction over bundled retail sales.

Some state officials have expressed concern that the proposed rule would infringe on state authority. FERC responded to this in the White Paper by clarifying that the Final Rule will not include a requirement for a minimum level of resource adequacy. In addition, the final rule will eliminate the NOPR’s requirement that Firm Transmission Rights be auctioned. The White Paper noted that each RTO or ISO will need to have a cost recovery policy outlined in its tariff, but each region may differ on how participant funding will be used. In addition, FERC stated that the final rule will allow for phased-implementation to address regional differences.

The report language that accompanied the Omnibus Appropriations Bill for FY2003 (H.Rept. 108-10) asked the Department of Energy to analyze the SMD NOPR’s impact on wholesale electricity prices, and the safety and reliability of generation transmission facilities. The Department of Energy (DOE) issued its report to Congress on April 30, 2003 but did not include changes from FERC’s White Paper in its analysis [<http://energy.gov/HQDocs/DOES0138SMDfinal.pdf>]. DOE, in part, quantitatively analyzed the wholesale and retail price impacts of SMD using two economic models: General Electric’s Multi-Area Production Simulation (MAPS) and DOE’s Policy Office Electricity Modeling System (POEMS).

Some of the assumptions that DOE uses are an annual increase in electricity demand of approximately 1.8% per year from 2005 to 2020; most regions are assumed to have reserve margins of 15%; current environmental laws and regulations are assumed to apply; generator efficiency for fossil steam plants is assumed to be 2 to 4% higher in new RTO regions with SMD; in the non-SMD case, the models were not able to take into account freezes on retail rates in states that are transitioning to competitive markets; in the non-SMD case, no increase in transmission capacity is assumed. Under the SMD case, a 5% increase in transmission capability by 2005 is assumed by DOE due to improved operational efficiency at regional seams. In addition, DOE assumes that adopting the SMD would result in some savings that are difficult to quantify but would be a result of the consolidation of control areas from the current level of 150, the possible avoidance of capital cost and software expenditures that would have been needed at existing control centers, improved regional planning, and consistency of market design. DOE assigns a 10% savings due to

these efficiency improvements. DOE believes that the assumptions used in the models are conservative and result in an underestimation of the net economic benefits of the SMD.

DOE calculates the median cost of FERC's SMD rule to be about \$760 million per year, or about 21 cents per megawatt-hour. The model's range for uncertainties is estimated to be about \$100 million. The cost varies significantly by region ranging from 47 cents per megawatt-hour for GridFlorida to 12 cents per megawatt-hour for PJM. Regions with existing RTOs have zero additional costs. Under the SMD case, the effects of SMD at retail rates are influenced to a significant extent by whether the states in question have cost-of-service regulation or competitive retail choice. DOE found that for some importing regions with cost-based rates, the net result could be increased costs associated with wholesale purchases, which would be passed through to retail customers. For some exporting regions with cost-based rates, additional utility revenues from exports are expected to lead to lower retail prices for the region under the SMD case. In contrast, in regions in which most states have adopted retail choice, increased electricity exports are expected to lead to higher market-clearing prices in the short-term markets and somewhat higher consumer prices. However in areas such as California that are projected to see increased imports, lower wholesale prices and lower prices for consumers are expected. DOE found that the magnitude of the projected changes, both positive and negative, decrease through 2020. Overall, DOE projects the net benefit for all consumers is about \$1 billion per year over the first 6 years, after factoring in the estimated \$760 million per year and RTO costs. Over the long-term (2016-2020), the net benefit is expected to be about \$700 billion per year. However, the projected change in retail prices varies by region. The mid-Atlantic region is expected to see a 4% decrease in retail prices, but Illinois, Wisconsin, and Arizona are expected to have a 3 % increase in retail prices as a result of SMD.

S. 14, as introduced, would have remanded the NOPR to FERC for reconsideration. FERC would not be able to issue an SMD rulemaking before July 1, 2005. H.R. 6, as passed by the Senate, did not include this provision. S. 954 would require Congress to approve of any SMD rulemaking. For additional information on Standard Market Design, see CRS Report RS21407.

Market Transparency. Some have argued that the wholesale power markets cannot be competitive without additional market transparency for both generation and transmission. S. 14, S. 475, H.R. 6, as passed by the House and Senate, and H.R. 1254 would require FERC to issue rules to establish an electronic information system to provide the public, FERC, state commissions, buyers and sellers of wholesale electric energy, and users of transmission services, with information on the availability and price of wholesale electric energy and transmission services. H.R. 1272 would require participants in the electric markets to provide FERC with records of all transmission and sale transactions.

Environmental Questions and Proposed Responses

The electric industry is a major source of air pollution as well as of greenhouse gases. Therefore, changes underway in the industry are being closely examined for their potential environmental effects. At issue is whether proposed legislation to restructure the industry should include environmental protections.

The Clean Air Act regulates emissions of conventional air pollutants from electric utilities. While it has historically focused on new construction in applying its most stringent standards, several current and prospective regulations would significantly increase controls on existing coal-fired facilities. These controls may diminish the attractiveness of renovating older, more polluting facilities, but the effectiveness of the regulations in coping with a restructured industry remains to be seen. In addition, greenhouse gas emissions are not regulated, so any increases in carbon dioxide would not be controlled under existing authorities.

Thus the environmental effects of restructuring depend on whether, for conventional air pollutants, the existing regulatory regimen will work effectively as the industry structure changes. For some pollutants, such as sulfur oxides, a nationwide emissions "cap" seems secure; but for others, particularly nitrogen oxides, the state-led implementation process may have difficulty coping with regional disparities in emissions. For carbon dioxide, any controls would be contingent on future ratification of the Kyoto Agreement to curtail emissions and on domestic legislation.

Several bills that deal with these environmental issues have been introduced in the 108th Congress. For a summary of these bills and legislative action, see CRS Report RL31779.

Calls for Additional Electric Regulatory Reform

PUHCA

One argument for additional PUHCA reform has been made by electric utilities that want to further diversify their assets. Currently under PUHCA, a holding company can acquire securities or utility assets only if the SEC finds that such a purchase will improve the economic efficiency and service of an integrated public utility system. It has been argued that reform to allow diversification would improve the risk profile of electric utilities in much the same way as in other businesses: The risk of any one investment is diluted by the risk associated with all investments. Utilities have also argued that diversification would lead to better use of under-utilized resources (due to the seasonal nature of electric demand). Utility holding companies that have been exempt from SEC regulation argue that PUHCA discourages diversification because the SEC could repeal exempt status if exemption would be "detrimental to the public interest."

For a number of years there has been significant bipartisan congressional support for repealing much of PUHCA. Since the 1980s, the Securities and Exchange Commission has testified before Congress that many provisions of PUHCA are no longer relevant and other provisions are redundant with state and other federal regulations [<http://www.sec.gov/news/testimony/021302tsich.htm>]. However, as a result of Enron's collapse, some in Congress have taken a somewhat different view toward significantly amending or repealing PUHCA [http://www.house.gov/commerce_democrats/press/107ltr129.htm]. Even though Enron had claimed exemption from PUHCA, on February 6, 2003, Securities and Exchange Commission Chief Administrative Law Judge Brenda P. Murray denied Enron's PUHCA exemption applications of February 28, 2002, amended on May 31, 2002, and April 12, 2000

(Initial Decision Release No. 222 (File No. 3-10909) can be found at: [<http://www.sec.gov/litigation/aljdec/id222bpm.htm>]). In the case of Enron, PUHCA, and many other laws, did not deter or prevent fraudulent filing of information with the SEC. (For additional information on Enron, see also the CRS Electronic Briefing Book on electricity restructuring at [<http://www.congress.gov/brbk/html/ebele1.shtml>].)

State regulators have expressed concerns that increased diversification could lead to abuses, including cross-subsidization: a regulated company subsidizing an unregulated affiliate. Cross-subsidization was a major argument against the creation of EWGs and has reemerged as an argument against further PUHCA reform. In the case of electric and gas companies, non-utility ventures that are undertaken as a result of diversification may benefit from the regulated utilities' allowed rate of return. Moneymaking non-utility enterprises would contribute to the overall financial health of a holding company. However, unsuccessful ventures could harm the entire holding company, including utility subsidiaries. In this situation, utilities would not be penalized for failure in terms of reduced access to new capital, because they could increase retail rates.

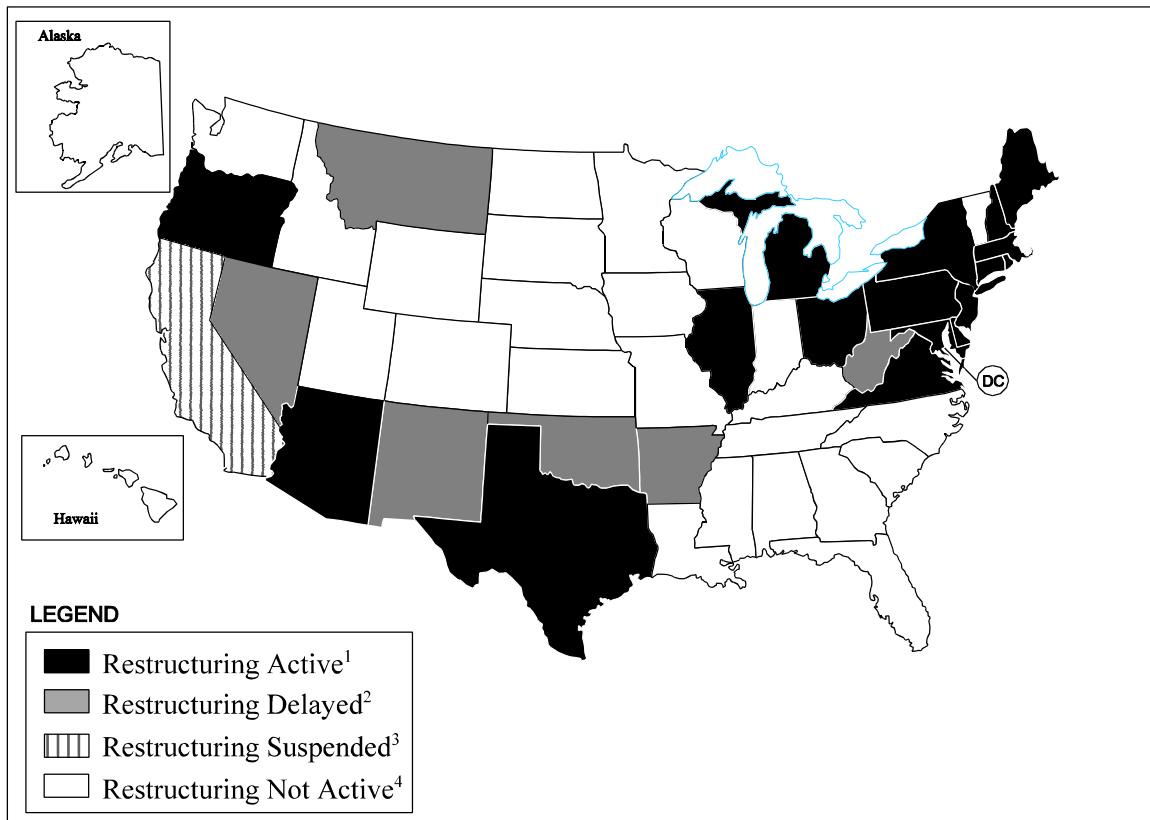
Several consumer and environmental public interest groups, as well as state legislators, have expressed concerns about PUHCA repeal. PUHCA repeal, such groups argue, could only exacerbate market power abuses in what they see as a monopolistic industry where true competition does not yet exist. The National Rural Electric Cooperative Association also opposes stand-alone changes to PUHCA. (For further information on PUHCA, see CRS Report RS20015.)

S. 14, S. 475 and H.R. 6, as passed by the House, would repeal PUHCA and give FERC and state commissions access to books and records.

PURPA

S. 475 and S. 688 and H.R. 1341 would prospectively repeal §210 of PURPA, the mandatory purchase requirement provisions. S 14 and H.R. 6, as passed by the House and Senate, would also prospectively repeal §210 of PURPA but only when certain competitive market conditions are met. Proponents of PURPA repeal — primarily investor-owned utilities (IOUs) located in the Northeast and in California — argue that their state regulators' "misguided" implementation of PURPA in the early 1980s has forced them to pay contractually high prices for power they do not need. They argue that, given the current environment for cost-conscious competition, PURPA is outdated. The PURPA Reform Group, which promotes IOU interests, strongly supports such bills by contending that the current law's mandatory purchase obligation was anti-competitive and anti-consumer.

Opponents of these types of bills (IPPs, industrial power customers, most segments of the natural gas industry, the renewable energy industry, and environmental groups) have many reasons to support PURPA as it stands. Mainly, their argument is that PURPA introduced competition in the electric generating sector and, at the same time, helped promote wider use of cleaner, alternative fuels to generate electricity. Since the electric generating sector is not yet fully competitive, they argue, repeal of PURPA would decrease competition and impede the development of the renewable energy industry. Additionally,

Figure 1. Status of State Electric Utility Restructuring as of October 1, 2002

Adapted by CRS from Magellan Geographix. Used with permission.

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

Source: Energy Information Administration

[http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html]

opponents of PURPA repeal argue that it would result in less competition and greater utility monopoly control over the electric industry. The Electric Power Supply Association (EPSA) also wants comprehensive legislation to look at all aspects of electricity regulation. State regulators are concerned that this legislation would prevent them from deciding matters currently under their jurisdiction. The National Association of Regulatory Utility Commissioners has opposed legislation that would allow FERC to protect utilities from costs associated with PURPA contracts.

Retail Wheeling

Some analysts believe the next logical step in restructuring is retail competition. Encouraging competition in the electric supply system is already occurring as some states

allow generating utilities to arrange for transmission of electricity from its sources to a retail consumer whether or not this transaction occurs within their service territory. EPACT expressly prevents FERC from ordering retail competition (retail wheeling). Such transactions remain under state regulatory control; FERC's open access Orders address wheeling at the wholesale level only. However, it is clear that FERC hopes that its Orders will pave the way for states to permit retail customers to shop for their electricity needs anywhere they want, rather than being limited to buying electricity from their local utility.

Indeed, who should determine the pace and boundaries of retail wheeling efforts is a fundamental issue. Electric service is a vital component of a modern economy; thus, national interests are at stake in what direction the restructuring debate takes. Concerns about economic efficiency and the treatment of various participants (such as electric utilities) may suggest to some that the federal government provide direction to current state initiatives. In contrast, others argue that the states, which have traditionally had responsibility over retail electricity issues, have the expertise and experience necessary to handle the situation (more so than the federal government) and that the national interest in electricity supply is neither threatened by state initiatives nor a justification for federal preemption of states' rights. Currently, retail choice is under state jurisdiction, and 24 states and the District of Columbia have moved toward retail competition. Congress may consider whether expanding federal jurisdiction is warranted in the continuing evolution of the electric utility industry or whether a "wait and see" attitude toward state proceedings is more appropriate at this point. No bills addressing retail wheeling have been introduced in the 108th Congress.

History of California Electricity Crisis

California's experience in 2001 with a marked decrease in reliability of electricity supply as well as retail price spikes in the San Diego region has now been replaced with excess generating supply. The original situation was partly due to California's restructured electric markets and market manipulation, increased demand, generating plant outages and lack of new transmission and generating capacity. Currently, California has more long-term contracts than it needs to meet demand, and the contracts are locked-in at prices higher than the current market price of electricity. On March 26, 2003, FERC ordered an estimated \$3.3 billion in refunds to California for unjust and unreasonable rates that were charged between October 2000 and June 2001. (*See also the CRS Electronic Briefing Book on electricity restructuring at [http://www.congress.gov/brbk/html/ebe1e1.shtml].*)

Price Caps

Several bills were introduced in the 107th Congress that would have imposed wholesale price caps in California, a return to cost-of-service wholesale rate regulation or demand-based time-of-use rates. Cost-of-service rate regulation allows for recovery of generating costs plus a reasonable rate of return. Those in favor of price caps argue that competition does not yet exist in California's wholesale generating sector and wholesale prices do not reflect what would be expected in a functional market. In addition, it is argued that generators in California were exerting market power by intentionally withholding generating capacity to increase wholesale prices. Those opposed to price caps, including President Bush, argue that price caps discourage investment in new generating facilities and would

further distort the wholesale electricity market. For further discussion on price controls, see [<http://www.congress.gov/brbk/html/ebele23.html>].

On June 18, 2001, FERC extended its price mitigation Order of April 26, 2001, to include the 11 states in the Western System Coordinating Council (WSCC). FERC's Order [<http://www.ferc.gov/electric/bulkpower/el00-95-031-6-19.PDF>] provided for a two-tiered rate structure for the day-ahead and hour-ahead spot market. If California entered a Stage 1 electricity emergency (reserves fall below 7%), the spot market clearing price for California was based on the bid from the least efficient gas-fired plant located in California that was needed by the Independent System Operator (ISO). All sellers into the California ISO spot market received the spot market clearing price. For sellers outside of California, California's spot market clearing price was the maximum price, but sellers could bid and receive less than the spot market clearing price. Generators, but not power marketers, had the ability to justify their cost if it exceeded the established spot market clearing price. When operating reserves were above 7% in California, the maximum price that could be charged was 85% of the spot market clearing price set during the most recent Stage 1 emergency. These price caps were expired in September 2002. For a chronological listing of important events in the California electricity situation, see the Chronology in the CRS Electronic Briefing Book at [<http://www.congress.gov/brbk/html/ebele18.html>].

On July 17, 2002, FERC issued a new price mitigation order for the Western markets (Docket Number ER02-1656-000 et al.). Unlike the order described above, the new price mitigation plan has no end date, and went into effect October 1, 2002. Unlike the soft cap of \$91.87 per megawatt hour that has been in effect since June 2001, the plan establishes a hard price cap of \$250 per megawatt hour for spot market sales. In addition, the plan creates an automated mitigation procedure (AMP) that will screen all bids that exceed \$91.87 per megawatt hour for possible market abuses.

Rate Refunds

Under current law, FERC may order refunds for rates found to be unjust, unreasonable, unduly discriminatory or preferential. However, the effective date of such refunds begins a minimum of 60 days after the original complaint is filed with FERC (16 U.S.C. 8 2 4e(b)). H.R. 964 and H.R. 1272 would allow refunds to be retroactive to the date a rate complaint is filed with FERC. S. 723 would require FERC to order refunds of at least \$8.9 billion for unjust and unreasonable rates charged between June 1, 2000 and June 19, 2001.

LEGISLATION

H.R. 6 (Tauzin)

Title VI would, in part, provide for incentive-based transmission rates, allow transmission owners in certain instances to exercise the right of eminent domain to site new transmission lines, allow transmission owners that do not belong to a regional transmission organization to preferentially serve native load customers, create an Electric Reliability Organization, and give new, but limited, authority to the Federal Energy Regulatory Commission (FERC) over municipal and cooperative transmission systems. It would repeal

PUHCA and give FERC and state public utility commissions access to books and records, prospectively repeal the mandatory purchase requirement of the Public Utility Regulatory Policies Act of 1978 if a competitive wholesale market exists, and require utilities to provide real-time rates and time-of-use metering. It would establish market transparency rules, explicitly prohibit round-trip trading, and significantly increase criminal penalties under the Federal Power Act. Introduced April 7, 2003; referred to multiple committees. Passed House April 11, 2003; passed Senate July 31, 2003.

H.R. 964 (Ose)

Would make electric rate refunds retroactive to the date a complaint is filed with FERC. Introduced February 27, 2003; referred to Committee on Energy and Commerce .

H.R. 1254 (Walden)

Would require FERC to issue rules to establish an electronic information system to provide the public, FERC, state commissions, buyers and sellers of wholesale electric energy, and users of transmission services, with information on the availability and price of wholesale electric energy and transmission services. Would prohibit round-trip electricity trading. Would increase criminal penalties under the Federal Power Act. Introduced March 12, 2003; referred to Committee on Energy Commerce.

H.R. 1272 (Dingell)

Would prohibit fraudulent, manipulative, or deceptive acts in electric and natural gas markets. Provides for audit trails. Increases criminal and civil penalties under the Federal Power Act. Would make electric rate refunds retroactive to the date a complaint is filed with FERC. Would require FERC to review all market-based rates on annual basis. Introduced March 13, 2003; referred to Committee on Energy and Commerce.

H.R. 1338 (Shadegg)

Would amend the Federal Power Act to provide for federal and state coordination of permitting for electric transmission facilities. Introduced March 18, 2003; referred to Committee on Energy and Commerce.

H.R. 1341 (Stearns)

Would prospectively repeal §210 of PURPA. Introduced March 18, 2003; referred to Committee on Energy and Commerce.

H.R. 1370 (Wynn)

Would establish an Electric Reliability Organization. In some instances, would allow transmission companies to exercise the right of eminent domain to acquire transmission rights-of-way. Would exempt regional transmission organizations from PUHCA. Introduced March 19, 2003; referred to Committees on Energy, and Commerce and Ways and Means.

H.R. 1627 (Pickering)

Would repeal PUHCA and would give FERC and state utility commissions access to books and records. Introduced April 3, 2003; referred to Committee on Energy and Commerce.

S. 14 (Domenici)

Comprehensive energy policy legislation. In part, would create an Electric Reliability Organization. Would remand the Standard Market Design NOPR to FERC and would not allow FERC to issue a final rule before July 1, 2005. Would give FERC additional authority to assure that municipalities and coops charge transmission rates that are comparable to the rates the municipalities and coops charge themselves (so-called FERC-Lite.) Would require FERC to issue a rule on transmission pricing. Would repeal §210 of PURPA when independently administered, auction-based day ahead and real time markets exist. Would require utilities to offer time-of-use rates and net-metering. Would repeal PUHCA and would give FERC and state utility commissions access to books and records. Would require FERC to establish an electronic information system to provide market transparency. Would prohibit slamming and cramming. Introduced April 30, 2003. On July 31, 2003, the Senate suspended debate on S. 14, and inserted the text of H.R. 4 from the 107th Congress as a substitute and passed H.R. 6.

S. 475 (Thomas)

Would establish an Electric Reliability Organization. Would repeal PUHCA and would give FERC and state utility commissions access to books and records. Would prospectively repeal §210 of PURPA. Would require FERC to issue rules to establish an electronic information system to provide the public, FERC, state commissions, buyers and sellers of wholesale electric energy, and users of transmission services, with information on the availability and price of wholesale electric energy and transmission services. Would prohibit round-trip trading. Would make electric rate refunds retroactive to the date a complaint is filed with FERC. Introduced February 27, 2003; referred to Committee on Energy and Natural Resources.

S. 681 (Cantwell)

Would require FERC to revoke market-based rates upon determination that effective competition does not exist. Introduced March 21, 2003; referred to Committee on Energy and Natural Resources.

S. 688 (Graham)

Prospective repeal of §210 to of PURPA. Introduced March 21, 2003; referred to Committee on Energy and Natural Resources.

S. 716 (Landrieu)

Would establish participant funding for transmission facilities. Would require FERC to establish technical standards and procedures for transmission interconnection. Would require cooperative and municipal utilities to provide transmission services with rates and conditions that are comparable to what the cooperative or municipality charges itself. Introduced March 26, 2003; referred to Committee on Energy and Natural Resources.

S. 723 (Boxer)

Would require FERC to order refunds of at least \$8.9 billion for unjust and unreasonable rates charged between June 1, 2000 and June 19, 2001. Introduced March 26, 2003; referred to Committee on Energy and Natural Resources.

S. 954 (Shelby)

Would allow states to regulate bundled retail sales, including the transmission component. Holders of existing wholesale contractual obligation would have preferential rights to transmission capacity. Would require participant funding for certain new transmission facilities. Congress would be required to approve any Standard Market Design proposed by FERC. Introduced April 30, 2003; referred to Committee on Energy and Natural Resources.

Note: For a complete description of H.R. 4 (107th Congress), see CRS Report RL31427, *Omnibus Energy Legislation: H.R. 4 Side-by-side Comparison*. For a listing of electric utility restructuring legislation in the 107th Congress, see CRS Report RL31210, *Electric Utility Restructuring Legislation in the 107th Congress*.