COUNTRY STUDIES

United States - Regulatory Reform in the Electricity Industry

1998

Introduction

The Review is one of a series of country reports carried out under the OECD's Regulatory Reform Programme, in response to the 1997 mandate by OECD Ministers. This report on regulatory reform in the electricity industry in the United States was principally prepared by Ms. Sally Van Siclen for the OECD.

Overview

Related Topics

BACKGROUND REPORT ON

REGULATORY REFORM IN THE ELECTRICITY INDUSTRY*

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Regulation of the electricity supply industry in the United States has been undergoing a major reform for several years. While inter-utility trading of electricity and generation by independent power producers have become substantial over the past few years, the present reform promotes an intensification of competition in generation by further diminishing the scope for discrimination in grid access, by divestiture of some generation assets, and by the creation of trading institutions such as spot markets. The introduction of independent system operators, which operate transmission facilities in a region, independently of their owners, are designed to further dampen the ability of vertically integrated owners to discriminate against competitors in generation. Some states are introducing further reform whereby all end-users may buy electricity directly from generators. Other states are reforming only to the extent required by changes at the federal level. That is, in the less reforming states, utilities are subject to *inter alia* "functional separation" and the requirements to file open-access transmission tariffs, to provide real-time information about transmission availability, and non-discriminatory transmission access.

Another key element of the reform is the transitional arrangements, which include mitigating, measuring, and compensating sunk costs that the reforms make unrecoverable by traditional regulatory means. New pricing schemes are also being introduced, so that *inter alia* reliability for large end-users is being transformed from an engineering concept into an economic good. In one area of the United States, a system of spot market nodal pricing, in which transmission congestion costs are reflected in the price of electricity, along with a system of tradable fixed transmission rights, has been adopted. Environmental goals for the sector are increasingly being met through market-based mechanisms, such as through the trading of SO_2 emissions permits, and the introduction of technology-neutral requirements that a pre-determined percentage of electricity be generated from non-hydropower renewable fuels.

The reform in the United States is being driven by the potential for lower prices and by technological change. A comparison of average prices charged industrial and residential users in each state shows that the highest state-wide average was almost four times higher than the lowest in 1996. California and the states of the Northeast—all high-priced states—have leading positions in the reform wave. Technological change enables more time-of-use metering, which enables more demand shifting by end-users of electricity.

The first state reforms were implemented in March 1998 and the most recent set of major federal reforms are not much older, so it is too early to assess fully their effectiveness. Nevertheless, it is already clear that further reform will be necessary to reduce current policy inconsistencies. States' reforms differ markedly but the geographic scope of electricity markets generally extend beyond individual states, though are much smaller than the country. The geographic scope of independent system operators do not always extend beyond state boundaries, thus potentially subjecting different parts of individual markets to differing rules. Both of these imply efficiency-reducing distortions. Further, traditional transmission pricing methods hamper the development of markets for power, both because of their effect on short-term transactions and because of their effect on grid investment.

1. THE ELECTRICITY SECTOR IN THE UNITED STATES

1.1. Key features

The United States' electricity supply industry and its reform are distinct from those of other countries. There are a large number of economic entities of diverse types active in the sector and a large number and diversity of regulations and regulators. There is extensive trade in electricity for re-sale among utilities. The sector is vast, with annual sales exceeding US$200 billion, about ten per cent of physical capital investment in the country, and large sunk costs. The reform is shaped by the federal nature of the country, the diversity of states' starting points, the traditional emphasis on individual rights and "open government," and the predominance of private property in the sector.

Economic actors in the sector can be grouped into five broad types. The predominant type is the vertically integrated, privately owned utility ("investor-owned utility" or "IOU"). These several hundred companies are subject to pervasive economic, safety, and environmental regulation by independent federal and state regulators. The size distribution is very skewed, with the largest ten IOUs accounting for almost 30 per cent of total electric operating revenue for IOUs (Table 33, EIA, 1997*g*). Traditionally, in most states they have franchise areas where they are the state-designated monopolist with an obligation to serve any customer within that area. They have interconnection agreements with neighbouring utilities and long-term requirements contracts[1] with municipal, co-operative, and other investor-owned utilities. The second type of economic entity is the federally owned utility, some of which are very large. Usually, they generate and transmit electricity but do not sell it directly to end-users. The third type of economic entity is a variety of state and municipal utilities, public utility districts, irrigation districts, state authorities and other state organisations, and rural co-operatives. While a few members of this group are large vertically integrated municipal and state utilities, most are small organisations that purchase electricity and distribute and supply it to their communities. Being publicly owned, these last two groups are subject to limited independent regulation**,** that is, they are self-regulating**,** and varying tax regimes. The fourth type of economic entity is privately owned independent power producers ("non-utility generators" or NUGs). These now account for about nine per cent of generating capacity and are expected to be responsible for more than 40 per cent of capacity increases over the period 1999 to 2001. The fifth type of economic actors are power marketers and brokers, who act as middlemen in the markets for power**.** These five types of entities have different degrees of vertical integration, owners, objectives, and subjection to independent regulation and other laws.

Box 1. **Major federal electricity industry participants**

U.S. Army Corps of Engineers: owns and operates 75 hydro-power/irrigation projects, totalling 20 720 MW (about 24 per cent of total hydropower capacity in the country), and transmission in the western United States.

Bureau of Reclamation of the U.S. Department of Interior:[2] owns and operates 59 hydro-power/irrigation projects, totalling 14 640 MW capacity (about 17 per cent of the country's hydropower capacity), and transmission in the western United States.

U.S. Department of Energy: includes Bonneville Power Administration (17 080 MW capacity, of which 90 per cent is hydropower, representing half of all the electric power of the Northwest region--states of Washington, Oregon, Idaho and portions of others; owns three-quarters of transmission in its region as well as links to other regions), Western Area Power Administration (10 600 MW capacity, of which almost all hydropower, and substantial transmission, including links to other regions, in the Southwest and Rocky Mountains), and three other power marketing agencies that generate and sell predominantly hydropower, operating under various legislative requirements; formerly included United States Enrichment Corporation, which makes fuel for nuclear power plants.

Tennessee Valley Authority: federal corporation with 28 000 MW generating capacity (73 per cent coal-fired) and substantial transmission in south-eastern United States.

In addition to the economic actors, there are two other major types of actors in the electricity sector of the United States. Independent regulatory bodies were created by federal and state governments to ensure that economic and public policy objectives are met by the privately owned utilities. Voluntary organisations of private and public utilities provide co-ordination and reliability of the electric system. The pinnacle of this system is the North American Electric Reliability Council and its successor organisation, the North American Electric Reliability Organization, which establish voluntary policies and standards, monitor their compliance by members, and assess the future reliability of the system over the United States, Canada, and a small part of northern Mexico (NERC, 1997*b*).

The mix of type of generation varies greatly from one area of the country to another. The Pacific Northwest has overwhelmingly hydropower, the Midwest overwhelmingly coal, the mid-Atlantic coal and nuclear, and the Northeast a mix of coal, oil, and nuclear. This heterogeneity results in a range of average state prices,[3] hence of stranded costs, and the pattern of public ownership (since, in the United States, large water control projects are, by tradition, publicly owned).

Table 1. **Geographic Distribution of Generation by Energy Source**

		1997 Net Generation by Energy Source (percentage)					
Census Division*	Terawatt-hours	Coal	Petroleum	Gas	Hydro	Nuclear	Other
New England	73.0	26.2	30.8	14.1	6.4	22.5	
Middle Atlantic	308.4	43.4	3.5	7.6	9.4	36.0	
East North Central	520.0	79.9	0.4	1.2	0.8	17.7	
West North Central	253.4	74.9	0.5	1.5	6.7	16.4	
South Atlantic	633.4	60.3	4.7	6.0	2.0	27.0	
East South Central	331.5	70.1	0.9	2.0	7.3	19.7	
West South Central	429.9	49.4	0.2	33.4	1.9	15.1	
Mountain	282.1	69.0	0.1	3.9	16.6	10.4	
Pacific Contiguous	273.7	3.1	0.1	13.9	69.3	13.6	
Pacific Noncontiguous	12.7	1.9	66.1	23.8	8.2	0	
US Total	3125.5	57.2	2.5	9.1	10.8	20.1	0.2

Source: U.S. Department of Energy, Energy Information Administration 1998d, Tables 7 to 13.

Traditional economic regulation of private utilities in the United States, takes the form of guaranteeing, *ex ante*, that expected total revenues exceed expected total cost by an amount sufficient to compensate for risk and attract sufficient capital. Public rate hearings, which are essentially adversarial in nature, reflecting the wider regulatory culture (see Chapter 2), are used to oversee the prudence of investment decisions and to allocate costs to be covered by the various classes of end-users. Estimates of quantity sold to each of the classes then determine the price for each class. This system was modified to allow more frequent adjustments for fuel costs after they became more volatile. The practical application of this system changed during the recession of the early 1980s when several large investments were found not to be prudent after they were made, so were not allowed to be recovered through regulated prices. Further, during periods of high inflation, the "fair" rate of return did not equal rates of return for alternative similar investments. Thus, in practice, the *ex post* equality of total revenues and total cost[4] did not always hold, although that was the principle.

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* New England is Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont; Middle Atlantic is New Jersey, New York, and Pennsylvania; East North Central is Illinois, Indiana, Michigan, Ohio, and Wisconsin; West North Central is Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota; South Atlantic is Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia; East South Central is Alabama, Kentucky, Mississippi, and Tennessee; West South Central is Arkansas, Louisiana, Oklahoma, and Texas; Mountain is Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, and Wyoming; Pacific Contiguous is California, Oregon, and Washington; Pacific Non-contiguous is Alaska and Hawaii.

More recently, economic regulation of private utilities has begun to move toward "performance based regulation" of monopoly activities, a variant of price caps and the "RPI minus x" type of regulation in the United Kingdom. The independent regulator sets maximum prices for various goods and services, defines a price index, and sets a factor "x" that reflects, say, expected efficiency gains. Maximum prices in the next period are automatically set at the current period prices, adjusted by the change in the price index and the "x" factor. Additional adjustments can be made only at predetermined review periods. However, unlike pure price caps, the regulator also sets non-price performance standards, such as for reliability, in addition to the price standards.

There is substantial trade among utilities. The non-integrated utilities have always bought electric power, primarily under long-term contracts, and the federal utilities have always sold electric power, but earlier reforms (*e.g.*, the 1978 Public Utility Regulatory Policy Act) induced entry by non-utility generators. A significant amount of short term "economy" transactions also takes place**.** The introduction of NUGs as well as, perhaps, an increased risk that investments might not be allowed to be recovered under the regulatory regime, expanded an already developed market for both short-term (spot) and long-term power transactions amongst utilities. Presently, about 55 per cent of total electricity consumed is not generated by the utility that sells it to the end-user (EIA, 1998*g*).

Box 2. **Overview of the US electricity industry**

Primary fuels (all energy usage): coal 31 per cent, natural gas 27 per cent, oil 22 per cent, nuclear ten per cent, hydroelectric five per cent, other five per cent (DOE 1998*b*, Fig. 4). One-fifth of the total is imported. Energy consumption per capita and per unit GDP is among the highest in the world (IEA, 1998).

Fuels used for electricity generation (1997): coal 57 per cent, nuclear 20 per cent, gas nine per cent, hydropower eleven per cent, oil two per cent, non-hydro renewable fuels 2×10^{-3} (about 7 500 mWh) (EIA, 1998*b*).

Electricity end-users (1996): 35 per cent residential customers, 29 per cent commercial sector, 33 per cent industrial sector and 3 per cent other end-users such as governments (EIA, 1998*a*).

Book value of electricity sector assets (1994): US$700 billion (10 per cent of the US total book value).

Sales of electricity (1997): US$214 billion (EIA, 1998*d*).

Average revenue (1997): US$0.0687/kWh (EIA, 1998*d*).

International trade (1996), in billion kWh: Imports 46.5 (45.3 Canada, 1.26 Mexico); Exports 9.02 (7.7 Canada, 1.32 Mexico), that is, less than one per cent of total generation.

Cost structure (1996): generation 74 per cent, transmission seven per cent, distribution 19 per cent.

Generation total: 3 652 teraWatthours; by ownership: 73 per cent investor owned utilities (about 350), of which about 11 per cent by non-utility power producers; 15 per cent publicly owned utilities (about 2 000), 10 per cent rural co-operatives (about 1 000); by size: the 34 largest utilities generate more than half the total (IEA, 1998).

Physical structure: there are five interconnections in North America, within which frequency is synchronised and between which are limited direct current links. Of these, three--East, West, and Texas--are predominantly in the United States. 157 control areas balance electric flows in their area and with adjacent areas, and some co-ordinate planning. There are nine reliability councils.

Emissions: the electricity industry accounts for about 65 per cent of SO_2 emissions and about 30 per cent of NOx emissions in the country.

An unusual feature of the current American reforms in the sector is the high level of public participation in the debates. The federal and various state reforms have been preceded and accompanied by discussions by utilities, academics, regulators and other parts of government**,** consumer, environmental and other special interests at conferences and public meetings, as well as in the newspapers, trade press and academic literature.[5] Much of the discussion and information is available on the Internet, so participation has likely been broader than it would have been had it taken place only a few years earlier. The public discussion has stimulated sophisticated arguments over the design of mechanisms and institutions, which has diminished the threat of "capture" by special interests and in principle resulted in a superior final design of the overall reform.

Another feature that distinguishes the American electricity reform from those of many other OECD countries is that it takes place against a backdrop of an already deregulated gas sector. Open, non-discriminatory access to the pipeline infrastructure is established, and large users are free to choose their supplier, which results in about 50 per cent of gas being sold by a non-traditional supplier. Some states are moving toward allowing small users and residential end-users to choose their gas supplier (IEA, 1998). Given that the remaining liberalisation in gas is limited to small end-users who, because of their load characteristics, are not particularly attractive to entrants, there is not expected to be significant interactions between the continuing liberalisation of electricity and, residually, of gas. However, changes in pipeline tariff setting could affect interactions between gas and electricity during periods of peak energy demand.

1.2. Policy objectives

Policy objectives of the United States, as set out in the Comprehensive Electricity Competition Plan (DOE, 1998*a*), include both economic goals and social goals. The economic goals are lower prices, reduced government outlays, greater innovation and new services, and increased reliability of the grid. The social goals include environmental goals—cleaner generation, increased energy efficiency, and reduced greenhouse gas emissions—and protection of consumers and adequate service to the poor. To comply with the Kyoto Protocol to the United Nations Framework Convention on Climate, which the United States has not yet ratified, greenhouse gas emissions would have to be much lower than current projections.[6]

States' policy objectives often differ from those at the federal level. In the high-priced states, reducing the price of electricity is a key, indeed driving, objective (White). In the low-priced states, maintaining low prices despite liberalisation in adjacent states is a key objective. (After high-priced states liberalise, utilities prefer selling into high-priced states to selling into low-priced states.) There is a positive correlation between price and reform (industrial and residential users apply greater pressure for reform in the higher-priced states). Arguments for granting end-user access all at once focus on fairness rather than on cost-benefit analyses of such access. The states also differ in their environmental priorities, from reducing SO_2, NOx, greenhouse gas and other emissions in fossil-fuel based states to maintaining wild salmon, other migrating fish, and migrating bird populations in hydropower-based states. The heterogeneity of the fifty states' objectives presents a challenge for reform.

2. Regulation and its reform

2.1. Main lines of reform

The United States is in the process of shaping one of the most liberalised electricity sectors in the world. Electricity reforms in the United States are distinct from those in most other OECD countries.

First, they vary significantly from state to state. The state-to-state variation is greater than in, *e.g.*, Australia, another federal country, but is comparable to that among Member States of the European Union. The variety of state reforms enables them to act as "test beds" for federal reforms, while at the same time providing flexibility to better match reforms to the individual states' starting points. However, this flexibility is constrained by the federal reforms, which form a framework within which the state reforms must fit. Second, where end-users get direct access to the electricity market, they typically all get access simultaneously (or over a very short period), unlike in Australia, New Zealand, and the European Union Member States, where access is phased in over several years, and not always to all end-users. Third, the reforms do not start from a unified, publicly owned system as they do in, *e.g.*, France, New Zealand, and England and Wales. Having private rather than public initial ownership implies a much greater concern in the United States about stranded costs.[7] On the other hand, like in many other countries, the reforms in the United States have not included privatisation of publicly owned utilities.

The United States places increasing reliance on markets to attain its policy objectives. The electricity reforms are fully consistent with this broad theme. As set out in its Comprehensive Electricity Competition Act, a proposed law introduced into Congress, the Administration intends *inter alia* to establish the necessary conditions—structural and regulatory—for competitive markets in generation ("wholesale competition" in American parlance) and encourage states to do the same for competition in retail supply ("retail competition").[8] Another main element of the reform is the mitigation, measurement, and recovery of stranded costs, which is a pre-condition for establishing competition in supply.

Box 3. **Conditions for competition in the electricity industry**

Competition requires a number of linked conditions along the whole supply chain:

- Non-discriminatory access to the transmission grid and provision of ancillary services.
- Sufficient grid capacity to support trade.
- Ownership or control of generators that is sufficiently deconcentrated to give rise to competitive rivalry.
- Competition law and policy that effectively prevent anticompetitive conduct or mergers.

Competition is enhanced by:

- Efficient access, including economically rational pricing, to the grid.
- Control of the grid fully independent from that of generators.
- Low barriers to entry into generation.
- A non-discriminatory, efficient market mechanism for electricity trade.
- A stranded cost recovery scheme that is non-distortionary and fair.
- Greater elasticity of demand, that is, that the buying side of the market be exposed to, and have the technology to react to, price changes, such as through time-of-use meters.
- End-user choice, with competition in retail supply to end-users.

A major part of the over-all reform effort is reforms to intensify competition between generators to supply electricity, that is, "competition in generation." Among the requirements for such competition is non-discriminatory access to the transmission grid and provision of ancillary services. Complete divestiture of generation from transmission would accomplish this, but divestiture to establish competition in generation is limited in the United States by pervasive private property in the sector: Many regulators cannot order divestiture of private property outright. Some states such as California, however, are providing powerful financial incentives to partially divest generation to owners from outside the present market. Indeed, significant fossil-fuel generating capacity in California and New England has already been divested to owners from outside of the respective areas. As an alternative to divestiture of all generation, a new structure has been devised to reduce the ability to discriminate in grid access. "Independent system operators" have been established in California, as well as in the Northeast and the mid-Atlantic seaboard (the PJM Interconnection). The ISOs operate and control the transmission grid, while the grid remains owned by the vertically integrated utilities. The ISOs are managerially and operationally independent of the vertically integrated utilities**.** While the Federal Energy Regulatory Commission (FERC) presently requires only "functional separation," a weak form of separation, of transmission from generation marketing activities, and encourages the formation of regional independent system operators (ISOs), the Administration proposes giving FERC authority to order the establishment of ISOs. FERC further limits discrimination by transmission owners by requiring third parties to be offered transmission service comparably flexible to that enjoyed by the owners themselves, and to be provided information about transmission systems in real-time.

Efficient access to the grid also enhances competition in generation. "Efficient access" involves access prices and conditions that are transparent, cost-reflective, and maximise economic welfare. Efficient access is to be ensured by FERC, the primary regulator of transmission access prices and conditions. FERC requires cost- or congestion-based open access tariffs. The PJM Interconnection (in the mid-Atlantic States) has adopted nodal pricing of electricity, a pricing scheme which aims to provide incentives for more efficient transmission use at each time period. Now, FERC has jurisdiction only over privately owned transmission; the Administration proposes extending FERC jurisdiction to all transmission in order to ensure a consistent non-discriminatory access regime.

Competition in generation also requires sufficiently unconcentrated ownership of generating plants. In California, the divestiture of generating capacity, mentioned above, was to multiple owners, in order to deconcentrate generation. Market concentration can also be reduced by increasing transmission capacity.

Spot markets, independently run, have also been established in the more liberalised jurisdictions. Spot markets, by providing price transparency, liquidity, and otherwise reducing transactions costs, facilitate competition by letting buyers more easily compare and switch among competing generators.

Current reforms also target other potential barriers to competition in generation, such as barriers to entry into generation. Regulatory barriers to entry into generation were significantly reduced in the Energy Policy Act of 1992 through the establishment of a new class of generators that are exempt from costly cogeneration or renewable fuels requirements under earlier laws. However, siting of both generation and transmission is often problematic because states and localities retain authority to approve siting.

The second major reform element in the United States is the promotion of competition to supply all end-users ("retail competition" or "full end-user choice"). It is allowed but not required under the Energy Policy Act of 1992, thus is, presently, a matter of state regulatory policies (FERC, 1996*b*). As of July 1998, Massachusetts, California, and Rhode Island (partially) had introduced supply competition, nine other states had enacted legislation that provided for competition to supply all end-users (by dates ranging from 2000 to 2004), and several others were working on legislation (DOE, 1998*i*). The Administration proposes that each utility be required to permit all end-users to choose their own electric power supplier by 1 January 2003, except where States or non-regulated utilities find, on the basis of a public proceeding, that an alternative policy would better serve consumers.

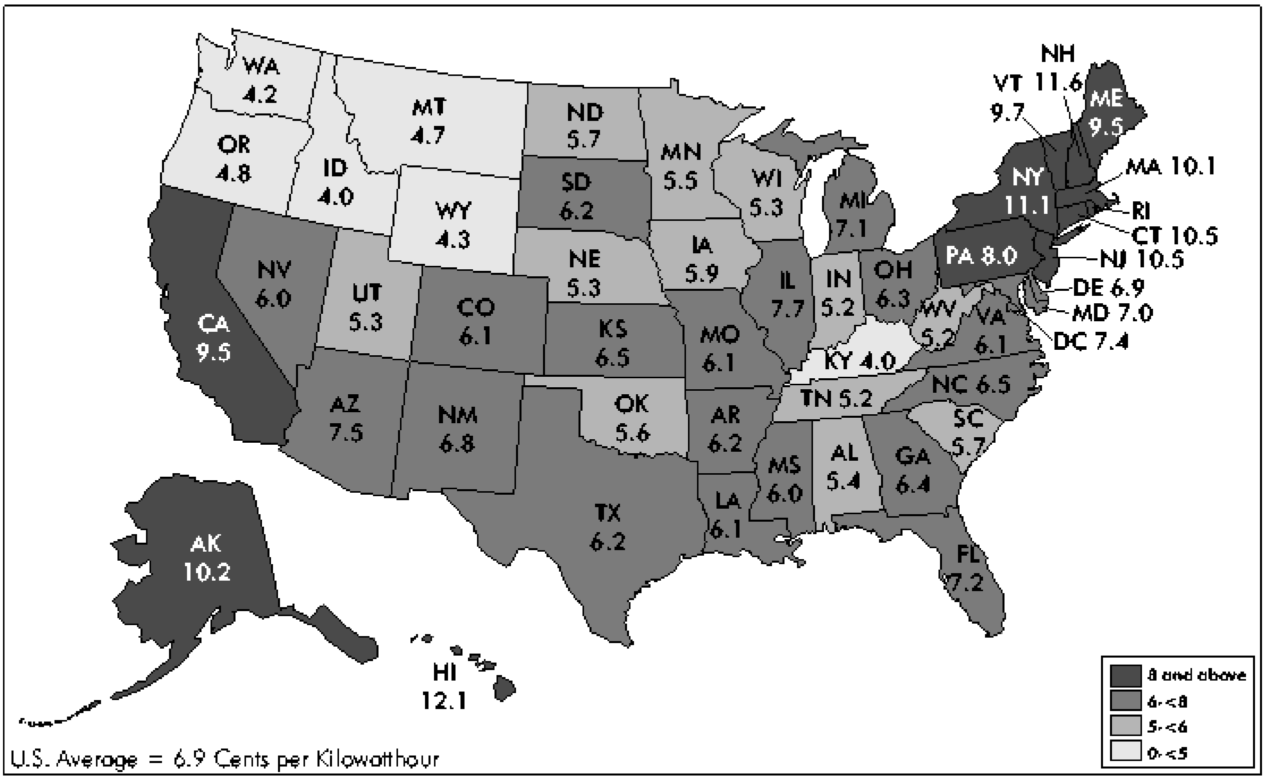
The third major element of the United States reform is the mitigation, measurement, and compensation for stranded costs. Stranded costs are unamortised costs, prudently incurred[9] under the prior regulatory regime, that will not be recovered under the new, more market-based regulatory regime. Compensation for stranded costs is a necessary condition for gaining support for the intensification of competition in the electricity sector.[10] Stranded costs are measured and recovered according to the rules of their corresponding regulators, federal or state. Mechanisms used to recover stranded costs include lump-sum exit fees and non-bypassable charges on end-users. The design of the recovery mechanism can distort competition.

Stranded costs are mostly attributed to investments in nuclear generation and in long-term power purchase agreements under the Public Utility Regulatory Policies Act of 1978. The range of stranded cost estimates is US$70 billion to US$500 billion; an often-quoted likely mid-range is US$135bn to US$200 billion (IEA, 1998). Estimates are sensitive to assumptions about future market prices for electric power and the date on which end-users have direct access to the market.[11] As sales of fossil fuel generating assets have taken place, prices received have exceeded earlier estimates (IEA, 1998); this suggests that estimates of total stranded cost will decrease somewhat. Stranded costs will also diminish as book values diminish, in line with accounting depreciation. As more generating assets are sold, the prices received provide better information about the market value of other, unsold, generating assets; this means that estimates of total stranded costs should become more precise. Compared with the book value and annual sales in the sector, estimated stranded costs are sufficiently large that the design of the recovery system will have important effects on the subsequent evolution of the sector.

While the more reformist states are moving at different rates along similar albeit not identical reform paths, other states are engaging in only limited reforms. Two examples of less reformist states are Idaho and Michigan. Idaho, having preferential access to federally owned hydropower that results in almost the lowest electricity prices in the country, is not liberalising and is working to retain its preferential access. Michigan, with a local duopoly and constrained import transmission, also controlled by the duopolists, allows a limited fraction of end-users to pay to switch electricity supplier, but has made few other changes.[12] By contrast, while the situation in the state of Virginia is similar to that of Michigan, with monopoly control over transmission raising concern that competition from “outside” generators may be blocked, full retail competition in Virginia is nevertheless set to begin in 2004 (EIA 1998*h*). Figures 1 and 2 illustrate the current pattern of how states have selected themselves to undertake more or less reform.

Figure 1. **Average Revenue from Electricity Sales to All Retail Customers**

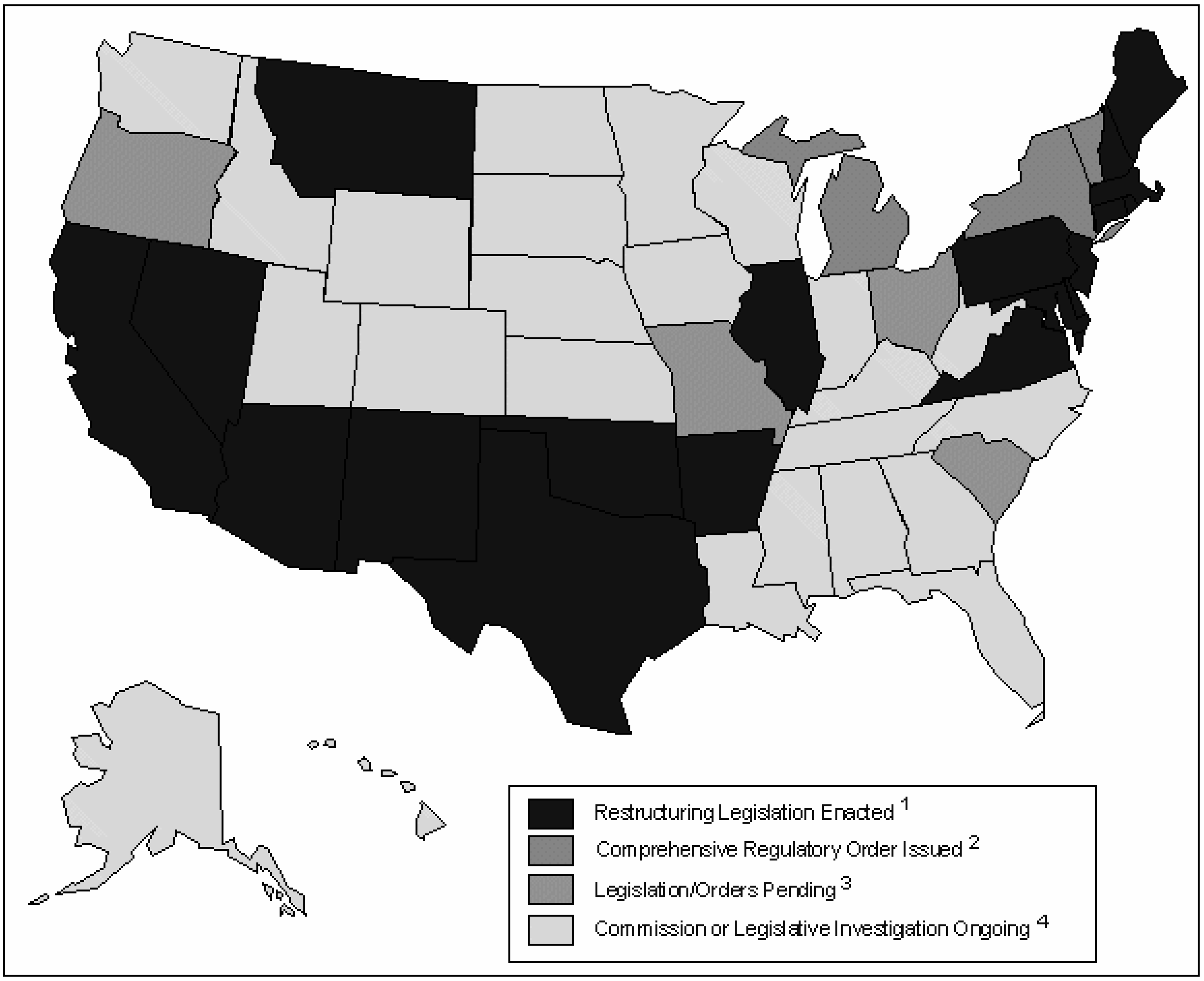
(1996, cents/kWh, by State)



Source: US Department of Energy.

Figure 2. **Status of State Electric Utility Deregulation Activity**

As of June 1, 1999



1 Arizona, Arkansas, California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, New Mexico, Oklahoma, Pennsylvania, Rhode Island, Texas, and Virginia.

2 Michigan, New York, and Vermont.

3 Missouri, Ohio, Oregon, and South Carolina.

4 Alabama, Alaska, Colorado, District of Columbia, Florida, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Nebraska, North Carolina, North Dakota, South Dakota, Tennessee, Utah, Washington, West Virginia, Wisconsin, and Wyoming.

Source: US Department of Energy, Energy Information Administration, Electric Industry Restructuring, Monthly Update.

Other policy goals in the United States are pursued by a combination of markets and direct government intervention. Environmental goals, for example, are pursued through subsidies—cash, tax advantages, or, newly, explicit surcharges on end-users—to support research, development, and adoption of emerging technologies for, *e.g.*, energy efficiency and cleaner generation; market-based regulation, such as the SO_2 emissions permits trading programme; and more traditional command and control regulation. The Administration proposes a requirement that a pre-determined percentage of electricity be generated from non-hydropower renewable energy sources, subject to a price ceiling. (Similar requirements have been adopted in some states.) Efficiency in the generation of "green" electricity would be encouraged by using market mechanisms to determine the technology, the generator, and the price received.

Policy goals with respect to reliability[13] of the electricity system would be assured, under the Administration's proposal, by moving from a set of voluntary agreements basis under the North American Reliability Council to a system of mandatory self-regulation under a NERC successor organisation, the North American Electric Reliability Organisation, overseen for its United States-based activities by the Federal Energy Regulatory Commission.[14] NAERO awaits approval (NERC 1997*b*). The comprehensive Electricity Competition Act, if adopted, would make this change in status from a voluntary to a self regulatory organisation under FERC, with respect to activities in the United States.

2.2. Institutional basis for regulation

The institution basis for regulation of the electricity sector in the United States is complex and rather opaque. The body of applicable regulations is a combination of laws passed by the federal Congress and relevant state legislatures, decisions and regulations issued by regulatory bodies, and court decisions. Power to regulate is shared among federal and state regulators, and some municipal regulators, with sometimes ambiguous boundaries between their authorities. In addition to economic regulators, there are specialised regulators for nuclear power, financial instruments, and environmental protection. There is also a boundary between those activities that are subject to economic regulation and those subject to market discipline. A significant portion of economic entities in the sector are publicly owned or otherwise have unusual legal statuses, thus are subject to only limited independent regulation.

Private firms in the sector have been subject to independent economic regulation since early in the twentieth century. Regulatory authorities are independent—in personnel, operations and funding—of the companies regulated. Typically, the authorities hold public hearings to collect relevant information and to hear opposing points of view. Decisions must be made in public and are accompanied by reasoned, public explanations. Decisions can be appealed to the judiciary.

Box 4. **Regulatory institutions at a glance**

Federal Energy Regulatory Commission (FERC): regulates interstate transmission, sale of electricity for resale, and mergers (concurrent jurisdiction with Antitrust Division and Federal Trade Commission).

State public utility commissions: regulate generation, distribution, service and prices to end-users, transmission siting, and environmental concerns.

U.S. Department of Energy (DOE): develops energy policy, sponsors energy research, and approves construction of international electric transmission lines.

Environmental Protection Agency (EPA): enforces federal environmental protection legislation, usually works in conjunction with state environmental departments; is an independent federal agency.

Nuclear Regulatory Commission (NRC): is responsible for ensuring safe operation of commercial nuclear power plants and that there are sufficient funds for their decommissioning; specifies maintenance rules, inspects, and issues public inspection reports; is an independent federal agency.

North American Electric Reliability Council (NERC): a non-profit corporation that oversees voluntary agreements to protect reliability across the United States, Canada and part of Mexico; is a non-profit corporation. In 1998 its successor organisation, the North American Electric Reliability Organisation (NAERO) was created.

Antitrust Division of the U.S. Department of Justice: has concurrent jurisdiction with FERC and Federal Trade Commission for mergers, concurrent jurisdiction with FTC for anticompetitive behaviour.

Federal Trade Commission (FTC): has jurisdiction for consumer protection concerning marketing and advertising, concurrent jurisdiction with FERC and Antitrust Division for mergers, concurrent jurisdiction with Antitrust Division for anticompetitive behaviour; is an independent federal agency.

Commodity Futures Trading Commission (CFTC): regulates markets for futures and options based on electric power.

Securities and Exchange Commission (SEC): has jurisdiction over some mergers under the Public Utility Holding Company Act of 1935, regulates markets for utility stocks.

The main federal economic regulator for the electricity sector is the Federal Energy Regulatory Commission (FERC). FERC is an independent commission, governed by five commissioners appointed by the President and confirmed by the Senate, for five-year terms. FERC has jurisdiction over all privately owned lines used in interstate transmission (that is, authority over rates, terms and conditions); in practice, this gives FERC jurisdiction over all privately owned transmission. Since the boundary between transmission and distribution is somewhat arbitrary, so also is the limit of FERC jurisdiction until specific lines are labelled as one or the other. FERC also has jurisdiction over sales of electric power for resale. FERC has only limited jurisdiction over entities owned by the public sector, which own about one-third of the grid and about a quarter of generation.[15] FERC does not have authority to order electric transmission siting (which contrasts with its authority to order gas pipeline siting).

State public utility commissions have jurisdiction over generation (excluding federally-owned), distribution, transmission siting and environmental concerns, residual revenue necessary to pay for the costs of transmission lines, and service and prices to end-users. They often do not have jurisdiction over municipal utilities: *E.g.*, municipal utilities may be able to opt-out of the reforms in their respective states. Thus, for example, Los Angeles Department of Water and Power decides whether Los Angeles end-users may choose their own electricity suppliers and the Massachusetts law requires municipal utilities to allow retail competition only if they seek to compete outside of their service areas.

Entities such as federal corporations, power marketing agencies, municipal utilities, irrigation districts, and co-operatives are subject to different regulations. Often their economic behaviour is controlled by their founding legislation or regulations. For example, they may be required to have revenues cover certain costs, or to sell power preferentially to publicly owned utilities.

In addition to the boundaries between various regulators' jurisdictions, there is also a boundary between that which is subject to economic regulation and that which is subject to antitrust law enforcement. This is defined, in part, by the antitrust laws' "state action doctrine." This doctrine removes, from the sphere of antitrust prosecution, behaviour that suppresses competition but that is an action of a state, or a political subdivision (such as a city) to which the state has delegated authority to regulate, or an action by a firm or individual actively supervised by a state, and taken pursuant to a clearly articulated state policy to displace competition. (See Chapter 3.) The Antitrust Division of the U.S. Department of Justice and the Federal Trade Commission are the federal institutions that enforce the antitrust laws. State attorneys general enforce antitrust laws, and have an interest in competition in the electricity sector.

Two important non-economic regulators are the North American Electric Reliability Council (NERC) and the federal Environmental Protection Agency (EPA). NERC is a voluntary organisation of utilities covering much of the continent. It promulgates voluntary policies and standards to promote reliability of the electric supply in North America. (It is being succeeded by NAERO, see above.) The

EPA and the state environment departments share a complex layering of authority over environmental protection. Key federal laws are the National Environmental Policy Act of 1969 that requires federal agencies to prepare environmental impact statements on major federal actions, the Clean Air Act[16]—which deal with the SO_2 emissions trading programme and NOx reduction programme—and the Clean Water Act, which covers wastewater discharges.

2.3. Regulations and related policy instruments in the electricity sector

2.3.1. Regulation of entry

Entry into electricity generation promotes competition by increasing the number of generators with independent incentives taking independent decisions. Entry into electricity generation is unregulated *per se,* and the regulation-induced cost of entry has fallen in the past decade**.** The Energy Policy Act of 1992 (EPAct) substantially reduced regulatory entry costs by relieving entrants of cogeneration and renewable fuels obligations.[17] Indeed, as noted above, non-utility generators now account for a large fraction of new capacity. However, some regulations continue to affect significantly the cost of entry**.** These include those for connection charges, siting rules, and emissions permits. Siting of generation and transmission assets is heavily influenced by zoning and other local use regulation, as well as by pressure from local citizens that the facilities be located "not in my backyard." Reducing the time required to get siting approval would reduce the time required for entry, hence reduce its cost. The asymmetric treatment of existing and new generators in the SO_2 emissions permit trading system (the former are given permits, the latter must buy them) is a regulation-created entry barrier. In practice, however, operating economics in many parts of the U.S. favor gas-fired generating plants, which are relatively easy to site and require few SO_2 permits**.** Finally, entry into generation in one geographic area by an existing generator located in another area is facilitated or blocked by the terms and conditions of access to transmission, as well as the availability of sufficient transmission capacity. (This is discussed later in Section 3 on markets.)

Restrictions on foreign entry into nuclear generation are contained in the Atomic Energy Act, which provides that a license to operate nuclear generating plants cannot be issued to anyone owned, controlled by or dominated by an alien, foreign corporation or a foreign government (42 USC Sec. 2133 (Sec. 103)). "Control" and "domination" are defined on a case-by-case basis. These restrictions may in the event be flexible, as indicated by announcements by British Energy to acquire and operate, through a joint venture, nuclear power plants in the United States.

Entry into retail supply is regulated at the state level through licensing requirements that do not restrict the number of entrants, but do, in order to provide some consumer protection, require a certain level of financial stability. One regulatory entry barrier into retail supply, one which also reduces incentives to enter generation, is created by introducing an asymmetry in consumers' switching cost: Massachusetts does so, by combining a low regulated price, the "standard offer," with a rule that end-users who switch to an entrant cannot later switch back to qualify for the "standard offer."

Further reducing regulatory entry costs would facilitate the development of competition in generation and, paradoxically, could decrease stranded costs. In particular, if foreign managers of nuclear plants are more efficient than domestic managers, then reducing barriers to the purchase of nuclear plants by foreign owners would increase their market value, thus diminishing stranded costs. In addition, eliminating regulation-caused switching cost asymmetries, such as that in Massachusetts, would facilitate competition in retail supply.

2.3.2. Grid access and transmission pricing regulation

The terms and conditions of access to the transmission grid influence competition in generation, and whether the grid is used and augmented in a cost-minimising way. The Federal Energy Regulatory Commission (FERC), the regulator for privately owned transmission,[18] regulates transmission tariffs, requiring grid owners to file open access non-discriminatory transmission tariffs. FERC also requires non-discrimination with respect to flexibility of service and information about the transmission grid. Transmission tariffs are cost- or congestion based. Whereas FERC formerly allowed only postage-stamp or contract-path pricing (see definitions in the box below), it has subsequently allowed incremental cost pricing for grid expansion or upgrades that relieve a grid constraint, and opportunity cost pricing for a change in operations that relieves a grid constraint. Distance-sensitive and flow-based pricing have been allowed more recently.

Two schemes for transmission pricing that have recently been introduced in parts of the United States are nodal pricing and zonal pricing. Under nodal pricing, there is a distinct price for electric power at each location in a grid that is used by the system operator in its model of the system. These prices equate demand and supply at each node. Under zonal pricing, there is a distinct price for electricity in each zone, which incorporates several nodes. California, for example, uses about 25 zones, whereas the somewhat larger PJM Interconnection (Pennsylvania, New Jersey, Maryland and Delaware and the District of Columbia) uses about 2 000 nodes, of which some are near-duplicates. Electricity prices change frequently, hourly in California and more frequently in PJM Interconnection.

The transmission tariffs are derived from the electricity prices in a way that reflects congestion. The tariffs have two parts, a fixed part and a variable part. The variable part of the transmission tariff is the difference between the price of electricity at the origin (a node or a zone) and the price of electricity at the destination. This difference is the congestion cost. When transmission is congested, transmission tariffs are high. Nodal and zonal pricing schemes are usually accompanied by fixed transmission rights**.** These rights are equivalent to perfectly tradable firm transmission rights (Hogan, 1998). They can be used to hedge, partially, against variations in transmission tariffs. They also ensure that using transmission rights to block access is costly.

Zonal pricing was adopted in California in 1998 and was tried in 1997 in the PJM Interconnection (Pennsylvania, New Jersey, Maryland and Delaware and the District of Columbia). Under the California system, zonal prices are found only when there is congestion: otherwise, there is a single spot price, in the day-ahead market of the Power Exchange, everywhere in the state. Market participants submit bids to the day-ahead market that may include how they would want the quantity they supply or demand to change as price changes. If the independent system operator (ISO) finds that there is congestion (*i.e.*, the state-wide market clearing price in the day-ahead market would imply physically impossible flows of power), the ISO uses the supply and demand bids to find the least-cost way of relieving the congestion. The congestion charges for each congested transmission path are calculated on the basis of the cost of relieving the congestion, *i.e.*, the bids and, if necessary, a default price. In addition, the schedule that comes out of the ISO's congestion-relieving process gives the incremental cost of power in each zone.

The zonal market-clearing price in each zone must meet three conditions:

1. It must cover the zonal incremental cost (the incremental cost of generating or delivering more power in that zone).

2. The difference in zonal market-clearing prices in two zones must be equal to the congestion charges determined by the ISO for the same two zones.

3. It is no higher than necessary to satisfy the two conditions above.

The zonal pricing scheme in California has built-in adjustment mechanisms. For example, conditions under which new zones are hived off from old zones were specified from the beginning. Thus, in the first year of operation, the number of zones increased from two to 25 to reflect congestion. Over time, the California zonal pricing scheme may become more like a nodal pricing scheme.

In the PJM Interconnection, the zonal pricing scheme did not work well: Congestion was underpriced, so market participants scheduled more bilateral transactions than could be accommodated by the grid, hence the independent system operator had to intervene administratively, constraining choice in the market, to preserve reliability. This experiment in zonal pricing in PJM was followed by the adoption of nodal pricing in April 1998.[19]

Under the nodal pricing scheme adopted by PJM Interconnection, prices are discovered in a spot market for about 2 000 locations. Under conditions of effective competition, the price at each node equals the system marginal cost at that node. Given these prices, each generator produces at its short-run profit maximising output. Therefore, the market equilibrium supports the necessary dispatch given transmission constraints. During the first five months of nodal pricing, PJM Interconnection has often experienced congestion, that is, times when prices varied significantly from one node to another.[20] At times, some nodal prices of electricity are negative, reflecting the value of "counterflow" in the system. This experience with nodal pricing shows that the constraints of a zonal pricing scheme (that nodal prices be identical within zones) would indeed be binding over significant periods of time. This experience has demonstrated that the independent system operator can indeed calculate and report nodal prices at five-minute intervals, sufficiently frequently for market participants to react (Hogan, 1998). One criticism has been that the individual markets are too thin to support the development of hedging instruments. However, trade in financial instruments for a few locations in the PJM Interconnection does occur. As trade concentrates at a few nodes, markets become sufficiently deep for hedging to take place.

Box 5. **Grid pricing in the United States**

The operation of the grid and dispatch of generation is always done in the United States in a way that maintains engineering system stability; investment is done so as to provide sufficient physical assets. Under the traditional system of regulation of the sector, the grid pricing scheme, if there were one, had only to ensure sufficient total revenues; operating decisions were made according to engineering reliability criteria and the marginal cost of generating plant. However, when American regulatory reform provides utilities with incentives to change their behaviour, the economic incentives of a grid pricing scheme become relevant. Grid pricing schemes that better align economic incentives with engineering requirements for stability reduce the scope over which system operators need to take administrative rather than market based decisions in order to maintain stability. Grid pricing schemes that better align economic incentives with requirements for investment reduce the scope over which command and control for investment is needed. A key characteristic of a transmission pricing scheme that aligns economic incentives with engineering requirements is that prices reflect transmission congestion, that is, that prices take into account externalities of transmission.

Any transmission pricing scheme must be complemented by a moment-to-moment control mechanism, which uses these prices as inputs along with the engineering reliability constraints. (In some places, such as in the New England region, system operators have long operated with the objective of reliability-constrained, economic dispatch, so this is not a large innovation.)

Transmission tariffs can be multi-part so that, for example, one part of the tariff varies with usage and another, usage-insensitive part, can be used to equate revenues to a regulated target.

Among the several grid pricing schemes in use in the United States are:

- *Postage-stamp pricing*: one price regardless of the locations of the buyer and seller.

- *Contract-path pricing*: summing prices of segments of transmission line between buyer and seller.

- *Grid pricing implied by zonal pricing of power*: Two-part transmission tariff, where the variable part of the tariff for transmission between two zones equals the difference in electricity prices in those two zones. Zones are defined so that their boundaries are where transmission congestion occurs. The price of electricity at any one moment in time is equal within each zone.

- *Grid pricing implied by nodal pricing of power*: Two-part transmission tariff, where the variable part of the tariff for transmission between two nodes equals the difference in electricity prices in those two nodes. Nodes are the nodes used by the system operator for system operation. The price of electricity at each node equates supply and demand at that node. In the absence of market power, the price at a location would equal the marginal cost of supplying load at that location, where the marginal cost is the sum of marginal generating cost and transmission.

Neither postage-stamp nor contract-path pricing is related to the actual flow—hence cost—of delivered electricity, nor do they reflect the economic value of a part of the grid under a particular pattern of use. Thus, these pricing schemes do not provide incentives for efficient grid use or augmentation. Nodal pricing, combined with effective competition, appears to induce efficient grid operation and dispatch. Different forms of grid pricing have different costs of setting up and operation, notably for information technology, so there may be a trade-off between these costs and the efficiency of the pricing scheme.

FERC tries to reduce the scope for discrimination by vertically integrated utilities by requiring transmission owners to offer flexibility of service to third parties that is comparable to that the owners enjoy (FERC, 1996*a*, pp. 29-39), and to provide, in real-time, the same information the utility itself uses about its transmission systems (according to FERC Order 888). The information is posted on Internet bulletin boards, and is supposed to facilitate the arrangement of sales of electric power across transmission lines owned by others. However, the present rules do not prevent transmission owners from understating transmission capacity or availability.

Transmission access pricing, as traditionally practised in the United States, is not fully consistent with liberalised electricity markets. The adoption of a nodal pricing by the PJM Interconnection and zonal pricing by California, by demonstrating that such schemes are, in fact, workable over a period of time, provide impetus for more widespread adoption of pricing schemes that better reflect transmission costs. It is too early to tell, however, whether nodal pricing, even when a fixed part is added to the transmission tariff, will indeed provide sufficient incentives for grid augmentation and for locating new generating capacity where it minimises system cost. The difficulty of inducing optimal transmission investment is discussed below in the section on independent system operators.

2.3.3. End-user tariff regulation

Tariffs charged end-users are traditionally regulated because utilities were, traditionally, monopolies with substantial protection from competitive entry. Where there is not direct access by end-users to electricity market (*i.e.*, not retail supply competition), the regulated tariff scheme may, or may not, reflect the marginal cost of delivered electricity, hence may, or may not, provide economic incentives for the efficient use of electricity. In general in the United States, regulated tariffs do not reflect the marginal cost of delivered electricity. Tariffs are, mostly, regulated by the state public utility commissions. Under the traditional system, generally each end-user was assigned to a category of user (*e.g.*, residential, commercial, small industrial, or industrial) and paid the regulated price for its category. The state public utility commissions regulated tariffs to provide for sufficient investment, a fair rate of return, and for “social” purposes (see Section 2.4.5). However, as technological change allowed larger users to threaten credibly to leave the system by generating power themselves (or moving to another region), they were able to negotiate individual tariffs. To the extent that utilities' revenues are constant, these tariff concessions were at the expense of other customers.

The states that are granting all end-users direct access to the power market are, in essence, expanding the ability to negotiate price to all users. However, there is usually a transitional arrangement whereby residential end-users have access to a regulated maximum price for several years into the future. In both California and Massachusetts, for example, the apparent maximum residential price is 10 per cent below the former regulated price. States may define categories to favour certain types of customers; *e.g.*, Massachusetts has a special "farm tariff." State public utility commissions also regulate for "social" purposes, which is being changed as end-users gain direct access to electricity markets (see Section 2.4.5).

To the extent that there is not market power in electricity markets, market prices should reflect the marginal cost of electricity. Hence, if these market prices are reflected in prices charged end-users then they should, in general, provide incentives to end-users to use electricity efficiently, and in particular to shift their usage of electricity away from periods of peak demand. (This is discussed in greater detail in Section 3.1.) Of course, this change in behaviour requires time-of-use metering as well as time-of-use pricing, and the fixed costs of such meters may be sufficient to deter small end-users from buying such meters.

2.3.4. Nuclear safety regulation

Electricity sector reform changes the economic incentives of owners of commercial nuclear power plants. Concern has been expressed that owners have reduced incentives for safe operation. However, the NRC has found that "safety concerns exist, in many cases, independently of economic deregulation" and that there is no correlation between a licensee's financial health and general indicators of safety (NRC, 1997). Hence, electricity sector reform is unlikely to decrease the level of safety at nuclear power plants. Indeed, the experience of the United Kingdom nuclear power plants suggests that economic efficiency and safety increase together.

2.4. Regulation for restructuring

2.4.1. Vertical integration

The ubiquitous vertically integrated utilities are increasingly required to vertically separate, in one form or another, generation from transmission and distribution. In Order 888, adopted in 1996, FERC required functional separation, maintaining as safeguards procedures whereby any person can file a complaint at FERC about misbehaviour and FERC monitoring of markets (FERC 1996*a*, pp. 57-59). The competition authorities had recommended operational separation over functional separation, and had noted the advantage of completely separating ownership and control (FTC, 1995, DOJ, 1995). The FTC argued that functional separation would leave in place both the incentive and the opportunity for utilities to discriminate against competitors, and that regulatory oversight to detect, *e.g.*, subtle reduction in quality of service to competitors, such as delays, would be very difficult, as would provision of timely remedies. More recently, the Administration has noted clear benefits from operational separation and, under the proposed Comprehensive Electricity Competition Act, would grant FERC the power to require the establishment of independent system operators.

Some state regulators are providing strong financial incentives for vertically integrated utilities to divest generation. For example, California is doing so for fossil-fuel generation.[21] In response, the three IOUs in California are divesting much of their fossil fuel generating plants, largely to IOUs that do not have generating facilities in the region.[22] In the Northeast, US$1.6 billion of fossil fuel and hydropower facilities were divested in 1998. In Arizona, utilities must divest all of their generation assets if they want complete recovery of stranded costs. In Connecticut, all non-nuclear generation must be sold by 2000, and all nuclear generation by 2004 (EIA, 1998*h*).

Box 6. **Types of vertical separation between generation and transmission in the United States**

Generation is vertically separated from transmission in order to ensure non-discriminatory access to the transmission grid and to reduce the scope for evasion of regulation. In order to ensure non-discrimination, both the vertically integrated utility's ability and its incentive to discriminate against a rival generator must be eliminated. Discrimination can be subtle, including for example delays, complications, and informational disadvantages. Discrimination hampers competition, thus resulting in inefficiency in the short-run and discouragement of efficient entry in the long run. Evasion of regulation, in which utilities shift costs from competitive to regulated activities, decreases efficiency in the competitive activities by disadvantaging lower-cost competitors. Regulatory evasion also attenuates the distributional effects of the regulatory regime. Types of vertical separation between generation and transmission include (ordered from stronger to weaker types):

Divestiture or ownership separation: Generation and transmission are separated into distinct legal entities without significant common ownership, management, control, or operations.

Operational separation: Operation of and decisions about investment in the transmission grid are the responsibility of an entity that is fully independent of the owner(s) of generation; ownership of the transmission grid remains with the owner(s) of generation.

Functional separation: Accounting separation, plus (1) relying on the same information about its transmission system as its customers when buying and selling power and (2) separating employees involved in transmission from those involved in power sales.

Accounting separation: Keeping separate accounts of the generation from the transmission activities within the same vertically integrated entity. This includes a vertically integrated entity charging itself the same prices for transmission services, including ancillary services, as it does others, and stating separate prices for generation, transmission, and ancillary services.

Of the four degrees of separation listed here, divestiture is the only one that eliminates incentives to discriminate. Divestiture also fully eliminates the ability to discriminate. Operational separation removes the ability to operate the grid or to make grid investments in a discriminatory manner, because all these decisions are made by an entity that is distinct from the owner of generation. Functional separation only somewhat reduces the ability to discriminate: common management and a common pool of staff can co-ordinate efforts across the functional divide. It thus requires an effective back-up system of regulation. Accounting separation affects neither the ability nor the incentive to discriminate; while effective oversight would force regulatory evasion, cross subsidies, and discriminatory pricing into the open, discriminatory behaviour and information access would remain undetected, and the allocation of joint costs and benefits would necessarily be arbitrary.

Where generation and transmission are not separated operationally or by divestiture, and an independent regulator is expected to enforce non-discrimination under accounting or functional separation, a variety of failures can occur. Detecting and proving anticompetitive behaviour can be difficult, since monitoring subtle and short-lived anticompetitive behaviour, as might be profitable in a complex environment such as electric systems operations, is complex and costly. Second, incentives to exploit market power will remain. Third, rules designed to reduce the use of market power can misidentify anticompetitive behaviour, thus “chilling” competition and increasing administrative and litigation costs (FTC, 1998*b*).

Divestiture, so that the transmission owner no longer also owns generation, implies that the transmission owner cannot increase its profits by favouring a subsidiary generator over other generators. In all the other types of separation, ownership of both transmission and generation remains with a single entity, so the incentive and ability to discriminate remains. If there is not divestiture, then non-discrimination requires the vertically-integrated utility to ignore its own economic interest. Not divesting also leaves in place incentives to find ways to evade regulatory constraints.

“Operational separation” is implemented, in the United States, with the establishment of Independent System Operators (ISOs). The effectiveness of this form of separation relative to functional or accounting separation depends on the degree of independence of the ISO from the vertically integrated utilities. Where the ISO is not truly independent, the problems of discrimination and regulatory evasion remain. Hence, the governance of the ISO is critical. This is discussed below in Section 3.2. Divestiture, by contrast, does not require the creation of a governance structure that ensures independent yet efficiency-enhancing and efficient decision-making.

Box 7. **Vertical separation of ancillary services from electric power**

Ancillary services provide the critical real-time balance of the system.[23] In effect, many ancillary services are the backup that allow the system to deliver consistent power to all customers, even as demand fluctuates or particular pieces of equipment unexpected fail. Traditionally, they were provided by vertically integrated utilities as part of their bundled energy product, but some reforms include the separate pricing and provision of some ancillary services from that of electric power, even though the actual decisions about how much of each service is needed at each hour, and where, remain primarily under the authority of the system operator. (It is the only institution with the real-time information to know what services are required, and it can arrange the provision of these services for the aggregate load rather than, at higher cost, for individual loads [DOE, 1998*c*]) Ancillary services operate over various time scales, from seconds to hours, and, because they can be transmitted only over certain distances, are differentiated as to place as well as time.

The split of ancillary services from power is also addressed in Order 888. FERC defined ancillary services and ruled that six are to be offered with, but priced separately from, transmission services and that others may be self-provided or provided by the transmitter or by third parties.[24] (FERC, 1996*a*, pp. 198-225, 246). The FERC imposes cost-based price caps for those ancillary services for which a utility has not demonstrated a lack of market power. The utility can offer discounts to reflect cost variations or to match rates available from third parties (FERC, 1996*a*, pp. 250-251). The difficulty for FERC is to set the price-caps so that a utility cannot prevent efficient entry through dropping prices charged those customers who are the most attractive customers for new entrants while subsidising from revenues gained from other customers.

The vertical separation between generation and retail supply promotes competition in generation.[25] While in principle the retail supply part of a vertically integrated entity can be required, by regulation, to purchase the “most economic” energy, in practice it is difficult to price the insurance that is implicit in electric supply contracts, especially requirements contracts, so it is difficult for independent regulators to oversee that, indeed, the most economic energy is purchased. Structural separation of retail supply from generation, with the imposition of a hard budget constraint, provides incentives to purchase the most economic energy, thus increase demand elasticity for electric power, thus competition in generation. The separation and reform of economic regulation of retail supply increases economic efficiency by reducing cross-subsidies to expensive-to-serve end-users, since entrants into retail supply would otherwise creme-skim the cheap-to-serve users. Retail supply separation permits other-than-geographic aggregation of end-users; *i.e.*, geographically diverse end-users may form joint buying groups.

The separation of retail supply from distribution raises issues that are similar to but not identical with those raised with respect to the separation of generation from transmission. The potential for regulatory evasion (the cross-subsidisation of the "competitive" activity--retail supply--by the "regulated" activity--distribution) is present here as well, and can take the form of using the trademark and established reputation from a long existence as a regulated monopolist in order to compete in the retail supply markets. The problem of subtle discrimination, such as delays in providing information or services to non-affiliated retail suppliers, exists in this vertical relationship as well. However, if all suppliers have equal access to information about extensions of the distribution grid, such as to new buildings or houses, then scope for discrimination is smaller than it is between generation and transmission. (This information flow from distribution to supply should not be confused with the informational advantage of the incumbent supplier over entrants into supply, which constitutes an entry barrier.)

In the more reformist states, entry by independent retail suppliers is unregulated, save for regulations to provide consumer protection. Traditionally, municipal utilities in the United States purchased the great majority of the electric energy they re-sold to end-users; the municipal utilities were free to choose their energy supplier. With effective oversight by end-users/voters, they should have had the incentives to procure least-cost energy. Hence, the extent of any entry by competitive suppliers and any resulting price decrease may be a measure of the effectiveness of this oversight.

2.4.2. Competition law and policy

There are three major strands to the competition law in the United States: monopolisation (akin to abuse of dominance in other countries),[26] agreements and mergers. (See Chapter 3 for more detail.) Each of these is relevant to the electricity sector, which is subject to shared jurisdiction by the FERC and the antitrust laws. In addition to enforcement by the federal competition authorities, any person, including individuals and corporations, who is injured by anticompetitive behaviour, including mergers, can sue directly under the antitrust laws, as civil actions, as can state attorneys general. Indeed, private lawsuits account for the vast majority of lawsuits under the American antitrust laws.

American antitrust law treats severely agreements among competitors on price, quantities or who will serve which customers; these agreements are prohibited and are subject to criminal prosecution. Where the same parties engage in repeated bidding against one another, under similar circumstances, they might be expected to learn about each other's bidding strategies. It is an unsettled area of law precisely where increased understanding of the other parties' strategies, and optimal responses putting that understanding to use, leads to a meeting of minds, which would constitute an illegal agreement. Such repeated interactions might occur in electric power pools.

Mergers in the electricity sector are reviewed both by the antitrust authorities and FERC. They apply different formal standards,[27] have available different sets of remedies,[28] but use a common framework, albeit differently interpreted, for evaluating the effect of a proposed merger on competition. The staffs exchange views about how to evaluate mergers in principle but, given the experience in other industries with dual oversight of mergers, such as airlines and railroads, these do not guarantee a common view on any given merger.

To evaluate the likely effect of a proposed merger on competition, both the antitrust authorities and FERC use the DOJ/FTC Horizontal Merger Guidelines, which set out both an analytical framework and specific standards. The five parts of the evaluation are: market definition, measurement and concentration; the potential for adverse competitive effects of the transaction; entry; efficiencies; and failure and exiting assets. This framework is applied on a case-by-case basis in a forward-looking manner, so that mergers in the sector would be subject to an evaluation under the new regulatory regime rather than under assumptions of the continuation of past patterns of *inter alia* inter-utility trade. The evaluation of mergers during the sector's regulatory transition is difficult because predictions about the future effects of a merger are more uncertain.[29] FERC has defined a "safe harbour" for mergers so that transactions that fall within its definition will not be subject to a full FERC hearing on the competition aspects of the merger (FERC, 1996*c*).

Box 8. **Merger evaluation in the electricity sector in the United States**

Markets usually have two dimensions, product and geographic. While there are potentially many different relevant product markets, it may be sufficient to consider only a few scenarios, such as peak, intermediate, and base, that present distinct competitive conditions and occur with sufficient frequency to be of concern. Product markets might also be delineated by duration and the date on which the energy is delivered, which could be several years hence. For each product market, a geographic market is defined. Geographic markets for energy and some ancillary services are limited by transmission congestion, line losses, and charges for transmission. Since these may vary from hour to hour, the scope of geographic markets may vary hour to hour. A refined analysis of a particular merger would likely require a sophisticated transmission model.

After defining markets, sellers into those markets are identified and their market shares are measured. Sellers are determined by the physical location of the generating units, except in the market(s) for reactive supply, which can be provided both from generation and transmission facilities. Market shares reflect generating units' marginal operating costs (*i.e.*, whether they are units that operate at baseload, intermediate, or peakload) and contractual or other commitments of that capacity. Market shares are calculated on the basis of capacity with marginal operating cost below or equal to the price in the market under consideration; *e.g.*, market shares in the intermediate load market would reflect capacity used at baseload and intermediate load. The market shares are used to calculate a measure of market concentration, the "Herfindahl-Hirschmann Index," which is used to form refutable presumptions about the likely effect of the merger. This presumption can be and often is overcome by other factors in the analysis.[30] (Under the DOJ/FTC Horizontal Merger Guidelines, an HHI above 1 800, which corresponds to fewer than five equal-sized firms, is considered "highly concentrated.") Entry is evaluated on the basis of timing (within two years), likelihood, and sufficiency (size).

In addition to mergers between electric utilities, three other kinds of mergers can potentially raise competition issues: between an electric generator and its fuel supplier ("convergence" mergers), between an unregulated and a regulated entity, and between an electric utility and a natural gas utility serving the same geographic area. Convergence mergers raise two sorts of competition issues, the potential to raise rivals' costs and the potential for price increases resulting from unfair access to rivals' confidential information. The first might arise if the generator acquires the only or one of the few suppliers to its rivals, there are no other choices for the rivals or for the downstream customers, and the costs of the generator and its rivals are similar. The second issue might arise if access to rivals' cost information could be used to raise and sustain, *e.g.*, bids into a pool. The second sort of merger might facilitate regulatory evasion, whereby the utility subsidises its unregulated activities from its regulated activities, raising the costs to the latter customers and inducing inefficiencies in both markets. The third sort of merger might reduce competition if the two sources of energy were considered substitutes for, *e.g.*, residential cooking, water heating, or space heating or cooling.

The antitrust laws provide an important safeguard in the liberalisation of the electricity sector. However, they are costly to employ and not omnipotent. One result is limited post-liberalisation remedies to insufficient competition in power markets, which has caused some states to encouraged or require divestiture of some generating assets as a part of the overall reform. Indeed, the proposed Comprehensive Electricity Competition Act would grant FERC the authority to order such divestiture. This seems to be a reasonable safeguard.

2.4.3. *Reliability*

Reliability[31] is provided through the North American Electric Reliability Council. NERC is a voluntary association whose membership constitutes virtually all investor-owned utilities and increasing numbers of independent generators in the United States, Canada, and part of northern Mexico. NERC establishes voluntary policies and standards that increase the reliability of the grid, monitors compliance, and assess the future reliability of the system. Much of the work is done by volunteers, with the large utilities providing the bulk of the expertise and money and wielding much of the power. NERC has an established reputation for technically sound judgement.

Under the old regulatory regime, utilities were content to comply with NERC guidelines. Under rate-of-return regulation, utilities did not have incentives to shirk in their reliability operations because regulators tended to allow all prudently incurred capital and operating costs to be recovered by regulated revenues. When the allowed rate of return was greater than their cost of capital, utilities had incentives to make reliability-promoting investments. Under the new regulatory regime, utilities can take actions that affect their profits but that may incidentally affect reliability. Also, utilities may seek to influence independent system operators in profit-increasing but reliability-decreasing directions. Further, deregulation has increased the number and heterogeneity of economic actors in the sector, thus the number of interests that have to be satisfied to reach a consensus. As a result of all these factors, voluntary compliance with reliability standards is expected to decline (NERC, 1997*b*).

In response to these changes, NERC created a new organisation, North American Electric Reliability Organisation, in mid-1998. NAERO is expected to continue the work of NERC, but with an intention to broaden participation and sources of funding, and to be prepared to be overseen by the appropriate regulatory authorities in the three countries. The latter change would enable mandatory reliability standards to be enforced and is intended to reduce antitrust liability in the United States for co-ordination by erstwhile competitors in order to comply with these standards. The Comprehensive Electricity Competition Act, if adopted, would make this change in status from a voluntary to a self-regulatory organisation under FERC, with respect to activities in the United States.

During the transition to competitive markets, reliability may decline from its current level, though to what extent is unclear. It might decline for two reasons. First, the pattern of use of the transmission grid under competition may be different from its pattern of use under the former regulatory regime, for which the grid was designed. In particular, there may be more long distance transmission. This different pattern of use may place the system under stress more frequently until the appropriate investments can be made. This effect can be reduced if independent system operators (ISOs) are regional, thus able better to take into account transmission congestion over larger regions. In addition, appropriate pricing of transmission, as discussed above, would discourage patterns of use that give rise to reliability concerns, and encourage congestion-relieving investment in the long-run. Explicitly pricing reliability would provide a spur to these investments, but there may nevertheless be a transitional period during which not all transactions desired by market participants can be made and there are financial incentives to operate closer to the limits of the system. (Explicitly pricing of reliability enables larger end-users who highly value reliability to pay for it, while allowing those with a low willingness-to-pay to buy lower-priced interruptible supply contracts. Whereas under the old regime, all customers had to be convinced to support investments for reliability, now those who highly value reliability can compensate utilities for their reliability-promoting investments and operating procedures. Of course, explicit pricing of reliability requires the ability to assign liability in the event of failure.)

The second potential cause of a decline in reliability is that the transition from the existing integrated planning process to a market-driven process of investment in generation and transmission may take some time. Decreased co-ordination of investment during the regime change can reduce reliability. At present, there appears to be a lack of effective mechanisms for paying for transmission extensions that benefit utilities or end-users who are in different states. Both the EIA and NERC have expressed concern that no one is taking responsibility for building new lines and supplying equipment to serve customers in other states.[32] However, if reliability were priced explicitly, or if ISOs were sufficiently large, then such a payment mechanism would likely exist. The Department of Energy has formed a special task-force to assess the impact of competition on reliability, and to recommend measures to help prevent reliability from declining to an uneconomic degree.

For smaller end-users, for whom the installation of equipment for shedding load may be too costly, "reliability" is associated more with weather-related outages, such as trees falling on power lines. For these end-users, reliability is a public good: investment to increase one neighbour's reliability cannot exclude the next door neighbour from benefiting. Regulation of distribution is needed to ensure sufficient provision of such public good reliability.[33]

The reliability regime, which has worked well over the past three decades, will necessarily change as economic regulation of the electricity sector changes. The regime will likely change toward mandatory self-regulation, overseen by the independent regulators of the three North American countries. It is not clear whether efficient long distance transmission investments can indeed be made under a system of state-by-state as well as federal regulation. Finally, it is not clear how the introduction of independent system operators will transform the reliability regime, still based primarily on utilities.

2.4.4. Environmental regulation and subsidies

There are three main points of intersection between environmental and electricity sector regulation. First, some emissions from generating plants are regulated. Second, "renewable portfolio standards," according to which a minimum fraction of electricity would be generated using non-hydropower renewable fuels, have been established in several states and has been proposed nation-wide by the Administration. Third, research, development, and demonstration for the adoption of new technologies to increase energy efficiency and to decrease emissions from generation, is subsidised both at state and federal levels. In addition, there are consumer protection concerns about potentially false claims about the "green-ness" of power.

A nation-wide sulphur dioxide emissions permit trading programme significantly reduced SO_2 emissions from generating plants at costs much lower than expected. (See Chapter 2.) The programme combines fully tradable permits for the emission of SO_2 and requirements for monitoring equipment with a safeguard that, permits notwithstanding, no utility may emit SO_2 above certain limits. Power plants are given permits, the quantity of which is based on historic fuel consumption and a specific emissions rate; new sources, *i.e.*, those joining the programme after January 2000, must buy permits from other participants. Permits can be traded, sold or "banked" (not used until a future year). The first phase, implemented January 1995, applied to 263 units at 110 power plants, mostly coal-burning and located in the east and Midwest. The second phase, beginning January 2000, applies to all utilities generating at least 25 MW. Continuous emissions monitoring systems must be installed in all fossil-fuel generating units over 25 MW and in new units under 25 MW that use fuel containing more than a specified percentage of sulphur (EPA, 1997).

The cost of reducing SO_2 emissions has been considerably lower than forecast: the price of a permit in early 1998 was about US$100/ton, versus expected prices of US$250 to US$400/ton. The average cost of reducing SO_2 emissions using retrofitted smokestack scrubbers was about US$270/ton in

1995, versus expected prices of US$450 to US$500/ton. Part of the reason prices are lower than anticipated is that unexpectedly low rail freight rates (due to changes in regulation of that sector) made switching to burning low sulphur Wyoming coal an unexpectedly cheap alternative to the installation of scrubbers. Also, 1998 prices are considered to be below the long-run average compliance cost because utilities are believed to have over-invested in scrubbers on the basis of pessimistic projections of permit prices (CEA, 1998).

As compared with SO_2, control of NOx is more difficult because utilities, which are easy to monitor, are not the primary emissions sources: Transportation accounts for about 49 per cent of emissions and non-utility combustion for 18 per cent. Utilities are subject to performance standards on NOx emissions that apply to some types of coal-fired boilers since January 1996, and will apply to the remaining coal-fired boilers after 2000. Together, two phases will result in reductions of annual NOx emissions from utilities of 2.4 million tons (EPA, 1998). The development of regional NOx emissions reductions trading is being encouraged by the Administration.

Reduction in the emission of CO_2, as set forth in the Kyoto Protocol on Climate Change, is the object of a number of initiatives. (The United States emits about one-quarter of the world total of CO_2.) Of those initiatives with domestic effect, the Administration estimates that its electricity sector restructuring proposal will reduce greenhouse gases by about 25 to 40 million tonnes per year, despite increased demand due to lower prices. This reduction is expected, by the Administration, both from changes in incentives for utilities to be efficient and from a number of associated initiatives. Much of the decrease in CO_2 emissions is anticipated to come from an accelerated shift from coal-fired to gas-fired power plants due to a more competitive marketplace. Important initiatives include the "renewables portfolio standards" detailed below, cross-subsidies to renewable energy and energy efficiency, "green" labelling to enable voluntary consumer switching to "green" electricity, and "net metering" to encourage small scale renewable fuel-based systems. The Administration proposes spending $6.3billion for R & D and tax initiatives to promote energy efficiency and renewable energy. If these measures are found to be insufficient as the Kyoto implementation timeframe approaches, the Administration proposes a domestic greenhouse gas emissions allowance trading programme, to be integrated with various international flexibility mechanisms such as international emissions allowances trading, "joint implementation" within Annex I countries, and the Clean Development Mechanism (under which "clean development" investments in developing countries "earn" allowances) (Administration 1998).

"Renewables portfolio standards" is a market-based regulatory mechanism to promote the generation of electricity by, usually, non-hydropower renewable fuels. Under such a programme, a specified percentage of electricity must be generated by renewable fuels. No restriction is placed on the technology or the generator. [34] In practice, the programme creates two separate markets, one for electricity generated by renewable fuels and another for all other electricity. Typically, the percentage required is reduced if the cost of renewable fuelled generation exceeds the price of other generation plus an adjustment factor. The "green" electricity is then traded in the competitive market, at whatever price can be received. The mechanism is used in some states, and the Administration has proposed its extension nation-wide. The state of Maine has imposed the largest share of "green" generation of any state, requiring that 30 per cent be produced by hydro-power or renewable fuels (EIA 1998*h*). In Massachusetts, the minimum share of non-hydro renewable fuelled generation increases according to a schedule that depends on the difference between the average cost of renewable technology and average spot market price. If the cost constraint does not bind, then 1 per cent of electricity sold in Massachusetts is to be generated from non-hydro renewable fuels by 2003.[35] The Administration's proposal would slowly increase the nation-wide share to 5.5 per cent in 2010-2015, but with a cost cap of US$0.015/kWh. By contrast, almost all (97.8 per cent) of the net generation of electricity by renewable sources in the United States was by hydropower (in 1996 and 1997) (EIA 1998*d*).

Other environmental programmes take the form of direct subsidies to research, development, and demonstration projects for energy efficiency, cleaner generation, and renewable fuels. With respect to energy efficiency, some U.S. Department of Energy programmes are aimed at buildings and industry, such as changing building codes to admit more efficient techniques, while others are aimed at increasing efficiency of conversion of fuels into electricity. Programmes for cleaner generation focus on coal. There are wind, solar, biomass, and photovoltaic system programmes. *E.g.*, the use of biomass for electricity generation is promoted by subsidies to research and development, studies and demonstration projects through partnerships with private entities, as well as a US$0.015/kWh tax credit for closed-loop biomass projects (those using dedicated energy crops) (DOE, 1996).

Some environmental programmes are funded through non-bypassable wires charges. For example, California and Massachusetts use this means to fund energy efficiency activities, including weatherisation of houses for poor families, and the development and promotion of renewable energy projects. The Administration has proposed that non-bypassable wires charges be used nation-wide for such environmental programmes. In California, consumers who choose a qualified "green" electric power provider will get credits (up to US$0.015/kWh), and the renewable power industry is directly subsidised.

The movement away from pervasive rate-of-return regulation toward greater competition can have effects on the environment directly, as well as indirectly through changing incentives under environmental regulations. The shift toward markets is expected to accelerate the shift toward gas-fired plants and away from coal and oil, which would reduce SO_2 and CO_2 emissions, but could also change the relative usage of baseload and peakload generators. The table below shows the relatively low levels of emissions from gas as compared to coal and oil.

Box 9. **Environmental effects of electricity sector reform**

The environmental objectives for the electricity sector include reduced emissions of and SO_2, NOx, various other noxious gases, CO_2 and other greenhouse gases, and secure storage of spent nuclear fuel. The control of some of these gases, notably of greenhouse gases but also NOx and SO_2, goes well beyond the electricity sector as the gases have significant sources (and for greenhouse gases, sinks) that are not part of the sector. The reform of the sector indirectly affects the level of emissions through possible changes in marginal input fuels, price-induced changes in quantity of electricity generated, and competition- and regulation-induced changes in efficiency. In particular, the introduction of competition in generation can induce changes in patterns of investment for generation that have implications for the mix of fuels used. For example, earlier retirement of coal-fired generation plants and replacement with gas-fired plants implies a reduction in emissions of several gases. Earlier retirement of nuclear power plants and replacement with fossil-fuel plants implies an increase in emissions of several gases. At the same time, if competition induces greater economic efficiency than the traditional form of regulation, then there would be greater incentives to reduce fuel costs, hence for greater technical efficiency of conversion of fuel into electricity, and thus a reduction in associated emission. Further, increased use of time-of-use pricing will discourage demand at peak periods, thus the use of less efficient older plants.

Table 2. **Estimated 1995 emissions from fossil fuel steam electric generating units at electric utilities by fuel type** (thousand short tons)

Fuel	Net generation (TWh)	SO_2	NOx	CO_2
Coal	1 653	11 248	6 508	1 752 527
Gas	307	1	533	161 969
Petroleum	61	321	92	50 878

Source: Electric Power Annual 1995, Volume 2. Energy Information Administration, U.S. Department of Energy, DOE/EIA-0348(98)/2, December 1996; cited in EPA 1997.

The reform of pricing to end-users changes incentives to subsidise energy efficiency-enhancing investments of the type made under "demand side management" programmes. Under the old regulatory regime, all consumers bore the cost of adding new generating capacity; if a subsidy to another consumer to reduce his demand, especially his peak load demand, was cheaper than the capacity addition, the subsidy reduced total cost to the subsidising consumers so was rational for them to pay. Under the new system, consumers who buy power at peaks will themselves pay substantially higher prices,[36] thus internalising the cost of capacity additions. Consumers' reactions may be to invest in time-of-use meters and "smart" appliances that can shift their use of electric power to off-peak periods. The overall reform of the sector can have other effects on incentives to make efficiency-enhancing investments: If the reforms do deliver lower electricity prices, or reduce the cost of new generating capacity, then these investments become less attractive.

Liberalised electricity markets and state-level environmental rules may have complex interactions. Electricity markets are generally larger than states, so generators competing in the same market generally are subject to different state environmental rules. In general, different rules create different costs of compliance. Liberalisation implies that there are limits to sustainable differences in compliance cost between states in the same electricity markets, because if a state imposes rules that increase generating costs significantly above those in an adjacent state, more power might be generated and exported by units in the other state. To prevent this, Massachusetts requires all electric energy sold within its boundaries to meet its own environmental rules, whether the electricity is generated in the state or not.[37] Effective brokerage of state environmental policies at the federal level, or the formation of regional pacts, may be a more efficient way of ensuring that environmental externalities, whether cross-border or not, are fully internalised.

2.4.5. Social legislation

Social legislation for the electricity sector is primarily under state, rather than federal control. Reforms of the sector are designed not to endanger existing social protections. For example, in both California and Massachusetts subsidies to low-income consumers will continue to be paid out of a fee assessed on all end-users. Most systems incorporating retail supply competition provide for a "retail supplier of last resort," so that consumers are not cut-off from electricity supply (Brockway). One example of social legislation changing in response to electricity market liberalisation is that, in California, special provision is made for an information system so that end-users with life support equipment (and thus needing special protection from being cut-off) are centrally identified even after they switch suppliers.

2.4.6. Consumer protection

In states where small end-users have direct access to electricity markets, there are consumer protection issues specific to the transition as well as traditional concerns. In some of the reforming states, utilities that have sent explanations of the reform and its implications for consumers with their monthly bills. California has spent $89 million, mandated by the public utility commission, to inform consumers about their new right to switch electric energy suppliers.[38]

Box 10. **Consumer protection in a liberalised electricity sector**

Consumer protection for this sector includes both variations on consumer protection provided in other sectors and, where end-users have direct access to markets, transitional issues that arise because consumers are newly empowered to take additional decisions. With expanded choice, consumers need expanded truthful information.

The more traditional consumer protection issues involve "slamming," "fly-by-night" sellers, false advertising, "red-lining," and the truthful disclosure of electricity supply contract terms and conditions. "Slamming" means switching consumers from one supplier to another without their knowledge. False advertising may take many forms, but a concern in this sector is that suppliers might falsely label the source of the generated electricity as "green," thereby falsely leading consumers to believe they are self-taxing toward a social goal when they buy a supplier's premium-priced energy. Suppliers might, also, falsely claim that switching suppliers would save consumers large amounts on their electricity bill, when in fact switching suppliers can only reduce charges for energy and not, for example, charges for wires and for stranded costs. "Red-lining" is discrimination on the basis of geographic location of the consumer.

In the United States, "slamming" has occurred in the telecommunications industry and commentators have drawn consumer protection analogies between the two industries. Provisions in, for example, the California law, for third party verification that the consumer really wants to switch supplier, and a three day period in which a small consumer can costlessly cancel a supplier change, should reduce this problem. The registration of all sellers, marketers and aggregators provides some protection that consumers will not be cheated by "fly-by-night" suppliers. In California, all electric service providers offering services to residential or small commercial customers must provide "proof of financial viability" and "proof of technical and operational ability" in order to register.

With respect to false advertising regarding "green" generation, the Federal Trade Commission has Guides for the Use of Environmental Marketing Claims that explain the application of the general requirement that such claims be truthful and adequately substantiated. "Red-lining" is being countered in California with the requirement that the utilities supply areas they were assigned before 31 March 1998. Finally, requiring the uniform disclosure to consumers of the separate charges (*e.g.*, for energy, wires, public goods and stranded costs), other terms and conditions, and other characteristics (*e.g.*, fuel mix and emissions) will help consumers to compare prices and to evaluate claims about the benefits of switching suppliers (which cannot regulated charges).[39] Consumer protection in this sector is, therefore, not different from that required for other goods and services save that, like other newly liberalised sectors, there is a particular transition role for consumer education.

2.4.7. Competitive neutrality

Where privately owned and publicly owned entities, involved in the same activities, receive different treatment, resulting in different costs, because of the difference in ownership, total cost is higher than it would be under equal treatment. The diverse types of economic entities are subject to diverse rules on taxation, regulatory oversight, access to federal hydropower, and other laws. In addition, publicly owned entities operate under accounting and budget rules that do not necessarily require the same accounting procedures for valuing assets or market-like rates of return on equity or market-like debt repayments. Together, these differences result in *inter alia* different costs of purchased electricity and different costs of capital, thus imply that there is not competitive neutrality.[40]

There are substantial differences in the cost of purchased power that result from preferential treatment under laws and regulations. Specifically, some utilities have preferential access to electricity generated by federal hydropower schemes. Electricity thus generated is not sold at market prices; rather, it is rationed, giving publicly owned utilities first call, with privately owned utilities allowed to buy any excess. The price at which this electric power is sold is determined by its marginal accounting cost, charges for irrigation water (a joint product), government accounting rules, and by budget rules that specify net budget flows, interest rates, and repayment terms for the cost of dams and associated infrastructure. These projects have very low marginal costs: Bonneville Power Administration (BPA) and Western Area Power Administration (WAPA), have short-run marginal costs of about US$0.016/kWh and US$0.011/kWh respectively. In 1997, BPA's "preference rate"[41] was US$0.0239/kWh and WAPA's average revenues were US$0.016/kWh, respectively. These figures compare with 1995 industry average revenues of US$0.060/kWh (BPA, 1997, BPA, 1998, WAPA, 1997). Thus, being a preferred customer of the federal hydropower schemes is a valuable status; in essence, it is a subsidy. In addition, the rationing process does not ensure, as a free market would, that electricity goes to those buyers who value it the highest. Hence, replacement by a market would result in a more efficient allocation of electricity generated by federal hydro-power schemes, and overall savings on the generation of electricity.

Differences in the cost of capital are also large. Debt is subject to different tax rules; for example, local publicly-owned utilities may issue bonds that are exempt from federal taxation, subject to some restriction. The cost of capital is lower for some public entities not only because of different tax treatment, but also because of markets perceiving their debt to be less risky because it is backed by a taxing authority and, for some, because they may not be required to return a market rate of return on investments to their owners or to make market-like debt repayments.

There are a variety of other unequal treatments. For example, the federal corporation Tennessee Valley Authority and federal power marketing administrations such as BPA and WAPA, are exempt from federal and state corporate income taxes. Publicly owned utilities may not be subject to regulatory oversight, notably with respect to their charges for transmission (although this would change under the Administration's proposed Comprehensive Electricity Competition Act), and may be exempt from various laws that affect their costs, ranging from environmental to labour standards laws. Further, as provided in the Energy Policy Act, certain companies have preferential access to research and development funding.[42] On the other hand, privately owned utilities, or their ratepayers, bear the costs of complying with regulation, *e.g.*, the cost of credibly conveying information to the independent regulator, a cost which is not borne by publicly owned utilities.

The Tennessee Valley Authority provides an example, albeit perhaps an unusual one, of the effect of the special treatment. While the TVA is required to be self-financing with respect to electric power, its prices do not reflect US$14 billion of non-producing nuclear assets. The implicit federal government guarantee has enabled TVA to borrow US$26 billion (as of September 1994) at low interest rates.[43] It pays no federal income tax. TVA is protected from competition by the EPAct, which does not require TVA to comply with the new grid access requirements, and by provisions in TVA's contracts with distribution companies that severely limit distributors' abilities to buy from other sources. (The contracts provide that TVA supplies all their electric power and, if a distributor wishes to cancel the contract, it must provide ten years notice.) However, TVA can be and has been ordered to provide transmission access to specific requestors. Despite these advantages, the Government Accounting Office writes that, "TVA would likely be unable to compete with its neighbouring utilities in the long term" (GAO, 1995).

Publicly owned utilities sell their power on average about one-sixth to one-fifth cheaper than do investor owned utilities. The American Public Power Association (an organisation of publicly owned utilities) estimates that tax-exempt financing accounts for four to five percentage points, and preferential access to federal hydroelectric power accounts for another 1.5 to two percentage points of this difference; the Edison Electric Institute (an organisation of IOUs) estimates that the entire gap is explained by tax, legal and regulatory advantages (IEA, 1998). However, if publicly owned utilities are not 11 to 13 per cent (of revenue) more efficient than IOUs (that is, if the remaining price difference is not explained by differences in efficiency), then the large difference in average price of power sold suggests that, even by conservative estimates, there is significant competitive non-neutrality.

2.5. Stranded costs

The third main part of the United States electricity reform is the measurement and recovery of stranded costs. This part is primarily about the redistribution of rents: the assets are already sunk in the sector, but the revenues that they will generate under the new regulatory regime are expected to be lower than the revenues they would have generated had the former regime continued. At the same time, a poorly designed recovery system can inflict real costs on the economy through distorting prices of electricity or distorting entry decisions.

Roughly two-thirds of the total stranded costs in the United States are estimated to stem from nuclear investment and the remaining one-third from high-priced power purchase requirements of cogeneration and renewable energies mandated by the Public Utility Regulatory Policies Act of 1978 (PURPA). Direct access to power markets by all end-users is estimated to cause 80 per cent to 90 per cent of the total (IEA, 1998). Owners of nuclear power plants are required, by independent regulators, to be prepared to bear the cost of decommissioning.[44] This regulation has not changed in the reforms. If electricity reform results in earlier than planned shutdown of nuclear plants, then this would be provided for as via the same mechanisms as other stranded costs.

Given that United States has radically reformed the regulation of numerous sectors, often in ways that changed the value of private assets, it is reasonable to ask, what is different about this sector that stranded costs are recovered? During the reform of natural gas regulation, a sector also under the responsibility of the FERC, the reform was challenged in court. That court told FERC that it must take into account the transition costs borne by regulated utilities when the Commission changes the regulatory "rules of the game." Hence, while much of the public discussion has focused on the fairness, or not, of requiring shareholders or captive customers to bear the costs of transition because of a regulatory change beyond their control, the FERC states that, "We learned from our experience with natural gas that, as both a legal and a policy matter, we cannot ignore these costs" (FERC, 1996*a*, p. 453).[45]

Box 11. **Stranded costs**

"Stranded costs" are those unamortised costs of prior investments or ongoing costs because of contractual obligations, prudently incurred under the prior regulatory regime, that will not be recovered under the new, more market-based regulatory regime. At the same time, some assets or rights are made more valuable by the reform. Stranded costs are associated with, and defined by, each regulatory authority that changes the regulatory "rules of the game."

The key reform elements are to provide incentives for incumbents to mitigate (reduce) stranded costs, to measure them accurately, and to assign their recovery in a way that is "fair" and that does not impede efficient entry or pricing of energy. Putting stranded cost charges in a usage-insensitive part of a multi-part tariff reduces their distortionary effects on future market behaviour. Making payments for stranded costs non-bypassable by users will not impede efficient entry decisions. The distribution of stranded costs and benefits has important wealth effects, so their assignment can influence whether efficiency-enhancing regulatory reform has sufficient support to be adopted.

The FERC defines "wholesale stranded costs" as "any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to: (1) a wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility, or (2) a retail customer, or a newly created wholesale power sales customer, that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility" (FERC, 1996*a*, p. 618). The idea is for the utility to recover costs incurred to serve a customer who now chooses to buy energy from another utility. The costs can only be recovered where the utility has shown that it had a "reasonable expectation" that the customer would remain in the generation system. Stranded costs must be directly assigned to the customer for whom those costs were incurred, and that customer must pay for all the costs assigned to it. Payment is either as a lump-sum or a surcharge on transmission.

According to FERC Order 888, the amount of stranded cost is calculated as the revenues that the customer would have paid had it remained a customer, for so long as the seller could reasonably have expected such purchases to continue**,** less the market value of the power the customer would have bought[46] (FERC, 1996*a*, pp. 492, 501, 573). There is no stranded cost unless the market price of electricity (when the customer leaves) is lower than the utility's cost. The stranded cost for a customer is finally determined only if that customer actually leaves the utility (FERC, 1996*a*, p. 479). (Customers who stay with their original utility continue to pay for past investments as part of the tariff for their bundled electricity service.) Divestiture of generating assets by utilities increases the information about the market value of generating assets, so that the market value of those assets that are not sold can be more precisely estimated.

In California, for example, the definition of stranded costs (called "transition costs") reflects the assets and activities over which the California Public Utility Commission (CPUC) has jurisdiction.[47] The CPUC determines the amount of transition costs,[48] and cannot adjust these costs after 2015. The transition costs for generation-related assets net out above-market and below-market transition costs of all utility-owned generation-related assets (CPUC 1997*c*). (In other words, if some generation-related assets have a market value above net book value, then these must be used to offset those that do not have a market value above net book value.) Transition costs are allocated to the various customer classes in substantially the same proportion as similar costs were recovered on 10 June 1996. Transition costs are non-bypassable and a "firewall" ensures that residential and small business customers do not pay more than their allocated transition costs. Transition costs are based on each customer's purchase of electricity. Departing load customers must pay a lump-sum fee that is equal to the net present value of the customer's remaining transition cost obligation (CPUC, 1997*b*). While most transition costs are intended to be paid off by end 2001, the transition costs for residential customers and the January 1998 rate reduction will not be. Instead, through 2002, residential and small commercial customers will pay “fixed transition amounts,” a surcharge, to a financing entity. These revenues will pay off “rate reduction bonds,” the proceeds of which pay the transition costs and financing costs thereof. These transition charges account for about one-third of residential monthly bills (EIA, 1998*h*).

3. Market structure

3.1. Market definition and market power

Liberalisation of the electricity sector in the United States has substantially increased the number and scope of markets. The United States is sufficiently large, and the transmission grid insufficiently dense, that there is not a single geographic market.

Box 12. **Market issues in the electricity industry**

The more fundamental reforms establish markets for electric power, some ancillary services, and financial instruments based on electricity. Markets for transmission rights could also be established. While electric energy *per se* is homogeneous, it is differentiated in time, duration, location, and reliability.[49] For example, the delivery date may be several years in the future, or within the next hour. Markets are defined by regulations (what is permitted to be bought and sold, who is permitted to participate). If regulations are not binding, the geographic extent of a market for electricity is determined primarily by transmission congestion and charges for transmission, as well as, secondarily, line losses.[50] These in turn greatly affect the degree of market power. The geographic scope of electricity markets may vary greatly over the short term: As more electricity is generated, transmission congestion increases, the geographic scope of markets shrinks (regions become isolated), the number of potential suppliers of electricity falls (changing the market structure), and their market power increases.

Market concentration

If power markets are to operate competitively, then the ownership or control of generators must not be unduly concentrated. Deconcentration can be promoted by augmenting transmission links between areas, thus expanding the geographic scope of markets, and by promoting divestiture of generating capacity or of long-term capacity contracts in a market to multiple owners.

Concentration of generating capacity does not always accurately predict the degree of competition in an electricity market because some underlying assumptions of the economic models that motivate the use of concentration measures may be violated, and because these measures do not account for the effects on competition of entry and vertical integration. First, a number of would-be competitors, the publicly owned entities, do not try to maximise profit. Second, many consumers are not price-sensitive; indeed, many are charged only an average of the market price. Third, an institution at the heart of the market, the system operator, makes commercially sensitive decisions on engineering rather than commercial bases. Each of these facts is a significant deviation from the usual assumptions in market models; this implies that the relationship between market power and measures of capacity concentration is more tenuous than usual.[51]

In addition to these shortcomings, market concentration measures ignore entry conditions and the degree of vertical integration. Entry, in the short-run, depends on transmission constraints and the opportunity cost of competitive generation capacity (that is, the profit that is given up if electricity is not sold into another market but rather into the market under discussion). Where transmission is constrained, generators near a load centre might profitably sell to the less than most efficient purchaser increasing constraints on transmission into its area, and thereby “separating” or “isolating” its area from a larger market. Where generation and transmission have common owners and the available capacity of or terms of access to transmission can be influenced by the owner, such variables may be used to affect competition in the generation markets. Most models underlying concentration measures implicitly assume no entry and competitive input markets. Therefore, market power is better measured using more sophisticated models that explicitly take into account the specific characteristics of the electricity supply industry, including transmission constraints.

Entry

Actual entry into generation markets reduces market power by reducing the concentration of generators. Given the significant sunk costs of entry and the likelihood that the "best" locations are occupied by incumbents, potential entry is relevant only for markets for electricity a few years in the future, or where entry could be effected over existing, uncongested transmission lines or sufficiently near load (a concentration of electricity users).

Demand-side effects

Demand influences market power in electricity markets. In particular, where demand is more inelastic (*i.e.*, less responsive to price changes), generators can receive higher prices. Where end-users have direct access to the market for electricity, the elasticity of demand can be increased by better price signals to end-users and increasing the ability of end-users to respond to price signals (*e.g.*, by more time-of-use pricing and interruptible contracts). Where end-uses do not have direct access to a market for electricity, the elasticity of demand can be increased by altering the regulation of franchise suppliers to increase their incentives to ensure lowest cost procurement in the wholesale electricity market(s), and by, for example, making the end-user tariff scheme more reflective of cost.

Markets for ancillary services

Some ancillary services can have rather unusual substitutes: reactive power produced by generators might be partially substituted by capacitors or other reactive compensation devices located at load centres (Borenstein, 1995); and demand for supplemental reserves can be reduced by increased use of interruptible supply contracts and time-of-use meters. Because the same infrastructure (generators) can supply either power or some ancillary services, where both are provided in markets there will be substantial interactions. Most generator-provided ancillary services can be transmitted over some distance so competitive markets could develop. However, other services provided by generators can be transmitted only over short distances, hence are likely to have very small geographic markets, which implies that competitive markets are less likely to develop[52] (DOE, 1998*c*).

Power markets have been examined in a few regions in the United States. Borenstein *et al.* looked at California and PJM Interconnection (in the mid-Atlantic region). They found that there was almost no market power at low levels of demand but that, at high levels of demand when transmission becomes congested, there is market power in sub-regions in both parts of the country. They state that, "In almost every electricity market that we, or others, have examined there is little potential for market power in off-peak, low demand hours. In many markets, however, there is significant potential for market power during peak hours" (Borenstein *et al.*, 1998).

Notwithstanding the general limits on the predictive value of generation capacity measures, where concentration is high and transmission is sometimes congested there is likely to be market power during periods of congestion. The IEA 1998 review of the United States noted several examples of regional market power in the following:

– Southwest Power Pool, within which Entergy owns 68 per cent of total generating capacity and 80 per cent of peak generating capacity, and which imports only five per cent of total sales (FT Energy World, 1998).

– Michigan, in which Detroit Edison and Consumers' Power own virtually all the generating capacity and transmission assets, and which has severely constrained transmission lines.

– The area served by Virginia Power, in which the company controls virtually all generation and the maximum transmission import capacity is only three GW to four GW to serve a peak load of about 15 GW (Virginia SCC, 1997).

There are two principal forms of entry into electric generation markets: new or expanded generating capacity within the existing product and geographic market, which may also serve to reduce transmission constraints thus expanding the geographic scope of markets**,** and enhanced access to existing generating capacity because of new or expanded transmission capacity (FTC, 1998*b*). Significant entry into generation is occurring: While only about 10 per cent of current generation is owned by "non-utilities," it is estimated that 50 per cent of all incremental generating capacity projected to come online within the next decade belongs to independent generating companies (NYMEX).

Increasing the elasticity of demand is another part of the development of markets for electricity in the United States. This is accomplished by the introduction of time-of-use metering and time-of-use pricing. When these are introduced, end-users have incentives and ability to react to changes in price. So long as consumers do not have a choice of supplier, so that they must pay the average price of electricity, and time-of-use meters are sufficiently costly, suppliers do not have incentive to separate consumers with price-sensitive demand from consumers with less price-sensitive demand. However, where there is competition in supply, suppliers have incentives to introduce time-of-use pricing and meters to separate consumers with price-sensitive demand, since these consumers can be supplied at lower cost that average consumers, when they are faced with time-of-use pricing. Granting direct access to electricity markets by all end-users in the more reformist states should increase elasticity of demand, as should innovations in pricing to better transmit to end-users the marginal cost of their choices.

3.1.1. Market transparency

Market transparency can refer to both markets for power and markets for transmission. Market transparency for the former is increased when there is greater publicly available information about prices of traded electricity. These prices might be spot market prices or prices for bilateral contracts. While prices for bilateral contracts are usually not public information, one of the advantages of an established spot market, such as the Power Exchange in California, is that the market clearing prices are immediately publicly known. The price spikes experienced in the Midwest in Summer 1998 (up to US$7.50/kWh—perhaps 200 times higher than average**--**for one hourly contract) are partially attributed to a lack of a centralised, deep, spot market, and one of the recommendations made to reduce the likelihood and magnitude of such a future event is the establishment of such a market (FERC, 1998*b*). It has been suggested that, given the relative lack of knowledge about how markets will work in the United States electricity sector, there be stringent market information reporting rules that might allow regulators to detect the exercise of market power. Such information should not be made available in a way to promote parallel pricing, that is, co-ordinated (but not agreed) pricing by utilities.

Market transparency in the United States with respect to transmission is increased by FERC Order 889, combined with other FERC rules, that ensure that open access tariffs and real-time information about the availability of transmission are publicly available. In other areas, notably the PJM Interconnection, fixed transmission rights are traded in a market.

Box 13. **Market transparency**

Where trade occurs primarily as non-public bilateral transactions, there is little price transparency. This makes it difficult for regulators to detect excessively high prices, and for economic entities to make rational decisions about entry or expansion. The introduction of anonymous, public trade in electricity-based financial instruments with immediate disclosure of prices provides price references and price transparency, and a liquid market for better handling of risk by generators, users and intermediaries.[53] Examples of risks that can be hedged are changes in the relative price of electricity and gas and changes in relative prices of electricity at different locations.

3.1.2. International trade

There is some international trade in electricity both with Canada and Mexico, although the Canadian-United States trade is much more substantial. Canada exports locally significant amount of electricity to particular parts of the United States, notably by Hydro-Quebec from Quebec to the major cities in the Northeast. As compared with total generation in the United States of more than 3 500 TWh, imports are small, albeit exports are significant in Canadian terms. However, since the United States is not a single market for electricity, a comparison of nation-wide statistics has limited importance. The following table provides the summary data.

Table 3. **Electricity Imports 1990-1996, in Terawatthours**

	1990	1991	1992	1993	1994	1995	1996
Imports							
United States	22.6	30.8	37.2	39.1	52.2	46.8	46.5
Mexico	0.6	0.6	1.0	0.8	1.1	1.2	1.3
Canada	19.4	7.9	7.9	9.8	6.5	8.0	7.7
Exports							
United States	20.5	8.5	8.9	10.7	7.6	9.1	9.0
Mexico	2.0	2.1	2.0	2.0	2.0	2.3	1.3
Canada	20.1	28.7	35.2	37.1	50.2	44.5	45.3

Source: Energy Information Agency, U.S. Department of Energy, International Electricity Data, at http://www.eia.doe.gov/emeu/international/contents.

The reciprocity requirement in FERC Order 888 has come to the attention of trade officials in Canada. Essentially, it requires that a utility that wishes to use another's transmission, offer transmission access to that utility. While the requirement might have been aimed at utilities in the United States, it has had an effect on Canadian utilities. In particular, it has been applied by FERC so as to require Canadian utilities that wish to sell into the United States at market-based rates to offer open access transmission tariffs.

Implementation of the Order 888 reciprocity test has impacted Canadian utilities in different ways. For provincial utilities in Manitoba, Quebec, and British Colombia, where energy exports represent a core business, domestically-generated power is highly competitive, and wholesale loads are negligible (so that providing open access to transmission lines was not viewed as exerting much, if any, competitive pressure on existing market share), compliance with the FERC reciprocity requirement proved the chosen course for accessing the U.S. wholesale market.

For another provincial utility, however – Ontario Hydro – the reciprocity issue has played out very differently. Due to fundamental differences in the Ontario industry structure, the province was not in a position to comply with the reciprocity requirement,[54] resulting in denial of its bid for open access to the U.S. wholesale market. Ontario Hydro has subsequently challenged FERC's authority to order open access as a condition of Canadian participation in the U.S. market, an issue which is before U.S. courts. In the meantime, Ontario Hydro has claimed that U.S. border utilities have been able to exert market power over it by refusing to sell transmission services.

These types of sector-specific restrictions may be based on legitimate public policy objectives. Whether or not such legitimate domestic objectives can be met through less restrictive means, however, seems a fair question.[55]

3.1.3. Financial markets

Financial contracts based on electricity are traded on the New York Mercantile Exchange, which is also the exchange for contracts based on crude oil, refined petroleum products, and gas, as well as a handful of other exchanges. Since 1997, electricity futures have been traded. Initially based on two nominal locations in the West (at the California-Oregon Intertie and the Palo Verde, Arizona switchyard) there are now futures with nominal locations elsewhere in the country. Other locations are being added. Options contracts have also been introduced. While the contracts allow physical delivery, only about one per cent is delivered (NYMEX).

Financial contracts can be used to reduce market price risk. As there is greater use of spot markets, utilities and end-users may wish to reduce their exposure to the riskiness of the spot market. A utility, for example, can buy a financial instrument that establishes a position that is opposite to its position in the "cash market," thus insuring itself regarding the price it will obtain for electricity. Financial instruments can even be used to shift risk onto entities that are neither utilities nor significant electricity end-users.

Box 14. **Financial markets**

Financial contracts greatly expand the possibilities for generators, users and intermediaries to manage market risk. The exchange of these financial contracts in an anonymous, public market with immediate disclosure of prices provides price references and price transparency, and a liquid market for better handling of risk. Examples of risks that can be hedged are changes in the relative price of electricity and gas and changes in relative prices of electricity at different locations.

3.2 Independent system operators: A new institution

A number of ways to organise regional transmission are under consideration or implemented. These include independent system operators (ISOs) and transmission companies (transcos). ISOs are newly developed institutions, designed to ensure non-discriminatory access to the transmission grid even while it is owned by vertically integrated utilities, and to ensure continued reliability of the power system. Four independent system operators (ISOs) have been approved, some conditionally, as of July 1998, in New England, the PJM Interconnection (in the mid-Atlantic states), California, and New York. A number of other ISOs are under discussion. It is important to note that the ISOs are heterogeneous, differing in important respects. Interestingly, there has been speculation that concerns about reliability and competition might lead to the consolidation of ISOs into as few as three ISOs to cover all forty-eight contiguous states (FTC, 1998*b*). A transco combines the ownership of the grid with the responsibilities of an ISO.

The governance structure of ISOs treads a fine line between maintaining independence from generators and transmission owners and users on the one hand, and having sufficient technical competence to ensure safe and reliable operation on the other hand. (Much of the technical competence rests within the vertically integrated utilities.) The ISOs must be, and be perceived to be, independent from the vertically integrated utilities; if they are not, then not only will independent generators will be hesitant to make investments in the territory of the ISO, but also grid expansion and grid access may be discriminatory, further discouraging entry.

The governance issue has been addressed in New England, PJM and California. In the former two, there is a two-tiered system, in which an independent non-stakeholder governing board, members of which are not affiliated with market participants, is advised by committees of stakeholders (FERC, 1998). For New England, this represented a broadening of governance from that of NEPOOL, the predecessor organisation. Oversight of both the ISO and the operator of the spot market in California is provided by a board of political appointees; ISO-NE is monitored by the state regulator.

The responsibilities of ISOs can vary from one ISO to another. For example, PJM is responsible for centralised dispatch, system stability and reliability, managing the open access transmission tariff, facilitating the spot market and accounting for energy and ancillary services (PJM). ISO-New England, in the north-eastern states, has similar responsibilities, save the accounting functions. By contrast, in California, Cal-ISO controls the transmission grid, but does not centrally dispatch. However, the cost-minimising merit order that is established in the PX (the spot market) is subsequently revised by Cal-ISO to take into account feasible and cost-minimising operation of the transmission grid.

While FERC has not mandated the establishment of ISOs, it has encouraged their development and provides principles for ISOs as a way to provide guidance for their approval. In essence, an ISO should have a governance structure that is fair and non-discriminatory, should provide open access to the transmission grid and services under its control, should have transmission and ancillary services pricing policies that promote efficient use of and investment in transmission, generation, and consumption, and should have responsibility for short-term reliability over its area (FERC, 1996*a*, pp. 280-286). An ISO does not necessarily have responsibility for transmission system augmentation.

One aspect of governance that has not been effectively addressed is how to provide an ISO with incentives to operate efficiently and to make economically appropriate investment decisions regarding expansion of the transmission grid. If it is difficult for an independent regulator to detect subtle discrimination, then it would also seem to be difficult for an ISO governing board to monitor and control the same activities. A transco, where the ownership of the transmission grid and the ISO are in the same hands, might reduce some of these incentive problems. No one has yet designed, however, regulations to ensure that a transco will discover the optimal investments and make them. The difficulties of devising operating rules for ISOs would remain even in a transco, since their objectives will continue to deviate from the socially optimal objective: The transco would seek profits while the desired operating rules would seek to minimise system cost.

The geographic scope of an ISO can affect its effectiveness. An ISO with limited geographic scope may suffer from two problems: insufficiently deconcentrated generation (hence problems of market dominance in generation) and insufficient diversity in generation (number and type) for adequate system reliability. Divestiture of generation to several different owners can eliminate market power or dominance in the area of an ISO. (Divestiture may have the additional benefit of improving the governance structure.) Further, a larger ISO, having greater incentives to strengthen transmission links in its area in order to avoid transmission bottlenecks, can increase overall reliability. As noted above, there have been suggestions that the 48 contiguous states may, in the end, have perhaps as few as three ISOs.

The institutional structure of ISOs is still evolving in response to actual experience in the United States markets. While some of the limits of the possible institutional structure have been identified on the basis of analysis of incentives of participants, no ISO has yet operated for a sufficiently long time that it is clear that this new institution will deliver on its promise, in practice. Hence, even where a reform does not require divestiture of generation from transmission, it is important that reforms contain the option to require divestiture in the event that an ISO does not, in practice, deliver the appropriate operational and investment outcomes.

4. Performance

4.1 Prices, costs and productivity

Electricity prices in the United States are low by comparison with other OECD countries. In 1996, average revenues per kWh (for sales to final consumers) were 7.12 cents for investor-owned utilities (about 75 per cent of the total quantity sold), 6.01 cents for publicly owned utilities, 6.74 cents for co-operatives, and 2.52 cents for the very limited sales to end-users by federally owned utilities. According to the IEA, average revenue (or expenditure) per kilowatt-hour for industrial customers was US$0.046 in the United States, but US$0.056 (at purchasing power parities) in the OECD as a whole, in 1996. For households, the corresponding figures were US$0.084 cents and US$0.104 cents, respectively (IEA, 1998*b*). (Given that the United States has a large weight in OECD averages, and its prices are significantly lower than average, the comparison here understates the price differences with other countries.) Given that utilities have been regulated so that revenues covered costs (including a "fair" return to capital) and that utilities operating in the liberalised markets are privately owned (thus over time revenues must exceed costs), low electricity prices imply low costs of generating and delivering electricity.

These average prices, however, mask sizeable variances in production costs and efficiency among producers. Within the United States there are significant differences in the cost of building comparable generating facilities, both nuclear and fossil fuel. There are also significant differences in the speed with which utilities adopt new technologies (Joskow, 1997). These imply that there is scope for increased productive economic efficiency in the sector over the medium to long-term.

The statistics on average revenue per kilowatt-hour do not give information about the structure of prices. As described earlier, price structure can significantly affect economic efficiency by encouraging or discouraging purchases when the marginal value of additional energy to end-users is higher than its marginal cost. At present, multi-part time-of-use pricing systems are not in widespread use; the traditional "average total embedded cost" pricing system is still dominant. Hence, there may be substantial allocative efficiency losses. One estimate that prices would be six to 13 per cent lower with marginal rather than average cost pricing, (EIA, 1997*f*) implies that large allocative efficiency gains would be possible.

Economic efficiency gains over the past two decades have been substantial, as the amount of inter-utility trading and the number of independent power producers have increased. Non-fuel operations and maintenance (labour, rent, lubricants, coolants, limestone and other services needed to run a plant) have declined 22 per cent from 1981 to 1995. The number of employees per megawatt of capacity fell 20 per cent over this period (EIA, 1998*g*). Labour cost per kilowatt-hour decreased from about 0.7 cent per kWh in 1986 to about 0.5 cent per kWh in 1995 (EIA, 1997*e*, Figure 17). Average availability rates for coal plants increased from 76 per cent to 81 per cent from 1984 to 1993 (EIA, 1997*f*).

4.2. *Environmental performance*

Another measure of performance, in terms of the United States' policy goals, is environmental performance. Emissions from utility-operated fossil fuel plants plus non-utility plants larger than one MW totalled about 6.2 tonnes of SO_2, 4.0 tonnes of NOx, and 1 198 tonnes of CO_2. With respect to CO_2 emissions, in 1995 the US emitted 0.86kg per dollar of Gross Domestic Product, which compares with an OECD average of 0.60kg/US$ (using 1990 prices and exchange rates). (The comparable figures for OECD Members in Europe and in the Pacific are, respectively, 0.46kg/US$ and 0.41kg/US$) (IEA, 1997).

With respect to emissions, the value of the environmental externalities from SO_2 and NOx would be expected to vary from location to location; hence, it is difficult to interpret a simple sum of emissions.

4.3. *Reliability and security*

The United States (and Canadian) performance as regards reliability, as evaluated by the North American Electric Reliability Council, is good. (The NERC standard is that no customer should lose power more than once in ten years.) Reliability is expected to be adequate over the next three to five years, with some short-term concern in regions where nuclear generation unavailability could cause capacity shortages during peak conditions. However, little investment has gone into strengthening the bulk transmission system over the past ten years. Further, the time required to plan, site, gain the necessary approvals and construct major transmission system projects is increasing (NERC, 1997*c*). National capacity margins were 18.9 per cent for the summer peak and 28.7 per cent for the winter peak (EIA 1998*f*).

The United States has a diverse fuel mix, as shown in Table 1. In addition, mechanisms are in place that encourage appropriate diversity: The choice of fuel inputs is not restricted in the United States, fuels can be and are purchased through liquid markets, markets for financial instruments derived from some fuels and electricity are developing, there is significant trade in electricity among utilities, and there is increasingly competition for sales of electricity directly to end-users. The first four conditions imply that utilities have the ability, and the last that they have the incentives, to provide an appropriate level of fuel diversity.

4.4. *Other aspects of performance*

The above measures of performance have been rather static. Another aspect of performance of a sector is its ability to deal with unexpected events. The evolving market and regulatory system demonstrated its robustness, although with a less than optimal performance, during price spikes in summer 1998. In June 1998, a combination of factors--weather, generation outages, and transmission constraints--resulted in dramatic price spikes in the Midwest. At its peak, there were significant hourly purchases in the US$3 000 to US$6 000 range, and one hourly price reached US$7 500/MWh. Some aspects of the market did not perform adequately. Nevertheless, there was adequate electricity delivered. In response, changes in tariffs and institutions have been proposed.[56]

Overall, the electricity sector in the United States performs well,[57] both relative to other OECD countries and in terms of the Administration's stated policy objectives. Prices are low, compared with those in other countries; given that revenues must equal costs for the regulated privately owned utilities, and they are the dominant form of enterprise, this suggests that the United States electricity sector is relatively efficient. In terms of environmental goals, much has been done toward reducing SO_2, NOx, and other noxious emissions. However, little has been done in the United States toward reducing emissions of

CO_2. Further, performance as measured by energy efficiency *per capita* and per unit GDP is low by the standards of IEA countries. Reliability is currently good, but ensuring adequate transmission investment may become a concern in the longer term.

5. Conclusions and policy options for reform

5.1. General assessment of current strengths and weaknesses

The United States has made substantial progress toward reforming its regulatory regime for the electricity sector, and is en route to attaining many of its policy objectives, but has not yet completed the journey. The reforms presently envisaged, if adopted, will likely achieve many economic objectives for the sector, but meeting the environmental objectives may require additional efforts. Social protections, *e.g.*, subsidies to poor consumers and consumer protection, are secured. The wide participation of interested parties, the public nature of the discussion, decision-making, and explanations of decisions, has protected the legitimacy of the reform and may well cause a superior outcome. There remain, however, unfinished aspects to the reforms, primarily with respect to the operation of and investment in the transmission grid, system operation, stranded cost recovery, and competition to supply end-users ("retail competition"), that have implications for economic efficiency and reliability.

The United States electricity sector seems to be well on the way to increasing economic efficiency. Electricity trading among utilities has already resulted in efficiency gains over the past several years. Nevertheless, the federal reforms to provide for non-discriminatory, efficient access to transmission and further grid investment, to support this trading, could be further strengthened.[58] The movement away from a cost-plus system of economic regulation toward greater competition in generation and retail supply and performance-based regulation of transmission and distribution should increase incentives for efficient entry of new competitors using new technologies, to reduce internal economic inefficiencies, to price more efficiently (*i.e.*, reflect cost and value to the buyer), and to provide new products that better meet the needs of end-users.

However, the extension of access to the electricity markets to end-users ("retail competition") is not yet complete. Indeed, it is in the dimension of retail competition that the heterogeneity of the American reforms has the greatest visibility and effect, not only directly, but also through its implications for other regulatory changes. The differences among states arise, in part, because the states are at different stages along similar reform paths, but also because there is not agreement that retail competition is, indeed, the path that every state wishes to take. While federal institutions are influential, state legislatures ultimately are responsible for the decision whether to allow retail competition. The federal-state split in responsibilities makes reaching a nation-wide decision difficult.

The heterogeneity of the United States electricity sector reforms creates opportunities and costs. The opportunities include faster innovation in regulatory regimes from learning from parallel yet different state reforms, as well as being able better to design reform appropriate to the starting point. Costs include building interfaces between different regulatory regimes, lost efficiencies from regional markets having to operate under multiple regulatory regimes, and increased compliance costs from utilities operating in multiple regimes. Regional pacts regarding the regulation of the sector, where the regions are coincident with electricity markets, could reduce some of these costs, while retaining the flexibility and heterogeneity to allow regulatory innovation. Indeed, FERC is moving to implement this type of solution with its announced generic Notice of Proposed Rulemaking on regional independent transmission entities.

Conveying to FERC, DOE's authority to organise regions of the country for reliability purposes may further this process.

The measurement of stranded costs seems to be converging toward a mechanism that also enables the post-transition structure to be conducive to competition, that is, by measuring the market value of assets by the price they receive when they are actually sold. As more assets are sold, their prices provide information that can be used to estimate more accurately the market value of assets that are not, in the end, sold. However, the recovery of stranded costs is not always designed in the US to minimise distortions. There are two potential types of distortions: too much (too little) electricity purchased, and too much (too little) entry. If stranded costs are recovered through a usage-sensitive fee (*i.e.*, on a per kilowatt-hour basis), then the fee acts like a tax, thus implies that too little electricity is purchased. If stranded costs are bypassable, then there may be too much entry because entrants would be able to sell to those users who can bypass, even if the entrants had higher costs than incumbents. If switching costs for users are high, then there may be too little entry. If stranded costs depend on prices actually realised in the market, then incumbents have an incentive to lower prices, excluding entrants, and receive their payments through higher stranded cost recovery. Beyond these concerns, the recovery of stranded costs is largely a political question, that can only be resolved through negotiation.

The structure of transmission pricing has undergone only partial reform. The structure of transmission pricing must complement the structure for dispatch (whether and how each generating unit is used) and transmission investment decisions. Nodal pricing has been adopted in only part of the country, and experimented with elsewhere, but the remainder of the country remains under zonal pricing or other types of pricing that depart further from pricing that would induce efficient short-term behaviour. While nodal pricing can be expected in theory to provide the signals for efficient operation and investment in transmission, implementation issues remain, as for any transmission pricing system. In addition, it is not clear that any pricing scheme, alone, will overcome regulatory difficulties of siting new transmission lines

Similarly, the structure of prices offered to end-users is only at the beginning of reform. Pricing structure reform could induce more efficient use of electric power. Allocative economic efficiency[59] is highest when price equals marginal *social* cost,[60] which is the total of the value of environmental and other externalities and the marginal cost of delivered electric power. Leaving aside the difficulty of calculating the value of the externalities, the marginal cost of delivered electricity is independent of stranded costs, and varies by time of use (low when demand is low, high when demand is high). Thus, moving stranded cost recovery from a usage-sensitive charge to a usage-insensitive charge (a "fixed" part of a multi-part tariff) would allow prices to move toward the level of marginal cost. Similarly, the introduction of time-of-use pricing would provide incentives to build more peak load capacity where it is needed and for consumers to shift demand away from peak periods. Clearly, there are fixed costs to switching pricing schemes: In choosing among the menu of pricing schemes, end-users would compare the benefits they would receive from time-of-use pricing with the fixed costs of time-of-use meters[61] plus, *e.g.*, the incremental cost of "smart" rather than "not-smart" appliances. Hence, the introduction of time-of-use pricing into the menu of pricing schemes will likely not immediately greatly increase the elasticity of demand, but may do so over time.

Competition has already resulted in new products being offered to end-users. For example, large end-users are offered interruptible contracts, according to which end-users lose electric power under conditions of the utility's choosing in exchange for lower prices. (In other words, reliability is explicitly priced.) In some states, end-users are offered "green" electricity, according to which a specified percentage of electric power is generated from specified (renewable) fuels. A greater degree of freedom in the structure of pricing can give rise to additional products that incorporate investments in energy efficiency and financial instruments (which has the effect of separately pricing electricity price risk).

If reliability is not explicitly priced, the effect of increased competition combined with the reduction in cost-plus regulation may reduce reliability over the medium and longer term. The Administration's proposal would address much of this concern by promoting mandatory self-regulation through the North American Electric Reliability Organisation with oversight, for its activities in the United States, by FERC.

The reforms are likely to help meet environmental objectives, though precisely to what extent remains unclear. The main positive environmental effects of the reforms act through their effect on incentives to generate from gas rather than coal, where gas has lower emissions per kilowatt-hour (FERC, 1996*a*). New generation is dominated by gas-fired units, which account for about three-quarters of new capacity announced for the next several years (Table 17, EIA, 1998*e*). This pattern results from past increases in competition in generation, so would be expected to continue with increasingly intense competition, provided the price of gas relative to the price of other fuels does not change significantly. Other, likely smaller environmental effects of the increase in competition will be incremental emissions if prices fall (since more electricity will be used), or if coal-fired plants are run more (due to increased electricity trade); or, on the other hand, reduced emissions caused by competition- and regulation-spurred increases in energy efficiency of conversion of primary fuel into electric power delivered to the end-user. (Compared to traditional cost-based regulation, competition provides greater incentives to reduce cost, thus may provide greater incentives to more energy efficient generation and transmission.) Competition also provides incentives for more widespread time-of-use pricing,[62] which encourages shifts from peak to off-peak usage, which means that the typically less efficient plants that are run at peak periods will be run less, and baseload plants may be run more. Finally, a competitive electricity industry is compatible with tradable emissions permits for greenhouse gases, such as those already in use for SO_2, as well as user surcharges and taxpayer-financed subsidies to support energy efficiency research, development and demonstration, and taxes such as carbon taxes. The programmes for tradable permits and direct subsidies to RD&D may need to be expanded in order to meet the environmental goals for this sector, so as not to diminish unnecessarily the economic efficiency gains from the reforms.

The reforms to date demonstrate certain weaknesses. For example, in some regions, such as Virginia and Michigan and other so-called load pockets, the ownership structure is just not conducive to competition: There is no spare transmission capacity and ownership of generation is highly concentrated. How to develop competition in these regions has not been adequately addressed. The concept of independent system operators is not satisfactorily developed: How can ISOs induce transmission expansion that might increase competition, if transmission assets remain in the hands of firms with substantial generation that would be harmed by an increase in competition? How can ISOs, which after all will have an expertise limited to the electricity sector, effectively deduce whether there is anticompetitive behaviour in a market? The reform has not adequately addressed how to promote transmission investments for inter-regional trading (*i.e.*, beyond the borders of a single ISO), including how to induce state regulators to take sufficient account of the interests of out-of-state, out-of-ISO utilities and consumers when considering transmission extensions. Finally, in an increasingly competitive environment, the absence of competitive neutrality, such as between investor-owned utilities, US Government utilities, and co-operatives and municipal systems, will result not only in transfers of rents, as they do today, but also in real inefficiencies.

The direct cost of the regulatory reform is relatively high. The cost of the California transition is perhaps the easiest to calculate. There, the sum of the costs of setting up the spot market (PX), the independent system operator, and restructuring to enable direct access to the electricity markets likely captures almost all of the direct costs. (While indeed utilities' shareholders have experienced losses and some end-users have gained or lost, these are transfers, not net costs to the economy.) These "restructuring implementation costs," totalled US$98 million in 1997, and were estimated to total US$980 million through 2001 for the three private utilities in filings submitted to the California Public Utilities Commission (CPUC, 1998*b*). In addition to these costs, the ISO and the PX may themselves incur costs. The ISO has been authorised by FERC to issue up to US$310million in long term debt (*ibid.*). Hence, one estimate of the cost of setting up the Californian regime is US$1.29 billion, or about US$42 per person. The California system may be extendable to other states at less than proportional cost due to experience already gained. An estimate for the cost of setting up the PJM system is much lower, well below US$100 million.

The high level of public participation in the reform, by which all interests are provided access to the public forums, the adversarial nature of the regulatory system, and public decision-making by regulators and legislators, together ensure that implications of policy changes are noted. Because there are practical limits on the ability to research and consider each of these policy linkages given time constraints, the thorough consideration of some policy linkages is deferred until after reform is partially implemented. For example, providing for investment in transmission to facilitate inter-regional trading is not yet resolved, despite the fact that reforms in some states have already been implemented. If these complex issues had had to be resolved before embarking on reform, then reform might have been blocked. While this approach runs certain risks, the regulatory regime seems sufficiently flexible to resolve issues sequentially, if the reforms provide sufficient efficiency gains to compensate, at each stage, rents lost, at each stage, by the sequential resolution of issues.

5.2. Potential benefits and costs of further regulatory reform

Electricity sector reform in the United States should continue until a suitable long-term solution is reached. In particular the elements for establishing competition in power are only partly established: conditions to prevent discriminatory access to the transmission grid are not yet fully in place, incentives for efficient grid and reliability investment and extension are not complete, and concentration in some markets at some times remains high. Further, the relationships between more liberalised and less liberalised states have not been properly addressed. Hence, there remain significant benefits to further regulatory reform.

These benefits may come from multiple sources. Some observers of the United States reforms do not expect them to come from improvements in productive efficiency in the short-run, because utilities had already developed co-operative pools and economic dispatch arrangements, which provide for dispatch on the basis of short-run marginal cost.[63] However, as the structure of pricing to end-users improves, benefits may flow from increases in allocative efficiency, and increased productive efficiency as demand is shifted away from peak periods where less efficient plants normally operate. Substantial benefits from the United States reforms are expected to flow from long-run productive efficiency gains from market-based investment decisions in generation and transmission capacity.

The Administration claims that its proposed legislation, the Comprehensive Electricity Competition Act, will result in US$20bn in annual consumer benefits, which is about ten per cent of annual sales in the sector. These estimated savings arise from a variety of sources. Estimated cost reductions are: US$6.7 billion from improved fuel acquisition, US$0.9 billion from improved heat rates on generating equipment, US$11.0 billion on non-fuel operation and management, US$6.0 billion on administrative and general expenses. Other savings are estimated to be US$0.6 billion from improved dispatch efficiency, US$0.8 to 2.6 billion from improved capital utilisation, and US$0.3 to 3.8 billion from reduced capital additions. This totals US$26.3 to 31.6 billion. The basic methodology is to assume that reform will raise the average utility's performance to the level of the top quartile, today. The magnitude of estimated cost savings does not seem to be excessive.

Potential costs of further reform, also, have multiple sources. One source is the potential for mis-design of the stranded cost recovery scheme: whereas much of the discussion centres around the reallocation of rents, which creates neither cost nor benefit to the economy, as mentioned above the design can be costly either in terms of providing incorrect incentives for entry or for electricity usage. A second source of potential costs are the social costs of reduced employment in the sector. Given that the rate of unemployment in the United States at present is very low, these social costs would be limited to those directly associated with changing employers and sectors. A third source of potential costs are those of designing and implementing the institutional structures to support the new regulatory regime, *i.e.*, those costs analogous to the US$1.29bn spent in California. In principle, learning should reduce the costs of implementing a similar system elsewhere.

5.3. Policy options for consideration

The following policy options are based on the Recommendations accepted by Member countries in the *OECD Report on Regulatory Reform* (June 1997).

1. Adopt at the political level broad programmes of regulatory reform that establish clear objectives and frameworks for implementation.

Ministers have recommended that overlapping or duplicative responsibilities among regulatory authorities and levels of government be avoided, and that regulations be clear, simple, and practical for users. Regulatory reform in the United States electricity sector has been hampered by the complexities of the relationships among federal and state authorities. In addition, the developing electricity markets extend across regions that comprise several states. Also, utilities experience higher compliance costs where states have heterogeneous regulatory systems. ***In order to reduce overlapping or duplicative regulatory responsibilities, and to promote clearer, simpler and more practical regulation, a framework for the establishment of regional pacts among states for electricity regulation should be established, and the delineation of the respective roles of federal and state regulators should be clarified.***

Ministers have noted that regulation should serve clearly identified policy goals, be effective in achieving those goals, and minimise costs and market distortions. The United States has articulated economic efficiency as a policy goal in this sector. Allocative economic efficiency can be increased by changing the structure of end-users electricity tariffs so that the marginal price reflects marginal social cost (*i.e.*, marginal cost including environmental costs and other externalities). Marginal cost changes substantially as the quantity of electricity generated changes, that is, by the time of use. Given the cost structure of generation, marginal cost pricing may not alone provide sufficient revenue to cover total cost; multi-part tariffs can enable sufficient revenues to be recovered. (The simplest multi-part tariff would be a two-part tariff, with a fixed charge and a charge for energy; the latter might vary by time-of-use.) Where end-user tariffs are not regulated, time-of-use multi-part tariffs imply that marginal price will be no less than marginal cost (taking account of operating requirements) at any given time. The shift from average cost to time-of-use tariffs shifts some price risk onto end-users; others may be better able to bear that risk. ***In order to achieve the stated goal of promoting economic efficiency, the use of time-of-use multi-part tariffs for end-users, with separate fixed and marginal cost-based elements, should be expanded; the development of financial instruments and markets for risk shifting should also be promoted.***

Ministers have said that regulation should produce benefits that justify costs (considering the distribution of effects across society), minimise cost and market distortions, promote innovation through market incentives and goal-based approaches, be clear, simple, and practical for users, and be compatible as far as possible with competition, trade and investment-facilitating principles at domestic and international levels. The regulation of transmission prices can substantially affect the achievement of these goals in the electricity sector. Electricity transactions, by causing transmission congestion, affect the costs of other transactions on the grid. Transmission pricing schemes that more closely reflect these effects would reduce the need for system operators to make reliability-constrained administrative decisions regarding use of the grid, thus would reduce market distortions and facilitate entry and competition in generation. Nodal marginal pricing of electricity**,** reflecting congestion costs, should theoretically provide appropriate market signals for efficient dispatch. Multi-part transmission tariffs, where the variable part is nodal, can provide appropriate incentives for expansion of generating and transmission facilities where they are most needed. However, since experience with nodal pricing is limited, practical issues remain for its wider implementation. Regulatory difficulties with siting may also inhibit optimal investment in transmisssion facilities regardless of the transmission pricing regime. ***In order to achieve the goals of good regulation, further experimentation in locational pricing of electric power should be undertaken, with a view to its wider implementation. Consideration should also be given to multi-part transmission tariffs to provide appropriate incentives for grid investment.***

The achievement of policy goals is helped by the availability of high-quality information, because it makes easier the monitoring of the effects of regulation. *The United States should continue to collect and analyse key information about the electricity sector, notably including investment.*

2. Ensure that regulations and regulatory processes are transparent, non-discriminatory and efficiently applied.

A key part of the regulations to ensure non-discriminatory access to the transmission grid is the requirement of transmission owners to use OASIS, which is intended to provide real-time information about the availability of transmission. If OASIS works as planned, it should provide potential sellers and buyers of electricity with accurate and timely information about transmission available, augmenting efficient trade, and enhancing competition in general***. The regulators should evaluate the effectiveness of the OASIS system and improve upon it as appropriate to ensure accurate and timely reporting.***

3. Review and strengthen where necessary the scope, effectiveness and enforcement of competition policy.

Ministers have recommended that sectoral gaps in coverage of competition law be eliminated, unless evidence suggests that compelling public interests cannot be served in better ways. They have further recommended that competition law be enforced vigorously where collusive behaviour, abuse of dominant position, or anticompetitive merger risk frustrating reform. They recommend that competition authorities be provided with the authority and capacity to advocate reform. In the United States, surveillance of the spot market for anticompetitive indications is sometimes under the responsibility of the independent system operator. Review of mergers is under the joint jurisdiction of the antitrust authorities and the Federal Energy Regulatory Commission. ***The antitrust authorities should continue their advocacy of competition in this sector at both federal and state levels. In order to ensure adequate enforcement of the competition law, the competition authorities should refine the methodology for reviewing mergers in this sector, should closely oversee the spot market surveillance by the independent system operators, and be responsible for investigating and remedying anticompetitive behaviour detected through this surveillance.***

4. *Reform economic regulations in all sectors to stimulate competition, and eliminate them except where clear evidence demonstrates that they are the best way to serve broad public interests.*

Ministers recommended that those aspects of regulation that restrict entry, exit, pricing, output, normal commercial practices and forms of business organisation be reviewed as a high priority. A significant barrier to entry for generation, hence to the development of competition, is the cost of receiving approval for the siting of facilities, most importantly those for transmission that would expand transfer capacity. The value of additional transmission capacity may accrue significantly outside any particular state because markets extend beyond individual states. ***Consideration should be given to granting to the Federal Energy Regulatory Commission siting authority for transmission.***

In order to promote efficiency and the transition to effective competition, where economic regulation continues to be needed because of the potential for abuse of market power, Ministers recommended that: (1) potentially competitive activities be separated from regulated utility networks, and that other restructuring be done as needed to reduce the market power of incumbents; (2) access to essential network facilities be guaranteed to all market participants on a transparent and non-discriminatory basis; (3) price caps and other mechanisms be used to encourage efficiency gains when price controls are needed during the transition to competition. Generation and retail supply are competitive or potentially competitive, but distribution and transmission are regulated networks because of their natural monopoly characteristics. The Federal Energy Regulatory Commission requires only "functional separation" of generation and transmission, and non-discriminatory transmission tariffs and access to information about transmission availability. Vertically-integrated albeit functionally-separated firms retain the incentives and perhaps the means to discriminate, overtly or subtly, against their competitors in granting access to the network. ***In order to achieve effective competition in generation and transparent, non-discriminatory access to the transmission grid and system operation, divestiture of generation from transmission should be required in the United States; where there is market power, divestiture should be to multiple owners; where mandatory divestiture is not feasible, "operational separation" should be required and divestiture encouraged. Transmission augmentation should also be used, where feasible, to reduce market power. Connections for new generation to the existing transmission grid should be provided on non-discriminatory terms. In order to achieve effective competition in supply, entry into supply should not be economically restricted and non-discriminatory access to distribution should be ensured. In order to provide greater incentives for efficiency in the sector, direct access by all end-users to electricity markets ("retail competition") should be granted as soon as possible as far as technically feasible. The governance of entities such as independent system operators, power exchanges and reliability councils should be structured in such a way as to avoid discrimination.***

5. *Eliminate unnecessary regulatory barriers to trade and investment by enhancing implementation of international agreements and strengthening international principles.*

Ministers recommended that countries implement, and work with other countries to strengthen, international rules and principles to liberalise trade and investment (such as transparency, non-discrimination, avoidance of unnecessary trade restrictiveness, and attention to competition principles), as contained in WTO agreements, OECD recommendations and policy guidelines, and other agreements. Federal Energy Regulatory Commission Order No. 888 provides that utilities that do not provide access to their transmission lines, on specified terms, may not sell electric power into the service areas of utilities that do provide such access. The effect is to limit the growth of competition in more reformist states that are adjacent to less reformist states or Canadian provinces, while holding out, as an inducement to reform, the promise of profitable trade to those utilities located in less reformist jurisdictions. ***The United States***

should consider whether the objectives of the reciprocity requirement in Order No. 888 could be met in a less trade restrictive manner.

The Atomic Energy Act provides that nuclear-powered electricity generation plants may not be owned or operated by foreign entities. However, given the incidence of nuclear power plants around the world, foreign entities may be better able to manage nuclear power plants in a safe and efficient manner than some current owners or operators. If so, then the value of those assets would be higher under foreign management. Further, opening the ownership of nuclear power plants to foreign entities would increase the number of potential buyers. Both of these would reduce the quantity of stranded costs. ***The United States should, consistent with maintaining national security, health and safety, consider loosening the restrictions on foreign ownership and operation of nuclear power plants.***

6. *Identify important linkages with other policy objectives and develop policies to achieve those objectives in ways that support reform.*

Ministers recommended that prudential and other public policies in areas such as safety, health, consumer protection, and energy security should be adapted as necessary. Electricity reliability is a function both of activities on the supply side (investment, operating procedures) as well as activities the demand side (time-of-use pricing, interruptible supply contracts, insurance contracts). Increasing the size of independent system operators enables them to provide reliability at lower cost. ***In order to reduce the cost of reliability, larger independent system operators should be promoted; where independent system operators are sufficiently large, they should be given some responsibility for reliability.*** Reliability councils increase the level of reliability, thus reduce total cost of the electricity system. Because reliability councils are voluntary organisations, utilities can opt-out of co-operation during crises, thus increasing costs. Further, because they do not appear to benefit from the State Action Doctrine, co-operative actions may expose them to antitrust liability. ***In order to adapt the reliability regime to the development of markets for electricity, the Federal Energy Regulatory Commission should be given oversight of reliability councils, such as NAERO, and their recommendations should become mandatory.***

Traditionally, incumbent electric utilities subsidised activities to support other public policies, such as subsidies to R&D, electricity generated from “green” sources, and to support poor, rural or other consumers, were funded through revenues generated from other customers. Internal cross-subsidisation to meet other public policies is unsustainable under free competition. ***Subsidies for public purposes should be supported by non-bypassable and transparent fees. The regulatory system to promote “green” generation should provide incentives for such generation to be provided at least-cost. Provision should be made for consumers to be allowed voluntarily to buy “green” generated electricity beyond that required.***

Ministers recommended that non-regulatory policies, including subsidies, taxes, and other support policies, be reviewed and reformed when they unnecessarily distort competition. Publicly owned utilities, which are subject to advantageous tax treatment and have access to cheap, federally-provided hydropower, supply electricity at lower prices than would be indicated by their productive efficiency. Competition is distorted. ***Distortions of competition should be reduced by making appropriate changes in the tax and subsidy systems, the jurisdiction of FERC and the antitrust authorities, and any other different treatment of public and private utilities. Consideration should be given to privatisation of the electricity-generating businesses of publicly-owned utilities, or at least corporatisation with market-like returns to debt and equity-holders for each of their commercial activities. Distortions of energy choices through subsidies, taxes, and other support policies should not unnecessarily distort competition.***

Ministers recommended that programmes designed to ease the potential costs of regulatory reform be focused, transitional and facilitate, rather than delay, reform. The measurement and recovery of stranded costs are a key part of ensuring support for reform in the United States. ***The recovery of stranded costs should not distort market prices, should not be bypassable, and should not affect the relative competitive positions of incumbents and entrants. The treatment of stranded costs should not imperil future changes in regulatory regime, nor unduly delay the onset of competition.***

NOTES

1. A “requirements contract” is one under which all or a portion of the requirements for electricity will be supplied on a firm basis. Hence, planning and timely investment for such requirements load are the responsibility of the supplier.

2. The U.S. Department of Interior has responsibility for natural resources, hence is not comparable to ministries with similar names in other countries.

3. Average state prices for industrial users varied from 2.7 cents per kilowatt-hour to 10.0 cents per kilowatt-hour in 1996 (EIA, 1998*a*). In California, the price of electric power was 30 to 50 per cent higher than the United States average. Much of the five-fold difference in average cost among 136 vertically integrated IOUs is attributed to the degree of participation in nuclear power. Smaller factors are the degree of exposure to independent power purchase agreements under the 1978 Public Utilities Regulatory Policy Act, and exposure to exogenous regional differences in factor prices and resource endowments (White, p. 218).

4. “Total cost” includes *inter alia* capital costs, fuel, and operating costs.

5. The open consultation process might be partly explained by the existence of an earlier court decision. FERC’s consultation and decision-making process was designed to be consistent with that decision in that it explained fully FERC’s decision, provided ample opportunity for all concerned to present arguments, and it ensured mitigation of market power in transmission (FERC, 1996*a*, pp. 453, 465, 470).

6. The Kyoto Protocol calls for the United States to reduce its average annual emissions of greenhouse gases to seven per cent below 1990 levels over the period 2008-2012. This reduction is net of adjustments for hydrofluorocarbons, per fluorocarbons, sulfur hexafluoride, and carbon sequestration.

7. Only if government budgets measured changes in the market value of their assets would “public stranded costs” be an issue; by contrast, private stranded costs are easily detected.

8. There can be confusion in terminology, as “wholesale” and “retail” have varying definitions, depending on the context and the author. IEA 1998 has an extensive discussion.

9. “Prudently incurred” means that the relevant economic regulator, *e.g.*, a state public utility commission, had examined a cost or investment and agreed to its recovery through regulated tariffs.

10. Clearly, utilities prefer higher compensation for stranded costs to lower.

11. The later end-user choice is introduced, the greater the fraction of book value that has been depreciated and recovered under the old regulatory regime, hence the smaller the stranded costs. Also, discounting further into the future reduces present value.

12. In particular, end-users bid (a “transition charge”) to be in the 2.5 per cent (increasing to 12 per cent by 2002) of load that is free to choose electricity supplier. Hence, those end-users with the greatest incentive to switch will do so.

13. Reliability is the constant delivery of electric power within the standards specified with respect to frequency, voltage, and other dimensions. This is sometimes called “security of supply.” There are other dimensions of “security” which relate to the wider energy market. Indeed, these other dimensions of energy security are being met through other government interventions such as the Strategic Petroleum Reserve and direct protection of energy infrastructure from physical and cyber threats.

14. Other parts of the Administration’s proposed reforms for ensuring against disruption of primary fuel supply are beyond the scope of this study on reform in the electricity sector.

15. FERC’s jurisdiction is limited but not absent; in 1997 it ordered the federally-owned Tennessee Valley Authority to provide access to its transmission grid.

16. These Acts have been amended since originally enacted.

17. The EPAct established a new class of generators, “exempt wholesale generators” (EWGs). These are exempt from the Public Utilities Holding Company Act (PUHCA) (FERC, 1996*a*, p. 42), which implies that EWGs do not need to meet PURPA’s cogeneration or renewable fuels limitations, and utilities are not required to purchase their power. The Public Utilities Regulatory Policies Act (PURPA) of 1978 required utilities to purchase power from qualifying facilities (QFs) at a price not to exceed the utility’s avoided costs, and to provide backup power to QFs. QFs were subject to technological and size limitations, as well as restrictions on utility ownership (FERC, 1996*a*, pp. 21-25, 42).

18. Access issues also fall under the jurisdiction of the antitrust authorities, although the extent of that jurisdiction is limited by the State Action Doctrine. Under the Administration’s proposed Comprehensive Electricity Competition Act, FERC jurisdiction would be extended to transmission services provided by the Tennessee Valley Authority, the federal power marketing administrations, municipal utilities, other publicly owned utilities, and co-operatives. However, under this proposal, FERC could modify or suspend its open access rules if it found that these entities did not have available adequate stranded cost recovery mechanisms.

19. The independent system operator operates a spot market, accepting bilateral schedules and voluntary bids. It finds an economic, secure dispatch and calculates the associated nodal prices. Spot market sales are made at those nodal prices. Bilateral trades are charged the difference between the price at origin and at destination for transmission. Financial hedges for nodal price differences are also traded under an associated system of “fixed transmission rights.”

20. The contemporaneous differences between lowest and highest price (per megawatt-hour) in PJM Interconnection during constrained periods in the first five months of operation are: April (average=US$49, median=$33), May (average=$75, median=$66), June (average=$64, median=$57), July (average=$46, median=$39), August (average=$47, median=$11). The contemporaneous price range exceeded US$1/MWh for 17 per cent of the time in April, 25 per cent in May, 13 per cent in June, 20 per cent in July, and 7 per cent in August.

21. The California Public Utilities Commission reduced the rate of return on equity to ten per cent below the long-term cost of debt. (Several reasons were provided for the reduced return on equity: there is reduced business risk from accelerated depreciation, it is equitable that ratepayers benefit somewhat and shareholders receive lower returns during the transition, it provides utilities incentives to mitigate transition costs, and it does not provide incentives to utilities to bid lower in the power exchange, thus increasing transition costs.) At the same time, the CPUC would eliminate this 10 per cent reduction if the utility would divest itself of at least 50 per cent of its fossil-fuel generation, and indeed the CPUC would provide for a 10 basis point increase in return on equity for each ten per cent of fossil-fuel generation divested (CPUC 1997c, pp. 172-175). The stranded cost implications of this process are discussed below.

22. They are retaining ownership of transmission and distribution, which are regulated by the CPUC. Pacific Gas & Electric will sell 7 400 MW, or 98 per cent of its fossil and all of its geothermal and hydro capacity. Southern California Edison will divest 10 300 MW or two-thirds of its total generating capacity to various buyers, keeping only its nuclear, coal and hydro plants (FT Energy World, 5/1998). San Diego Gas & Electric will divest its entire generating capacity—fossil, nuclear, and long-term purchased power contracts—but a related subsidiary will build a large gas-fired plant in Nevada (Enova 1998, pp. 36-7).

23. There are many different ancillary services. Some are, essentially, a co-ordination function, ranging from real-time to longer periods beforehand. Others maintain the balance between generation and load, over periods ranging from seconds to minutes to hours, through the centralised control (for those with quick reaction times) and use of generating units at various levels of readiness. Other ancillary services inject or absorb reactive power to maintain voltages. There are also services for metering and communications. Another service enables a network to restart operations after a blackout. Some ancillary services are provided by generators, others by the transmission grid, and others by a control centre (DOE 1998*c*).

24. FERC required system control, and reactive supply and voltage control from generation sources, to be bundled with transmission; regulation, energy imbalance, and both spinning and supplemental operating reserve to be offered with transmission but customers be allowed to buy from third parties or self provide; and did not require transmission providers to offer load following, real power loss replacement, dynamic scheduling, backup supply, system blackstart capability or network stability services.

25. The separation of supply from distribution is less important for the development of competition in supply because the threat of discrimination against non-integrated supply competitors is relatively small. If all suppliers have equal access to information about extensions of the distribution grid, such as to new buildings or houses, then scope for discrimination is virtually foreclosed. (This information flow from distribution to supply should not be confused with the informational advantage of the incumbent supplier over entrants into supply, which constitutes an entry barrier.)

26. Monopolisation entails both the possession of monopoly power in the relevant market and the wilful acquisition or maintenance of that power. Hence, unlike abuse of dominance, charging "high" prices is not monopolisation. Market share is the most important factor in determining the existence of monopoly power, so market definition is crucial; the second important factor is barriers to entry. One of the more famous monopolisation cases is *United States v. Otter Tail Power Co.*, 410 U.S. 366 (1973), in which the Supreme Court found that Otter Tail, an investor-owned utility, had engaged in monopolisation by *inter alia* refusing to sell electric power at wholesale to municipal distribution companies, as well as refusing to allow them access to its transmission grid in order to buy electric power from other generators, despite Otter Tail's ability to provide such access.

27. The FERC reviews mergers under the Federal Power Act standard that mergers must be consistent with the public interest, although a positive benefit is not necessary, whereas the antitrust agencies review mergers under the Clayton Act standard that prohibits mergers or acquisitions where "the effect of such acquisition may be substantially to lessen competition, or to tend to create a monopoly." The FERC considers three factors: the effect on competition, the effect on rates, and the effect on regulation (FERC, 1996*c*).

28. The Antitrust Division and the FTC would not usually require divestiture if electric power markets turn out to be too concentrated after liberalisation. By contrast, remedies available to FERC include a variety of structural and behavioural remedies: requiring transmission expansion, requiring the merging parties not to use a constrained path for its own off-system trade when other transmission service requests are pending, divestiture of generating plants or of ownership rights to energy and capacity, deferring to an independent system operator, or, with other remedies, introducing time-of-use pricing.

29. When evaluating a proposed merger, the antitrust authorities will normally examine the present and past operation of the market(s). However, because the economic environment of the electricity sector is changing radically, the past is not a good indication of the future. Given the limited information about how

competitive electric markets in the United States operate, and the inability to order *ex post* divestitures, the head of the Antitrust Division has suggested the consideration of changing the burden of proof for some electricity sector mergers during the period of transition to competitive markets (Klein, 1998).

30. Among the factors are the responsiveness to competitors to increases in market prices, the incentives of the merged firm to raise prices, the existence of contracts that undermine the ability to detect or punish defections from a price cartel or that enhance buyers' bargaining position vis-à-vis sellers, and factors related to the repeated nature of the interactions of sellers, under a pool system, which may make collusion easier to arrive at and to sustain.

31. "Reliability" as used here means short-term, operational stability and investment in assets.

32. "No group in the electric power industry has stepped forward to take responsibility for building new lines and supplying equipment to support out-of-state electrical system usage. Unbundled electric utilities will not consider projects outside their service territories or competitive markets. However, how system reliability will function in a period of downsizing and cost cutting remains to be seen" (EIA, 1998*g*, Chapter 7). NERC, responsible for reliability, "expect[s] states to show reluctance in allowing the construction of transmission enhancements that serve customers in other states. We cannot depend on market forces to provide incentives to enhancement while transmission is regulated as it is. Quality of the transmission system could deteriorate in the future. That would not only hamper the development of an open and competitive electricity market, but it would also lead to a deterioration of reliability. The future of the transmission grid requires far more attention than it has got, to date, in the discussions of deregulation" (NERC, 1997*b*, p. 35).

33. In other countries that may be taking a different approach from that taken by the United States, specific instruments have been devised to counter potential failures in the regulatory-market system, *e.g.*, so-called capacity payments to generators in England and Wales--which are now being abandoned.

34. Precisely what sources of primary energy qualify for the "portfolio standard" varies from jurisdiction to jurisdiction. *E.g.*, the state of Maine includes hydro-power in its "portfolio standard," but many other jurisdictions exclude it. Within sources of primary energy, the "portfolio standards" are often technology-neutral, *i.e.*, they do not specify how that primary energy gets transformed into electrical energy, nor do they specify the identity of the owner of the generator. A key element in incorporating non-hydro renewables fuelled generation into an electric system is the provision of ancillary services, *e.g.*, backup power, to those generators.

35. Precisely, the schedule is: one per cent by end 2003 or one year after the average cost of any renewable technology is within ten per cent of the average spot-market price, whichever is soonest; 0.5 per cent for each year thereafter until end 2009; one per cent for each year thereafter until a date yet undetermined (Section 50 of Massachusetts Act).

36. The EIA estimates that in the United States, generation prices could fluctuate from less than two cents to as much as 15 cents per kilowatt-hour, increasing to as much as 50 cents per kWh during times of capacity shortage (EIA 1997*c*).

37. If a regional emissions pact among the north-eastern states is agreed before a given date, then this unilateral emissions rule does not come into force.

38. Only 9 000 had switched as of the end of February 1998. The small number is likely the result of the 10 per cent mandated consumer rate reduction, that reduced the scope for suppliers' offers to induce switching.

39. In California, consumers' monthly electric bills will separately itemise the amounts paid for electric energy, transmission, the competitive transition charge, and the public goods charge.

40. Competitive neutrality means that economic entities are treated symmetrically without regard for their type of owner or legal form.

41. The "preference rate" is the rate BPA charges public or people's utility districts, municipal utilities, co-operatives, and federal agencies in the Pacific Northwest.

42. The EPAct authorised federal programs and industry-government joint ventures to provide financial assistance for a number of energy-related purposes, including for research and development in fuel efficiency, renewable energy and advanced manufacturing in the energy sector. To receive funds under this Act, firms must make investments in the United States in research, development and manufacturing. Further, the recipient must be a US-owned company or a US-incorporated company whose parent is incorporated in a country which affords adequate and effective protection of intellectual property rights of US-owned firms and provides to US-owned companies access to such joint ventures and local investment opportunities comparable to that afforded to any other company (OECD 1995).

43. Financing costs of the debt in 1994 were 35 per cent of its power revenues, as compared with an average of 16 per cent for neighbouring utilities.

44. Proof of an ability to pay for decommissioning funds is made in two ways: electric utilities must set aside funds during the operation of the plant, and non-utilities must make up-front assurances of having adequate funds. Licensees who formerly qualified as "electric utilities" might, under rate deregulation, be transformed into non-utilities subject to the tougher decommissioning funding requirements applied to non-utilities.

45. The arguments advanced regarding electricity reforms may or may not be parallel to those advanced regarding natural gas reforms.

46. This is the rule for contracts executed before 11 July 1994. 11 July 1994 is the date the initial Stranded Cost Notice of Proposed Rule-Making was published. For contracts executed after 11 July 1994, the amount of stranded cost that can be recovered is that amount that is specified in the contract; if there is none it is zero, unless there is language like "as the FERC determines" in which case there is a default calculation.

47. "Transition costs" are defined as "the costs, and categories of costs, of an electrical corporation for generation-related assets and obligations, consisting of generating facilities, generation-related regulatory assets, nuclear settlements, and power purchase contracts, including, but not limited to, voluntary restructurings, renegotiations, or terminations thereof approved by the commission, that were being collected in commission-approved rates on 20 December 1995, and that may become uneconomic as a result of a competitive generation market in that those costs may not be recoverable in market prices in a competitive market….Transition costs shall also include the costs of refinancing or retiring debt or equity capital of the electrical corporation, and associated federal and state tax liabilities" (California, 1996, Section 11 adding Section 840 of the Public Utilities Code). "Uneconomic assets" are those assets whose net book value (original cost recorded in the company's books, less depreciation) exceeds their market value (CPUC, 1997*c*, pp. 2, 187). This determination is to be made on an asset-specific basis.

48. On 3 September 1997, the CPUC authorised, respectively, \$3.5 billion to Pacific Gas &Electric, \$3.0 billion to Southern California Edison and \$0.8 billion to San Diego Gas & Electric, the three privately owned utilities active in California (CPUC, 1998*a*).

49. There are also, potentially, markets for various ancillary services, similarly differentiated in time, duration and location. Also, there can be other markets in which end-users are provided, bundled or un-bundled, a variety of metering, billing, energy management, and other services.

50. The existing pattern of flows cannot be taken as an indicator of the extent of geographic markets for electric power because lines that are not, or rarely, used can make credible the threat of generating and transmitting energy from the "other end of the line," thus providing competition to generators (Borenstein, *et al.* 1997).

51. Market concentration measures can take account of the differing marginal costs of various capacity so that, *e.g.*, market concentration for capacity with marginal cost below $USx/kwh can be calculated.

52. In particular, the energy services associated with regulation, load following, spinning reserve, supplemental reserve, backup supply, energy imbalance and loss replacement can be transmitted some distance, but voltage control, blackstart capability and network stability cannot.

53. Liquid markets require *inter alia* a sufficient number of participants.

54. In contrast to most U.S. utilities that have less than 10 per cent wholesale load (and FERC-guaranteed recovery of stranded assets in the move to greater competition), Ontario Hydro has a 70 per cent wholesale load and no analogous mechanism for stranded asset recovery. Ontario Hydro maintains that it cannot offer open access until provincial industry restructuring is complete – expected in the year 2000.

55. Further, the effect of such reciprocity provisions would be expected to vary, depending on the incentives (including regulatory regime) and cultures of the utilities involved.

56. In particular, there were dramatic price increases in the wholesale electricity markets in the Midwest. Unseasonably hot weather increased demand; above-average planned and unplanned outages (notably of large quantity of baseload nuclear plant) reduced generating capacity available in the region, and transmission constraints reduced the ability to move power to where it was needed. Prices, for some hourly transactions, rose from around US$25/MWh to as much as US$2 600/MWh, with significant hourly purchases in the US$3 000 to US$6 000 range, and one hourly price reached US$7 500/MWh. At the same time, weighted average price for the week was about US$60/MWh. (The difference is due to the relatively small quantity of electricity transacted on hourly markets.) In addition to the "physical" factors cited above, other contributing supply-side factors to the price spikes included a lack of timely, objective price information and fear of default by trading counterparts. On the demand-side, since small end-users do not have incentives to adjust their demand based on price, utilities made public appeals for voluntary usage reduction, which did result in some reductions. The market response has demonstrated the robustness of the system. Some utilities are proposing new tariffs that allow certain industrial users to sell their firm power entitlements back to their local utility under peakload conditions. Utilities have said that they changed their trading strategies. There is recognition of the need for timely, more complete provision of information about market prices. Planned expansions of generating capacity is proceeding. Despite suggestions for the imposition of price caps, the FERC staff were offered no compelling arguments for such a movement away from competition. This experience, of extraordinary high spot market prices, and the responses of the market participants and the regulator, demonstrate the robustness of a market system, while also suggesting that further market refinements would be in order (FERC, 1998*b*).

57. One observer has noted, "In particular, it supplies electricity with a high level of reliability; investment in new capacity has been readily financed to keep up with (or often exceed) demand growth; system losses (both physical and those from theft of service) are low; and electricity is available virtually universally" (Joskow, 1997).

58. FERC estimated the potential cost savings from non-discriminatory transmission access to be about US$3.8 to US$5.4 billion per year, plus better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion" (FERC Order No. 888-A (Order on Rehearing) 4 March 1997).

59. Allocative economic efficiency is highest when there is no other allocation of resources that would make someone better off without making someone else worse off.

60. Marginal cost means the cost of an additional unit.

61. In the United States, customers typically buy their own meters.

62. If end-users may choose whether to have time-of-use pricing, then those with less costly to serve load profiles will opt for it, leaving behind end-users with costlier load profiles, thus raising their average prices. Absent competition, the cross-subsidies could be maintained.

63. Baumol, Joskow and Kahn state that, "In our opinion, the opportunities for improvements in *productive* efficiency flowing from a fuller opening of electric generation to competition are very limited in the *short-run*" (emphasis theirs, Baumol, 1995, p. 23).

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