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REGULATORY REFORM IN THE ELECTRICITY INDUSTRY:

THE UNITED STATES

In the context of the OECD's programme on Regulatory Reform, country reviews are being undertaken. The scope of the review covers thematic areas and two sectors -- telecommunication and electricity. This work is aimed at producing, for each country reviewed, a multi-disciplinary review of progress on regulatory reform based on international bench-marking, self-assessment and peer-review. Two delegates are nominated as lead speakers for each chapter: a delegate from CLP and a delegate from SLT/IEA. Other delegates are then invited to comment on the policy of the country being reviewed. The draft chapter will be then incorporated in a country review report destined for publication.

The attached draft chapter on the US Electricity Industry is submitted to CLP Delegates FOR DISCUSSION at the forthcoming meeting of the Standing Group on Long-term Co-operation at the International Energy Agency, 9 rue de la Federation, Paris on 21 October 1998.

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Chapter Summary

1. The electricity sector in the United States

1.1. Key features

1. 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

Tennessee Valley Authority: federal corporation with 28,000 MW generating capacity (73% coal-fired) and substantial transmission in southeastern United States.

6. 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.

7. 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. The introduction of NUGs as well as, perhaps, an increased risk that investments might not be allowed to be recovered under the regulatory regime, promoted the development of trading amongst utilities. Presently, about 55 percent of total electricity consumed is not generated by the utility that sells it to the end-user. [EIA 1998g]

Background Statistics

Primary fuels (all energy usage): coal 31%, natural gas 27%, oil 22%, nuclear 10%, hydroelectric 5%, other 5%. [DOE 1998b, 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%, nuclear 20%, gas 9%, hydropower 11%, oil 2%, non-hydro renewable fuels 2 x 10^{-3} (about 7500 mWh). [EIA 1998b]

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

Book value of electricity sector assets (1994): US$700 billion (10% of the US total)

Sales of electricity (1994): US$212 billion. [DOE 1998a]

International trade (1996), in billion kWh: Imports 46.5 (45.3 Canada, 1.26 Mexico); Exports 9.02 (7.7 Canada, 1.32 Mexico)

Cost (1996): generation 74%, transmission 7%, distribution 19%.

Generation (199?): total: 3 652 teraWatthours; by ownership: 73% investor owned utilities (about 350), 15% publicly owned utilities (about 2000), 10% rural co-operatives (about 1000); 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.

Emissions: the electricity industry accounts for about 65% of SO2 emissions and about 30% of NOx emissions in the country.

8. 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 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

2. Regulation and its reform

2.1. Main lines of reform

12. 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.

13. 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.

Conditions for Competition

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

14. A major part of the over-all reform effort is reforms to intensify competition between generators

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, California, the states of the Northeast and the states of the PJM Interconnection (in the mid-Atlantic seaboard) have established "independent system operators," managerially and operationally

20. 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-

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

(1996, cents/kWh, by State)

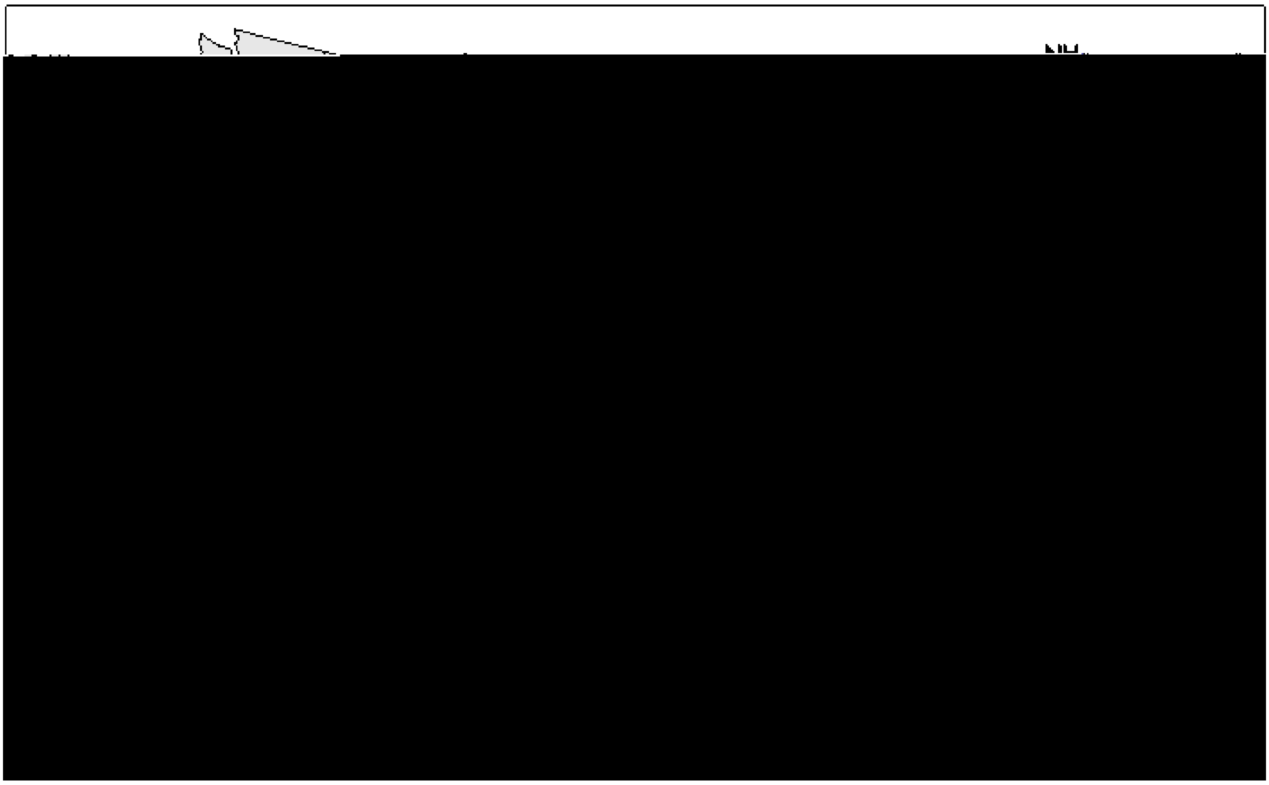
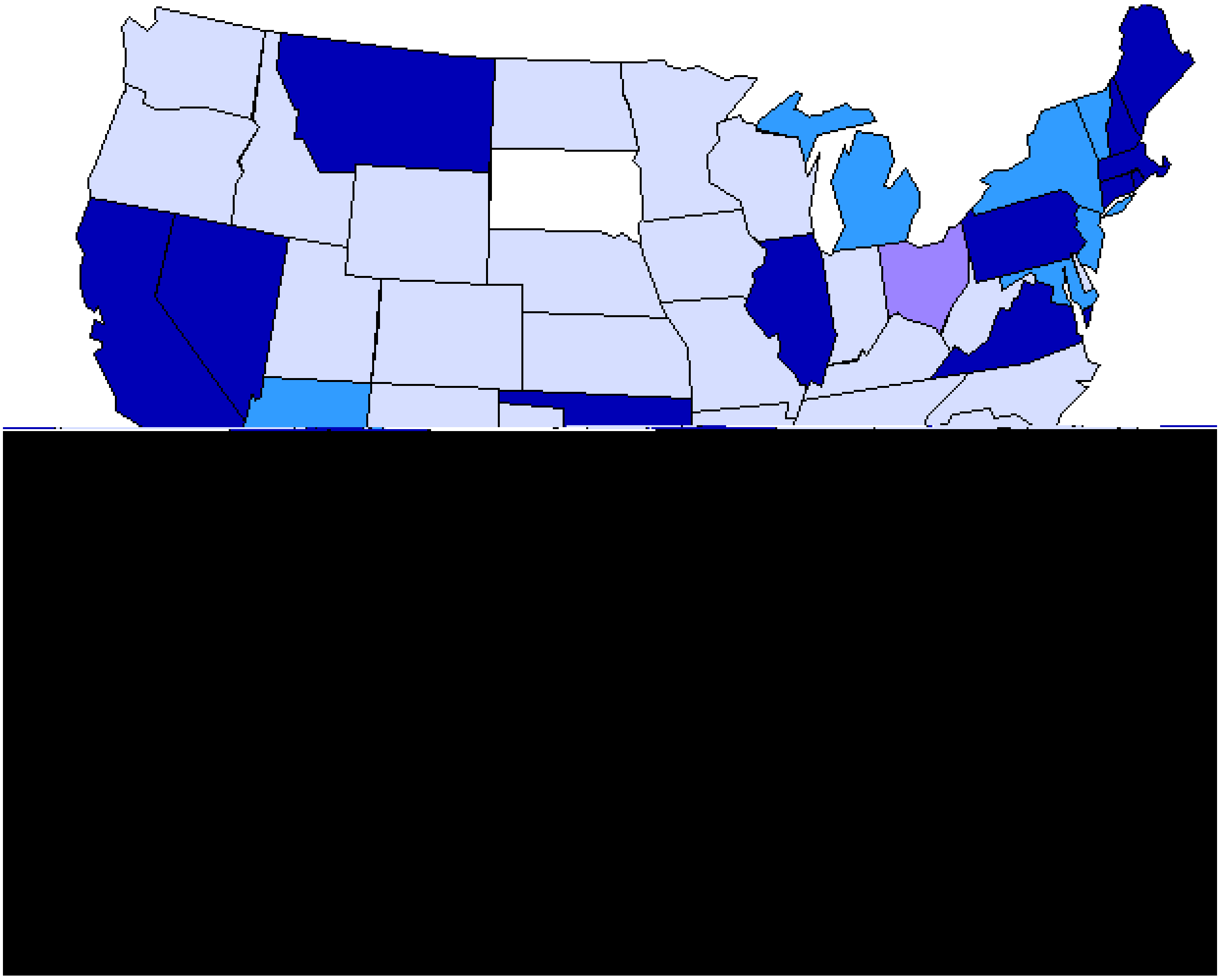


Figure 2. Status of State Electric Utility Deregulation Activity

as of September 1, 1998



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

23. 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 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 SO2 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.

24. 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] In anticipation, NAERO was formed in mid-1998. [NERC 1997b]

2.2. Institutional basis for regulation

25. 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.

26. 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 are required to be made in public and are accompanied by reasoned, public explanations. Decisions can be appealed to the judiciary.

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

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

27. 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).

28. 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.

29. 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.

30. 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.

31. 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 SO2 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

32. 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*, but there are some entry costs that are significantly increased by regulation. The Energy Policy Act of 1992 (EPAct) substantially reduced regulatory entry costs by relieving entrants of cogeneration and renewable fuels obligations.[17] Regulations that continue to affect significantly the cost of entry include

tariffs, and FERC 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 *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: grid marginal pricing that reflects the cost, somewhere in the system, of transmission congestion. (Zonal pricing means that, within a defined zone, there is one price for power at any point in time. Zones are supposed to be defined so that their boundaries are where transmission congestion occurs.)

grid pricing implied by locational marginal pricing of power: grid marginal pricing that reflects the cost of transmission congestion; when there is no transmission congestion, the grid marginal price is zero. (Under locational marginal pricing, also called *nodal pricing*, the price of electricity at each location at each time period equals the marginal cost of supplying load at that location, where the marginal cost is the sum of energy marginal cost and the cost of delivering the energy, reflecting transmission congestion.)

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. Locational pricing, where the prices reflect marginal cost of delivered electricity—including transmission congestion cost—at that moment, induces efficient grid operation and dispatch. (Where there is no transmission congestion, zonal pricing is equivalent to locational marginal pricing.) This locational pricing 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 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% 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

42. 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

43. 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 1996a, 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

proposed Comprehensive Electricity Competition Act, would grant FERC the power to require the establishment of independent system operators.

44. Some state regulators are providing irresistible 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$1.6bn 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 1998h]

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. An independent system operator is one means of operational separation, when the independent system operator has a governance structure sufficient to ensure that its decisions independent.

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 anticompetititve behaviour, thus “chilling” competition and increasing administrative and litigation costs. [FTC 1998b]

46. 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.

47. “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

Vertical Separation of Retail Supply from Other Functions

understanding to use, leads to a meeting of minds, which would constitute an illegal agreement. Such repeated interactions might occur in electric power pools.

53. 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.

54. 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 1996c]

Merger Evaluation in the Electricity Sector in the United States

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.

55. 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

56. 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.

57. 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 1997b]

58. In response to these changes, NERC created a new organisation, North American Electric Reliability Organisation, in mid-1998. NAERO continues 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 would 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

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.)

60. 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 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.

61. 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]

62. 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

63. 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.

64. A nation-wide sulphur dioxide emissions permit trading programme significantly reduced SO2 emissions from generating plants at costs much lower than expected. (See Chapter 2.) The programme

combines fully tradable permits for the emission of SO2 and requirements for monitoring equipment with a safeguard that, permits notwithstanding, no utility may emit SO2 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]

65. The cost of reducing SO2 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 SO2 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]

66. As compared with SO2, control of NOx is more difficult because utilities, which are easy to monitor, are not the primary emissions sources: Transportation accounts for about 49% of emissions and non-utility combustion for 18%. 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

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% be produced by hydro-power or renewable fuels. [EIA 1998h] 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% 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 share to 5.5% in 2010-2015, but with a cost cap of US$0.015/kWh. By contrast, almost all (97.8%) of the net generation of electricity by renewable sources in the United States was by hydropower (in 1996 and 1997). [EIA 1998d]

69. 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] In both Massachusetts and California, a surcharge on all electricity consumers funds energy efficiency activities, including for the poor, and the development and promotion of renewable energy projects. 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.

70. 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 SO2 and CO2 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.

Environmental Effects of Electricity Sector Reform

The environmental objectives for the electricity sector include reduced emissions of and SO2, NOx, various other noxious gases, CO2 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 SO2, goes well beyond the electricity sector as the gases have

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)	SO2	NOx	CO2
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.

71. 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.

72. 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

2.4.6. Consumer protection

74. 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]

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 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]

78. 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.

79. 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.

80. There is a variety of other unequal treatment. 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.

81. 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$14bn of non-producing nuclear assets. The implicit federal government guarantee has enabled TVA to borrow US$26bn (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 10 years notice.) 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]

82. 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 2 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% (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

83. 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.

84. 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% to 90% of the total.

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.

86. 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 1996a, 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.

87. 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, less the market value of the power the customer would have bought.[46] [FERC 1996a, 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 1996a, 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.

88. 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 1997c] (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 1997b] 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 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 specificities 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

- the area served by Virginia Power, in which the company controls virtually all generation and the maximum transmission import capacity is only 3 GW to 4 GW to serve a peak load of about 15 GW. [Virginia SCC 1997]

92. There are two principal forms of entry into electric generation markets: new or expanded generating capacity within the existing product and geographic market, and enhanced access to existing generating capacity because of new or expanded transmission capacity. [FTC 1998b] Significant entry into generation is occurring: While only about 10% of current generation is owned by "non-utilities," it is estimated that 50% of all incremental generating capacity projected to come online within the next decade belongs to independent generating companies. [NYMEX]

93. 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

94. 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$7,500/MWh for one hourly contract) are partially attributed to a lack of a centralised 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 1998b] 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.

95. 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.

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

96. 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.

Table3. 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

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.

100. 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

hesitant to make investments in the territory of the ISO, but also grid expansion and grid access may be discriminatory, further discouraging entry.

105. 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.

106. 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 northeastern 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.

107. 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 1996a, pp. 280-286]. An ISO does not necessarily have responsibility for transmission system augmentation.

108. 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.

109. 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.

110. 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

111. 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% 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 1998b] (Given that

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]

116. With respect to emissions, the value of the environmental externalities from SO2 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

117. 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 1997c] National capacity margins were 18.9 percent for the summer peak and 28.7 percent for the winter peak. [EIA 1998f]

118. Without knowing more about the cost of switching fuel mixes, the cost of generating electricity using various fuels, and fuel price volatility, it is difficult to evaluate whether the United States performance with respect to diversity of fuel inputs into electricity is adequate. However, 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

119. 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]

120. 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 SO2, NOx, and other noxious emissions. However, little has been done in the United States toward reducing emissions of CO2. 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

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 kilowatthour 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 by users are high, then there may be too little entry. Beyond these concerns, the recovery of stranded costs is largely a political question, that can only be resolved through negotiation.

126. 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 or locational 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 might induce efficient investment in transmission, it is not clear that it will do so, and the present methods of pricing for transmission expansion have not induced transmission investment to increase inter-regional transfer capability for several years.

127. 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.

128. 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

130. The reforms are likely to help meet environmental objectives, but it remains unclear whether the reforms will be sufficient to achieve these goals. 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 kilowatthour. [FERC 1996a] 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 1998e] 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

133. 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

134. The present stage of the electricity sector regulatory reform in the United States is not one suitable for the long-term: rather, reform must 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 the present relationship between power prices and decisions of the system operator is not sustainable. Further, the relationships between more liberalised and less liberalised states have not been properly addressed. Hence, there remain significant benefits to further regulatory reform.

135. 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 the earlier reforms had allowed utilities to develop co-operative pools and economic dispatch arrangements, which provide for dispatch on the basis of short-run marginal cost.[63]

5.3. Policy options for consideration

138. 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.

139. 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

appropriate grid pricing schemes should take into account not only the economic efficiency losses from imposing the price constraints implicit in those schemes, but also implementation costs. Based on these results, consideration should be given to the widespread application of locational pricing.. Consideration should be given to multi-part transmission tariffs so as to provide appropriate incentives for grid investment.

142. 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.

143. 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. Where OASIS does not provide to potential sellers and buyers of electricity accurate and timely information about transmission available, efficient trade is reduced and competition in generation is hampered. *The regulators should evaluate the effectiveness of the OASIS*

particular state because markets extend beyond individual states. *Consideration should be given to granting to the Federal Energy Regulatory Commission siting authority for transmission.*

146. 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 mandatory divestiture is not feasible, "operational separation" should be required and divestiture encouraged; 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 and within technical feasibility. 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. In order to reduce the market power of incumbents in those markets and conditions where it exists, there should be appropriate divestiture (sale of generation to multiple owners) or transmission augmentation.*

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

147. 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 reduce 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.*

148. 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.

149. 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, and their recommendations should become mandatory.*

150. Traditionally, incumbent electric utilities subsidised activities to support other public policies, such as subsidies to 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.*

151. 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 corporatization 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.*

152. 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 kilowatthour to 10.0 cents per

12. In particular, end-users bid (a “transition charge”) to be in the 2.5% (increasing to 12% 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 1996a, 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 1996a, 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 cooperatives. 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 locational marginal cost prices. Spot market sales are made at those locational prices. Bilateral trades are charged the difference between the price at origin and at destination for transmission. Financial hedges for locational 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% of the time in April, 25% in May, 13% in June, 20% in July, and 7% in August.

21. The California Public Utilities Commission reduced the rate of return on equity to 10% 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% reduction if the utility would divest itself of at least 50% of its fossil-fuel generation, and indeed the CPUC would provide for a 10 basis point increase in return on equity for each 10% 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% 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 coordination 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 center. [DOE 1998c]

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 scheduing, backup supply, sustem 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. Monopolization entails both the possession of monopoly power in the relevant market and the willful acquisition or maintenance of that power. Hence, unlike abuse of dominance, charging “high” prices is not monopolization. Market share is the most important factor in determining

owned utility, had engaged in monopolization 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 1996c]

28. The Antitrust Division and the FTC would not usually require divestiture if electric power markets turn out to be too concentrated after liberalization. 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 1998g, 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 gotten, to date, in the discussions of deregulation." [NERC 1997b, 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 fueled generation into an electric system is the provision of ancillary services, e.g., backup power, to those generators.

35. Precisely, the schedule is: 1% by end 2003 or one year after the average cost of any renewable technology is within 10% of the average spot-market price, whichever is soonest; 0.5% for each year thereafter until end 2009; 1% 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 2 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 1997c]

37. If a regional emissions pact among the northeastern 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% mandated consumer rate reduction, that reduced the scope for suppliers' offers to induce switching.

39 In California, consumers' monthly electric bills will separately itemize 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 symetrically 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, cooperatives, and federal agencies in the Pacific Northwest.

42 The EPAct authorized 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% of its power revenues, as compared with an average of 16% for neighboring 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 December 20, 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

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

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*

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