Issue Study 3. Electricity in North America:

Some Environmental Implications of the North American Free Trade Agreement (NAFTA)

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Acronyms

AECB	Atomic Energy Control Board (Canada)
ANIQ	*Asociación Nacional de la Industria Quimica* (National Association of the Chemical Industry)
ATC	available transfer capability
BANCOMEXT	*Banco de Comercio Exterior* (National Foreign Trade Bank)
BCG	billion cubic feet
BCFD	billlion cubic feet per day
BLT	build lease transfer
BPA	Bonneville Power Administration (United States)
CCGT	combined cycle gas turbine
CEA	Canadian Electricity Association
CFE	*Comisión Federal de Electricidad* (Federal Electricity Commission)
CO_2	carbon dioxide
CONAE	*Comisión Nacional para el Ahorro de Energía* (National Commission for Energy Conservation)
CRE	*Comisión Reguladora de Energía* (Energy Regulation Commission)
DFAIT	Department of Foreign Affairs and International Trade
DFO	Department of Fisheries and Oceans (Canada)
DOE	Department of Energy
EIA	Energy Information Administration
EPAct	Energy Policy Act
EPA	see USEPA
EPECO	El Paso Electric Company
EPMI	Enron Power Marketing Inc.
ERCOT	Electric Reliability Council of Texas
EWGs	exempt wholesale generators
FCCC	Framework Convention on Climate Change
FDI	foreign direct investment
FERC	Federal Energy Regulatory Commission
FIDE	*Fideicomiso de Apoyo al Programa para el Ahorro de Energía* (Trust for Energy Efficiency)
FTA	Canada-United States Free Trade Agreement
GHG	greenhouse gas
GW	gigawatt
GWH	gigawatthour
IAQMB	(USA-Mexico) International Air Quality Management Basin
ICA	*Ingenieros Civiles Asociados* (Associated Civil Engineers), Mexican engineering and construction firm
INE	*Instituto Nacional de Ecología* (National Ecology Institute)
IOUs	investor-owned utilities.
IP	Illinois Power
IPPs	independent power producers
ISO	independent system operator
ITC	investment tax credit
kV	kilovolt

LLW	low-level waste
MAPP	mid-continental area power pool
MBTU	million British thermal units
MCF	million cubic feet
MCM	million cubic meters
MVA	mega-voltamperes
MLLW	mixed low-level waste
NARUC	National Association of Regulatory Utility Commissioners
NEB	National Energy Board (Canada)
NERC	North American Electric Reliability Council
NO_x	nitrogen oxides
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission (United States)
NUG	non-utility generator (United States and Canada)
PEMEX	*Petróleos Mexicanos* (Mexican National Oil Company)
PCBs	polychlorinated biphenyls
PM	particulate matter
PURPA	Public Utility Regulatory Policies Act
QFs	qualifying facilities (United States)
RFF	resources for the future
RTU	remote terminal units
SCADA	supervisory control and data acquisition
SDG&E	San Diego Gas & Electric
SE	*Secretaría de Energía* (Energy Secretariat; Mexico)
Secofi	*Secretaría de Comercio y Fomento Industrial* (Trade and Industrial Promotion Secretariat; Mexico)
Semarnap	*Secretaría de Medio Ambiente, Recursos Naturales y Pesca* (Environment, Natural Resources and Fisheries Secretariat; Mexico)
SERC	Southeast Electric Reliability Council
SO_x	sulfur oxides
SRP	Salt River Project
STP Alliance	Salt River Project-Tenaska-PowerEx marketing alliance
TCF	trillion cubic feet
TQM	Trans-Quebec and Maritime Pipeline Inc. (Canada)
TMGT	Trans-Maritime Gas Transmission
UIC	United Illuminating Company (Connecticut utility)
USEPA	US Environmental Protection Agency
USAID	US Agency for International Development
VAT	value-added tax
VPSB	Vermont Public Service Board
WSCC	Western Systems Coordinating Council

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I. Introduction

The purpose of this study is to consider the environmental implications of expanded North American trade and investment under NAFTA by implementing a general framework developed by the Commission for Environmental Cooperation's (CEC) NAFTA Effects Project. The scope of the study is sectoral, focusing on the generation of electricity by private and publicly owned entities in Canada, Mexico and the United States. It includes the upstream industries that provide the major fuel sources from which electricity is generated in North America, notably coal, natural gas and hydroelectricity. It also considers downstream processes of consumption for industrial, commercial and residential purposes, and some relevant industries. The important but complex question of overall demand for electricity, and how the growth stimulated by NAFTA-related trade has increased such demand, largely lies beyond the scope of this study. The study focuses in particular on linkages between the NAFTA regime and recent changes in the electricity sector in the three NAFTA countries and on their environmental implications.

The major arguments in this study follow the line of analysis described in the NAFTA Effects General Framework (Phase II), composed of elements designed to trace the linkages from trade and investment to the environment. Section II provides the environmental, economic, social and geographic contexts for the issue. This section is particularly important since many changes taking place in the electricity sector date back to the period prior to the implementation of NAFTA, and, in the case of the natural-gas sector, prior to the negotiation of the 1994 trade agreement and even its predecessor, the 1989 Canada-United States Free Trade Agreement (FTA). Although the energy chapter of NAFTA was widely viewed by analysts as having included relatively few changes, there are several important energy-sector impacts, direct and indirect, associated with NAFTA that must be considered in the larger context of environmental changes and macro-economic policies.

Section III describes the major NAFTA rule changes affecting the electricity sector, as well as some of the institutional changes resulting from NAFTA's provisions. It then discusses the trade flows and investment patterns in the sector and presents estimates of the impact of NAFTA on these flows. While other economic forces have been important, the impact of NAFTA has been both discernable and significant, clearly establishing the NAFTA connection. Even though trade liberalization is not the primary cause of changes currently underway in the electricity industry, the NAFTA regime has contributed to the push for open access and restructuring in North American electricity markets. As economies open and consumption increases, spurred in part by NAFTA's economic stimulus, public policy choices loom that could have significant environmental consequences.

Section IV examines the main linkages from these changing patterns of trade and investment to the natural environment through the processes of production, management and technology, physical infrastructure, social organization and government policy. The direct and indirect environmental linkages associated with the electricity sector, such as the production of fuels for use in power plants, are reviewed in this section.

Section V offers estimates of the environmental impacts in the sector that are most amenable to measurement and proposes the use of various indicators for their ongoing monitoring and evaluation. The discussion contained in "Environmental Impacts and Indicators" reviews several quantitative and qualitative indicators that provide measures of the environmental impacts of the sector. This effort might facilitate the identification of environmental and electricity-sector indicators that would, over time, permit the analysis of the energy sector's short- and long-term impacts in the context of the changes taking place in the energy sector at the subnational and national levels in Canada, the United States and Mexico. Given the limitations of the data, an important contribution lies in identifying key indicators and monitoring systems that will help the three nations evaluate longer-term interactions between North American trade and investment and the environment in the electricity sector.

The following four scenarios might be useful to an examination of the complex issues and relationships raised in this study. None of these scenarios constitutes a prediction of the evolution of the electricity sector under NAFTA. Rather, the future hinges on policy choices that have yet to be made. A critical variable is how environmental considerations will figure in new national and subfederal government policy and regulatory regimes for electricity.

A first scenario is that open grids could improve environmental quality by accelerating capital turnover and eliminating the competitive advantage of older coal-fired plants in the United States over new market entrants by virtue of inconsistent pollution standards. One recent assessment estimates that requirements for "all fossil plants to meet the same emissions standards met routinely by post-1977 power plants would decrease US power-sector emissions of sulfur dioxide and nitrogen oxides by 75-80 percent from otherwise projected levels by the year 2000."[1]

Even without such regulatory change, assuming that some incentives are incorporated to promote the use of cleaner, more advanced technologies or renewables, open grids and customer choice over electricity suppliers could provide a mechanism that would promote capital turnover and the development of cleaner generation capacity, thereby enhancing environmental quality.

The removal of regulatory subsidies for existing units might allow the open grid to become a powerful force for upgrading old industrial infrastructure. Almost two-thirds of US generating capacity is more than twenty years old; almost one-fourth is thirty years old.[2] Open grids should eliminate the capacity of monopoly owners to shield these aging plants from newer, cleaner competitors. In areas where constraints on transmission capacity limit competition from newer sources, an expanded transmission infrastructure would be required to facilitate the increased flows.

Assurances that incumbent generators are indeed functioning independently of the monopoly systems that historically have protected them from market pressures would be critical. As industry restructuring begins, many transmission and distribution monopolies continue to own generation. Transmission and distribution companies enjoying monopoly rents have obvious incentives to favor that part of the competitive generation market comprised of their own power-plant investments. Mechanisms will be needed to overcome that conflict of interest; otherwise, residual monopolies could vitiate market operation.

A related issue is the inclusion, as an element of electricity-industry restructuring, of government subsidies for selected power plants. California closed important markets to competitors from every western jurisdiction, foreign and domestic, when it guaranteed above-market payments to more than 4,500 MW of nuclear generation in 1995. Washington State's subsidies in the form of tax credits for upgrading 1,300 MW of coal-fired capacity in Centralia, WA, provide similar protection.

[1] A. Cohen (1997), *Unfinished Business: Cleaning Up the Nation's Power Plant Fleet* (Boston: Clean Air Task Force, August).

[2] Clean Air Network (1997), *Clearing the Air* (July): 1, (citing EIA data).

In addition, the current configuration of the three-nation grid poses some immediate limitations on potential direct impacts of cross-border electricity trade. As of 1997, for example, Mexican-United States interconnections could accommodate only about 900 MW of exchanges. Canadian-US transfer capacity is at least twenty-fold greater, but even that represents less than two percent of continental generation capacity (see Appendix A). Problems of synchronization between systems appear to be greatest between the main part of Mexico's grid, which is not linked to the northwestern Mexico system (a part of the WSCC), and the United States. Synchronization has also posed a major challenge to large-volume exports from Quebec to the northeastern United States, for it requires substantial investments.

Recent developments in power electronics create numerous new options for increasing transmission capacity inexpensively. The challenges posed by synchronization can be addressed by investing in direct-current lines or other types of interties, but the costs are substantial. Since the expansion of economic incentives for relieving transmission bottlenecks is emphasized as an objective of industry restructuring, the process will likely encourage investment in transmission beyond the ranks of integrated utilities. Moreover, entrepreneurs have already discovered that electricity can be traded across borders without physically occupying cross-border transmission lines. Together, these considerations should help prevent existing physical constraints from frustrating the "open grid."

Second, trade liberalization may well open new markets for cleaner generation technology. NAFTA introduces a significant new force into capital turnover within the power plant sector by opening more international markets to vendors of combined-cycle gas turbines, fuel cells and renewable energy resources, as well as cleaner fuels, including low-sulfur coal and natural gas. In relative terms, Mexico particularly should benefit from the increased import and use of cleaner technologies, which will accelerate fuel switching away from the high-sulfur residual oil that now provides half that nation's electricity supply. NAFTA procurement guidelines, along with simultaneous restructuring in the United States, enable Mexico's CFE to consider and accept bids from suppliers in the United States and Canada with potentially superior emissions profiles. These processes are assisted by autonomous Mexican government policies favoring clean fuels and the displacement of emissions in heavily polluted areas. The CFE's access to public funds, private investment capital and credits for procurement will be an important variable in this process. The result should be a cleaner atmosphere in Mexico and adjacent areas in the United States, along with reductions in GHG emissions.

Third, harmonized incentives and regulations could benefit end-use efficiencies and renewables. At least three specific strategies have emerged for promoting energy efficiency and renewable energy under electricity-industry restructuring; all raise NAFTA issues. Elements of each can be found today in all three countries, but fully integrated packages are only beginning to emerge. This section outlines the options for attacking the market barriers to long-term investment in efficiency and renewable energy technology and suggests the potential contributions of these options to environmental quality.

The first scenario replaces the financial contribution traditionally made by integrated utilities with uniform charges on distribution and transmission services. These charges operate independently of markets in generation services and do not affect competition for grid access and power markets. Typically, they represent 1.5 to 4 percent of retail electricity bills. Proposals are now pending in the US Congress and in at least one Canadian province for a uniform, volume-based charge on transmission use, which in the United States would be used to match dollar-for-dollar, qualifying state-level investments in energy efficiency, renewable energy and other public purposes.[3] It seems likely that Canadian or Mexican generators using US transmission services to sell into the US market would be assigned such a

[3] See H.R. 1359 (DeFazio) and S. 687 (Jeffords); Mark Jaccard (1997), "Reforming British Columbia's Electricity Market," BC Task Force on Electricity Market Reform, *Second Interim Report*, December.

charge, since they are assigned to the load, not the generator. It remains to be seen whether such charges might be challenged under NAFTA as a barrier to market access. In the event of such a challenge, however, the charges would likely be upheld if it could be demonstrated that they were applied in an equal and non-discriminatory way, thereby meeting the national-treatment requirements of NAFTA.

Other NAFTA issues could arise regarding a second and related strategy, which focuses on renewable energy and assigns a minimum-content requirement to all generation owners. They can meet this obligation either by acquiring qualifying renewable capacity or buying credits from those with surplus renewable production. At least four bills pending in the US Congress incorporate such requirements, which are designed to encourage an increase in the nationwide contribution of renewable energy.[4] Several state-level plans, such as those of Massachusetts and Maine, include so-called portfolio requirements.[5] It remains to be seen whether such state-level requirements could be imposed on Canadian and Mexican electricity entering the US market. Like transmission charges, portfolio requirements may well survive a challenge under NAFTA if applied in an equal and non-discriminatory way to all electricity production, regardless of origin.

A third strategy is based on the reality that North America has at least two decades of experience with direct government regulation of equipment and building efficiency, based on mandatory minimum standards. However, no NAFTA signatory has come close to exhausting the potentially cost-effective contribution of tighter appliance and building standards.[6] Opportunities to coordinate such initiatives across national boundaries have barely been touched. Also needed is the synchronization of national investment and regulatory policies; for example, distribution and transmission charges can increase the efficacy and political attractiveness of efficiency regulations by paying at least part of the cost of enforcement and compliance. Further, electricity systems have already used targeted financial incentives for the appliance and building sectors to help minimize the costs and controversy associated with tighter minimum-efficiency standards.[7]

NAFTA could make a direct contribution to the influence of existing and future efficiency standards throughout North America. Both the reality and anticipation of increased trade, coupled with increased intracorporate activity across borders, could prompt manufacturers and customers, even in the absence of government intervention, to use equipment designs that meet the highest efficiency standard applicable in any part of the NAFTA area. And government can assist by working collectively, in part through NAFTA's rules and institutions. NAFTA's institutional process may foster increased communication, capacity building and regulatory convergence on the part of the three countries in this sector. So far, the experience under NAFTA is mixed, given the proposal for a North American Energy Efficiency Group that has yet to be acted upon. NAFTA's dispute-settlement mechanisms may also function to deter firms from employing poor environmental practices.

[4] See H.R. 1960 (Markey); H.R. 655 (Schaefer); S. 237 (Bumpers); and S. 687 (Jeffords), all introduced during the 1997 legislative session. Typically, these bills set the initial minimum-content requirement at the current average contribution of renewable sources other than hydropower—about 2 percent—and then gradually increase it, reaching (in the case of H.R. 1960 and S. 687) 10 percent by 2010. The mandate reaches 20 percent by 2020 in S. 687. These charges are also designed to cover electricity services targeted at low-income customers.

[5] See L.D. 1804 for the Maine legislation, and Appendix H for further detail on Massachusetts.

[6] The potential for environmental and economic benefit is illustrated in a recent assessment by two US national laboratories; they investigated the impact of federal legislation enacted in 1987, which phased in minimum efficiency standards for seven equipment categories. Government expenditures to develop the standards, about US$50 million, were dwarfed by the cumulative net benefit delivered by lower appliance operating costs: some US$46 billion through the year 2015, along with 1.5-2 percent reductions in nationwide emissions from all sources of sulfur dioxide, NO_x and CO_2. [M. Levine, J. Koomey, J. McMahon, A. Sanstad and E. Hirst, "Energy Efficiency Policy and Market Failures," *Annual Review of Energy and the Environment* 20 (1995): 535, 543-47.] (Equipment categories are residential furnaces, room air conditioners, central air conditioners, electric heating, water heating, refrigerators and freezers; net benefit estimate reflects a real discount rate of 6 percent and "a net present cost of US$32 billion for higher-priced appliances and a net present savings of US$78 billion.").

[7] For example, an increase in the US minimum-efficiency standard for refrigerators drew on technological advances from multi-utility program that successfully integrated higher efficiencies with a CFC phase-out.

A fourth and final scenario recognized in this report is that inconsistent emissions standards and regulatory uncertainty could lead to increased pollution. The most important environmental variable for North American electricity is the fate of more than 300 gigawatts (GW) of underutilized coal-fired generation. This equipment now produces more than half of US generation, and comprises roughly 35 percent of the total installed capacity in North America, roughly twice the installed capacity of Mexico and Canada combined. Most of these US facilities "are allowed to pollute at emission levels 4 to 100 times those that must be met by their new competitors."[8] If the competitive advantage associated with these lower standards proves decisive, US coal-fired generation could raise existing production by as much as one-third in response to continental demand growth, access to new markets, and new competitive pressures.[9]

Thus, this scenario envisages a near-term surge of production from aging coal-fired plants that overwhelms more tightly regulated competitors, coupled with the phase-out of aging nuclear facilities and declining utility-sector investment in energy efficiency and renewable generating technologies. However, there is nothing inevitable about this prospect, and multiple strategies are available to secure environmentally superior results.

The dramatic increase in customers with access to competitive generation markets underscores such concerns. At the wholesale level, much of Canada and the United States is already operating under "open access" rules by which transmission owners must operate their systems essentially as common carriers for all participants. The result is an expanding commodity market for electricity, with auction-based power exchanges and prices that shift rapidly. Units facing higher environmental standards must find offsetting efficiencies or lose market share to competitors in less demanding jurisdictions connected to the same grid.

At the same time, industry restructuring could work to stall recent progress in bringing new non-polluting technologies to market. An immediate potential victim may be improvements in end-use efficiency, which faced formidable market barriers even before the restructuring process gained momentum. Although "[t]he efficiency of practically every end use of energy can be improved relatively inexpensively,"[10] "customers are generally not motivated to undertake investments in end-use efficiency unless the payback time is very short, six months to three years."[11] These market failures generate "systematic under-investment in energy efficiency," resulting in electricity consumption at least 20 to 40 percent higher than cost-minimizing levels.[12]

[8] A. Cohen (1997), *Unfinished Business: Cleaning Up the Nation's Power Plant Fleet* (Boston: Clean Air Task Force, August). Cohen goes on to explain that the "anomaly stems from the 'old source' exemption granted to existing fossil fuel plants in the original *Clean Air Act*, in 1970 and in 1977, on the theory that these older plants would be retired within 20-30 years."

[9] This is among the findings of the Environmental Impact Statement prepared in conjunction with FERC Order 888. FERC (1996), *Final Environmental Impact Statement: Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities* (RM95-8-000) (April). FERC's view is that coal will not achieve this level of penetration due to aggressive competition from gas-fired units.

[10] US National Academy of Sciences Committee on Science, Engineering and Public Policy (1991), *Policy Implications of Greenhouse Warming*, 74.

[11] US National Association of Regulatory Utility Commissioners (1988), II Least Cost Utility Planning Handbook (December), II-9.

[12] See M. Levine, J. Koomey, J. McMahon, A. Sanstad & E. Hirst (1995), *Energy Efficiency Policy and Market Failures*, 20 Annual Review of Energy and the Environment 535, 536, 547; Alliance to Save Energy et al., (1997), *Energy Innovations: A Prosperous Path to a Clean Environment* (June).

There are many explanations for the universal reluctance to make long-term energy-efficiency investments.[13] Decisions about efficiency levels often are made by people who will not be paying the electricity bills, such as landlords or developers of commercial office space. For North America as a whole, these market barriers mean that energy prices alone are an insufficient incentive to exploit a continental pool of inexpensive savings. Restructuring exacerbates these market failures by reducing utilities' incentives to overcome them. These pressures could put an end to a fifteen-year period during which hundreds of North American utilities proved that they could invest productively in a host of end-use energy-efficiency improvements. The end of integrated utility monopolies compels the substitution of new models for undertaking investment of this kind. A further challenge is to accommodate them with open grids under NAFTA.

This study will present the electricity sectors of Canada, Mexico and the United States in a broader North American context, focusing on the aggregate environmental impacts attributed to the sector and the substantial variations in terms of capacity, resource bases, prices and regulatory trends. It will consider the potential impact of NAFTA in conjunction with the related move toward changing markets in the United States and Canada and more modest restructuring in Mexico. Because the electricity sector is experiencing dramatic change, and will continue to do so in each of the three countries, it is premature to qualify the environmental impacts as positive, negative or a combination of the two. At present, it is only possible to determine trends in the sector, establish their relationships with the liberalization of trade and investment in North America, and consider their environmental consequences should they continue.

[13] An extensive assessment appears in US Congress, Office of Technology Assessment (1992), *Building Energy Efficiency*, (Washington, DC: OTA): 73-85.

II. The Issue in Context: Environmental, Economic, Social and Geographic Conditions

A. The Environmental Context

Electricity production plays a critical role in contributing to North America's principal environmental challenges. The continent's electricity bill is less than 3 percent of its gross domestic product, but, for major air pollutants, the relative contribution of electricity is more than ten-fold greater. Electricity production can contribute to urban and regional ozone, fine particles, acid deposition, eutrophication of important water bodies, impacts on health and ecosystems from mercury releases, nitrogen saturation of forest ecosystems, regional haze and climate change. In addition, electricity is important in debates over the disposal of radioactive waste, the preservation of endangered salmon fisheries and of undammed rivers.[14]

The production and trade of fuels used in electricity production also have important environmental impacts. In addition, assessments of the impacts of liberalized electricity markets have indicated that the environmental benefits and costs of electricity restructuring are likely to hinge on fuel price and availability, in particular for coal and natural gas.[15] There are a number of environmental pressures associated with the production of these fuels. Electric utilities are responsible for 33 percent of the NO_x emissions in the United States, 10 percent in Canada, and 15 percent in Mexico. Natural gas production in Canada is responsible for an additional 10 percent of NO_x emissions. Indeed, in Canada, natural gas and oil extraction resulted in the cumulative release of almost 4,000 metric tons (3,943,965 kgs) of pollutants into the environment in 1994.

The following section outlines the major ways that the production of electricity impacts upon the environment through the media of air, water, land and biota.

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[14] Letter to Congressman Edward J. Markey from Mary D. Nichols, Assistant Administrator for Air and Radiation, 28 March 1997, 1.

[15] See FERC, *Final Environmental Impact Statement*.

1. Air

The pollutant releases and environmental impacts associated with electricity include sulfur oxides (SO_X), nitrogen oxides (NO_X), mercury and carbon dioxide (CO_2). These emissions are understood to result directly from economic activity, from the generation of fossil-fired and potentially, geothermal, generating stations, and from the production of fossil fuels. For North America as a whole, about one-third of these emissions originate in power plants, and all four emissions categories have substantial cross-border consequences.[16] With the exception of mercury, emissions are monitored in all three countries.

Sulfur and nitrogen emissions cause varied and sometimes linked damages to ecosystems and public health. Evidence also exists of public-health losses associated with minute airborne particles, many directly traceable to fuel combustion in power plants.[17] Moreover, NO_X contributes to urban ozone problems in all three countries, inflicting harm on residents with respiratory ailments, especially among the elderly and the young.

Airborne mercury emissions and mercury's subsequent accumulation in animal fats are additional unwelcome byproducts of coal combustion, most of which is used to generate electricity. Results include liver and kidney damage, infertility, fetal malformations, and multiple forms of damage to aquatic ecosystems.

Fossil fuels used in electricity generation also cause air emissions and other environmental impacts associated with their extraction, processing and distribution. The emissions of concern include primary emissions, such as greenhouse gases and acid gases that have direct effects, and secondary compounds such as ground-level ozone and respirable particulates that can be formed in the atmosphere.

Acid Deposition

In the United States, electric utilities were responsible for 6.4 million tons of (NO_X) and 10,519 tons of (SO_2) emissions in 1995.[18] This is approximately 33 percent of US NO_X emissions and 70 percent of the SO_2 emissions. Coal-fired power plants in Illinois, Indiana, Michigan, Ohio and Wisconsin were responsible for 25 percent of the electric utilities' NO_X emissions and 28 percent of the SO_2 emissions.

Electricity generation in Canada was responsible 186,000 metric tons of NO_X and 524,000 metric tons of SO_2 in 1995. This is approximately 10 percent of Canada's NO_X emissions and 22 percent of Canada's SO_2 emissions. Acid gases also contribute to the formation of respirable particulates and, in the case of NO_X, the formation of ground-level ozone. Electric utility emissions in Mexico accounted for 48 percent of total SO_X emissions.

Greenhouse Gases

Electricity generation alone represents more than 30 percent of North American CO_2 emissions, and its contribution is growing.[19] In the United States, electric utilities were responsible for 1.7 billion tons of CO_2 equivalent, representing approximately 33 percent of US GHG emissions in 1995. Coal-fired power plants in the midwestern states of Illinois, Indiana, Michigan, Ohio and Wisconsin were responsible for 20 percent of the utilities' GHG emissions.

[16] See Commission for Environmental Cooperation (1997), *Continental Pollutant Pathways: An Agenda for Cooperation to Address Long-Range Transport of Air Pollution in North America* (Montreal: CEC). For example, electric utilities' contribution to total sulfur dioxide emissions is 22 percent, 48 percent and 70 percent for Canada, Mexico and the US, respectively; for nitrogen oxides the figures are 10 percent, 15 percent and 33 percent. *Ibid*, 21. Mexican data on mercury emissions were unavailable, but US and Canadian power generation accounted for 21 percent and 4 percent of national releases, respectively. *Ibid*, 22. For discussion of cross-border consequences, see *Ibid*, 4-8.

[17] Estimates of the annual death toll for the United States alone run as high as 60,000. *Ibid*, 14 (citing estimates by Harvard University researchers). See generally R. Wilson & J. Spengler (1996), *Particles in Our Air: Concentrations and Health Effects* (Harvard School of Public Health).

[18] Energy Information Administration, *US Electric Utility Environmental Statistics*, "Preliminary Estimates of Emissions" (Table 22).

[19] Carbon dioxide (CO_2) emissions from electricity generation challenge the commitments of the United States and Canada to stabilize and subsequently reduce concentrations of greenhouse gases (GHGs) in the atmosphere. Emissions from all three countries are increasing despite pledges by the United States and Canada to stabilize GHG releases at 1990 levels by the year 2000. With the conclusion of the Kyoto Protocol in December 1997, international efforts to address the threat of global climate change have moved into a new phase oriented toward meaningful reductions of GHG emissions in accordance with binding target. Under the agreement, which will have to be ratified in both countries, the United States and Canada will commit to reduce emissions of six GHGs to levels 7 percent and 6 percent below 1990 emissions levels by 2007-2012.

In Canada in 1995, electricity production was responsible for 103 million metric tons of CO_2 equivalent, representing 16.6 percent of Canada's total inventory. In Mexico in 1990, electricity production was responsible for 73 million metric tons of CO_2 representing 25 percent of Mexico's total emissions.

Respirable Particulate Matter

In the eastern United States and Canada, particulate matter often contains a large amount of sulfate aerosols. In the western United States and Canada, where sulfate levels are lower, it often contains nitrates.[20] Fine particulates formed from sulfates are of significant concern since they have an atmospheric life that spans three to five days and can travel over 600 miles.[21]

Respirable particulates are categorized as particulate matter smaller than 10 microns (PM_{10}); they can be inhaled into the lungs. Standards for PM_{10} have been developed in the United States as a replacement for the Total Suspended Particulate (TSP) standard, which included larger particles that were not inhalable. The US standard for ambient air quality is 150 micrograms/m^3 for 24 hours and 50 micrograms/m^3 for annual concentrations. As of September 1996, 81 areas were in non-compliance with the standard for PM_{10}.[22] Canada is currently developing national ambient air quality objectives for PM_{10}. British Columbia's objective for PM_{10} is 50 micrograms/m^3 for 24 hours and 30 micrograms/m^3 per year.

A recent review of studies on the health impacts indicate that exposure to inhalable particulate matter can impair lung function, lead to increased respiratory symptoms and functional limitations, increased physician and emergency visits for asthma, increased hospitalization for respiratory conditions and increased mortality.[23] Recent science indicates that approximately 50 percent of the ambient respirable particulate matter is derived from the formation of secondary compounds of acid gases such as nitrogen oxides and sulfur dioxide.[24]

Tropospheric Ozone

Emissions of precursors of ground-level ozone from fossil-fuel generating plants also pose significant health and environmental impacts. Ground-level ozone is produced in the lower atmosphere when nitrogen oxides react with volatile organic compounds in the presence of sunlight over a period of six to twelve hours.[25] The method of formation results in a time lag between emissions of nitrogen oxides and ozone measurement, thereby creating a long-distance transport problem involving multiple jurisdictions and agencies in developing strategies for mitigation.

The health effects resulting from increased exposure to ground-level ozone include increased incidence of asthma, respiratory infections and chronic respiratory problems, including bronchiolitis. Ground-level ozone also inhibits the growth of vegetation, decreases crop yields and degrades building materials and structures.

High levels of ozone have been measured in major urban areas of Canada, the United States and Mexico. For example, in Canada, the Lower Fraser Valley of British Columbia, the Windsor-Quebec corridor, the southwestern areas of New Brunswick and Nova Scotia periodically exceed the Canadian standard for ground-level ozone (82 ppb over 1 hour). The United States is divided into 257 air-management zones, out of which 68 are in noncompliance for the US

[20] *United States-Canada Air Quality Agreement, Progress Report*, 1996: 47.

[21] Natural Resources Defense Council *et al.* 1997. *Benchmarking Air Emissions of Electric Utilities in the Eastern United States* (April): 32.

[22] US EPA, *National Air Quality and Emissions Trends Report*, 1995: 4.

[23] *Health Effects of Wood Smoke: A Report to the Provincial Health Officer of British Columbia*, Sverre Vedal, Environmental and Occupational Lung Diseases Research Unit, University of BC, 1993: 21-22.

[24] "Screening Level Valuation of Air Quality Impacts Due to Particulates and Ozone in the Lower Fraser Valley," Senes Consulting Limited, Vancouver, British Columbia, (29 March 1994): 2-8.

[25] *Ibid.* It is estimated that ozone and its precursors can travel up to 500 miles.

ground-level ozone ambient air quality standard (120 ppb over 1 hour). In Mexico City and Tijuana, where ozone is measured at ambient air monitoring stations, ozone levels exceeded 230 ppb on 162 days in Mexico City and measured 67 ppb on average in Tijuana.

As a result, ground-level ozone is considered to be North America's most pressing urban air-pollution problem. Since ozone forms in the atmosphere over time, growth in the use of fossil fuels in the United States electricity-generation sector has the potential to frustrate the attempts to reduce ozone problems in Canada-US border areas, namely the Windsor-Quebec corridor and the northeastern United States. Such attempts are currently being explored by the Air Quality Committee established through the Canada-US Air Quality accord. A Regional Ozone Study Area (ROSA) initiative is assessing the impacts of ozone in the New York State-Ontario region. In addition, an open-market emissions trading pilot project for NO_X has been established between Michigan and Ontario.

The environmental impacts of gas extraction, processing and transmission can be measured qualitatively and quantitatively. Qualitative impacts, such as species and habitat reduction, result from the infringement on wilderness areas caused by building roads for exploration, drilling and gathering. Criteria air contaminants, including NO_X, carbon monoxide (CO), methane and SO_X, are released at flaring and processing sites.[26] While flared emissions are not measured, emissions at processing plants are quantified for site-specific permits. The last complete inventory of criteria emissions from Canadian sources, completed for 1990, indicates that natural gas processing plants emitted some 247,532 metric tons of SO_X, and 117,489 metric tons of NO_X. Total emissions from Canadian sources were 3,295,867 metric tons of SO_X and 2,062,297 metric tons of NO_X.[27]

The pipelines used to transport natural gas to markets from production areas have specific environmental impacts resulting from the use of natural gas as a fuel for compressor stations and the disruption of habitat along pipeline corridors and the roads to service the pipelines. Currently, the natural-gas gathering system in Canada is made up of 3,547 kilometers of pipelines; another 54,094 kilometers are used for transmission to market. There are 292 compressor stations on the gathering, transmission and distribution pipelines. In 1996, these compressors used 6,344 MCM of natural gas, resulting in the release of approximately 12 million metric tons of CO_2.[28] According to the most recent emission inventory for British Columbia, completed for 1990, natural-gas transmission through the province's 2,981-km system results in 7,449 metric tons of NO_X emissions per year. Estimates for Canadian NO_X emissions for the remaining 51,000 km of transmission are not available.

2. Water

The water-pollution impacts of the energy sector include the contamination of rivers, lakes and other bodies of water with acid and nitrogen depositions associated with air emissions, as in the case of the acid-deposition problem in the northeastern United States and eastern provinces of Canada. In addition, groundwater contamination may result from the production of fossil fuels as well as the construction and operation of hydroelectric facilities. Cooling water emitted from power plants into receiving bodies may affect water temperature. The most significant effects on water are due to the development and operation of hydroelectric projects.

[26] Gas losses during production can be significant: in 1996, for example, Canada produced 197,472 million m^3 (MCM) of natural gas at the wellhead. Of this, approximately 16 percent was consumed in gathering, flaring, and processing, and a further 6 percent was injected into storage fields, yielding a total of 153,578 MCM of marketable natural gas. This volume was complemented by 13,979 MCM taken out of storage to produce a total supply of 167,557 MCM. Of this, domestic consumers used 80,182 MCM and export markets in the United States consumed another 80,117 MCM (sales valued at C$7.432 billion). The remaining 7,258 MCM were consumed as pipeline fuel and pipeline losses, with 6 MCM lost through line pack fluctuation. [Statistics Canada, Catalogue Number 57-205-XPB.]

[27] Environment Canada (1996), *Canadian Emissions Inventory of Criteria Air Contaminants* (1990), EPS 5/AP/7E (February).

[28] CO_2 emissions are calculated using a 49.68 kg per GJ, and an average heat content of 38 MJ per m^3.

One of the main environmental problems with water diversions and reservoirs comes from the disturbance of natural water flows. This results in a variety of effects on other environmental media, such as biota and land. However, the impacts on water quality and quantity are also significant. In terms of water quality, reservoirs can lead to changes in toxicity by providing an opportunity for specific bacteria to transform elemental mercury into methyl mercury. Reservoir flooding can also change the temperature, the nutrient content and the acidity of impounded water bodies. In addition, as more dissolved oxygen is consumed by decomposing plant material, carbon dioxide content increases.

Diversions and reservoirs can cause changes in water quality in downstream areas by denying rivers and streams the volumes of water needed for flushing fine material and by altering the patterns of replenishment for larger bodies of water. In Canada, an average of 4,200 cubic meters of water per second are being diverted for the production of electricity.[29]

Acid rain deposition through the air can also affect water quality. It is projected that even after the full implementation of the US and Canadian acid rain programs, 791,000 square kilometers of eastern Canada and the northeastern United States will receive acid deposition in excess of critical loads. Current trends indicate that most lakes in eastern Canada are showing little change in acidity, despite significant emission reductions in Canada. A key question posed by electricity restructuring is whether this trend will continue or whether it will be abated by the early retirement of fossil-fueled power plants.

The Canadian Council of Resource and Environment ministers established a target loading for sulfur deposition of 20 kg/ha per year, which the Canadian Acid Rain Program is intended to meet. The area of eastern Canada receiving 20 kg/ha has declined from 0.71 million km^2 in 1980 to 0.29 million km^2 in 1993. The 20 kg/ha target was derived from limited data available in the early 1980s and was based on attaining a pH level of 5.3. It is widely recognized that this target will not protect most aquatic organisms and may result in the serious impairment of biologically sensitive waters.[30] Regional analysis of monitored sites in Nova Scotia, Newfoundland, Quebec and Ontario indicates that 11 percent of monitored sites are continuing to acidify, 33 percent are recovering and 56 percent exhibit no change.[31] This trend is due to the continuing flow of acidifying emissions from the United States.[32] In Mexico, acid deposition has been detected in Mexico City. It is causing damage on the east coast of Mexico.

Airborne mercury emissions from fossil-fuel combustion may also be deposited in water bodies. Recent reviews of existing data bases and studies comparing modern background mercury concentrations and historic levels of mercury in lake sediments indicate that anthropogenic emissions and deposits of mercury in remote areas have had a significant impact on the natural mercury cycle.[33] The Environmental Protection Agency is currently preparing a report to Congress that examines the contribution of electric utilities to hazardous air emissions.[34] In Canada, electric utilities were responsible for 4 percent of the air emissions of mercury. In the United States 33 percent of mercury emissions are from electric utilities.

Fuel production and processing can also affect water quality. Acid drainage associated with uranium and coal mining can have negative impacts on water quality. Naturally occurring acids found in waste piles may dissolve when exposed to air and certain bacteria. These acids then leach metals from waste piles and the surrounding area, which can then percolate into ground water and eventually reach water bodies. Modern mining operations use impermeable barriers, dikes

[29] Environment Canada, *State of Canada's Environment Report*, Table 11.9.

[30] Environment Canada (1996), *Acid Rain*, *Canada's National Environmental Indicators Series*, Spring.

[31] Canada-United States Air Quality Agreement, Progress Report, 1996: 35.

[32] Environment Canada (1996), *Trends in Lake Acidity in Southeastern Canada*, *Canada's National Environmental Series*, Spring.

[33] Fitzgerald, Engstrom, Mason and Nater (1997), "The Case for Atmospheric Mercury Contamination in Remote Areas," Minnesota Office of Environmental Assistance (4 November).

[34] David Fiesta and Stacey Davies (1997), "Moving on Mercury: First Steps for Electric Utilities," *The Electricity Journal*, August/September.

and other technology to reduce the incidence of ground water contamination from acid drainage. Due to their low sulfur content, coal mines in western Canada are not expected to be large producers of acid drainage.[35]

3. Land

Land-use changes range from the fairly localized impacts due to the construction and operation of generating stations, oil and gas wells, and coal or uranium mines, to the substantial habitat and land-use changes associated with the construction of gas, oil and electricity transmission lines, to the far more massive dislocations associated with the flooding of rivers and gorges as a result of the construction of hydroelectric facilities.

The solid-waste generation associated with the production of fossil fuels, as well as the construction and operation of electricity generation and transmission infrastructure, also affects land. The types of solid waste may range from the comparatively benign, such as used equipment, drilling muds and oily wastes, to highly toxic and dangerous wastes, such as the polychlorinated biphenyls (PCBs), historically used in capacitors and other electrical equipment, and radioactive wastes generated by nuclear power stations in each country.

In Canada, it is estimated that 20,000 km^2 of land have been flooded for hydroelectric reservoirs. Transmission and pipeline corridors have also occupied large amounts of land in Canada and the United States. In many cases, the use of land for corridors is not an exclusive use, particularly on agricultural land.

Mining waste from coal production also affects land. Coal is extracted from open pit mines as well as from deep underground mines. These production facilities can have severe impacts on land, water and air. As of 1989, Canada had reclaimed 15,900 hectares of the 41,700 hectares that were disturbed by coal mining. By comparison, in Kentucky, one of the primary coal-producing states in the United States, there are 80,000 acres of abandoned mine lands formerly used for coal production. Since 1982, 18,000 acres have been reclaimed.[36] In terms of operating impacts on land and water, coal-burning facilities require waste and water treatment and disposal for ash and byproducts of pollution-control equipment. Treatment-plant effluents also have an impact on biota.

In Canada, Alberta is the largest consumer of coal for generating electricity, annually using approximately 24 million metric tons of steam coal for electricity production. Coal mining in Alberta resulted in 15,000 hectares of land disturbance, with 7,000 hectares reclaimed through environmental mitigation. In mountains and foothills, land may be restored to wildlife habitat or forestry uses, while on the prairies it may be restored to agricultural use.[37] In Canada, for every 10 metric tons of coal produced there are 2 metric tons of coal waste. In 1991, there were approximately 20 million metric tons of coal waste generated in Canada.[38] However, the material is usually recycled as backfill for open pit mines or for land reclamation.

Mining waste from uranium production affects land. Uranium mill and mine waste tailings require long-term disposal resulting in the exclusive, and sometimes perpetual, occupation of land. Approximately 203 million metric tons of low-level radioactive tailings are stored on 1,570 hectare of land in Canada. Canada is the world's largest producer of uranium, accounting for 31 percent of the world's output. This waste, which can remain radioactive for tens of thousands of years, can also contain toxic substances such as arsenic and assorted heavy metals.

Land can also be affected by solid waste from nuclear plants. Canada has an additional 1.3 million cubic meters of low-level radioactive waste that must be stored, including residues and irradiated equipment from processing facilities, power plants and other facilities. All high-level nuclear fuel waste is stored at nuclear reactor sites. There are currently approximately 17,000 metric tons of nuclear fuel waste stored at reactor sites in Canada.

[35] "Human Activity and the Environment," 1994 Statistics Canada (Cat. No. 11-509E): 166.

[36] *State of Kentucky's Environment*, 1994 Status Report.

[37] Environment Canada (1997), *State of Canada's Environment*.

[38] *Ibid*.

The United States, the world's largest producer of high-level radioactive nuclear waste, is currently in the process of developing a long-term storage site at Yucca Mountain in Nevada. The United States produced approximately 30,000 metric tons of high level nuclear waste and 104,000 tons of contaminated fuel assemblies from commercial nuclear power reactors between 1968 and 1994.

4. Biota

Electricity-sector impacts on biota may be direct—through the flooding of reservoirs or the construction of transmission lines or pipelines, for example—or indirect, related to the deposition of acid materials or other pollutants.

Air emissions from thermal power plants contribute to environmental impacts on plants and animals. Acid gases—which are deposited on land and water through dry deposition—and precipitation—in the form of rain and snow—have had demonstrable impacts on fish, water fowl and forests. Fish surveys in eastern Canada have found that as the pH of water bodies changes, there are lower numbers of species of fish and lower populations. This may be caused by minerals that leach out of the surrounding area and change the water quality. Water fowl that rely on fish are also at risk from changes in fish populations.

Forest monitoring in Canada and the United States has found that although there is no evidence of widespread forest decline as a direct result of acid deposition, this deposition can and does have detrimental effects on forests. Sample plots used to monitor the effects of acid deposition on trees in acid-sensitive soils have shown demonstrably declining conditions. In addition, the health of New Brunswick birch stands that were exposed to acid fog has been declining, and the monitoring of sample plots revealed that tree mortality was several times higher than in non-exposed areas.[39]

Soil monitoring has revealed decreases in soil nutrients that may also affect the health of the forest. Ground-level ozone also reduces the productivity of vegetation and increases morbidity in and the mortality of humans. It is suspected that ozone's effects on the environment may be compounded due the synergistic effects of acid gases and other atmospheric pollutants.

Hydroelectric reservoirs can eliminate or severely limit habitat for mammals, alter the survivability of fish and eliminate productive plant life. In Canada, it is estimated that 20,000 km^2 of land have been flooded due to reservoirs. Flooded land can produce a number of measurable impacts on biota. For example, increased nutrients in flooded reservoirs can lead to a rise in phytoplankton populations, followed by an increase in zooplankton. There may also be changes in fish populations, predation patterns, spawning behavior, and survival rates for offspring. Further problems associated with reservoirs include the potential for a rise in the amount of methyl mercury found in biota. Mercury levels in fish found in reservoirs in the James Bay area range from 0.06 to 0.21 parts per million (PPM) for whitefish and 3.0 PPM for Northern Pike. Fish containing more than 0.5 PPM are considered unsafe for continued consumption.[40] Regulators in forty US states have issued advisories restricting the consumption of fish that may have elevated levels of mercury.[41]

Diversions and reservoirs also impact on birds and other biota found in estuaries at the mouths of altered rivers. Changes in flow regimes cause changes in estuarian water cycles that alter the naturally occurring mix of salt water and fresh water. As the mix changes, the feeding area for birds and the organisms they feed on will also change.

Transmission corridors also reduce growing areas for trees and can provide easy access for predators. In Canada, there are approximately 157,000 kilometers of bulk transmission lines occupying transmission corridors. In many

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[39] Canada-United States Air Quality Agreement, *Progress Report*, 1996: 38-42.

[40] Environment Canada (1997), *State of Canada's Environment Report*.

[41] David Fiesta and Stacey Davies (1997), "Moving on Mercury: First Steps for Electric Utilities," *The Electricity Journal*, August/September.

instances, there are three or more transmission lines in these corridors, which reduces the overall amount of cleared land used for the lines. Pipeline corridors for natural gas gathering plants can also open up otherwise inaccessible wilderness areas. Once areas are open, hunting and logging operations can move into the area, thereby impacting on biota.

Waste from mining—such as radionuclides, which are found in effluent discharges from uranium mills and waste piles—can accumulate in aquatic biota. Acid drainage from mining waste may also impair fish survivability in nearby water bodies. While new mines and mills are continuously upgrading their environmental performance, the mitigation of past problems is ongoing. In Canada and the United States, government agencies, in collaboration with the mining industry, have developed programs and regulations to address the issue of reclaiming abandoned mines and improving waste treatment.

In the United States, reclamation fees to repair abandoned sites or sites improperly restored prior to 1977 are collected on coal production. Surface mines pay 34 cents per ton, underground mines pay 15 cents and lignite mines pay 10 cents. As of 1996, there were over 10,000 problem areas associated with abandoned mines in the United States. The majority of these sites are coal mines. Uranium mining is almost inactive in the United States.

The electricity sector has given rise to a number of innovative ways of addressing environmental problems. The industry's continent-wide SO_X and NO_X emissions have dropped over the past two decades, at control costs far below initial projections. High-efficiency natural gas and renewable-energy applications offer attractive replacements for aging fossil and nuclear fleets. End-use efficiency improvements, many pioneered with utility investment, provide abundant opportunities in all three national economies to deliver more and better service with less electricity and pollution.

B. The Economic Context

Electricity's impact on the environment increases with its rapid growth and expanding share of the energy market. Between 1993 and 1996, growth in electricity consumption in Mexico was slightly over 20 percent. In the United States, growth was around 8 percent. In Canada, growth during the same period was 7 percent.[42]

Electricity's market share has expanded in all three nations. In Mexico, electricity's share of final consumption is now nearly 12 percent, compared to less than 8 percent in 1979. This reflects the fact that since 1991, growth in electricity consumption in Mexico has been second only to natural gas; over the longer term, in the period since 1979, electricity has outpaced all other fuel types, including natural gas. Since 1991, final consumption of electricity has averaged 4.75 percent growth, compared to 5.87 percent for natural gas, 1.86 percent for petroleum and 1.91 percent for solid fuels. The rapid growth in natural gas consumption appears to be at the expense of petroleum, which has lost market share steadily since 1992. Some subsectors of the petroleum-fuels sector, however, have registered rapid growth: gasoline consumption, for example, increased 31 percent during the 1991-1995 period.[43]

Between 1973 and 1996, electricity consumption in the United States increased by almost 80 percent, while natural gas and petroleum use recorded virtually no change during the period. This trend continued in recent years, even with rapid growth in petroleum consumption that was driven by low real oil prices and changing vehicle ownership patterns; over 1991-1995, electricity consumption outpaced other sectors, averaging about 1.4 percent annual growth, compared to the 0.9 percent annual growth over 1991-1995 in petroleum consumption (two-thirds of which is made

[42] Canadian Electricity Association (CEA) and Natural Resources Canada (NRCAN), *Electric Power in Canada, 1995* (Ottawa: CEA and NRCAN, 1996): 50. Secretaría de Energía (SE), *Documento de Prospectiva del Sector Eléctrico* (1996-2005) (Mexico, DF: SE, 1996): 17. See also, Annex 3.

[43] Secretaría de Energía, *Balance Nacional de Energía*—1995, (Mexico City: SE, 1996): 55.

up of transportation fuels), equivalent to a 6-percent gain for the period.[44] In Canada, electricity has expanded its share of secondary energy consumption to the 24 percent recorded in 1995, up from 11 percent in 1960.[45]

All three NAFTA countries anticipate steady growth in electricity consumption. The Energy Information Administration (EIA) forecasts average annual growth in per capita electricity consumption of 1.4 percent, 1.9 percent and 4.5 percent in the United States, Canada and Mexico, respectively, between 1995 and 2015. Meanwhile, all three countries are also increasing the role of markets and competition in what have traditionally been regulated monopoly systems.

NAFTA is only one of the many factors affecting trade, cross-border investment and environmental impacts in the electricity sector. Other factors include the levels of demand, drought that reduces hydroelectricity supplies, limited transmission capacity and the cost of capital in this very capital-intensive industry. Yet another major factor is a microeconomic one: the changing character of the sector from its former status as a heavily regulated (and often government-owned) monopoly.

This latter factor is of particular importance in this sector. North Americans traditionally have obtained electricity from integrated monopolies with tightly defined geographical franchises. The monopolies were responsible for meeting all local power needs by building generation dedicated to, and paid for, by all customers within their service territories. The transmission grid that evolved around and through the local monopolies was shaped to fit their peculiar domestic needs. Interchanges between systems were modest.

This system began to change in the 1960s with the construction of the Pacific Intertie.[46] In the 1960s, and especially during the oil-shock years of the 1970s, US-Canadian trade in electricity increased dramatically. In the 1990s, NAFTA is among a host of causes that also include technological change, local economic pressures and independent initiatives by industry and regulatory leaders in all three countries, with numerous states and provinces now adopting deregulatory measures. At the heart of the electricity restructuring trend is a vision of a competitive generation sector fighting for markets across a continental transmission grid. Although not yet fully realized anywhere in North America, this open grid is key to reform initiatives in all three countries and draws support from the spirit and letter of NAFTA.[47]

To appreciate the role of NAFTA in the evolution of structural reforms in the electricity market in the United States and Canada, it is important to recognize that the economic costs and benefits of cross-border electricity trade are not necessarily distributed evenly among the affected parties. For example, access to cheap and reliable hydro-electric power from British Columbia (BC) offers benefits to US consumers.

Of particular importance to electricity exporters are the issues of access to and cost of transmission systems. While regional transmission systems in North America make it physically possible to deliver power from any one point on the transmission grid to any other, the portion of the transmission system within each utility's service area is owned and operated by that utility, including the transmission interties necessary for cross-border trade. Regulators in the United States, and to a lesser degree in Canada, have tried to correct for potential abuses of monopoly power

[44] US Energy Information Administration (EIA), *Monthly Energy Review* (January 1997), and EIA, "Annual Energy Outlook, 1996." Internet: www.eia.doe.gov.

[45] CEA, *Electric Power in Canada*, 1995: 55.

[46] The Pacific Intertie links Oregon and California, thereby allowing for expanded interconnection between British Columbia and Alberta in Canada with at least eleven states in the United States and northwest Mexico; current simultaneous transfer capacity for the AC and DC elements of the system is close to 8,000 MW.

[47] See for example, US Federal Energy Regulatory Commission, Order No. 888, 18 C.F.R. Parts 35 and 36 (24 April 1996); Order Denying Motion for Stay, 79 FERC 61,367 (20 June 1997) (addressing open access issues in the context of NAFTA requirements, in proceeding brought by Ontario Hydro).

that would lead to discrimination against non-utility or cross-border power producers within the existing monopoly structure through measures such as requiring utilities to use competitive bidding processes to acquire new generation resources. However, many independent power producers, large industrial customers and other key players have come to favor full competition.

Faced with the challenges of global competition (increasingly apparent in the context of NAFTA and other international trade agreements, such as the GATT) and the need to reduce costs, large-volume industrial customers have become the strongest proponents of market reform, particularly in areas where nuclear power plants have since become very uneconomical to own and operate. Many want the option to purchase electricity directly from the cheapest sources they can find anywhere on the grid instead of relying on their local utility to find and make these choices. Trade agreements facilitate this objective in two major ways: reducing the tariffs charged on equipment used in electricity projects; and reducing the tariff charged on certain fuels as well as electricity.

In some areas, large customers recognize that electricity produced by older power plants, which were financed through cost-of-service rate-basing, is cheaper than the average cost of many new plants proposed by utilities. Large electricity consumers would like the opportunity to make direct purchases of the cheaper power and avoid paying for new generation. Conversely, in some areas of North America, utilities have invested in expensive generating resources, such as nuclear plants and some renewable sources, which produce electricity at average costs above the cost of many new generating technologies, notably combined-cycle natural gas turbines. In those areas, customers would like to choose the new resource as their preferred source of power. In either case, customers, often invoking international competitiveness, prefer to purchase the cheaper power and not be required to purchase directly from the monopoly utilities' portfolio of generating resources.

C. The Social Context

Important social forces are at work in the push toward competition in the United States and Canada. Perhaps the most important underlying motivation of efforts to deregulate electricity is to provide lower prices. State legislation of deregulation often includes provisions for immediate rate reductions in the period prior to competition, with the expectation that rates will decline further as a result of competition. In Illinois, for example, legislation signed by Governor Jim Edgar in December 1997 contains a 15 percent rate cut in August 1998, followed by another 5 percent cut in 2002, at which point retail competition will begin.

With lower rates comes the expectation that economic growth will accelerate. The argument that electricity deregulation will spur job growth by improving regional competitiveness is being used increasingly now that a first wave of several state and provincial deregulation initiatives have been implemented in the United States and Canada. Officials in the second wave of jurisdictions, such as Ontario, that will follow the lead of the earlier states and provinces, have emphasized that deregulation is necessary first to keep up with other jurisdictions, and then to gain competitive advantage over them.[48]

At the same time, restructuring at many of the large, state-owned electricity enterprises in North America may well bring about changes that could lead to job losses. This makes the decision to restructure a sensitive political issue in jurisdictions where the state firms have at times been viewed as employers of last resort. In the case of Mexico's *Comisión*

[48] See for example, Ontario Ministry of Energy, Science and Technology (1997), *Direction for Change: Charting a course for competitive electricity and jobs in Ontario*, (Toronto: Government of Ontario): 1-9. Also, the Coalition for Choice in Electricity and other business groups in Ohio are concerned that they are falling behind their competitors as Michigan and Illinois move ahead with deregulation. "Illinois, Massachusetts and Michigan restructuring efforts accelerate," *Daily Power Report*, 1 December 1997. Internet: www.powermarketers.com.

Federal de Electricidad (CFE), the company's total workforce declined by about 25 percent between 1984 and 1994, but most of the change occurred in construction jobs. The number of permanent staff stayed roughly the same during the period, with some growth in the number of jobs through the mid-1980s and a decline from 1989 onwards, to some 51,500 persons in May 1994.[49] By comparison, the workforce of Hydro-Québec, a utility with an installed capacity similar to that of CFE, is roughly 36,500 persons.[50] Potential job gains in new private-sector generation must be set against these job losses in the public sector. In addition, the dynamics of electricity restructuring are taking place in a context in which consumer and environmental groups, and networks or subfederal actors and industry associations are all actively seeking to determine outcomes.

D. The Geographic Context

The electricity sector in North America exhibits substantial variation in terms of the resource base used, the patterns of consumption and demand, and the pricing of electricity in each nation.

1. Resource Base and Generation Patterns

North America's electric sector has almost 912,000 MW of installed generating capacity. Roughly 66 percent is fossil-fuel fired, 18 percent is hydroelectric, 13 percent is nuclear, and just under 2 percent is based on renewable sources other than hydroelectricity. (See Table 1 and Appendix B) Installed capacity in the United States accounts for over 763,000 MW of this total, or roughly 83 percent. Canadian installed capacity makes up 13 percent, and Mexico around 4 percent.

The resource bases of each country are distinct in that Canada's installed capacity is over 50 percent hydro-based, while US capacity is principally coal-based, and Mexico's generation fleet is largely oil-fired.

Table 1 Installed Electricity Generation Capacity in North America, 1995/1996

Installed Capacity (MW)*	Fossil Fuels	Hydroelectric	Nuclear	Renewables	Total
Canada[1]	33,307	64,770	16,393	1,035	115,505
United States[2]	549,026	91,114	107,896	15,395	763,431
Mexico[3]	21,645	9,329	1,309	755	33,037
Total	603,978	165,213	125,598	17,185	911,973
Percentages					
Canada	28.8	56.1	14.2	0.9	100
United States	71.9	11.9	14.1	2.0	100
Mexico	65.5	28.2	4.0	2.3	100
Total	66.2	18.1	13.8	1.9	100

*Nameplate capacity: [1]as of 31 December 1995; [2]as of 1 January 1996; [3]as of 31 December 1995. *Sources: CEA, EIA and CFE.*

[49] *Comisón Federal de Electricidad, Informe de Labores*, 1993-1994, (Mexico: CFE, 1994): 79.

[50] Hydro-Québec (1997), "Hydro-Québec, a world leader in energy," pamphlet.

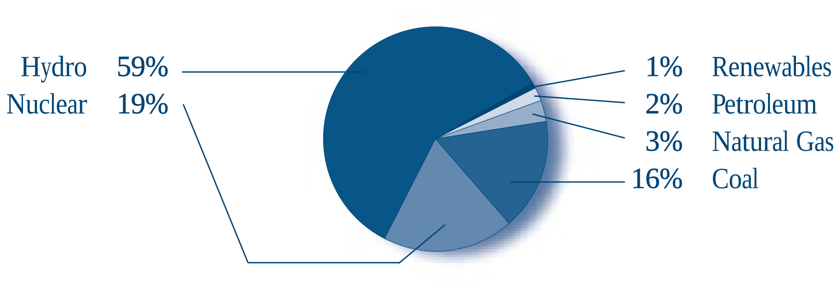
The characteristics of the installed capacity of each country influence the balance of generation by fuel type. Annual generation data will vary as a function of the amount of hydroelectric generation made possible by annual variations in rainfall and the availability of nuclear capacity.

In 1994, Canada's gross production of electricity was 554.2 terawatthours (TWH), of which hydropower accounted for 59 percent, nuclear 19 percent and fossil fuels 21 percent. Fossil generation was made up of 16 percent coal, 3 percent gas, 2 percent oil and 1 percent renewable sources (see Figure 1).

Gross US electric generation in 1994 was 3,473.6 TWH. US generation is dominated by fossil fuel generation, which made up 72 percent of total production in 1994. Of this, coal represented 52 percent, natural gas 14 percent, and oil 3.4 percent, with alternative sources such as waste-to-energy plants making up another 2 percent. Nuclear power contributed 20 percent of total generation and hydropower 8 percent. Geothermal, solar, and wind power made up the remaining 0.6 percent of total generation (see Figure 2).

In 1996, US electricity generation showed a different pattern, with hydropower and coal-fired generation increasing while natural gas decreased. Specifically, in 1996, coal accounted for 56 percent, with nuclear making up another 22 percent. Hydropower accounted for 11 percent, natural gas provided 9 percent, petroleum-fired capacity generated 2 percent and renewables accounted for 1 percent.[51]

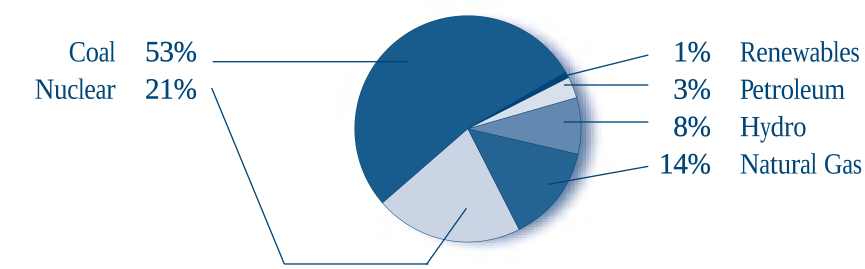
Figure 1 Generation by Fuel Type in Canada, 1994



Gross production at Mexico's power generating facilities was 147.9 TWH in 1994. Fossil fuels accounted for 80 percent of total generation, with fuel oil providing 59 percent, another 12 percent coming from natural gas, and 9 percent from coal. Of non-fossil fired generation, hydropower contributed 14 percent of the country's electricity, while geothermal contributed 4 percent and nuclear accounted for 2 percent (see Figure 3).

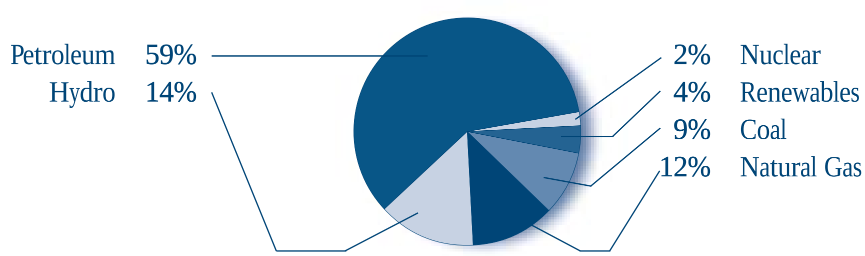
[51] US Department of Energy (1997), *Monthly Energy Review* (October): 95.

Figure 2 Generation by Fuel Type in the United States, 1994



Source: EIA, 1998.

Figure 3 Generation by Fuel Type in Mexico, 1994



Source: CFE, 1995.

2. Regional and National Trends in Demand and Electricity Consumption

Electricity consumption is growing and is expected to grow most rapidly in Mexico, followed by the United States and Canada. Since 1994, Mexico has registered an average growth in electricity consumption of roughly 5 percent per year, while growth in the United States and Canada has been less than 3 percent. Mexico anticipates peak demand growth of 4.5 percent over 1997-2005, whereas peak demand in the United States is expected to increase at 1.7 percent annually over the same period. Canadian peak demand is expected to grow at a rate of 1.6 percent annually.

3. Consumption Trends at the State/Provincial Level

Within each country, there is substantial variation in the rates of growth of electricity consumption and demand for power. This section presents available data on demand growth at the subfederal level and, where possible, by sector at the subfederal level, with a view to identifying those regions of the continent that have registered the most rapid growth and those that are expected to grow the fastest in the future. Tables showing recent figures for consumption and consumption growth, by state/province, are presented in Appendix C.

In Mexico, several states have posted consistently high growth in consumption during the 1994-1996 period. Double-digit growth appears in states along the northern border with the United States, such as Baja California, Sonora and Coahuila, where maquila activity is located (the other border states of Chihuahua and Tamaulipas have registered rapid, but not double-digit, growth), as well as other heavily populated or industrializing states, such as the State of

Mexico, Nuevo León, Puebla, Querétaro, Aguascalientes and Durango. Other regions have not seen such rapid growth in the most recent period, but are also growing quickly over the longer-term. This is especially true of the states of the Yucatán peninsula, notably Quintana Roo.

In the United States, 1993-1996 data show that the fastest growing consumption of electricity in the US is occurring in the southern part of the country, especially in the Sun Belt states of Georgia, the Carolinas, Alabama and Arizona, as well as in the plains states of North Dakota, Missouri, Nebraska and Minnesota. In Canada, for which detailed 1996 data are not yet available, the fastest consumption growth is occurring in the central-western and northwestern parts of the country, in the provinces of Manitoba, Alberta, and in the Northwest Territories and, especially, the Yukon Territory, which posted 31.3 percent growth between 1994 and 1995.

Aggregate consumption of electricity in North America registered an average growth of about 3 to 4 percent annually during the 1993-1996 period (see Table 2).

Table 2 Electricity Consumption in North America

	Consumption (GWH)				Growth (%)		
Country	1993	1994	1995	1996	1993-94	1994-95	1995-96
Canada	482,515.0	493,452.0	503,357.9	516,954.7	2.27	2.01	2.70
United States (contiguous)	2,848,428.0	2,921,083.0	2,999,591.0	3,070,620.0	2.55	2.69	2.37
Mexico	100,876.4	109,532.9	113,365.1	121,571.2	8.58	3.5	7.24
N.A. Total	3,431,819.5	3,524,067.9	3,616,313.9	3,709,145.9	2.69	2.62	2.57

Source: Statistics Canada, Energy Information Administration (US Department of Energy), and CFE.

4. Patterns in Average Electricity Tariffs

A recent evaluation of average electricity prices by state and province for the United States and Canada reveals two general low-cost regions (defined as having average prices less than 4.5 US cents per kWH).[52] These are in the northeast of the continent (encompassing the provinces of Quebec and Labrador and Newfoundland), the northwest (encompassing the province of British Columbia and the states of Washington, Idaho and Wyoming), and in the central Canadian provinces of Alberta and Manitoba. Kentucky is an isolated low-cost state. Two high-cost regions (defined as having average prices over 9 cents per kWH) are the northeast United States (New England, New York and New Jersey) and California. Electricity prices in the rest of the United States and Canada range between 4.5 cents and 9 cents per kWH.

Meanwhile, Mexico would fall under the low-cost heading for 1995, although it is important to point out that continued effects of the December 1994 devaluation of the peso distorted such comparisons in 1995. Since 1995, CFE's tariffs have increased substantially to keep pace with the inflation set off by the devaluation. Within Mexico, there are significant regional variations. In 1995, average electricity prices ranged from a low of 2.5 cents (0.1967 pesos) per kWH in Michoacán state in the central-west part of the country to 4.2 cents (0.3211 pesos) per kWH in Campeche in the southeast and 3.7 cents (0.288 pesos) per kWH in Baja California in the northwest.[53]

[52] Hydro-Québec (1997), *Plan Strategique* (Montreal: Hydro-Québec): 14.

[53] See CFE's webpage for detailed tariff data: www.cfe.gob.mx.

5. Patterns in Residential Electricity Tariffs

Residential electricity prices tend to exceed industrial and commercial tariffs, but the geographical distribution of higher residential rates tends to follow the pattern noted above, with some variations. A regularly updated survey of 60 investor-owned, municipal, rural electric cooperatives and federal systems maintained by the Jacksonville (Florida) Electric Authority (JEA), suggests that the highest residential rates (in excess of 10 US cents/kWH are charged in the north-eastern United States, certain areas of the midwest (Chicago and Cleveland, especially) and California. The lowest rates, meanwhile, appear in areas of the southeast, Texas, and the Pacific northwest (see Appendix D).[54]

JEA's summary of historical data covering the period from 1986 to 1997 indicates that, for the most part, the utilities registering the highest rates in January 1998 have also registered the largest total increases over the last decade. Conversely, those utilities registering the least increase (six of the 60 registered net decreases) were among those posting the lowest rates in 1998. Only in a limited number of instances did utilities in high-cost areas register decreases, and vice-versa. Among the unusual cases is San Diego Gas & Electric, whose residential rates decreased by 4 percent during the 1986-1997 period. Texas Utilities Electric Co. (Dallas), meanwhile, posted a 58-percent increase, but remains a low-priced utility, with residential rates around 7.6 US cents/kWH.[55]

6. Patterns in Industrial Electricity Tariffs

Industrial electricity tariffs are an important factor in determining the competitiveness of industries for which energy costs are a significant part of overall production costs. In North America, there is significant variation in average industrial tariffs between regions, and this is giving rise to concerns regarding the competitiveness of businesses operating within the increasingly competitive continental marketplace. As noted above, major industrial consumers of electricity have led the drive for electricity deregulation on the grounds that competition in the electricity sector will lead to lower prices. The prospect of regulatory change in neighboring jurisdictions is increasingly likely to spur demands for similar action in other regions. Such arguments about preserving industrial competitiveness appear to be central to the Ontario provincial government's plans to introduce competition in the province by 2000.

A comparison of industrial tariffs reveals significant disparities within each of the countries in the NAFTA region as well as between them, as noted in Table 3. Ontario tariffs appear toward the top of the list for Canadian cities, while cities in the hydro-rich provinces of Manitoba, Quebec and British Columbia appear toward the bottom. In the United States, cities in the hydro-rich northwest appear toward the bottom of the list, while the northeast, where fossil-fired generation is dominant, ranks far higher.

In Mexico, average tariffs by state show a far tighter distribution of price levels than in Canada or the United States. This may be related to the fact that, for policy reasons, industrial tariffs are set by the *Secretaría de Hacienda y Crédito Público* (SHCP) at levels below the long-run marginal cost of providing the power. On average, however, it appears that industrial electricity tariffs in Mexico are situated on the lower end of the scale found in the United States. Moreover, the lowest-ranking states in Mexico are either located close to the country's major petroleum-producing regions in the Gulf of Mexico, and are large markets where volume-related pricing may apply, or, as in the case of Baja California, are situated close by significant geothermal capacity. These geographic disparities may, in general. provide an incentive for industries with high electricity input costs to locate in Mexico, and for their US and Canadian competitors to demand an open grid to lower such costs for them. For certain sectors in Mexico, however, the applicable electricity tariffs may be higher than those faced by competitors in the United States or Canada. An analysis performed by Mexico's *Asociación Nacional de la Industria Química* (ANIQ) indicates that Mexican electricity prices in 1997 were very close to those faced by competitors in the US and Venezuelan petrochemical and steel industries, but were higher for Mexican companies in the glass, chlorine and caustic soda, and aluminum sectors when compared to US and Canadian competitors.[56]

[54] JEA, "Monthly Residential Rate Comparison," Internet: www.jea.com/ratecomp/ratecomp12.asp.

[55] *Ibid.*

[56] José Montemayor Dragonne, Commercial Director, Química PennWalt, personal communication, 19 December 1997.

The comparisons also demonstrate some of the market-related forces behind trade within North America, particularly in the northeastern United States. Alongside the high electricity prices in the US northeast, the low prices in Montreal and Quebec's surplus hydroelectric capacity clearly illustrate the economic incentive for Quebec to sell power into New England. The price variations are suggestive of the potential gains from exporting power south into California out of British Columbia or the US Pacific northwest, or north out of Baja California in Mexico. All other things being equal, in the absence of such cross-border sales, there could be a tendency for industries with high electricity costs to relocate to areas where local power prices are lower.

Table 3 Industrial Electricity Tariffs in North America, 1996

Country	City and State/Province	USD/kWH	Pesos/kWH
Canada	Toronto,Ontario	0.0627	
	Ottawa, Ontario	0.0502	
	Calgary, Alberta	0.0407	
	Vancouver, British Columbia	0.0407	
	Montreal, Quebec	0.0399	
	Winnipeg, Manitoba	0.0349	
United States	Boston, Massachussetts	0.0843	
	Detroit, Michigan	0.0717	
	Houston, Texas	0.0598	
	Minneapolis, Minnesota	0.0505	
	Seattle, Washington	0.0404	
	Portland, Oregon	0.0395	
Mexico	Quintana Roo	0.0433	0.3295
	México DF	0.0420	0.3197
	Guanajuato	0.0419	0.3187
	Morelos	0.0404	0.3075
	Tamaulipas	0.0401	0.3053
	Chihuahua	0.0400	0.3040
	Jalisco	0.0398	0.3030
	BCN	0.0390	0.2967
	México State	0.0378	0.2877
	Nuevo León	0.0355	0.2698
	San Luis Potosí	0.0332	0.2523
	Veracruz	0.0321	0.2440
Exchange rate			7.605

Sources: Mexican data, CFE; US and Canadian data, Electric Power in Canada 1995: 25

7. Regulation of Electricity in North America

There is also substantial variation in the structure of regulation in North America. Whereas the United States and Canada exhibit a division of regulatory responsibilities between federal agencies and subfederal entities, Mexico's system of energy regulation is entirely federal. The number of electricity providers also varies from the more than 3,000 private, public, federal and other types of entities in the United States, to a far more reduced number exhibiting similar variation in Canada, to the two (very different in size) state-owned electricity companies in Mexico. This dramatic variation has important implications, both from an analytic perspective and in terms of the mechanisms available for pursuing integrated solutions to the environmental issues associated with North America's electricity sector.

III. The NAFTA Connection

This section identifies how the NAFTA regime—its rules and institutions—may be increasingly relevant to the electricity sector, even though the trade agreement itself includes only a few provisions directly relevant to trade in electricity. The relevance of NAFTA begins with its changes in such areas as government procurement and trade in equipment. It extends to the creation of a broader commercial, economic and political environment that favors movement toward the liberalization and restructuring of electricity markets at the national and international levels. It also includes NAFTA institutions that may become vehicles for cooperation and regulatory convergence.

The NAFTA regime is relevant to the electricity market in two key ways: first, it has reinforced the market pressures for a competitive North American electricity market; second, it has and will continue to expand on the institutional frameworks within which the economic integration of the Canadian, US and Mexican electricity markets may take place, including the establishment of mechanisms for resolving trade disputes. Before considering these impacts of NAFTA, it is useful to review both some of the main provisions of the NAFTA covering the energy sector and those sections of the NAFTA text having the most direct impact on the electricity sector.

A. NAFTA Rule Changes

The most direct NAFTA rule changes involve trade and investment in the electricity sector. One of the most important achievements of NAFTA in the energy sector is the opening up of PEMEX and CFE procurement processes to foreign suppliers. The share of contracts open to foreign bidders begins at 50 percent in NAFTA's first year, extends to 70 percent by year eight, and will be 100 percent by year ten. The energy chapter also includes provisions comparable to GATT disciplines that will ensure that US and Canadian companies enjoy fair access to CFE and PEMEX procurement processes.[57]

NAFTA also provides for significant decreases in tariffs on imported equipment for electricity generation in the utility and private power sectors. The tariff reductions are most apparent in Mexico, reflecting the fact that tariffs were comparatively low in the United States and Canada. Of 14 general categories of equipment most often involved in energy project investments, the vast majority of the individual items listed under the categories of gas turbines, steam turbines, internal-combustion engines and other piston engines are already tariff-exempt under the NAFTA tariff-reduction program.

In addition, although not a direct result of NAFTA, certain "environmental" equipment that is not manufactured in Mexico is exempted from tariffs when imported into the country, as part of the "zero-tariff" policy adopted in 1996

[57] Hufbauer, Gary C. and Jeffrey J. Schott (1993), *NAFTA: An Assessment* (Washington, DC: Institute for International Economics): 33-34.

by Secofi and Semarnap to promote investment in pollution-control technologies. Pollution-control equipment used in many energy-sector projects would fall under this category, including devices for capturing volatile substances in gas flows (such as packed columns, absorption and adsorption columns), equipment for recovery of particulate matter from gas flows (such as electrostatic precipitators), devices for treating gas flows (such as burners and NO_x-reducing equipment), systems for separating particles and gases, and measurement and monitoring equipment.[58]

NAFTA also liberalized trade in coal and natural gas. Mexico eliminated its 10 percent tariff on imported coal and will guarantee national treatment for US and Canadian imports. However, a 6 percent VAT charge on sales to parastatal enterprises (such as CFE) still remains in effect. Tariffs on natural gas will also decrease; Mexico has committed to reduce its tariff of 10 percent by 1 percent per year. However, some market observers report that since open-access on gas transmission in Mexico went into effect in early 1997, the tariff remains too high for industrial consumers in the country to find imported supplies economically viable, and private imports of gas have been negligible.[59]

NAFTA's impact on the electricity sector in North America is arguably most important in the area of creating a more favorable environment for trade and investment flows across borders. NAFTA disciplines on government procurement, intellectual property rights and guarantees for investors foster greater certainty and transparency in transactions, which in turn lead to increased international investment flows within the region.

Chapter 6 of NAFTA, like the relevant parts of the FTA, aims to reduce the capacity of government regulators to involve themselves in cross-border energy sales by removing barriers to free trade in energy and preventing the creation of new ones. In addition to incorporating the FTA provisions related to export taxes and restrictions on trade, NAFTA subjects energy regulatory measures in the three countries to national treatment.[60] This discipline will very likely be important in resolving trade disputes in the future. Of particular relevance to Canadian-US electricity trade are two developments:

- the elimination of the Canadian National Energy Board's minimum requirement and least cost-alternative tests for approving export prices; and,
- the mandatory direction to the Bonneville Power Administration (the US federal government agency that owns and operates the electricity transmission and distribution network in the Pacific northwest) to modify its Intertie Access Policy in order to afford BC Hydro national treatment.

Each Party reserves the right to apply its antidumping laws and countervailing duty laws in conformity with NAFTA.

In the context of a competitive market for energy, trade liberalization agreements such as the FTA and NAFTA provide the groundwork for establishing North American economic integration. The FTA dovetailed with the deregulation of the natural-gas industry to facilitate economic integration of this industry between Canada and the United States. The importance of NAFTA as a catalyst for restructuring in the electricity industry has been the motivation and confidence it provides, particularly in light of the example of the natural gas industry. NAFTA clearly signified a political commitment at the highest levels to promote fair competition. The establishment of the institutional and legal framework provided the rules for allowing the process of economic integration to evolve rationally. Thus far, the relationship between the access to international markets offered by NAFTA and the restructuring of electricity markets has been an iterative process. As restructuring proceeds, NAFTA will be instrumental in providing the institutional framework for allowing economic integration between Canada and the United States to occur without reaching an impasse over trade and transborder investment issues.

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[58] SECOFI and SEMARNAP, *"Catálogo de equipos para el control y la medición de la contaminación ambiental,"* pamphlet. The zero-tariff policy was published in the *Diario Oficial* on 28 December 1996, effective 1 January 1997.

[59] See Baker, George (1997), "Mexico's gas import duty," *North American Free Trade & Investment Report*, 15 December : 15-17.

[60] National treatment refers to the principle that signatories to a given trade agreement, such as the NAFTA, accord companies from other signatories the same regulatory treatment accorded to their own companies, i.e., the "national treatment" accorded to those companies.

The demand for reciprocity from US producers has already become a prominent issue relating to cross-border trade. Under NAFTA, a Party is not required to provide reciprocity, but only national treatment for the goods of another Party. Market participants in Canada, such as BC Hydro, have for the time being chosen to agree to reciprocity voluntarily rather than insist on their rights and embark on a lengthy trade dispute; but it may become difficult to accept this limitation to their access if US jurisdictions proceed with the implementation of retail competition and Canadian federal and provincial regulators lag behind, forcing Canadian producers to lose opportunities to enter new markets as they open up.

Another issue that may lead to cross-boundary complaints is the pricing of transmission services and access to transmission capacity. Two ways for a utility to hinder other producers from competing for its customers are to charge discriminatory or excessive fees for the use of its transmission system, or to post zero availability over certain pathways on the OASIS information system.[61] In the future, it is possible that exporters may complain that certain transmission charges or other tranmission-company practices constitute a barrier to trade. Similarly, environmental regulation may be challenged as a non-tariff trade barrier in the event that its application is performed in a discriminatory or anti-competitive fashion.

B. NAFTA's Institutions

NAFTA institutions and processes have thus far dealt with electricity questions to only a very limited degree. However, they could be used to exploit environmental and economic opportunities. Industry, regulators and other stakeholders at federal and subfederal levels should benefit from strengthened dialogue, the sharing of best practices, and regulatory convergence. Further, the NAFTA institutions and the trilateral, intergovernmental processes they help form can result in increased communication among the three countries, capacity building and regulatory convergence on the part of national governments, as well as communication between other relevant stakeholders.

Although there is no NAFTA body whose mandate directly includes the issue of electricity trade, there are several committees whose related mandates could potentially have substantial impacts on the electricity sector. For example, an extensive network of subcommittees and working groups has been developed under the auspices of the Committee on Standards Related Measures (NAFTA Article 913). This committee is charged with the monitoring and implementation of the Technical Barriers to Trade portion of NAFTA. It is also responsible for providing a forum for the Parties to cooperate on developing compatible standards. In addition, the Small Business Subcommittee of the Government Procurement Committee created a "how to" guidebook to facilitate small- and medium-sized businesses' access to government procurement contracts. This group has dealt directly with electricity through its work on the Mexican formula for calculating the PEMEX and CFE set-asides.

Apart from NAFTA, there exist a wide range of energy-sector institutions and voluntary groups, such as the North American Electric Reliability Council, the Western System Coordinating Council (WSCC), the Western Regional Transmission Association, and the western states and provinces' Committee on Regional Electric Power Cooperation. Their activities have promoted greater integration between the three countries on energy issues. Further detail on these and other institutions is provided in Appendix E.

[61] The Open-Access Same-Time Information System (OASIS) is an electronic bulletin board required by FERC in Order 889. All transmission providers falling under FERC jurisdiction are required to participate in OASIS to provide open-access transmission customers with electronic information about available transmission capacity and tariffs. All jurisdictional transmission providers were required to be in compliance with the OASIS regulations by December 1996.

A prospective non-NAFTA-related body was proposed in 1996 to deal with energy efficiency, based on existing bilateral Canadian-US cooperation.[62] Those in Canada's Department of Foreign Affairs and International Trade (DFAIT) responsible for NAFTA welcomed this initiative, offering a NAFTA home for the new body if this was desired. Initially, the United States devised a program that would allow US manufacturers to place one label in three languages that would apply to all of North America. DFAIT hoped that it could next turn from labels to energy-efficiency ratings, an idea on which Canada and the United States are bilaterally very close to an agreement. The system could then expand from products such as kitchen appliances to televisions, lamps and bulbs. The three countries might find it easy to harmonize on new applications, for example, by introducing one North American energy-efficiency standard for televisions or computers.

There are also a series of other institutions, including bilateral mechanisms between the United States and each of Canada and Mexico, which provide a vehicle for addressing energy issues of mutual concern. While such vehicles are clearly more limited than the trilateral bodies relevant to NAFTA, they do serve as means for advancing many of the concerns discussed in this report.

NAFTA's dispute-settlement and surveillance mechanisms (NAFTA Chapters 11, 19, 20 and NAAEC Articles 14-15, 24), and the deterrent effect that they create, make it less likely that firms and other actors will anticipate a systematic lack of enforcement on the part of governments and thus employ poor environmental practices in their operations.[63] The consultation mechanism previously contained in Article 905 of the FTA (and employed by the Alberta and British Columbia governments to initiate consultations with the California Public Utilities Commission after contractual disputes) has been dropped from NAFTA Article 606 in favor of the dispute-resolution mechanism of NAFTA's Chapter 20.

In the context of trade liberalization in North America, FERC Orders 888 and 888-A seek to eliminate anticompetitive restrictions on transmission access by requiring all US public utilities to post a pro forma open-access transmission tariff with FERC. The implication of the FERC reciprocity policy is that provincial governments, with jurisdiction over transmission access in Canada, must restructure their electricity markets to provide the same level of transmission access to US generators as is provided by the pro forma tariff. As subsequent experience has shown, variations from the pro forma tariff to accommodate geographical and jurisdictional differences are not well received by FERC. So far, Canadian utilities have tried to secure access to US customers by attempting to comply with FERC's reciprocity requirement. In some provinces, notably Alberta, substantial progress toward open access has been made.[64] An issue of fundamental importance to the integration of cross-border electricity trade in the context of electricity-market restructuring in North America is the extent to which the national treatment obligations of NAFTA prohibit FERC (and other state regulators) from demanding reciprocity of market access from another Party. It is possible that Canadian utilities could approach the federal government to file a complaint under NAFTA's dispute-settlement mechanism.

Another issue related to the impact of FERC 888 and 888-A is the question of FERC's jurisdiction over transmission lines belonging to FERC-regulated utilities that cross international boundaries, and specifically whether open-access rules apply. FERC's assertion of jurisdiction was challenged by El Paso Electric Co. (EPECO) in a dispute originated by Enron Power Marketing (EPMI) in 1996 when EPECO denied EPMI access to two transmission lines between El Paso's system and that of the CFE in Ciudad Juárez, Mexico, claiming that all capacity had been fully subscribed.[65] FERC officials have indicated that the case is still pending.

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[62] See Commission for Environmental Cooperation (1997), *NAFTA's Institutions: The Environmental Potential and Performance of the NAFTA Free Trade Commission and Related Bodies*, CEC Environment and Trade Series, No. 5. (Montreal: Commission for Environmental Cooperation).

[63] For the details of one case currently underway under NAAEC Article 14: 53.

[64] Indeed, some would argue that the Alberta Transmission Administrator offers superior open transmission access than the FERC *pro forma* tariffs.

[65] See FERC Docket No. EL96-74-000, "Order on Complaint, 4 October 1996" in the case of *Enron Power Marketing Inc. v. El Paso Electric Company*.

C. Trade Flows

The relationship between NAFTA and trade in the electricity sector can be assessed with reference to the flows of electricity between the NAFTA partners ("trade in electricity") and the trade-related economic activity that creates increased demand for electricity ("trade-related demand"). The electricity sector is also linked to NAFTA in other ways that include: trade in equipment for the construction, maintenance and upgrading of infrastructure for the generation, transmission and distribution of electricity, including both utility and industrial entities; trade in natural gas, increasingly the fuel of choice for electricity generation, as well as coal; investment flows for the construction of utility as well as industrial generation capacity; and investment in the natural gas and coal sectors.

Trade in electricity is far easier to measure than trade-related demand for electricity. However, it is likely that actual trade in electricity represents a far smaller volume of electricity generation than does trade-related demand. The potential environmental impacts are correspondingly smaller. The available data suggest that trade flows respond to several factors, of which international commercial agreements such as NAFTA constitute only one. Technical and supply/demand considerations in each country, or in regions within each country, play a decisive role in creating the bases for trade, while NAFTA is usually a supporting factor.

1. Trade in Electricity

Trade in electricity is far greater, both in terms of volume as well as value, between the United States and Canada than between the United States and Mexico or between Canada and Mexico (through the US system). There are several reasons for this disparity, most of which involve technical constraints to power flows, as well as the policies pursued by Mexico's CFE with regard to capacity expansion and investment in transmission infrastructure to handle US-Mexican power flows. Table 4 summarizes trends in US-Canadian and US-Mexican electricity trade.

Table 4 Trade in Electricity in North America

Year	US Trade with Mexico			US Trade with Canada			Trade Balances in Electricity		
	Imports	Exports	Total	Imports	Exports	Total	Mexico*	US	Canada
1982	8	17	25	34,276	3,522	37,798	(9)	(30,745)	30,754
1983	88	16	104	38,579	3,320	41,899	72	(35,331)	35,259
1984	185	79	264	4,034	2,479	6,513	106	(1,661)	1,555
1985	241	152	393	45,659	4,812	50,471	89	(40,936)	40,847
1986	1,468	126	1,594	39,245	4,689	43,934	1,342	(35,898)	34,556
1987	2,042	130	2,172	50,176	5,750	55,926	1,912	(46,338)	44,426
1988	1,996	179	2,175	36,840	6,888	43,728	1,817	(31,769)	29,952
1989	1,934	621	2,555	24,176	14,514	38,690	1,313	(10,975)	9,662
1990	1,951	590	2,541	20,554	19,935	40,489	1,361	(1,980)	619
1991	2,116	616	2,732	28,696	7.923	36,619	1,500	(22,273)	20,773
1992	2,022	990	3,012	35,181	7,865	43,046	1,032	(28,348)	27,316
1993	1,993	849	2,842	37,088	9,805	46,893	1,144	(28,427)	27,283
1994	2,011	1,067	3,078	50,218	6,523	56,741	944	(44,639)	43,695
1995	2,257	1,154	3,411	44,502	7,992	52,494	1,103	(37,613)	36,510
1996	1,263	1,316	2,579	45,280	7,449	52,730	(52)	(37,778)	37,831

Figures in GWH. *Source: DOE, Office of Fossil Energy, 1996.*

* These trade figures do not take into account the very small amounts of electricity sold by Mexico to Belize. Mexico is currently negotiating with Guatemala to export power to that country as well.

a. United States-Canada

Electricity trade in North America has historically been comprised of exports from Canadian producers to US utilities. These have remained at substantial levels throughout the period from 1982 to 1995. In 1982, Canadian exports were 34 terawatt-hours (TWH);[66] they reached levels slightly over 50 TWH in 1987 and again in 1994. Exports have dropped below 20 TWH only once, in 1984, reflecting climatic and technical considerations more than economic or commercial ones. The FTA consolidated the market access in the United States enjoyed by Canadian energy exporters. But the trend in Canadian sales to the United States does not exhibit a significant jump until 1994, when exports increased by 30 percent. It is not clear to what extent NAFTA contributed to this increase.

Substantial Canadian exports to the United States began during the 1960s and increased in the 1970s, as large Canadian hydropower (as well as thermal) developments came on line. The northeastern United States offered a significant market for substantial volumes of excess power generated in Canada at the same time that cheap hydropower became increasingly attractive to US electricity consumers affected by the 1973-74 and 1979 oil-price shocks.[67] Canadian exports doubled to over 11 TWH from about 5.6 TWH between 1970 and 1975. In the late 1970s, growth in exports was met largely by thermal stations using imported coal, but hydropower sales became the dominant resource exported beginning in the early 1980s.[68]

High oil prices in the 1970s and early 1980s underscored the competitive advantage of Canadian hydroelectric power exported to the United States, which has been apparent ever since the first US-Canadian interconnection was constructed in 1901 at Niagara Falls to sell hydropower to US consumers. At present, Canadian electricity exports are dominated by hydropower, which made up 78 percent of exports in 1995. Generation using imported coal accounted for 15 percent.[69]

US exports to Canada have remained significantly lower than imports, with the exception of 1989 and 1990, when capacity shortages due to drought, plant outages and limitations on coal-fired generation in Canada, coupled with higher than expected growth in local demand forced Ontario Hydro (OH) to rely on more imported power.[70] US exports have ranged from 2.4 TWH in 1984 to just under 20 TWH in 1990. Since 1994, exports have moved slightly higher from the 6.5 TWH exported that year, to 7.4 TWH in 1996.

As a result of open access to wholesale transmission services within the United States, some observers argue that Canada's sizable electricity trade surplus will erode and that Canada could become a net importer of electricity, as the cost of power from the midwestern United States is expected to be competitive with Canadian power production.

Ontario Hydro's 1997 closure of seven nuclear facilities may also contribute to such a trend in the near term by reducing the capability of OH to export large blocks of power to the United States.[71] Existing fossil-fuel plants (operating at 75-percent capacity) could make up about 2,000 MW of the 3,755 MW of lost nuclear capacity, with imports from the United States filling the rest of the gap.[72]

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[66] A terawatt (TW) equals 1,000 gigawatts (GW), 1 million megawatts (MW) and 1 billion kilowatts (kW).

[67] Interview with Hans Konow, President, CEA, 19 August 1997.

[68] CEA, "Electric Power in Canada: 1995," 87.

[69] *Ibid.*, 87.

[70] US Department of Energy, Office of Fossil Energy (1996), "Electricity Transactions across International Borders - 1995," mimeo.

[71] DePalma, Anthony, "Ontario shuts 7 nuclear reactors near border for safety," *New York Times*, 14 August 1997. Also, interview with Hans Konow, CEA, 19 August 1997.

[72] Sierra Club of Canada (1997), Media Backgrounder, 18 August.

However, OH's ability to fill the gap using existing coal-fired capacity may be limited by restrictions on pollutant emissions from those facilities, and imports may be costly and/or difficult to secure. According to an Ontario Hydro official, the utility would need to make up about 5 TWH of generation per year, of which about 3 TWH could be covered by imports over interconnections with Michigan and New York. The obstacle to securing this energy is regulatory. OH's ability to purchase electricity at affordable prices would be influenced by the willingness of Detroit Edison, the Michigan utility at the border, to permit other companies in the interior of the United States to "wheel" (transmit) power over its lines. In recent filings before FERC, Detroit's positions suggest that it might not be willing to make transmission capacity available to rival generators that could serve OH.[73] In an agreement signed between Detroit Edison, Consumers Energy and OH in January 1998, covering the 1998-2000 period, the two Michigan-based utilities will provide OH with 1.5 TWH off-peak during January-April, with OH returning the power (two-thirds on-peak) during May-September.[74] These levels are well below the 5.8 TWH that OH exported to the Michigan market in 1995.[75]

In light of the impact of the changes at OH, the utility's export ranking might slip from its position as the second most important electricity exporter to the United States (after Hydro-Québec) to third after Manitoba Hydro, and possibly even fourth, after the New Brunswick Electric Power Commission (NB Power). In 1995, OH exported 9,195 GWH, second to Hydro-Québec's 17,049 GWH. OH's export level in 1995 was down 27 percent from the 12,835 GWH it exported in 1994.[76]

Separately, Hydro-Québec faces opposition as well as support in Canada and the United States to its involvement in US markets, which may expand since the company obtained its marketer's permit from FERC on 12 November 1997. Statements from indigenous communities opposed to Hydro-Québec's major hydroelectric developments in the northern parts of the province argue that approval of HQ's application does not take into account some of FERC's own criteria. These groups, along with environmental organizations in both Canada and the United States, have threatened to challenge the FERC decision. Conceivably, further opposition before FERC, if successful, could have an impact on the utility's ability to export larger blocks of power to the United States in the years ahead.[77] It remains to be seen to what extent consumer support in Canada for power sales to the United States will continue. In the past, such sales have been credited with making it possible for domestic tariffs to remain at their comparatively low levels.[78]

Projections of aggregate Canadian exports to the United States call for levels below those registered in recent years. According to Canadian utility and NEB projections, exports in 2000 will stand at about 29 TWH, slipping to 19 TWH in 2005 and 18 TWH in 2010. However, these projections may be low due to the fact that they do not count interruptible power sales, which can be a substantial component of sales depending on the year and the province.[79]

b. United States-Mexico

Levels of total trade between the United States and Mexico are tiny by comparison with US-Canadian trade. For example, total two-way trade has ranged from 1.5 TWH in 1986 to 3.4 TWH in 1995, with Mexican exports generally outpacing US exports by at least 2 to 1, except for 1996, when Mexico posted a trade deficit with the United States for the first time since 1982.

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[73] Interview with Barry Green, Senior Advisor (External Markets), Regulatory Affairs, Ontario Hydro, 24 October 1997.

[74] "Consumers Energy, Detroit Edison and Ontario Hydro sign long-term power sales agreement," *Daily Power Report*, 7 January 1998.

[75] CEA, "Electric Power in Canada: 1995," 88.

[76] CEA, "Electric Power in Canada: 1995," 86.

[77] "Decision on Hydro-Quebec puts Quebec energy supply at risk" and "Hydro-Quebec granted US marketing license by FERC," *Daily Power Report*, 14 November 1997. See also, DePalma, Anthony, "Storm exposes Quebec's 'power' politics," *New York Times*, 15 January 1998.

[78] See Michael MacMillan (1997), "Canadian utilities looking to sell electricity beyond the US border," 25 June. Internet: www.electricityforum.com/et/mar97/ferc.htm.

[79] CEA, "Electric Power in Canada: 1995," 126.

Total two-way trade increased four-fold in 1986, suggesting that Mexico's liberalization of trade that same year provided a more favorable trade environment that stimulated trade in electricity. However, it seems likely that the 1986 trade increase reflects technical considerations rather than purely commercial ones. In April 1985, CFE's northwestern system (which is not connected to the rest of the *Sistema Interconectado Nacional*, or SIN) joined the WSCC, which meant that CFE had to adhere to the WSCC's standards of system stability and reliability.[80] Transactions involving far larger volumes of electricity than previously possible could be realized once CFE had met those technical requirements. Consistent with this interpretation, the increase in Mexico's electricity exports was pronounced, while change in flows in the other direction was minimal.

Since 1986, electricity transactions have exhibited a trend upwards, which may well reflect increased economic growth in the border region (particularly in Baja California) as well as demographic pressures. However, CFE projections for energy trade with US utilities during the next five years suggest that the amount of power going northwards at the border will decline dramatically, to substantially less than 100 GWH per year through 2001, after which time exports are expected to increase to between 100 and 200 GWH per year.[81]

This decline in Mexican exports, coupled with tighter CFE reserve margins in the northwestern and main CFE systems, suggests that power sales to CFE by US utilities could increase in the near term, at least until several major power projects now underway or planned in northwestern and northern Mexico come on line. Indeed, CFE is issuing solicitations for annual contracts for capacity and electricity beginning in 1998. With open access, CFE has invited power marketers and utilities inside the United States to bid, in addition to the border utilities that have traditionally been its main suppliers. The increased competition has yielded significant benefits for CFE: in the 1996 bid for power and electricity at Ciudad Juárez, El Paso Electric, the incumbent supplier and ultimately the winner of the new contract, reduced its price substantially. The original winner of the contract was Salt River Project (SRP), which had to drop its offer when it was unable to negotiate with El Paso to obtain the necessary transmission capacity from its system to the border at El Paso.[82]

c. Canada-Mexico

Until 1997, no electricity sales by a Canadian utility to the CFE in Mexico had been executed, although the interconnection of the Canadian and northwest Mexican systems within the WSCC certainly made such sales technically possible. In 1997, however, the power export division of BC Hydro (PowerEx), in cooperation with San Diego Gas & Electric (SDG&E), won a bid to supply CFE with 40 MW of firm capacity in July and 50 MW in August and September over the interconnections owned and operated by SDG&E between San Diego and Tijuana. SDG&E will also provide capacity for a total reported at 200 MW. Previous sales by SDG&E had been made using its own generation capacity or power purchased from other US generators; with the PowerEx sale, SDG&E simply used a more distant source.[83]

[80] US Department of Energy and *Secretaría de Energía, Minas e Industria Paraestatal* (now *Secretaría de Energía* or SE), "United States / Mexico Electricity Trade Study," (Washington, DC: DOE, 1991): pp. 4-5.

[81] In the *Documento de Prospectiva*, CFE observes: "[a]fter [the expiration of CFE's 70 MW sales contract with Southern California Edison in August, 1996], the capacity that was committed to the export sales was available for the Baja California system." CFE's sales projections show a sharp decline in exports from 1996 to 1997. See Table 1.3, SE, *Documento de Prospectiva* (Mexico City: SE, 1996): 20, 46 (for quote).

[82] "Salt River, El Paso Electric reach wheeling impasse," *Megawatt Daily* (22 November 1996): 1.

[83] Interview with S. Ali Yari, Supervisor of Transmission Planning, SDG&E, 15 September 1997. Also, remarks of Ken Peterson, CEO of PowerEx, "Unleashing the Potential: Symposium on Cross-Border Trade in Electricity," Phoenix, AZ, 24 October 1997.

The potential for significant flows of electricity are limited in the near term, however, because of the substantial costs of transmitting ("wheeling") the power across the western United States. In the case of the PowerEx deal, five different parties were involved in transmitting the power, which reduced the margin that PowerEx could expect on the deal. In the future, if fewer parties were involved, or wheeling charges were lower, the potential for such deals, which take advantage of the availability of cheap excess hydropower capacity in British Columbia during the summer peak in northwestern Mexico, would be enhanced.[84] With such enhancements in physical infrastructure and business experience, the combination of open-grid restructuring and NAFTA's opening of the Mexican market will make a full, single NAFTA-wide competitive marketplace in electricity.

2. Trade in Fuels

Coal and natural gas are of particular importance to the electricity sector, given the predominance of coal-fired capacity in the United States and the emergence of gas-fired facilities (gas turbines and combined-cycle facilities) as the preferred investment to meet new capacity requirements in all three countries. These two energy subsectors are also important in the context of NAFTA's provisions in both areas.

a. Natural Gas

Trade in natural gas has existed in North America since the 1950s. In general, trade between the United States and Canada has been more substantial than the trade between Mexico and the United States. With the increasing popularity of gas-fired generation technologies, the natural-gas sector has become an important one in the dynamics of the continental electricity sector. The deregulation of natural-gas transmission and distribution in all three countries (in the United States and Canada in the 1980s, in Mexico since 1995) has had a significant impact on prices and availability throughout the region, contributing to the emergence of gas-fired generation technologies as the investment of choice. In addition, environmental regulations requiring tighter emissions standards for industry and utilities in all three countries have played an important role in promoting the use of natural gas.

The major gas-producing regions in North America include the province of Alberta, which is responsible for 84 percent of Canadian gas production, the Oklahoma-Texas-Louisiana-Mississippi region and offshore fields in the US zone of the Gulf of Mexico, and the (as yet undeveloped) unassociated ("dry") gas fields of northeastern Mexico as well as the associated ("wet") gas production in Mexico's petroleum-producing regions in the Gulf of Mexico region (onshore and offshore).[85]

In 1996, Canada produced 197,472 million cubic meters (MCM)—equivalent to approximately 5.6 trillion cubic feet (TCF)—of natural gas at the wellhead. Canadian production is set to increase in the near future with supplies from new gas fields in the Maritime provinces that are now under development. US production was about 20 TCF and consumption around 23 TCF. In Mexico, production is about 1.1 TCF, with consumption standing at the same level. Although US production is roughly three times that of Canada, Canada exports roughly 50 percent of its production (to the United States), making it the most important exporter in North America and the second-largest in the world after Russia.[86]

An extensive natural gas pipeline system in Canada transports 48 percent of the gas destined for domestic consumption from the western provinces to Ontario and Quebec. Natural gas power generation in Canada correlates closely to the availability of the resource. Alberta and British Columbia have 64 percent of Canada's natural gas power generation,

[84] Ken Peterson, remarks at "Unleashing the Potential," 24 October 1997.

[85] Natural gas is produced in two ways: in conjunction with production of petroleum in cases where the oil-bearing rock contains petroleum and natural gas (referred to associated as or "wet" gas); or from deposits containing only natural gas (unassociated or "dry" gas).

[86] Secretaría de Energía (1997), *Perspectiva del Mercado de Gas Natural 1997-2006*, (SE: Mexico City): 33-35.

Ontario has 31 percent, and Saskatchewan 4 percent. This network of gas lines is linked in several locations to the extensive gas transmission network in the United States, which covers much of the country, with the most important corridors linking the gas-producing regions of the Gulf Coast to the northeast and the north-central regions of the country. Several trunk lines extend across the southwest, linking gas producers in the mountain states to the Pacific Coast. In Mexico, the gas transmission system is limited to the connections linking the Gulf Coast regions where gas is produced to the central region of the country (Mexico City, Guadalajara and the Bajío) and the northeastern and north-central industrialized regions of the country (serving, among other cities, Monterrey, Saltillo, Chihuahua and Ciudad Juárez).

(i) United States-Canada Trade

Substantial US-Canadian trade in natural gas predated the implementation of FTA and NAFTA. However, growth in trade since 1994 suggests that trade liberalization has stimulated increased flows between the United States, Canada and Mexico. In general, Canadian exports to the United States have maintained levels in excess of 1 TCF since 1988, surpassing 2 TCF in 1992. To explain this trend, however, it is important to consider the impact on trade flows of deregulatory initiatives not necessarily tied to FTA and NAFTA. Table 5 summarizes trends in US-Canadian natural-gas trade.

Canadian gas exports flow primarily to the northern and western parts of the United States, with the midwest accounting for 35 percent, California 24 percent, the northeast 23 percent and the Pacific northwest 17 percent. Increasingly, exports are executed under short-term (up to two years) National Energy Board orders, with long-term contracts (which may be for as long as 25 years, but more recently are averaging less than 15 years) now accounting for 40 percent of total sales.[87]

The EIA forecasts that total US natural gas consumption will increase from 22.18 TCF in 1995 to 30.97 TCF in 2015. Out of the 8.79 TCF increase, 5 TCF will be from increased gas consumption by electricity generators. To meet that demand, the EIA anticipates that imports of Canadian natural gas into the United States will increase to 4.34 TCF by 2015. In contrast, US exports to Canada have never exceeded the 67 billion cubic feet (BCF) registered in 1992. Canada's extensive natural gas reserves and good transmission system have limited imports of US natural gas to situations where Canadian buyers find it cheaper or perhaps more convenient for geographic reasons to use imported supplies.[88]

(ii) United States-Mexico Trade

Two-way US-Mexican trade has rarely been significantly higher than 100 BCF. It rose to those levels during a brief period of gas export development in Mexico following the second oil shock (1979-1984) and again in the early 1990s. However, total trade has declined since 1995. Mexican exports exceeded imports during the 1979-1984 period and again in 1996, when Mexico posted its first trade surplus in natural gas since 1984. In 1997, Mexican exports stood at 13.4 BCF, while US exports to Mexico were 8.2 BCF (see Table 5).

Natural gas production and consumption have been closely tied to the needs of the petroleum subsector, both in the sense that associated gas production was contingent on petroleum production as well as with regard to the resources available for investment in the transmission and distribution infrastructure required to increase the consumption as well as the export of natural gas. The level of Mexican trade in natural gas has varied in accordance with the growth in domestic consumption, domestic supply, and the availability of transmission capacity.[89]

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[87] National Energy Board (NEB) (1996), "Natural gas imports and exports," Annual Report. Internet: www.neb.gc.ca.

[88] NEB, *op. cit*.

[89] For a complete overview of the evolution of natural gas policy in Mexico, see Rodríguez-Padilla, Victor and Rosío Vargas (1997), "El comercio de gas natural con Canadá y Estados Unidos: Una mirada al futuro," *Comercio Exterior*, March: 234-239.

Table 5 Trade in Natural Gas in North America

Year	US Trade with Mexico			US Trade with Canada			Trade Balances in Natural Gas		
	Imports	Exports	Total	Imports	Exports	Total	Mexico	US	Canada
1982	95.0	2.0	97.0	783.0	0.5	783.5	93.0	(875.5)	782.5
1983	75.0	2.0	77.0	712.0	0.5	712.5	73.0	(784.5)	711.5
1984	52.0	2.0	54.0	755.0	0.5	755.5	50.0	(804.5)	754.5
1985	0.0	2.0	2.0	926.0	0.5	926.5	(2.0)	(923.5)	925.5
1986	0.0	2.0	2.0	749.0	9.0	758.0	(2.0)	(738.0)	740.0
1987	0.0	2.0	2.0	993.0	3.0	996.0	(2.0)	(988.0)	990.0
1988	0.0	2.0	2.0	1,276.0	20.0	1,296.0	(2.0)	(1,254.0)	1,256.0
1989	0.0	17.0	17.0	1,339.0	38.0	1,377.0	(17.0)	(1,284.0)	1,301.0
1990	0.0	16.0	16.0	1,448.0	17.0	1,465.0	(16.0)	(1,415.0)	1,431.0
1991	0.0	60.4	60.4	1,710.0	14.8	1,724.8	(60.4)	(1,634.8)	1,695.2
1992	0.0	96.0	96.0	2,094.0	67.8	2,161.8	(96.0)	(1,930.3)	2,026.2
1993	1.7	39.7	41.4	2,267.0	44.5	2,311.5	(38.0)	(2,184.5)	2,222.5
1994	7.0	46.5	53.5	2,566.0	52.6	2,618.6	(39.5)	(2,474.0)	2,513.4
1995	6.7	61.3	68.0	2,816.0	27.6	2,843.6	(54.6)	(2,733.9)	2,788.4
1996	13.9	33.8	47.8	2,813.0	50.9	2,863.9	(19.9)	(2,742.2)	2,762.1
1997*	13.4	8.2	21.5	1,258.0	26.5	1,284.5	5.2	(1,236.7)	1,231.5

Figures in billions of cubic feet (BCF).

* Through May 1977. By comparison, year-to-date imports from Canada in 1996 were 1,141 BCF and 1,189 BCF in 1995; year-to-date imports from Mexico were 8.914 BCF in 1996 and 0.308 BCF in 1995. Exports to Canada stood at 24.155 BCF in 1996 and 11.308 BCF in 1995; exports to Mexico stood at 10.293 BCF in 1996 and 30.577 BCF in 1995.

Source: EIA, Natural Gas Annual 1994.

(iii) Canada-Mexico Trade

At present, there does not appear to be any Canada-Mexico trade in natural gas, although the extensive transmission system in Canada and the United States does permit such trade. The extent of Canadian exports to Mexico in the past is unclear.[90] The impediments are most likely pipeline capacity and cost of transmission, which, together with the competitive supplies of natural gas in Texas, may well make it difficult for Canadian gas to compete effectively in the Mexican market.

Thus, it seems that, consistent with the energy provisions of NAFTA, trade in natural gas has yet to experience a sustained increase among the three Parties, although the overall NAFTA-sustained integration may well encourage such results.

b. Coal

Canada is the preeminent exporter of natural gas in North America, and the United States is the leading producer and exporter of coal in the NAFTA region. In 1994, Canada produced roughly 84.3 million short tons (of which approximately 60 percent was steam coal), and Mexico produced just under 12.1 million short tons (most of which was steam coal). In the same year, US production exceeded 1 billion short tons (of which some 87 percent was steam coal). Coal trade in North America appears to have declined since the early 1980s, when US exports to Canada reached the highest levels recorded.

[90] Reference is made in Rodríguez-Padilla and Vargas, *op. cit.*, but no data are given.

In Canada, virtually all coal production occurs in British Columbia, Alberta, and Saskatchewan. In 1994, Alberta accounted for 49 percent of coal production, BC 32 percent and Saskatchewan 14 percent. The Atlantic Provinces accounted for the remaining 5 percent. The quality of Canadian coal varies, ranging from the anthracitic and high-volatile bituminous varieties produced in Quebec and New Brunswick, to the lower-quality lignitic varieties produced in Ontario, Manitoba and Saskatchewan and the commercially prized low-volatile bituminous coals produced in Alberta and British Columbia.[91]

Coal consumption in Canada is limited due to the remoteness of the main production areas from the core population centers of the country and the country's extensive hydroelectric resources (coal accounts for only 15 percent of power generation). Consumption in 1994 rose by 6 percent, to 61.3 million short tons. Of this, 88 percent was used for electricity generation, 9 percent by the steel industry, and the remaining 3 percent by general industry. In keeping with the geographic distribution of coal production, coal use for power generation is highest in Alberta. Ontario accounts for 20 percent of coal consumption for power generation, and Saskatchewan represents another 14 percent. British Columbia has 32 percent of Canadian production but has no coal-fired power facilities. Since there are no mines in Ontario, over half of the coal used (59 percent in 1995) is imported from US producers in the midwest and Appalachian regions, due to their geographic proximity. Other major coal-importing provinces are New Brunswick and Manitoba.[92]

In 1994, Canada was a net exporter of coal (mostly coke and metallurgical coal), with some 23 million short tons of excess production (about 40 percent of the total output). The primary markets for Canadian coal are the Pacific Rim nations, particularly Japan and South Korea. The major US markets are in Europe (accounting for almost 25 percent of total shipments), particularly the Netherlands, Denmark, Britain, Germany and Italy.[93]

US coal production is distributed across much of the Appalachian, Ohio and lower Mississippi River regions of the country, and in the Rocky Mountain states of Montana, Wyoming, Colorado, New Mexico and Arizona. Although the consumption of coal for generation and metallurgical uses broadly parallels the geographic distribution of production, with the central, midwest and mountain states accounting for 92 percent of total consumption in 1994, tighter sulfur dioxide emissions regulations put in place with the Clean Air Act modifications of 1990 created new demand for lower-sulfur subbituminous coals, which are primarily found in the mines of the Rocky Mountain region. This contributed to expanding production from the western mines.[94] The excess US coal output available for export was about 100 million tons.

Mexican coal production is concentrated in the northern state of Coahuila, at the large mines of Río Escondido (MICARE) as well as the smaller-scale mines of the Sabinas region. Most Mexican coal has relatively high sulfur and ash contents and calorific value compared to US coal. Coal consumption in Mexico is highly concentrated, with coal-fired generation located exclusively in Coahuila and the greatest consumption of metallurgical coals occurring in the major steel-producing centers in the northwestern states of Nuevo León, Coahuila and Tamaulipas. This pattern of consumption is expected to change only slightly once new coal-fired capacity is installed at Altamira, Tamaulipas, adding up to 1,350 MW to CFE's current 2,600-MW coal-fired fleet (see Appendix F). In 1994, Mexico was a net importer of coal.

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[91] Environment Canada (1992), "Canada's Greenhouse Gas Emissions: Estimates for 1990," Report EPS 5/AP/4, December.

[92] Statistics Canada, *Electric Power Annual Statistics*, *1995* (Cat. 57-202-XP3): 20-21 (Table 6).

[93] Energy Information Administration, *Coal Industry Annual*, 1995. Internet: www.eia.doe.gov.

[94] Data from the Office of Surface Mining, Department of the Interior for FY1997, show that the seven major eastern producing states (West Virginia, Pennsylvania, Virginia, Ohio, Kentucky, Indiana and Illinois) account for almost half of total production, while the major western producing states (Wyoming, Montana, Colorado, New Mexico and Arizona) generate about 40 percent of total tonnage. Western production comes primarily from surface mines, while eastern production is more likely to be come from underground mines. About 45 percent of US reserves are low-sulfur material (less than 1 percent sulfur), about half of which are concentrated in surface deposits of lignite and subbituminous materials in Montana and North Dakota. About 20 percent of total reserves are made up of higher sulfur (1.1 to 3.0 percent and over 3 percent bituminous materials) located in the states of Illinois, Ohio, West Virginia, Pennsylvania and Kentucky. See "Sources of chemical energy," in Babcock & Wilcox, *Steam: Its Generation and Use* (Barberton, OH: Babcock & Wilcox, 1992): 8.1-8.10.

(i) United States-Mexico Trade

Mexican tariff reductions and national-treatment guarantees for trade and investment in coal, which resulted from NAFTA, appear to have had a dramatic impact on trade in coal between the United States and Mexico. US exports of steam coal to Mexico rose to over 500,000 short tons in 1995 and 1 million short tons in 1996, as CFE began purchasing coal from Colorado for consumption at its coal-fired plants in the border state of Coahuila.[95] The environmental impact of this change may well be positive since the imported coal has a lower sulfur content than the Mexican coal traditionally used in those facilities. The net result could be a reduction in SO_x emissions that affect visibility in Texas, for example. By comparison, Mexican exports of coal to the United States are virtually non-existent at present, but registered levels in the range of 40,000 to 50,000 short tons in 1988 and 1989 (see Table 6).

(ii) United States-Canada Trade

US steam coal exports to Canada increased by 20 percent in 1996 to almost 6 million metric tons, after having declined sharply in 1993 from the levels between 7 and 14 million metric tons between 1981 and 1992. It is unlikely that this increase reflects any tariff change, coming so long after the implementation of the FTA. Rather, changes in generation resource bases in Canada, especially Ontario, are more likely to have been decisive. Overall, the advent of new nuclear and hydroelectric generation capacity was likely responsible for the marked decline in coal imports in the mid-1980s. Imported coal was an important fuel for electricity generation, especially for export, in the late 1970s, but coal declined in importance as nuclear power increased dramatically in 1983 (to 1,800 GWH from 96 GWH a year before) and hydropower exports moved 26 percent higher in 1985 (mostly from new capacity at the La Grande station in Quebec)[96] (see Table 6).

Data for coal exports to Canada in the late 1970s are not readily available. Since several nuclear facilities in Ontario were shut down in August 1997, coal-fired generation in Canada may increase, leading to increased coal imports from the United States. Canadian exports of coal to the United States have declined since the mid-1980s, and have ranged from 6,000 to 70,000 metric tons since 1991.

(iii) Canada-Mexico Trade

Canadian exports of coal to Mexico declined between 1993 and 1996, to about 290,000 metric tons. Canada exports relatively little steam coal; its trade in metallurgical coal, on the other hand, involves larger volumes, but is primarily directed to markets in Europe and Japan. Trade in coal from Mexico to Canada is virtually nonexistent, as Mexico's coal exports have been limited and mostly directed to the United States.

[95] Interview with CFE Generation Division, December 1996.

[96] CEA, "Electric Power in Canada – 1995," 87.

Table 6 Trade in Steam Coal in North America

Year	US Trade with Mexico			US Trade with Canada			Canadian Exports			Trade Balances in Coal		
	Import	Export	Total	Import	Export	Total	US	Mex	Tot.	Mex	US	Canada
1981	N.A.	135.6	—	N.A.	1,1295.2	—	N.A.	N.A.	—	—	—	—
1982	N.A.	54.5	—	N.A.	12,421.5	—	N.A.	N.A.	—	—	—	—
1983	N.A.	63.3	—	N.A.	9,253.8	—	N.A.	N.A.	—	—	—	—
1984	N.A.	30.8	—	N.A.	11,584.0	—	N.A.	N.A.	—	—	—	—
1985	N.A.	57.8	—	N.A.	8,529.9	—	N.A.	N.A.	—	—	—	—
1986	0.7	81.9	82.6	393.2	7,303.6	7,699.8	393.2	N.A.	—	(80.9)	6,994.5	—
1987	N.A.	88.2	—	749.4	8,921.6	9,671.0	749.4	N.A.	—	—	—	—
1988	40.3	94.0	134.3	821.5	10,867.1	11,688.6	821.5	N.A.	—	(53.6)	10,099.1	—
1989	52.1	57.5	109.6	71.1	9,052.1	9,123.2	71.1	N.A.	—	(5.5)	8,986.4	—
1990	5.6	188.6	194.3	194.4	10,104.5	10,298.8	194.4	N.A.	—	(182.7)	10,092.7	—
1991	0.0	46.8	46.8	66.1	6,507.8	6,573.9	66.1	N.A.	—	(47.3)	6,488.2	(3,775.5)
1992	0.0	36.7	36.8	46.1	9,290.1	9,336.2	46.1	N.A.	—	(36.4)	9,280.9	(4,664.5)
1993	2.1	54.3	56.4	26.1	3,841.4	3,867.4	26.1	40.0	66	(51.8)	3,828.9	—
1994	0.2	25.8	26.0	6.0	4,710.4	4,716.4	6.0	40.0	46	(25.5)	4,730.0	—
1995	0.2	496.9	496.9	48.1	4,523.0	4,571.1	48.1	—	—	(496.4)	4,971.8	—
1996	N.A.	944.2	—	11.0	5,453.5	5,464.5	11.0	—	—		—	—
1997	N.A.	N.A.	—	N.A.	N.A.	—	N.A	N.A.	—	—	—	—

Figures in thousands of metric tons.

Sources: US Department of Energy, Energy Information Administration; US Department of Commerce, International Trade Administration; Statistics Canada.

Thus the post-NAFTA period has seen a sharp rise in US coal exports to both Mexico and Canada. In the former case, they are a result of NAFTA tariff reductions and promise clear environmental benefits when replacing more polluting fuels.

3. Trade in Energy-Sector Equipment

Data on trade in equipment typically used in investments in generation and cogeneration capacity suggests that investment is growing faster in Mexico than in the United States or Canada. Such trade appears to have grown most rapidly between the United States and Mexico, rather than between the United States and Canada. This pattern is consistent with the differential impact of NAFTA tariff reduction and other changes across the two major relationships. However, growth in US exports of equipment to Canada has been substantial, with the overall level of US exports to Canada about four times that going to Mexico.

Data available from US and Mexican sources on trade in equipment are not necessarily presented in a uniform manner, due to different levels of aggregation by tariff codes. Hence, the US- and Mexico-sourced data presented in Appendix G may not coincide even for trade of equipment and materials under the same general tariff classifications. Nevertheless, the data from the US Census Bureau and Mexico's Banco Nacional de Comercio Exterior (BANCOMEXT) do suggest several of the same conclusions, as follows:

- Total two-way trade (US-Mexican and US-Canadian) of products and materials typically used in energy-sector investments increased between 1995 and 1997. However, BANCOMEXT data suggest that total trade within the NAFTA countries may not have recovered to its 1994 levels.
- The rate of growth in US-Mexican trade during the 1995-1997 period was faster than that posted by US-Canadian trade during the same period. In the case of US-Mexican trade, growth was faster for US exports to Mexico rather than in the other direction, a pattern that reflects the impact of the NAFTA reductions.
- The United States is a net exporter of equipment and materials in the sector to both Canada and Mexico. Canada is probably a net importer of equipment and materials from Mexico.

It is difficult to make comparisons between the NAFTA period covered by the analysis referred to above and the period prior to 1994, since either many of the tariff classifications changed in 1994 or data are not available. However, it is likely that NAFTA contributed to increased trade, given the increase in Mexican imports beginning in 1995, even taking into account the impact of the peso devaluation. Beyond the overall trend, a review of the applicable tariffs and tariff-reduction schedules for specific types of industrial process equipment shows that a wide range of equipment used in electricity sector projects received favorable treatment under the NAFTA, thereby encouraging trade. The trade-promoting effect is likely to have been greatest in trade between Mexico and its NAFTA partners. Trade in equipment between the United States and Canada already benefited from relatively low tariffs at the time that NAFTA took effect, whereas the net change in Mexico's tariffs was greater.

A preliminary evaluation of data for Mexico's trade with selected non-NAFTA countries (China, Finland, France, Germany, Italy, Japan, Sweden, Switzerland and Spain) suggests that trade in certain equipment used in the electricity sector has varied significantly from country to country, but has declined sharply in the aggregate. While trade with China has increased by a factor of over 100, trade with other major trading partners such as France and Japan has declined by as much as 90 percent. On the other hand, trade with Germany increased by over 100 percent, Italy by 54 percent, and Swiss imports increased by a factor of 10 (see Appendix G).

D. Transborder Investment Flows

The strategic value of the electricity industry and the highly capital-intensive nature of the sector limit the rapidity with which trade and investment flows will change in response to the changes brought about by NAFTA. Furthermore, government budgetary and regulatory involvement in investment decisions in the sector is significant. Indeed, it may take from three to five years for a power plant project to move from the planning and approval steps through construction to commissioning, with even longer lag times for certain transmission projects.

In the more deregulated and more pluralistic energy markets of the United States and Canada, investment decisions are less centralized than in Mexico. In Mexico, a national expansion plan (the annual *Documento de Prospectiva*) prepared by the CFE and approved by the *Secretaría de Energía* is the blueprint for investment by the CFE as well as large-scale investment by the private sector. By contrast, investment decisions by US and Canadian utilities and independent power producers (IPPs) are generated more autonomously, although regulatory and sectorally imposed limitations intervene in the development of projects at various stages and with regard to a range of issues (such as system stability and reliability, environmental impact and impact on regulated rates).

The flows and stocks of foreign direct investment (FDI) in the electricity sector must be considered in the light of overall trends—both domestic and foreign—in the sector. Available data suggest that overall investment trends in the United States, Mexico and Canada differ broadly, based on the underlying balances of capacity and demand in each country. Whereas demand is growing rapidly in Mexico (even during the economic contraction of 1995-1996), it is growing far more slowly in the more developed economies of Canada and the United States. This suggests that investment in Mexico will continue at a faster pace than in the United States and Canada, after adjusting for the size of the Mexican economy. For data on each country, see Appendix F.

1. Mexico

According to the CFE's investment program, the roughly 13,100 MW of new capacity planned between 1997 and 2006 (equivalent to growth of 39 percent) may be built and operated primarily by private consortia (although the so-called "immediate action plan" calls for 750 MW of gas-turbine capacity to be built by CFE using its own resources), in keeping with changes in the legal regime that took effect in late 1993 and early 1994. Between 1997 and 2006, approximately 49 percent of the projected capital expenditure budget of US$12 billion will be allocated to power plants; 16 percent will be spent in transmission and over 15 percent in distribution. In 1998, CFE's budget is over US$3 billion, of which 60 percent will be allocated to generation activities and 40 percent to transmission.[97] CFE's strategy includes plans to diversify its thermal generation fleet to include more combined cycle and dual units that offer the flexibility of burning oil, coal or gas. Private investors may also participate in substation and transmission line construction.

Considering the increasing interest of the private sector in external generation projects, and of private industrial investors in cogeneration, CFE will become the residual investor in the system, apart from programmed expenditures for upgrading interconnections between regional systems, the conversion and reporting of aging generation facilities, and the shift to natural gas instead of oil in many thermal units. CFE will not spend considerable amounts on new capital formation except where private investors consider a project unprofitable.

The interest of international firms seeking an investment position in the Mexican energy market has increased over the past two years. This reflects renewed confidence in the economy and builds on the regulatory changes implemented before the peso crisis. A brief examination of the bids at CFE and of PEMEX's recent tenders reveals that the proposed systems for power generation, power transmission, transportation and distribution systems for natural gas are as technologically advanced as any production system installed in the United States or Europe. Mexico is taking advantage of this interest of major international suppliers by choosing proven advanced technologies at competitive prices. Examples include the combined-cycle units to be built in Chihuahua and Nuevo León states (where efficiency is comparable to the most efficient plants installed in the United States and Canada) and the Supervisory Control and Data Acquisition (SCADA) system that will control the injection and extraction of natural gas in PEMEX's pipeline network, which is also as advanced as systems used by US and Canadian gas firms.

CFE has traditionally had access to state-of-the art technology for building generation capacity. Technology was purchased from international suppliers of equipment, subject to budgetary constraints, with the decision to choose one technology over another driven by the availability of financing. With deregulation, the same state-of-the art technology

[97] "Giant PEMEX and CFE investment budgets for 1998 whet private sector appetite," Infolatina News Service, 8 December 1997. In January, Finance Secretary Gurría announced reductions in the federal budget due to oil-revenue shortfalls that will affect PEMEX and, to a lesser extent, CFE. Press accounts indicate that the reduction in CFE's budget will be minimal. *Reforma*, 17 January 1998.

is available and the choice of supplier is made through bidding. The *Comisión Reguladora de Energía* (CRE) oversees the bidding according to published criteria, and the chosen technology is part of a package including equipment, capacity, costs and prices of energy. Participating firms are not only from North America, but also from Europe and Japan and have come to enhance the potential development of the energy sector and the skills of their Mexican partners.

In electricity generation and gas distribution, foreign firms team with Mexican partners in consortia usually comprised of more than two companies. Foreign firms are usually the technology and equipment suppliers, while Mexican firms perform the civil engineering and construction tasks. From the technical standpoint, foreign firms are endowed with the expertise necessary for electricity-generation projects that the Mexican private sector lacks, since until recently power has been the exclusive domain of the CFE. For that reason, participants in these projects are international consortia organized specifically for the project, with the Mexican partners supplementing their strengths with those of foreign entities. For example, in the Samalayuca II build-lease-transfer (BLT) power project, one financial firm (GE Capital) teamed with El Paso Energy International and ICA, a Mexican engineering firm. In Merida III, the first independent power project, Nichimen of Japan joined with the US AES and Grupo Hermes, a Mexican holding company.

Mexican construction firms, such as Bufete Industrial and ICA, which participate in most bids of both electricity and gas distribution, have expertise in "basic engineering," consisting of facility lay-out and the determination of gross technical requirements of the generator and its plant. Some foreign firms specialized in plant design (such as Bechtel and Fluor Daniel) may also participate in these projects. Their contribution would be "detail engineering," which is several steps ahead of basic engineering as it involves the matching of technical capabilities given by the chosen equipment with the physical plant design. This technological contribution impinges on flows of fuels and output and, therefore, on costs, efficiency and environmental impacts.

The contribution of foreign firms is mainly in the area of technology, the development and design of technologies, as well as equipment construction and maintenance. For example, GE Power Systems and Nichimen participated in the Samalayuca II and Mérida III bids, respectively. These firms have lengthy experience in the research and building of equipment, as well as in the operation of generation systems. Operation and efficiency levels in these generators are reflected in costs and in financial returns. The contribution of these firms also includes maintenance standards, cost accounting, planning techniques and financial management.

When participating in consortia, the foreign investors share management responsibility with the other parties to the consortia. This allows for the technical knowledge of the foreign investor to become available to its partners, especially in the areas of setting standards for maintenance, operation, efficiency and planning. Foreign firms are also active in training technical personnel, a significant contribution to the improvement of Mexico's technical capabilities.

Recent examples of international consortia involved in electricity and gas projects in Mexico include:

- Samalayuca II, a 700-MW BLT project with an investment of US$645 million, is being undertaken by a group formed by GE Power Systems, GE Capital Services, El Paso Energy International, International Generating Company (InterGen, a joint venture of Bechtel and PG&E Enterprises) and EMICA, an affiliate of the Mexican engineering firm, ICA.

The structuring of this consortium reveals the synergy between Mexican and foreign firms in a newly deregulated sector as well as that between different foreign firms. In this project, largely financed with debt, arrangements were primarily made by GE Capital and InterGen. The package includes US Eximbank loans, International Development Bank (IDB) loans and construction financing. In addition, the foreign firms are providing US$132 million investment in equipment, distributed as follows: GE Capital, 40 percent; El Paso Energy International, 20 percent; InterGen, 20 percent; and EMICA, 20 percent.

This distribution is based on the technical strength of the participants regarding the type of equipment, which, therefore, defines the technological characteristics of the project. El Paso Energy, which until now had not participated in investments in Mexico, is enhancing its position in the newly deregulated sector, as Samalayuca II will be located 30 miles south of El Paso.

Samalayuca also offers another example of the synergy created by deregulation and equity participation by foreign investors. The facility will be fueled by a 38-kilometer gas pipeline to be built and operated by a new consortium named *Gasoductos de Chihuahua*. The pipeline will also be connected by another, 34-kilometer pipeline to a compression station in Texas, thereby guaranteeing the gas supply to the station. *Gasoductos de Chihuahua* is structured as follows: PEMEX, 50 percent; El Paso Natural Gas, 40 percent; and El Paso Energy International, 10 percent. El Paso Energy also has equity in the generator, while the participation of PEMEX can be explained by the need to have its approval and support for gas imports directly from a US supplier.

- Mérida III was the first project approved by the authorities for an independent producer under the 1993 reforms to the Energy Service Law. This project consists of a 440-MW plant with a cost of US$500 million. PEMEX will supply natural gas to the plant through a pipeline built as a separate project. Participating firms in Mérida III include AES Corporation, of the United States; Nichimen, of Japan; and *Grupo Hermes*, of Mexico.

  In a similar fashion to the consortium organized for Samalayuca II, this consortium has distributed the technical tasks according to the strength of each participant. Nichimen and AES provide the technology and most of the equipment, while Grupo Hermes will provide equity and part of equipment and local services. The participation of Nichimen as an equity partner is explained by its long-term interest in Mexico's electricity as a supplier of equipment. Thus, deregulation of electricity in Mexico has opened up opportunities for foreign firms outside of the NAFTA region not only as investors, but also as sellers of equipment.

2. Canada

Expansion in Canadian capacity between 1997 and 2006 is expected to be modest in comparison to Mexico. According to industry data, total capacity is expected to increase by a net 4,840 MW by 2005 and another 3,370 MW by 2010, relative to 1996 figures. This is equivalent to a growth of 4.1 percent between 1996 and 2005 and 7 percent between 1996 and 2010. Growth in capacity is expected to be greatest in the hydroelectric and natural gas subsectors, with hydro capacity expanding by 1,890 MW (45 percent) and natural gas increasing by 6,390 MW (9.7 percent).[98] Most of the projected capacity expansion is expected in the provinces of British Columbia (29 percent of the total), Quebec (52 percent), and Nova Scotia (5 percent).

[98] CEA, "Electric Power in Canada – 1995," 124. These figures do not incorporate the large capacity expansions contemplated by Hydro-Québec as part of its strategy to tap export markets in the United States. According to CEA data, proposed expansions for Quebec alone could total 8,300 MW. Other Statistics Canada data from "Electric Power Capability and Load" (catalogue no. 57-204-XPB) show a total of 4,251 MW added to the system by 2007.

Total investment between 1997 and 2006 is expected to reach US$30 billion. Forty percent of this investment will be in generation capacity, 20 percent in transmission and distribution, with the balance falling under the heading of "other" expenditures. The majority of new generation capacity will be constructed by provincial utilities and will not involve FDI. However, considerably more expansion is expected among private-sector independent power producers, industrial cogenerators and small utilities than has occurred in the past.

3. United States

It is more difficult to project capacity expansion in the United States than it is in Mexico. Recent projections of capacity for the United States suggest growth of about 6 percent in net summer capacity between 1996 and 2005, for a total of about 43,000 MW. Of this new capacity, around 68 percent is expected to be provided by gas-fired technologies, 12 percent by coal-fired equipment, and 14 by oil-fired capacity.[99] The largest increases in new capacity are expected in the southeast, some of the mid-Atlantic states, and several states through the Ohio Valley and the midwest.

As restructuring occurs, most activity related to the acquisition and ownership of generating assets will likely be either in the selling and or refurbishment of existing assets. There has already been significant activity of this type in California and Massachusetts, including the construction of new capacity by independent power producers, industrial concerns and other non-utility generators to operate on a more speculative basis. Indeed, recent new construction in certain states indicates that growth in capacity may exceed those projections long before 2005, although such new plants may well replace older capacity as they are retired from operation. Two recent examples are:

- The Houston Industries-Enova Corporation joint venture, El Dorado Energy, shows how recent project developments geared to exploit new opportunities in deregulated markets suggest that capacity expansion projections will have to be revised. The venture consists of the construction of a 480-MW natural-gas-fired combined-cycle facility near Las Vegas, Nevada, which will be operated on a merchant basis serving wholesale customers throughout the western United States.[100] This plant by itself would increase capacity in Nevada by five times the expansion projected by the EIA in its inventory of US power plants issued in 1996.
- Connecticut's United Illuminating Co. (UIC) is joining two other developers, Duke Energy Power Services and Siemens Power Ventures, to build a 520-MW gas-turbine facility in Bridgeport, CT. Duke and Siemens will lead financing for the facility, while UIC, in exchange for providing the plant's site, will have the option to purchase a one-third share of the plant or buy power from the plant at wholesale. In the short term, the plant will help fill the capacity shortfall caused by the closure of three nuclear reactors at the Millstone station in Waterford, CT, in 1996. In the longer term, when deregulation occurs in Connecticut, the plant will provide low-cost power to UIC to help it meet the challenge of in-state and out-of-state competitors. Authorities at the Connecticut Siting Council have observed an increase in interest in siting new plants in the state, reflecting the appeal of the market due to high electricity prices and technical limits on the volumes of power that can be imported from out-of-state generators. The Bridgeport facility would be the first major facility built in the state in a decade.[101] According to the EIA projections, no new capacity is planned in Connecticut. If other facilities are developed in the state in the next few years, the new capacity may well exceed the lost capacity from the Millstone station, thereby exceeding the projections.

[99] EIA, "Inventory of Power Plants in the United States—1995," Table 17.

[100] "Houston Industries, Enova Corporation partner on Nevada merchant power plant," *Daily Power Report*, 18 December 1997.

[101] Rabinovitz, Jonathan, "Big power plant planned for Connecticut," *The New York Times*, 27 June 1997.

Another trend in the electric sector encouraged by the move toward competitive markets for electricity is consolidation among enterprises. Since 1992, merger and acquisition activity in the power sector has accelerated, despite some false starts due in part to regulatory action by FERC and state regulators. Since 1994, roughly US$50 billion in US merger and acquisition activity has been announced.[102]

In general, restructuring activities in the United States may be grouped under the following headings:[103]

- *Mergers of electric utilities.* The objectives of achieving increased efficiency through economies of scale and reduced duplication are often stressed in cases where companies with contiguous service territories merge, although the objective of diversifying the generating resource base and fuel mix may be an important issue as well.
- *Mergers of complimentary businesses.* In the case of mergers between electric utilities and gas utilities and/or pipeline operators, the main objectives may include those of diversifying business areas, offering integrated energy services to customers, increasing customer base, achieving vertical integration, and enhancing financial position. Often, the underlying motivation is a defensive one, as merging entities seek to shore up their regional and market positions in the face of deregulation.
- *Combination of converging businesses.* A similar, yet distinct, trend is for major energy companies, principally in the oil and gas sector, to expand into the electricity business, especially as power marketers as opposed to just being generators. The motivations involve not only the development of integrated services, but also risk-management objectives. Here, Enron's acquisition of Portland General and Amoco's expansion into generation and power marketing are good examples.
- *Alliances or virtual mergers.* Alliances offer the advantage of greater simplicity and speed when compared with merger deals, an attractive feature in a rapidly changing marketplace. There are numerous examples of such marketing alliances, which are undertaken in order to offer a broader range of services to customers. Examples include the Salt River Project/Tenaska /PowerEx (STP) marketing alliance, for electricity, the WestCoast Energy/Coast alliance for gas production, transmission and distribution, and AllEnergy, involving New England Electric System and Eastern Enterprises, a subsidiary of the Boston Gas Company.

Throughout the region, restructuring is bringing about a surge in investment, including investment of a transborder character. In the case of the United States and Canada, traditional forms of foreign direct investment are in evidence, whereas in the case of the United States and Mexico, the emphasis is on joint ventures, business alliances and build-lease-transfer (BLT) arrangements. In both cases, however, the environmental enhancements from the efficiencies brought by new investment and technology transfer appear promising. The openness and stability brought by NAFTA's investment provisions appear likely to sustain and reinforce these processes into the medium and long terms.

[102] CFE and Salt River Project, with Price Waterhouse and Econergy International Corporation (under contract to Bechtel Corporation, for USAID's Energy Technology Innovation Project) (1997), *Study on Legal and Regulatory Factors Affecting Cross-Border Trade in Electricity between Mexico and the United States: Final Report*, (Washington, DC: USAID): 84-85.

[103] *Ibid.*: 86-87.

IV. Linkages to the Environment

This section reviews the four major processes through which trade and investment trends in the electricity sector can affect the environment. The first are the production processes (including management and technology) that the trends in electricity, fuel and technology trade and investment are encouraging or sustaining. The second is the physical infrastructure that supports trade. The third linkage between NAFTA-induced economic activity and the environment is through processes of social organization. The fourth, and possibly the most important given the importance of regulation for the sector, is through government policy and regulation.

A. Production, Management and Technology

The environmental consequences of trends in the electricity sector depend critically on the sources of additional generation and the extent to which energy-efficiency improvements can substitute for additional power production. The open-grid movement draws continuing impetus from the collapse of historic generation monopolies. Largely vanished is the availability of integrated utility monopolies as regulated investors in new generating assets, with repayment guaranteed by levies on captive customers. Generation additions are now subject to competitive procurement in all three NAFTA countries, and new equipment must compete in an increasingly open marketplace.

Units built under the old monopoly regimes are beginning to change hands as pressures mount to separate competitive generation assets from the regulated monopolies that, despite some erosion, continue to control transmission and distribution systems. Beyond this, two trends in the electricity industry stand out in their contribution to the movement toward changes in the electricity sector in the United States, Canada and Mexico: the impact of new generation technologies and the impact of new enabling technologies. These trends will be examined in turn.

1. New Generation Technologies

NAFTA can provide a powerful assist to generators and transmitters seeking to use the newer generation of technologies that increase efficiencies and direct environmental benefits. Tariff reductions on equipment emerging from the new technologies can accelerate the process of the transfer and diffusion of technologies throughout the NAFTA region and among firms in the electricity sector within each member country. Restructuring reinforces this NAFTA-catalysed process by leading firms to adopt new technologies to meet new competitive pressures.

The lower price and increased availability of new generation technologies, particularly those fired with natural gas, have facilitated the growth of independent power producers (IPPs) that sell electricity to utilities for resale to customers. The involvement of IPPs in the electricity industry has lent credibility to the notion that a competitive market is possible. IPPs of all sizes, industrial and commercial concerns, and other non-utility generators (NUGs), as well as the traditional utilities and their affiliated companies, are increasingly utilizing new generation technologies to develop private power projects and sell to utilities at a wholesale level, at prices lower than those incurred by utilities to construct and operate equivalent new capacity themselves.

Technological developments, combined with the impact of natural gas deregulation in the United States, have greatly reduced the capital and operating costs associated with natural-gas-fired turbines, which, in the increasingly widespread combined-cycle configuration, offer high rates of efficiency, low capital costs, and competitive operating and maintenance costs.

Smaller-scale combined-cycle gas turbine (CCGT) plants have been used aggressively by IPPs. These technologies, coupled with open transmission systems and the guarantees of NAFTA's investment provisions and national-treatment, market-access rules can allow independent power producers to build plants in any jurisdiction to provide power for users in neighboring jurisdictions. Many of these new technologies are less polluting than older plants, they permit siting in otherwise difficult-to-permit areas (from the air-emissions perspective), but their construction results in a need for new infrastructure that may have environmental impacts.

A recent evaluation of the marginal cost of competing generation technologies performed by the Energy Information Administration (EIA) at the US Department of Energy demonstrates the economic advantages of natural-gas-fired technologies.[104] In this comparison, an analysis of fuel costs, capital costs, and operating and maintenance costs is used to determine the marginal cost of each plant type. Emission and waste factors are also considered.

The analysis compares the construction costs of a 500-MW coal-fired plant and a 250-MW CCGT. The overall results of the analysis, which included capital outlays, operation and maintenance costs, interest rates and operating assumptions, suggest that although the fuel costs for a coal-fired power facility are lower, the lower capital and operating costs of gas-fired facilities, along with their increased energy efficiency and environmental benefits, make new gas-fired plants more competitive than new coal-fired units in the long run. The gap between the two widens (in favor of natural gas) at lower capacity factors, with virtually no difference at 100 percent. This suggests that utility operators would have an incentive to run existing coal-fired facilities more, all other things being equal.[105] It also points to the need to properly internalize and account for the environmental costs of coal-fired generation.

This assessment remains valid despite projections of future fuel costs for coal and natural gas that show that the differential between the two will widen: the cost of coal is expected to remain virtually constant, while the price of natural gas is projected to climb by the year 2015. In 1995, steam coal cost US$1.32 per million British Thermal Units (MBTU) of caloric value; prices are projected to drop to US$1.28/MBTU by 2015. Meanwhile, natural gas prices are projected to climb to US$2.95/MBTU in 2015, from US$2.04/MBTU in 1995.[106]

Another area where new natural-gas-fired generation technologies have made a substantial impact is the emerging market for "distributed generation" applications. With very small gas turbines offering high levels of efficiency, small businesses, restaurants and smaller manufacturing facilities can consider installing their own power resource. Widespread deployment of distributed generation resources reduces the need for large utilities to add new capacity.

Electricity-sector expansion plans for all three countries are consistent with the overall conclusion that natural-gas-fired plants are a most attractive option for new capacity from the economic standpoint.

In the United States, a review of demand profiles and resources by the North American Electric Reliability Council (NERC) regions, and the comparison of generating facilities by fuel type and technology, underscores the competitive advantages of CCGT technologies. Regional data from the United States suggest that CCGT technologies will provide a large segment (as much as 70 percent) of new capacity. The extent to which gas-fired capacity will dominate new

[104] Beamon, J. Alan and Steven H. Wade, "Energy equipment choices: fuel costs and other determinants," Energy Information Administration, US Department of Energy. Internet: www.eia.doe.gov.

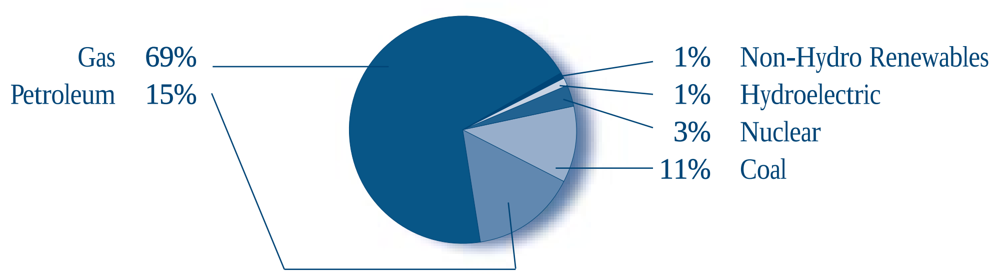
[105] *Ibid.*: 7-11.

[106] *Ibid.*: 8.

generation is likely to vary from region to region. For example, data for ERCOT suggest combined-cycle facilities will make up some 60 percent of new capacity, whereas data for the WSCC show coal-fired capacity will account for 50 percent of capacity expected to be built before 2005. Data for the United States are summarized in Figure 4.

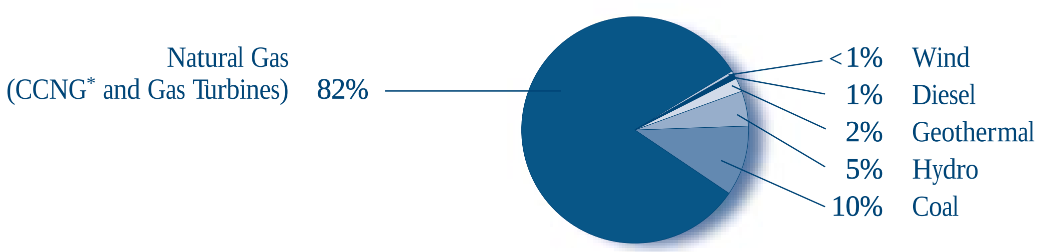
In Mexico over the next decade, the CFE plans to issue bid packages for a total of over 10,000 MW of new gas-fired capacity (comprising both combined-cycle and turbogas technologies), and contracts for the conversion of over 4,000 MW of existing capacity to natural gas.[107] Planned capacity in Mexico is presented in Figure 5.

Figure 4 Total Projected Additions of US Electricity-Generating Capability by Technology Type, 1996–2005



Source: US Department of Energy, EIA, 1997.

Figure 5 Technology Selected for New Capacity in Mexico, 1998–2006



*CCNG: combined cycle natural gas

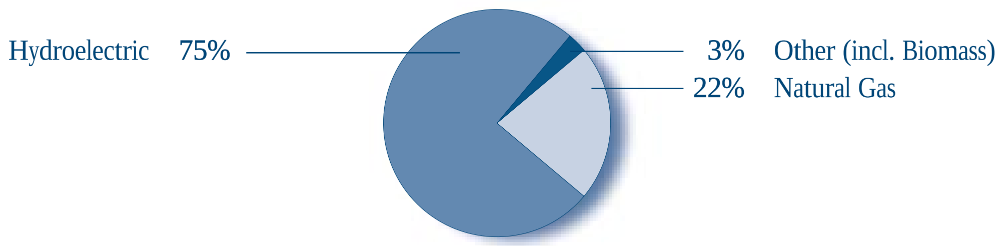
Source: CFE, Documento de Prospectiva, 1997.

In Canada, 8,212 MW of new net capacity is expected to be added to the system by 2010. Actual capacity additions will be somewhat larger, however, to accommodate the retirement of 356 MW of thermal steam capacity (both oil- and coal-fired). In addition, 769 MW of nuclear capacity will be decommissioned, but will be replaced by an equal amount of new nuclear capacity, yielding no net change in nuclear capacity between 1996 and 2010.[108] The composition of projected net capacity changes are presented in Figure 6.

[107] See *Documento de Prospectiva del Sector Eléctrico 1996-2005* (Mexico City: Secretariat of Energy, 1997): 73.

[108] Statistics Canada, Catalogue no. 57-204-XPB. The CEA and Statistics Canada data do not coincide exactly. StatsCan projects substantially less expansion in hydroelectric capacity (roughly 2,500 MW as opposed to about 6,390 MW in CEA publication) and slightly less gas-fired capacity (1,330 MW as opposed to 1,890 MW projected by the CEA). The CEA also projects additions of biomass-fired capacity not mentioned by Statistics Canada.

Figure 6 Projected Canadian Capacity Expansions 1996-2010



Source: CEA, 1997.

In order to assess the likely course of resource development over the next decade in the various NERC regions of North America, it is important to consider the constraints on the transmission and distribution of electricity between regions and between countries. The impact of regulatory changes in the United States, and to a lesser extent in Canada and Mexico, thus becomes important. As movement to open-access transmission proceeds in the United States for wholesale and retail markets, it is increasingly important to consider purchases of energy transmitted from distant generation facilities as an alternative to building new generation facilities.

As Section B on physical infrastructure discusses in more detail, there are substantial variations in the availability of transmission capacity between NERC regions in the United States. As a result, the potential for long-distance transmission may be limited in certain corridors. A recent effort to model transmission-induced emissions prepared by researchers at Resources for the Future (RFF) suggests that the mid-continental area power pool (MAPP)[109] region enjoys the lowest average prices for bulk power, but is restricted from exporting large blocks of power due to transmission limitations. Under various trading scenarios, the RFF paper indicates that increased power trading would lead to flows into the Northeast (NPCC region), the Southeast (SERC), and the southern plains states (SPP region). Major exporting regions would be the midwest and northern plains areas (ECAR, MAIN and MAPP), and the central Atlantic states (MACC).[110]

A similar study undertaken by the Energy Information Administration (EIA) argues that limitations on transmission capacity serving the northeast would restrict the degree to which exports from the midwest could be increased. The EIA study predicts substantial short-term increases in exports from the midwest into the southeast (SERC), and to a lesser degree, the southern plains (SPP).[111] In the longer-term, new transmission capacity could facilitate higher exports to the northeast. However, the EIA contends that excess generation capacity would be limited in the longer term due to demand growth in areas currently enjoying excess capacity. The extent to which exports could increase in the long term would depend on the rate of growth of transmission capacity as well as construction of new generation facilities. The RFF study incorporates various scenarios regarding growth in transmission capacity.

[109] See Appendix E for an explanation of the NERC regions.

[110] Palmer, Karen and Lance Burtraw (1996), "Electricity restructuring and regional air pollution," Resources for the Future Discussion Paper 96-17-REV2 (July): 25-27.

[111] EIA (1996), "Service Report: An analysis of FERC's Final Environmental Impact Statement for electricity open-access and recovery of stranded costs" (September): 22-23.

Preliminary evidence suggests that substantially increased power flows from the midwest to the northeast are not only possible but have been occurring since 1996. A brief study undertaken by the Energy Workgroup of Northeast States for Coordinated Air Use Management (NESCAUM)[112] based on EIA and FERC electricity trading data for representative midwestern utilities suggests that deliveries by those utilities to companies in the MAAC and NPCC regions increased substantially in 1996, in parallel with an increase in coal-fired generation by midwestern firms.[113] Other evidence points to increased transmission capability between the midwest and the northeast. As will be discussed in Section B, "Physical Infrastructure," new capacity and line upgrades will be entering into service in the near future, and they could reduce transmission constraints between the two regions.

a. Impact of New Enabling Technologies

Advances in telecommunications and information technologies, especially in the area of wireless communications and the Internet, have improved the availability of market information that is necessary to allow a competitive electricity market to function, and improvements in grid-control technologies promise to allow more sophisticated bulk transactions to take place. These include the development of so-called SCADA systems, which involve the deployment of remote terminal units (RTUs) throughout a system to relay data to a central control system. The application of advanced communications technologies such as wireless voice and data transmission, real-time data acquisition, especially via the Internet, and state-of-the-art metering equipment will permit utilities to monitor more customer loads on a real-time basis than was previously possible.

These developments are mandated in part by FERC as part of the OASIS requirements contained in Order 889. The OASIS system will provide information to entities seeking open-access transmission capacity offered by utilities under FERC jurisdiction. In order to be most useful, OASIS systems will have to provide real-time coverage. Substantial advances in OASIS operations have already occurred. In Florida, five utilities execute trades in transmission capacity via the Internet using IBM and Siemens software and Internet systems. The system is maintained by IBM and Siemens as a service to the utilities; it is operated from Boulder, Colorado.[114]

However, utilities predict savings on operational costs and enhanced customer service through the creation of a communication network to provide two-way connections to residential, commercial and industrial users. The systems provide automated meter reading, the remote configuration of meters and other devices installed on the customer's premises, and communications services such as messaging and load control. In a recently announced contract, Illinois Power (IP), a major investor-owned utility (IOU), will use wireless communications developed by Whisper Communications in conjunction with advanced metering equipment provided by Schlumberger, an industry giant, to serve 1 million customers in IP's service territory of 15,000 square miles. When installed, the system will be the largest of its kind in the United States.[115]

[112] This Boston-based organization includes the air resources divisions of the state environmental agencies of New Jersey, New York, Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire and Maine.

[113] See NESCAUM (1998), "Air Pollution Impacts of Increased Deregulation in the Electric Power Industry: An Initial Analysis," 15 January. The NESCAUM study has been criticized by at least one utility for which data were presented, American Electric Power (AEP), which serves almost 3 million customers in the Ohio Valley region. However, the NESCAUM study is careful to note its limitations, and therefore adequately contemplates the charges reportedly made by one AEP official; the AEP rebuttals do not refute the available data showing increased deliveries by AEP to entities in the MAAC region, nor do they challenge data showing increased coal-fired generation. See "AEP says NESCAUM study not representative of industry, takes numbers out of context," *Daily Power Report*, 22 January 1998.

[114] "Five Florida utilities to trade power transmission capacity over the Internet," *Daily Power Report*, 14 January 1998.

[115] Illinois Power and Schlumberger sign contract for largest two-way automatic meter reading system," *Daily Power Report*, 8 January 1997.

2. Trends in Energy Production

The fleet of generation facilities in North America exhibits substantial diversity in terms of technology and resource type. Fossil fuels are used to produce electricity in varying proportions in Canada, Mexico and the United States. Coal plays a preponderant role in US generation, providing over 50 percent, with natural gas accounting for between 8 and 14 percent and oil about 3 percent. In Canada, coal supplies about 15 percent of total generation. The Mexican generation system relies primarily on oil-fired capacity, which provides about 60 percent of electricity generated, while natural gas accounts for 12 percent and coal contributes 9 percent. In contrast to the United States and Mexico, hydroelectric facilities provide over 60 percent of Canadian generation, compared to about 20 percent in Mexico and 11 percent in the United States.

a. Coal

Subject to transmission constraints, growth in electricity demand in Canada and the United States is expected to lead to the increased operation of the existing fossil-fuel fleet, along with increased trade in electricity and fossil fuels.[116] As a result, the consumption of coal is projected to increase substantially, with harmful environmental effects. NAFTA tariff liberalizations, however, provide an incentive for greater exports of low-sulfur US coal to Mexico, with attendant environmental benefits.

Coal-industry executives and energy analysts in the United States and Canada predict that coal consumption by utilities will increase by as much as 30 percent as a direct result of restructuring in the electric power industry.[117] In a report on the environmental effects of restructuring in Ontario, prepared for the Advisory Committee on Competition in Ontario's Electricity System, expert independent analysts concluded that the useful lives of coal-fired power plants would be extended and the plants might even be operated at higher capacity factors.[118] Moreover, the Vermont Public Service Board (VPSB) states that many of the older thermal power plants, which were exempted from the 1970 Clean Air Act, are still in operation, and in a deregulated market such plants will enjoy a competitive advantage over plants that currently must comply with modern emission standards.

Generation data for 1996 suggests an increase in coal-fired electricity production in the United States. The NESCAUM analysis of generation and sales data for 1995 and 1996 reports that at the national level, coal-fired generation increased 83 TWH, while gas-fired generation decreased 44 TWH during that period. Furthermore, the study documents increased generation at power stations owned by three midwestern utilities (AEP, Indianapolis Power & Light [IPALCO] and Illinois Power Co.) with relatively high per-unit emissions rates for SO_X, NO_X and CO_2. All three registered increases of 3 to 10 percent in NO_X emissions, 3 to 9 percent in SO_X output, and 3 to 13 percent for CO_2 emissions.[119] Both AEP and IPALCO incurred costs associated with increased SO_X emissions. The NESCAUM study also notes that emissions from the New England Power Pool (NEPOOL) increased in 1996, also resulting from a 9.7-percent increase in coal-fired generation and a 128 percent jump in gas-fired production. This production increase, the study argues, was due to increased outages at nuclear facilities rather than wholesale market sales made possible by open-access rules.[120] It remains to be seen whether a change in export levels from Quebec also played a role in the increased generation levels.

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[116] The EIA Service Report, for example, predicts a minimum increase of 2 percent in coal-fired generation by 2000 under every scenario except the one in which the differential between coal and natural gas prices remains constant. The differential is expected to widen, favoring the use of coal. The EIA estimates of increases in emissions are lower than those presented by Palmer and Burtraw, *op. cit.*, as well as several other studies.

[117] Docket No. 5854, *Investigation into the Restructuring of the Electric Utility Industry in Vermont*, Draft Report and Order, pp. 97-98, 16 October 1996.

[118] ARA Consulting Group (1996). "Electricity Competition in Ontario: Environmental Issues" pp. 2-17, 8 April.

[119] NESCAUM, *op. cit.*: 9.

[120] *Ibid.*: Attachment B, 11-14.

Growth in Mexico is likely to be met with new natural-gas-fired power plants and through the conversion of existing oil-burning plants to higher-efficiency natural-gas combustion. However, some new coal-fired capacity will be brought on line in the northeastern part of the country. In the context of cross-border sales of electricity by US utilities to the CFE, an important question is whether increased generation in the United States will result in a net increase in emissions compared with emissions that would result if CFE satisfied its requirements using its own resources. A preliminary assessment of this issue suggests that in the near term, the likely resources used on the US side would be coal-fired, whereas the resources displaced on the Mexican side would be oil-fired. Based on representative per-unit emissions factors, the study suggests that the result would be mixed in terms of its environmental consequences: net SO_X and NO_X emissions would decline, but net CO_2 emissions would increase.[121]

b. Natural Gas

The contribution of new investment to improving production technologies in gas and electricity lies mainly in the efficiency of fuel use, fewer environmental emissions as a result of improved controls, switching to gas, and lower production costs.

There is also a link between new investment in Mexico's electricity and natural-gas transport and distribution and cleaner, more efficient production technologies. It is important to note that once Mexico signed NAFTA and opened its electricity sector and natural gas to private participants, its access to international technology and advanced production processes increased, as demonstrated by the diversified investment base participating in the projects put out to bid.

The restructuring of the Mexican gas sector has generated some changes in consumption patterns, since Mexico's trade balance in gas appears to be reversing. The consumption of natural gas is a key part of the *Secretaría de Energía's* (SE) development strategy for the energy sector. An important element of the overall SE's energy policy is the Integrated Fuels Policy, which the SE has promoted through an inter-secretarial group known as the Fuels Policy Group. The policy seeks to reverse the trend toward the increased consumption of petroleum-based fuels by promoting the consumption of natural gas. The increased consumption of natural gas will require 2.06 billion cubic feet a day (BCFD) of new supply. Consumption of natural gas forms the cornerstone of SE's program to improve the environmental performance of CFE. Between 1997 and 2000, a total of slightly over 4,000 MW of existing generating capacity will be converted to natural gas,[122] while an additional 10,795 MW of new generating capacity using natural gas (out of almost 13,200 MW) is planned between 1997 and 2006 (see Appendix F).

The CFE's emphasis on developing gas-fired capacity fits into a larger energy policy initiative designed to promote the consumption of natural gas and to increase its availability. The reforms designed to open gas transmission and distribution are intended to support this objective, along with increased spending by PEMEX on gas-field development, production and processing to expand domestic gas supplies, and investments in refinery processing capability to produce higher-quality, low-sulfur gasoline and diesel fuels.

According to a preliminary policy paper, the SE's Integrated Fuels Policy will lead to a substantial reversal in the consumption of petroleum-based fuels and coal. Whereas in 1994 natural gas accounted for 37 percent of the 4.9 trillion BTUs of fuels consumed per day (TBTU/D) in Mexico (excluding transportation consumption), by 2005 it is expected to provide 51 percent of the projected 7.2 TBTU/D consumed. The use of high-sulfur fuel oil, which in 1994 accounted for 51 percent of industrial consumption, is expected to shrink to 18 percent.[123] These changes in production, spurred by Mexican government policy and aided by NAFTA's spur to increased gas exports and environmental awareness, promise environmental benefits.

[121] USAID, SRP, CFE (1997), "Environmental Annex to the Study on Legal Regulatory Factors Affecting Cross-Border Trade in Electricity between Mexico and the United States" (22 January): 24-25.

[122] SE, *Documento de Prospectiva* 1996: 56.

[123] Mauricio Toussaint (1995), "Mexico's Integrated Fuels Policy," working paper, *Subsecretaría de Política y Desarrollo de Energéticos, Secretaría de Energía*. Current projections might be somewhat different.

c. Hydroelectricity

There is thus far, a mixed pattern for the changing use of hydropower in the post-NAFTA period.

(i) Canada

Hydroelectric facilities in Canada are characterized by large reservoirs that are ideal for load following and taking advantage of price fluctuations in short-term markets. Canadian hydro utilities can purchase electricity from the market during low price periods and "store" it for later sale. In addition, due to the low variable costs of hydroelectricity, many Canadian utilities expect to be able to compete with thermal generation in the United States.

The environmental impacts of hydro development have been extensively documented. Problems with hydro-plant operations can also be significant if the operators are unconstrained and take advantage of spot market price fluctuations. In the US Pacific northwest, utilities have been attempting to mitigate the environmental damage caused to salmon migration by hydroelectric facilities on the Columbia River system. The costs of these activities has been substantial. For example, the region's Public Utility Districts spent nearly US$50 million in 1996 on programs to improve salmon management, production and habitat. The Bonneville Power Administration (BPA), the region's federal power marketer, has an annual budget of US$100 million each year for its fish and wildlife programs for the period from 1996 through 2001.[124] Programs operated by the utilities include efforts to restore fish habitat, developing bypass routes for juvenile salmon, operating and evaluating hatcheries, environmental education, water monitoring, and reintroducing anadromous fish.

Impacts of ongoing hydroelectric operations include:

- *Reduction in flows.* Reduced flows can result in decreased habitat due to diminished water availability; they can also result in changes in stream temperature. Reductions can also mean less flushing of fine material from downstream gravel, changes in velocity, less waste dilution and changes in ice buildup.
- *Rapid flow fluctuation.* The rate of change of flow can impact on fish habitat and disturb spawning areas. In particular, it can leave fish stranded in pools or create conditions that force fish from preferred habitat.
- *Inadequate flushing flows.* Inadequate flushing flows can result in sediment buildup and lead to damaged habitat.
- *Reservoir drawdown.* Drawdown can result in reduced habitat within the reservoir, the stranding of fish, changes in water quality, reduced invertebrate production, and shoreline sloughing from wave wash and sediment release.[125]

Other impacts from operations include the disruption of fish and wildlife migration as well as impacts on recreational and commercial activities along dammed rivers. In addition, there is a potential for increased evaporative losses, changes in siltation patterns, increased turbidity, altered temperature profile and reduced dissolved-oxygen content. Hydroelectric facilities can also impact on biota by reducing shoreline biodiversity, disrupting animal habitat and migratory routes, reducing downstream plankton populations, and disrupting fish spawning routes. Hydroelectric facilities, by their nature, have an immediate impact on the environment due to reservoir flooding, potential mercury contamination, construction, road building and the need for transmission lines. Reservoirs can also cause changes in local micro-climate such as increased humidity, decreased rainfall, increased cloud cover, increased fog and moderated temperature.

[124] In fiscal years 1996 and 1997, BPA did not spend its full budget; the remainder is carried over, plus interest, for spending in subsequent years. These budgeted amounts do not cover expenses from other agencies (approximately US$36 million annually in 1996 and 1997), related capital investments (about US$76 million in each year), or the cost of river operations (about US$102 million in 1996 and 1997). Personal communication with John Taves, BPA, 30 January 1998. See also, "Public Utility Districts spent nearly $50 million for salmon last year," *Business Wire*, 18 November 1997.

[125] CEA, "Response from Canada to Article 14 Complaint under the North American Agreement on Environmental Cooperation," 21 July 1997: IV/2-4.

Hydropower in the province of Quebec has been at the heart of a long-standing debate over the social and environmental impact of mega-developments. Indigenous communities in northern Quebec, along with Canadian and US environmental organizations, have argued that the developments harm the environment in the regions they inhabit and force the relocation of human settlements. In addition to the alteration of river flows, blockage of animal migration routes and other physical dislocations, the flooding of dammed rivers has been implicated in the build-up of mercury compounds in tissues of lake fish, leading to similar build-ups in animals and humans up the food chain. Recent research on the production of certain gases, such as methane, in flooded vegetation also suggests that hydropower developments in certain regions may contribute to emissions of GHGs.[126]

The debate about hydropower's environmental and social consequences has also occurred in Hydro-Québec's major export markets in the northeastern United States. In 1991, for example, concerns about the social and environmental impacts of the Great Whale project in the province galvanized public opposition to a long-term energy purchase contract being considered by the New York Power Authority. That project was put on hold in 1994.[127] More recently, similar concerns led to filings before FERC by indigenous groups, and others in Quebec and the United States, to oppose Hydro-Québec's application for a power marketer's license for the US market.[128]

(ii) United States

The use of hydropower in the United States involves the same environmental implications as in Canada, with perhaps greater emphasis on the impacts of hydroelectric projects on recreational uses of rivers, especially in the west. In the case of recreational uses of rivers, supporters of certain dams in the desert southwest argue that the lakes created by the dams provide popular recreational uses, including boating and fishing, while dam opponents cite the whitewater rafting and kayaking opportunities as well as the appealing scenic wilderness of unspoiled rivers.

In a recent decision, FERC refused to relicense an older dam in Maine. Since 1986, FERC has been required to evaluate conservation, recreation and environmental values along with the energy-producing benefits of dams during the licensing process. FERC determined in November that the benefit of electricity generation from the 160-year-old Edwards Dam on the Kennebec River did not compensate for the hindrance it poses to migratory fish, including economically valuable species such as sturgeon and salmon. However, the energy provided by the 3.5-MW dam is small compared to other large dam projects in the country.[129]

(iii) Mexico

Mexico has hydroelectric capacity along the Pacific slope of the Sierra Madre Occidental and Sierra Madre del Sur ranges, in the states of Sonora, Sinaloa, Durango, Jalisco, and in Chiapas in the south. Mexico's hydroelectric facilities are substantially smaller than Canadian and US hydroelectric stations. Documentation of the extent to which the environmental impacts of these developments may be correspondingly smaller has not been uncovered to date. However, conversations with representatives of NGOs active in Chiapas, where almost 3,930 MW of Mexico's current total of roughly 10,000 MW is located, suggest that there is substantial concern that the state's inhabitants do not receive enough of the development benefits from the hydroelectric facilities, including adequate supplies of electricity.[130]

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[126] See Chamberland, André, Camille Belanger and Luc Gagnon (1996), "Atmospheric emissions: hydro-electricity versus other options," *Ecodecision* (Winter): 56-60; and Gagnon, Luc, and Joop F. van de Vate (1997), "Greenhouse emissions from hydropower," *Energy Policy* 25 (1): 7-13.

[127] See DePalma, Anthony, "Storm exposes Quebec's 'power' politics," *New York Times*, 15 January 1998.

[128] See filing by the Grand Council of the Crees and the New England Coalition for Energy Efficiency and the Environment before the FERC regarding Hydro-Québec's filing (Docket ER97-851-000); letter from Natural Resources Defense Council (NRDC) to the FERC (10 October 1997); letter from the Finger Lakes/James Bay Alliance to the FERC (18 October 1997).

[129] Goldberg, Carey, "Federal agency orders demolition of Maine dam to aid fish migration," *The New York Times*, 26 November 1997.

[130] Personal communication with José Warman, President of *Espacios Naturales y Desarrollo Sustentable*, AC, December 1997. Representatives of other organizations in and outside of Chiapas have expressed similar views.

d. Nuclear

Nuclear power has played an important role in the development of the electricity sectors of North America, especially in the United States and Canada. In Mexico, one nuclear facility provides a relatively small percentage of the nation's power. Changes in the use of nuclear-generated power have thus far been driven far less by NAFTA-catalyzed processes than by autonomous factors such as Ontario Hydro's closure of seven reactors in 1997.

In 1995, there were 132 operating nuclear power units in North America. The 109 operating units in the United States constitute the largest nuclear power plant fleet in the world. These plants generated 673.4 TWH of electricity in 1995, which represents 20 percent of net US electricity generation. Canada had 21 units in operation in 1995, generating 92.3 TWH, representing 17.3 percent of total electricity generated. Mexico's two reactors at the Laguna Verde facility generated 8.4 TWH in 1995. This constituted an increase of 96 percent over 1994, and represented 6 percent of the net electricity generated in Mexico in 1995.

(i) United States

With deregulation in the US power sector leading to increased competition in power generation, projections for nuclear power show declining capacities in North America. Operating nuclear capacity in the United States is projected to decrease by 36 percent from 99.4 net GWH in 1995 to 63.7 net GWH in 2015. Canada's projected capacity is also calculated to fall by 14 percent from 14.9 net GWH in 1995 to 12.8 net GWH in 2015. Mexico's capacity is projected to remain constant at 1.3 net GWH through 2015.

Safety and environmental factors concerning the storage of waste and the decontamination of plant sites is hindering the future performance of nuclear generation. Inadequate spent-fuel management programs, the lack of storage facilities, and the increasing cost of cleaning decommissioned sites all present costly problems for the industry. Over the next 19 years, 49 of the 109 US operating plants are scheduled to be retired. This will create increased demand for the storage of waste and for site decontamination at decommissioned plants.

There are three types of nuclear waste that are by-products of the generating process. These are categorized into High-Level Waste (HLW), Mixed Low-Level Waste (MLLW), and Low-Level Waste (LLW). HLW is primarily the spent nuclear fuel that makes up less than one percent of the waste but represents 99 percent of the radioactivity. Disposal of this waste was assigned to the federal government in the Nuclear Waste Policy Act of 1982. However, underestimates of development and licensing have resulted in long delays in the construction of a site for HLW. The Yucca Mountain site in Nevada is still under construction, with an opening date of 2010. In the meantime, fuel is stored in pool storage sites or in independent fuel storage sites.

LLW accounts for more than 99 percent of the volume of all waste and less than 0.1 percent of the radioactivity. It is comprised of mostly equipment, clothing and tools from the plant. There are only two sites in the United States currently accepting LLW; they are located in Hanford, WA, and Barnwell, SC. The lack of available storage sites is an impediment to decommissioning sites, as the current infrastructure can hardly handle the waste from the 11 plants that have so far been shut down. The development of one proposed site in Ward Valley, CA, has been held up in the courts due to safety and environmental opposition.

Major uranium reserves in the United States are located in south-central Texas, northern New Mexico and Arizona, eastern Washington, western Nebraska, and throughout Colorado, Wyoming and Utah. Uranium concentrate is mined only from some of these reserves. Two facilities operate in south Texas, another in southeastern Utah, two in north-central Wyoming, and one in western Nebraska. Uranium fuel fabrication is completed at five facilities in the United States. These facilities are located in Richland, Washington; Hematite, Missouri; Columbia, South Carolina; Lynchburg, Virginia; and Wilmington, North Carolina. The facility in Lynchburg, Virginia, has a capacity of 400 MTU (metric tons of uranium per year) and is operated by B&W Fuel Company. ABB Inc. operates the 450-MTU facility in Hematite, Missouri, while Siemens Power Corp operates a 700-MTU facility in Richland, Washington. Westinghouse and General Electric operate larger 1,150- and 1,200-MTU facilities in South and North Carolina, respectively.

(ii) Canada

Canada's nuclear power program got underway in the early days of World War II. In 1952 a crown corporation, Atomic Energy of Canada, was formed to market Canada's reactor design, Candu (Canadian Deuterium Uranium). The design features the ability to refuel while operating, an attribute that helped Canada's reactors become an industry leader. Since 1971, 22 Candu reactors have entered into service in Canada, for a total of 16,390 MW of capacity, all but 1,365 MW of which are located in Ontario. According to CEA data, in 1995 the Pickering 8 and Pickering 7 units in Ontario, and the Point Lepreau facility in New Brunswick, ranked fourth, fifth and seventh, respectively, in terms of reactor performance.[131] In 1997, however, a review of reactor operations undertaken by Ontario Hydro uncovered numerous problems that may mean a decline in performance at numerous reactors in Canada in the next several years.[132]

The Candu design involves heavy-water reactors, and therefore the Canadian plants do not rely on the production of unwieldy fuel rods for this reactor type, which is the main fuel used in US commercial reactors (Mexico's 1,350 MW Laguna Verde facility is a light-water, BWR-type reactor). Canada also has uranium reserves and operates fuel-preparation facilities.

(iii) Mexico

In Mexico, proven reserves of uranium oxide in excess of 14,000 tons are located in the northern states of Sonora, Chihuahua, Nuevo León, Tamaulipas, Durango and San Luis Potosí, and also in Oaxaca in the south. This is more than sufficient to supply fuel for the Laguna Verde plant and another one of similar size for their entire operating lifetimes.[133] Mexico also operates fuel-preparation facilities.

(iv) Reactor Decommissioning

The recent closure of seven reactors in Canada demonstrates the important environmental trade-offs that are likely to emerge over the next two decades as reactors in the United States and Canada are decommissioned. Public concerns about the environmental hazards of nuclear plants have been an important part of the history of nuclear power in the United States and Canada, and, to a lesser extent, Mexico. Given these concerns and the costs associated with their construction and decommissioning, virtually no new nuclear plants are being constructed at the present time. Although the anti-nuclear protests have disappeared—since no new plants are being built—concerns about the safety of existing plants have not, and they seem likely to increase as the facilities approach the close of their useful lives.

The US industry provides a recent example. An assessment of the nuclear program of Commonwealth Edison (ComEd) prepared by the Institute for Nuclear Power Operations and released by the Nuclear Regulatory Commission (NRC) contained an indictment of plant safety at the utility's 1973 Zion plant, near Chicago. ComEd has the largest reactor fleet, with 12 plants, and six of these reactors are on the NRC's reactor "watch list." There are a total of 13 reactors on the list.[134] In early 1998, ComEd announced a reorganization of its nuclear operations and the closure of the Zion plant.[135]

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[131] CEA, "Electric Power in Canada: 1995," 86.

[132] See DePalma, *op. cit.*, and DePalma, Anthony, "Exported for decades, Canadian reactors are plagued by operating problems," *New York Times*, 3 December 1997.

[133] Eduardo Arriola Valdés (1994), "Recursos Energéticos Primarios y Tecnologías de Generación de Electricidad," in Daniel Reséndiz-Nuñez (ed.), *El Sector Eléctrico de México* (Fondo de Cultura Económica: Mexico City): 81-84, 103-104.

[134] Matthew Wald, "Report cites poor safety at nuclear plant near Chicago," *New York Times*, 27 November 1997.

[135] "Illinois nuke plant to shut down," *Daily Power Report*, 16 January 1998.

Elsewhere in the United States, five of New England's eight nuclear plants were taken off line in 1996 and 1997, forcing local utilities to increase fossil-fired generation, as documented in the NESCAUM analysis.[136] Three of these five plants could be restarted in 1998, although some observers have cited the age of one as being an impediment. The other two (of 1968 and 1972 vintage) are deemed too old to reopen.[137]

When the existing nuclear fleet is decommissioned, the missing capacity will be replaced, in the near term, perhaps with coal and hydroelectric capacity, as appears likely in Ontario, and in the long term, by natural gas, coal or hydro. The environmental trade-off between nuclear-power issues of radioactive solid waste and public health and the air and land impacts associated with fossil-fired and hydro capacity is inevitable and will play an important part in the future environmental ramifications of the electricity sector in North America.

e. Renewable Energy

NAFTA's overall intensification of competition is likely to decrease the use of environmentally friendly renewables, which are often relatively costly and require subsidies for their expanded use. In the United States, the renewable-energy sector experienced significant growth in the 1980s and early 1990s following the Public Utility Regulatory Policies Act (PURPA) of 1978, which encouraged energy efficiency and renewables as a result of the oil crisis in the 1970s. As the price of oil increased by 300 percent in the mid-1970s, PURPA was implemented to decrease the country's dependency on foreign oil. Renewables currently face substantial challenges as the electric power industry deregulates in the United States, creating greater generating competition, and through the possible repeal of sections of PURPA that encourage renewable usage. Originally, utilities were mandated under PURPA to purchase renewable power from "qualifying facilities" (QFs). These QF generating facilities were able to lock in flat rates with purchasing utilities. With the subsequent decrease in fuel costs and increased competition in the generation sector, renewables with locked rates have become a burden to the purchasing utility.

In volatile electricity-commodity markets, often characterized by near-term capacity surpluses, renewables are at a competitive disadvantage due to their front-heavy cost structure. In addition, the introduction of combined-cycle gas turbines into the generating market has made power generation much more competitive. Gas-turbine generating costs compete with the cost of older, large-scale electricity production. In a market with increased competition, renewables are at a disadvantage due to their smaller economies of scale and high short-term capital costs and lower long-term operating costs. Larger coal- and gas-fired plants have larger economies of scale and dominate despite their relatively higher cost of capital and operating costs.

Comparing cost data from several renewable projects to cost data of fossil-fuel plants leads to some useful conclusions regarding the competitiveness of renewable-energy technologies. In general, most renewable applications have high up-front capital costs and comparatively low variable costs of operation and maintenance. In the calculation of the levelized cost of energy, the high capital costs combined with risk considerations that affect the cost of financing leads to results that may put the renewable development at a disadvantage when compared with coal or natural gas. However, under favorable circumstances, bagasse,[138] small-scale hydroelectric, geothermal and wind projects can all be competitive. In the case of solar projects, grid-connected facilities typically have large capital costs but relatively low operations and maintenance outlays, thus yielding energy costs at the more competitive end of the range given in Table 7, which also reflects the costs of smaller-scale applications.

136 NESCAUM, *op. cit.*: Attachment B, 11-14.

137 "Three New England nuclear plants set to reopen in 1998," Knight-Ridder/Tribune Business News, January 5, 1998.

138 Bagasse is sugar-cane stalk that has been crushed to extract the juice. Infrequently, the term is also used to refer to other woody agricultural waste.

Table 7 Representative Capital and Operational Costs for Renewable Energy Technologies

Technology	CapitalCost ($/kW)	VariableCosts ($/kWh)	Levelized Energy Cost ($/kWh)
Wind	900	0.009	0.06
Bagasse	900 - 1,500	0.005 - 0.01	0.05 - 0.08
Hydro	1,000 - 4,000	0.01	0.037 - 0.136
Geothermal	1,000 - 4,000	N.A.	0.03 - 0.075
Solar	2,000 - 7,650	0.005 - 0.07	0.25 - 3.00
Coal*	1,300	0.025	0.051
Natural Gas	450	0.02	0.03

*Costs are for pulverized coal with flue-gas desulfurization.

Source: Econergy International Corporation and Battelle, Pacific Northwest Laboratory, 1997.

The greatest challenge that the renewable sector faces as it seeks to expand market share is to incorporate the environmental and efficiency benefits of generation into the market place. Currently the positive features of renewables, such as decreased environmental impacts, reduced exposure to fuel price fluctuations and decreased dependence on imported fuels, are not adequately reflected in the marketplace. While the benefits of renewables are passed on to the general public, the market price does not permit project owners to receive payment for those benefits.

This situation could be changed through further regulation, additional fiscal incentives, increased demand by the public for green power—or a combination of these. Renewables already benefit from some fiscal incentives, such as the investment tax credit (ITC) in some states in the United States. Promising developments in a deregulated electricity sector include portfolio requirements, and "green pricing" programs currently exist at several utilities around the United States.[139] At the same time, further technological developments and cost reductions on the supply side, or an increase in natural gas and coal prices, would make renewables more competitive and stimulate the development of new renewable capacity.

(i) Trends in the Use of Renewable Resources

Many energy analysts do not consider large-scale hydroelectric plants a "renewable" resource. In the sense that construction of such facilities entails the permanent alteration of local ecosystems and the range of other environmental impacts detailed in the discussion of hydropower. Strictly speaking, however, hydroelectric facilities depend on waterways that are renewable in that the plant does not progressively use them up, as is the case with coal or other fossil plants that consume a non-renewable resource. That "broader" definition is used in this study, but the distinction is made between hydro and non-hydro renewables.

United States

In the United States, electricity generating capacity from renewable sources (broadly defined, including hydroelectric and pumped storage) was just under 94,000 MW in 1996, about 12 percent of the total installed capacity. Non-hydroelectric renewable capacity totaled almost 15,400 MW, accounting for just 1.9 percent of the total.[140] Between 1992 and 1994, total renewable capacity grew by 4.7 percent from 89,353 MW to 93,590 MW; in 1994, non-hydro renewable capacity reached its highest level between 1992 and 1996, at almost 15,550 MW. From 1994

[139] See discussion under "Social Organization."

[140] EIA, *Renewable Energy Annual* – 1997, (Washington, DC: DOE, 1997): 12 (Table 7).

to 1996, total renewable capacity grew only slightly, less than 0.5 percent, with growth in hydroelectric and wind capacity offsetting declines in geothermal and biomass, while solar capacity remained unchanged. EIA analyses for future trends suggest that only a limited amount of non-hydro renewable capacity, at most 380 MW, is expected to be installed in the period from 1996 to 2005.[141]

In terms of generation, non-hydro renewable sources of electricity have expanded their role, especially in the industrial sector (including cogenerators, IPPs and small power producers). Among electric utilities, however, non-hydro renewables have declined. In 1996, gross generation in the industrial (non-utility) subsector totaled 94.2 TWH, of which biomass provided 65 percent, hydro 17 percent, and geothermal 11 percent. Wind represented 3.7 of total non-utility generation. Among utilities, the resource mix is far less evenly distributed: hydropower provides 97 percent of total generation, geothermal adding 1.5 percent and biomass 0.5 percent.

In the aggregate, biomass provides the bulk of non-hydro generation by the industrial (non-utility) and utility sectors. It accounted for 75 percent of the 84.7 TWH of non-hydro renewable generation in 1996. Geothermal contributed 19 percent in 1996, with wind accounting for 4 percent. In summary, between 1992 and 1996, production from biomass, wind and solar increased, while geothermal generation declined. Wind and solar increased by at least 20 percent during the period, while geothermal dropped by about 2.5 percent. Hydroelectric production increased by almost 38 percent during the same period (see Table 8).

Recent market reports suggest that non-hydro renewable capacity might grow faster than the EIA predicted in 1996. In California, where marketing activity has increased sharply in anticipation of retail competition beginning 1 January 1998, Edison Source, a division of Edison International Co., will offer EarthSource, an energy product made up of either 50 percent or 100 percent renewably generated electricity. IPPs are also preparing to meet the projected demand. In November, Enron Corp. announced that it will build a 39-MW wind farm in Southern California to provide power for Enron's own branded product, Enron Earth Smart Power.[142] Smaller entities are also getting into the market early. Green Mountain Energy Resources, a Vermont-based company, will also offer a green electricity product.[143]

The marketing claims of these and other entities will be reviewed through the "Green-e" logo program. This program has created a widely used voluntary certification for retail electricity service in California. Green-e guarantees a minimum of 50 percent renewable energy content and a commitment to the rigorous verification of all claims regarding product content. The monitoring process will include the requirement of a signed affidavit, including a corporate code of conduct and disclosure and verification provisions from responsible corporate officers prior to certification. Third-party audits will be provided by financial auditors to provide an on-going scrutiny of activities. CRS will also work with state and regulatory bodies in the development of complementary data and verification of claims.[144]

[141] EIA, *Inventory of Power Plants in the United States* – 1995, (Washington, DC: DOE, 1996): Table 17.

[142] "Enron announces the construction of new wind farm in Riverside County to generate power for California consumers," *Daily Power Report*, 19 November 1997.

[143] "Utility deregulation stokes surge of 'green power' ads," *Daily Power Report*, 19 December 1997.

[144] Karl Rabago, Environmental Defense Fund, personal communication, 14 December 1997.

Table 8 US Generation from Renewable Energy Resources, by Source, 1992-1996

Generation Source	1992	1993	1994	1995	1996	Change (%)
Industrial Sector						
Biomass	53,606.8	55,745.7	57,391.5	56,975.2	62,107.0	15.9
Geothermal	8,577.8	9,748.6	10,122.2	9,911.6	11,014.7	28.4
Hydroelectric	9,446.4	11,510.7	13,226.9	14,773.8	16,711.8	76.9
Solar	746.2	896.7	823.9	824.1	908.1	21.7
Wind	2,916.3	3,052.4	3,481.6	3,185.0	3,507.3	20.3
Utility Sector						
Biomass	2,092.9	1,990.4	1,988.2	1,649.1	1,967.0	-6.0
Geothermal	8,103.8	7,570.9	6,940.6	4,744.8	5,233.9	-35.4
Conventional Hydroelectric	243,736.0	269,098.3	247,070.9	296,377.8	331,935.5	36.2
Solar	3.1	3.8	3.4	3.9	3.1	0.0
Wind	0.3	0.2	0.3	11.0	10.1	3,266.7
Imports and Exports						
Geothermal (Imports)	889.8	877.0	1,172.1	884.9	649.5	-27.0
Conventional Hydroelectric (Imports)	26,948.4	28,558.1	30,478.8	28,823.2	33,359.9	23.8
Conventional Hydroelectric (Exports)	3,254.2	3,938.9	2,806.7	3,059.2	2,336.3	-28.2
Summary						
Biomass	55,699.7	57,736.1	59,379.7	58,624.3	64,074.0	15.0
Geothermal	16,681.6	17,319.5	17,062.8	14,656.4	16,248.6	-2.6
Hydroelectric	253,182.4	280,609.0	260,297.8	311,151.6	348,647.3	37.7
Solar	749.3	900.5	827.3	828.0	911.2	21.6
Wind	2,916.6	3,052.6	3,481.9	3,196.0	3,517.4	20.6
Total Renewables (excluding trade)	329,229.6	359,617.7	341,049.5	388,456.3	433,398.5	31.6
Total Non-Hydro Renewables	76,047.2	79,008.7	80,751.7	77,304.7	84,751.2	11.4

Figures in GWH. *Source: EIA, Renewable Energy Annual 1997, Table 4.*

It is unclear whether demand for the branded energy products will be strong enough to sustain growth in renewable capacity in California and elsewhere, such as Maine, where deregulation measures include provisions for in-state renewable capacity. Actual demand will not be known until after the markets have been permitted to work, but there is evidence to suggest that demand could be substantial. In Massachusetts, 31 percent of residential consumers in a pilot program selected green power supplies.[145] In addition, studies and actual practice in a Michigan community indicate that consumers are willing to pay up to 10 percent more for "green" electricity. Several other states have initiated such programs. As of July 1997, 17 regulated utilities in the United States offered green pricing initiatives to their customers.[146]

Canada

Canada's main strength in the renewable sector, broadly defined, is in hydroelectric power, which accounts for 56 percent of total installed capacity. In 1996, the 1,390 MW in non-hydroelectric renewable capacity accounted for 1.2 percent of the total. Government fiscal restraints on research and development and marginal demand for solar and wind technologies have made it difficult for other renewables to develop in Canada. In addition, the rules governing sales of power to provincial utilities by non-utility generators, many of which use renewable, especially biomass-fired cogeneration configurations to generate electricity, may also have limited the exploitation of renewables in Canada.

[145] EIA, "Status of state electricity utility deregulation activity, as of 31 October 1997," Internet: www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html.

[146] These include: Sacramento Municipal Utility District, Traverse City Light and Power, Public Service Company of Colorado, Gainesville Regional Utilities, Niagara Mohawk Power Corporation, Detroit Edison, Wisconsin Public Service, Wisconsin Electric Power, Northern States Power, Fort Collins Light and Power, Gulf Power, Hawaiian Electric, Holy Cross Electric Association, Aspen Municipal Electric Department, Austin Electric Utility Department, Cooperative Power and Portland General Electric. See "Research Report," Renewable Energy Policy Project, University of Maryland (July 1997).

Environment Canada has established a consumer labeling program titled the "Ecologo." In November 1996, Ontario Hydro was awarded the right to use the logo for its Green Power Purchasing program. Commercial consumers who purchase 25 percent of their power requirements from green power sources may display the logo on their premises, company letterhead, business cards, products and promotional literature. Green power sources are defined as clean renewable energy sources such as solar, wind, biomass, biogas, landfill gas and mini-hydro (run-of-the-river plants of less than 20 MW).

Mexico

In comparison with its NAFTA neighbors, Mexico's development of non-hydroelectric renewable resources is more extensive when considered as a percentage of total installed generating capacity. Even so, renewables play a small role in Mexico's electricity sector. The major areas of opportunity for CFE, and Mexican industry in general, include wind, solar, geothermal and small-scale hydroelectric generation. In 1996, hydroelectric capacity accounted for 28 percent of installed capacity and for 14 percent of production in 1994, while geothermal and windpower, the major non-hydro renewables in use, represented just over 2 percent of total installed capacity and 4 percent of total electricity production (see Appendix F). Solar energy has been used extensively in rural electrification applications in over 60,000 stand-alone units and continues to show promise for the more remote regions of the country.

f. Cogeneration, Demand-Side Management (DSM) and Other Energy-Efficiency Measures

Opportunities for enhancing energy efficiency are substantial throughout North America, but perhaps they are most apparent in Mexico, where there exist numerous opportunities for cogeneration at industrial facilities as well as for the implementation of programs to prevent the waste of electricity, gas and other sources of energy. In absolute terms, however, US cogeneration potential is far larger than that of Mexico and Canada.

In general, the existence of numerous opportunities for energy savings through cogeneration reflects the comparative inefficiencies of the older and poorly maintained equipment and capital stock at many industrial facilities in Mexico. More importantly, however, the regulatory framework has only recently permitted private power generation, whether through cogeneration or other regulatory means. These changes occurred in 1993, and with the peso crisis of 1995-1996, project development activities initiated during 1993-1944 were abandoned or put on hold. In the United States, meanwhile, regulatory reforms undertaken in the 1970s made cogeneration a viable business opportunity. In Canada, regulatory changes were made in some provinces during the 1980s as well as more recently.

A comparison of the three countries' energy-savings performances from DSM and other energy-efficiency programs suggests that Mexico lags behind its NAFTA partners in energy efficiency on the basis of capacity savings relative to peak demand, but exceeds both Canada and the United States in terms of energy savings as a share of total generation. Projections for Mexico's performance suggest a rapid improvement in energy and peak demand saving compared to the United States and Canada, with levels of performance in excess of those projected for the two northern members of NAFTA (see Table 9).[147]

(i) Mexico

Cogeneration. The potential for cogeneration in Mexico reflects the relative newness of the regulations permitting private industry to generate power for sale to the grid. Changes in natural gas regulation have also enhanced the prospects for cogenemeration. Prior to deregulation in 1995, it was impossible to secure a long gas-supply contract, an essential part of assembling a viable cogeneration project for financing by commercial banks or even internally for many companies.

[147] The 3.8 percent energy savings figure also tends to understate performance since the savings figure is for 1994, compared to generation in 1995.

According to research performed by the National Commission for Energy Conservation (*Comisión Nacional para el Ahorro de Energía*, or CONAE), the potential for cogeneration in Mexico is between 7,500 MW and 14,200 MW of new capacity, depending on the assumptions applied in the analysis. Of this potential capacity, CONAE estimates that industrial facilities account for 68 percent, refineries and other gas and petroleum sector facilities operated by *Petróleos Mexicanos* (PEMEX) account for 21 percent, while retail/commercial installations make up the balance.[148]

There are important structural and macroeconomic considerations that have impeded the development of cogeneration in Mexico. Even with the possibility of private investment under the new electricity-sector regulation, there are relatively few successful cases of cogeneration projects in Mexico with contracts to sell power to CFE. According to Mexican and US project developers, this reflects the difficulties involved in negotiating a sales contract with CFE; attractive prices on wheeling contracts are reported to be similarly difficult to arrange.

Table 9 Comparative Impact of Energy Efficiency Programs in North America

	Estimated Savings							
	1995 Total	1995 (%)	2000[1] Total	2000[1] (%)	2005[1] Total	2005[1] (%)	2010[1] Total	2010[1] (%)
Capacity (MW)								
Canada	4,942	5.7	5,708	5.9	-	-	6,617	6.0
United States*	29,561	4,8	36,425	5.5	-	-	-	-
Mexico	732	3.0	1,939	6.5	2,536	6.6	-	-
Energy (GWH)								
Canada	4,611	0.9	12,247	2.2	-	-	17,528	2.8
United States*	57,421	1.7	71,800	2.0	-	-	-	-
Mexico**	5,485	3.8	7,920	4.6	9,939	4.4	-	-

	Demand and Generation			
	1995 Total	2000 Total	2005 Total	2010 Total
Peak Demand (GW)				
Canada	87,220	96,044	102,382	110,838
United States***	616,790	665,526	724,308	-
Mexico	24,465	29,729	38,136	-
Generation (GWH)				
Canada	534,869	567,070	592,200	623,911
United States	3,351,093	3,556,242	3,893,844	-
Mexico	143,776	173,004	225,474	-

[1] Estimates.
* Estimates for 2000 from EIA, "US Electric Utility Demand-Side Management: Trends and Analysis."
** Energy savings figure is from 1994, FIDE, Memorias , 1990-1994.
*** Peak demand is for 1996 (summer).
Sources: CFE, Documento de Prospectiva *and* FIDE, *Memorias* , 1990-1994. CEA, *Electric Power in Canada, 1995* NERC, *Internet: www.nerc.com, and* EIA.

Furthermore, although they have increased to make up for inflation during 1995-1996, the tariffs charged by CFE for industrial power remain below the long-run marginal cost of production. These rates leave very little, if any, margin when compared to the effective cost of generation often associated with cogeneration projects. Since the peso devaluation in December 1994, these considerations have frequently made it difficult for project proponents to convince industrialists to invest in cogeneration facilities.

[148] CONAE (1995), *Potencial Nacional de Cogeneración* – 1995 (SE: Mexico City): 13-16.

Demand-Side Management. Other energy efficiency opportunities are extensive in Mexico. In this area CONAE, together with the Trust for Energy Efficiency (*Fideicomiso para el Ahorro de Energía*, or FIDE), which is funded in part by the CFE, has made important progress toward raising the consciousness of industrial managers about the economic benefits of energy-efficiency projects. The energy savings have been substantial. FIDE estimates that between 1990 and 1994 its programs have resulted in annual electricity savings equivalent to over 3 percent of total consumption, with total savings in 1994 equivalent to about 5,485 GWH.[149]

(ii) United States

Cogeneration. Cogeneration projects played an important role in the emergence of IPPs in the United States after the regulatory changes contained in the Public Utilities Regulatory Policies Act (PURPA) of 1978. Under PURPA, IOUs are required to purchase power from generators exempted from FERC regulation, at the IOUs' own avoided cost of power, leading to the rapid growth of generation by the so-called "qualifying facilities" (QFs), as the exempted IPPs are known. The taxonomy of non-utility generators (NUGs) in the United States is complex, but may be summarized as follows:

- Under the heading of PURPA QFs, there are cogenerators and small power producers, which must be based primarily on renewable resources.
- As a result of the Energy Policy Act, a new class of NUG was created, known as exempt wholesale generators (EWGs), which include producers affiliated with an IOU (or APPs, for affiliated power producers) and independent power producers (IPPs).[150]

By the mid-1980s, when petroleum prices dropped to levels near or below those recorded prior to the oil shocks, a substantial amount of cogeneration capacity had been built. At present, non-utility capacity in the United States, of which 66 percent is provided by cogeneration qualifying facilities, totals 68,460 MW, or roughly 9 percent of total installed capacity. In 1996, non-utility producers accounted for almost 12 percent of the country's net generation.[151] Natural gas is the fuel of choice, accounting for 41 percent of capacity, followed by oil or oil/gas facilities (18 percent), wood waste (15 percent), coal (15 percent), and other renewable resources (12 percent).[152]

Since 1986, cogeneration has not been as attractive an investment as it was during the period following the oil-shocks. However, some new capacity has been built and will continue to be built. In two recent announcements, Occidental Energy Ventures and Conoco Global Power announced the completion of financing for a 440-MW gas-fired cogeneration facility at a site in Texas next to two chemical plants owned by the parent companies of each developer, OxyChem and DuPont; and Rolls-Royce announced that it had won a C$7-million contract to build a 29-MW gas-fired cogeneration facility at London Health Sciences Centre, a hospital located in London, Ontario.[153]

Demand-Side Management. Since the early 1980s, utility demand-side management activities in the United States have led to substantial savings in terms of energy and capacity. The primary impetus for such programs came from federal legislation in the mid-1970s and state regulatory bodies, which increasingly favored DSM for the expansion of generation capacity for environmental as well as economic reasons. They were therefore willing to permit utilities to recoup DSM investment costs just as they had permitted utilities to recoup investments in other capital plant and equipment. For 1995, the EIA reports energy savings at 583 large utilities of 57,420 GWH, with capacity reductions of about 29,560 MW.[154] Given that these figures are for a subset of the total utility and generator population of the country, they will tend to underestimate total energy and capacity savings.

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[149] FIDE (1995), *Memorias* – 1990-1994 (FIDE: Mexico City): 61.

[150] CFE and Salt River Project, et al., *op. cit.*: 13.

[151] US Department of Energy (1997), *Monthly Energy Review* (October): 94.

[152] *Ibid.*, 13.

[153] "Power units of Occidental and Conoco to build Texas cogeneration facility," *Daily Power Report*, 9 January 1998, and "Rolls-Royce wins C$7 million hospital cogeneration project," *Daily Power Report*, 7 January 1998.

[154] EIA (1996), Electric Operating and Financial Data Branch, "US electric utility demand-side management 1995" (Washington, DC: DOE): 4. Internet: www.eia.doe.gov/cneaf/electricity/pub_summaries/dsm_sum.html.

Based on EIA data derived from utility surveys, energy savings and peak-load reductions increased from 1993 to 1994, but at a slower rate than in previous years. More importantly, utility expenditures on DSM programs decreased roughly 1 percent, to US$2.72 billion from the US$2.74 billion recorded in 1993, the first decline observed by the EIA since it began collecting such data.[155] Another measurement of the effect of DSM programs, potential peak-load reductions,[156] declined in 1994 relative to 1993, which may reflect changes in reporting practices for utilities, reductions of some DSM activities that are no longer cost-effective or that cause negative rate impacts, and changes in DSM activity away from rebate and other financial incentives. After accounting for reporting changes for utilities, the EIA reports that the figures for potential peak-load reductions in 1995 represents a decline relative to 1994. However, survey responses do not provide conclusive evidence that competition is necessarily behind this change.

For the period following 1995, EIA analyses suggest that spending on DSM will decline at a slower rate than the energy savings and peak-load effects of the programs. Indeed, DSM costs in 1995 appear to have declined only slightly compared to 1994. In addition, evaluations of DSM performance indicate that utility programs have become increasingly efficient, driving the cost of savings per kWH as low as 2 cents per kWH in some instances.

The key uncertainty with respect to DSM programs is whether restructuring will render DSM and energy-efficiency programs more or less attractive. A detailed discussion of this issue is beyond the scope of this study, but the following are general observations:

- Problems associated with energy-efficiency programs have been understood for several years, reflecting data on such programs in numerous industrial markets. In general, market failures are apparent due to the incomplete information available to consumers, limited incentives for landlords to make energy efficient investments when their tenants pay the electricity bills, and losses in efficiency when key decisions are not taken into account prior to construction.[157] These problems are not likely to change as a result of electricity restructuring, but rather as a result of incentive programs, technical improvements in appliance efficiency (driven by government or corporate policies), and other market trends.
- In general, regulators who want DSM investment to continue must establish appropriate cost-recovery mechanisms and financial incentives for a restructured utility industry where the regulated monopoly is no longer responsible for meeting domestic generation needs. Promising options include so-called "system benefits charges," which are non-bypassable charges on distribution services that underwrite system-wide investments in cost-effective energy-efficiency improvements.
- Lower electricity prices will reduce the number of DSM programs that are cost-effective, and recent downward trends in prices may explain declining DSM activity in the United States. Projections of electricity prices in the United States in restructured markets do suggest that prices will decline in the near to medium term.[158] In the medium term, as well, capacity additions are expected to be relatively limited, reflecting surplus capacity situations in regional markets. However, continued demand growth, encouraged by lower prices, will inevitably lead to capacity shortages, thereby necessitating investment in new generation facilities and upgrades in transmission and distribution systems. In a restructured sector,

[155] EIA (1996), Electric Operating and Financial Data Branch, "US electric utility demand-side management: trends and analysis" (Washington, DC: DOE): 4. Internet: www.eia.doe.gov/cneaf/pubs_html/feat_dsm/contents.html.

[156] Potential peak-load reductions measure forecast reductions based on projections as opposed to peak load reductions based on annual operating data.

[157] EIA (1995), "US Electric Utility Demand-side Management": 10. Also, Swisher, Joel (1996), "Regulatory and mixed policy options for reducing energy use and carbon emissions," *Mitigation and Adaptation Strategies for Global Change* 1 (Belgium: Kluwer): 26-27.

[158] See EIA (1997), "Electricity prices in a competitive environment" (Washington, DC: DOE): 26-31.

however, price signals will have to be sufficient to ensure investors a reasonable return at variable and uncertain market prices. Under these circumstances, as well as in the case of sudden increases in fuel prices, targeted DSM (especially in view of the low per-kWH costs associated with current programs) and distributed resources investments can provide substantial benefits.[159] Thus, the decline in DSM may be cyclical rather than permanent.

- Trends in electricity pricing toward rates based on marginal costs will tend to reduce the negative revenue impacts associated with DSM programs implemented under regulation. Recent analyses have confirmed that changes in rate designs have reduced the revenue losses experienced by utilities as a result of DSM programs. This suggests that the more efficient rate structures that utilities will be forced to adopt as competition increases are likely to reduce the disincentives associated with DSM programs, and could even become a source of competitive advantage for utilities, since in some instances changed rate designs yielded lower average costs of DSM programs over the life of those measures.[160] The extent to which this effect will occur in a restructured sector is unclear.
- As the utility sector restructures, companies may find that packaging energy services, including efficiency measures, provides a competitive edge. Such services may include more traditional energy efficiency measures but could also include more state-of-the-art strategies, such as the use of advanced metering systems to offer more sensitive time-of-use and real-time pricing to consumers, interactive load management programs and details about energy-information services with recommendations of DSM strategies to enhance efficiency.[161]
- Regulators in states embarking on deregulation have included provisions for set-asides to support energy-efficiency programs. In addition, utilities in various parts of the United States have formed consortia to support energy-efficiency programs directed at creating sustainable markets for energy-efficient products. In the aggregate, such programs may reduce the cost of long-term energy savings as well.[162]

(iii) Canada

Cogeneration. In Canada, cogeneration provides about 30 percent of total non-utility capacity, which stood at about 8,714 MW in 1995, or 7.5 percent of total installed capacity. In 1995, NUGs produced over 58,500 GWH of electricity, but a relatively small part of this (19 percent) was sold to utilities.[163] In Canada, NUGs are made up of industrial generators (located in the Yukon Territory and all provinces but Prince Edward Island), minor utilities (located in Newfoundland, New Brunswick, Quebec, Ontario and British Columbia), and IPPs (located in all provinces but Manitoba, Prince Edward Island and Newfoundland; neither are they found in the Yukon or the Northwest territories).[164] Industrial generators are by far the most important group, accounting for 75 percent of capacity and 73 percent of total generation.

The prices at which NUGs may sell power to provincial utilities vary dramatically from province to province, depending on the regulatory arrangements in place. In the case of Ontario, which accounts for 70 percent of total purchases from NUGs, pricing for renewable or high-efficiency resources is negotiated in the case of projects supplying over 5 MW, while smaller projects receive prices of between 6.5 and 7.3 cents (C$) per kWH for summer and winter peak generation. Off-peak pricing is between 1.9 and 3 cents (C$) per kWH. Other pricing mechanisms are available under long-term contracts that provide slightly less favorable prices than for renewable or high-efficiency resources.[165]

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159 EIA (1995), "US electric utility demand-side management": 11. Also, Swisher, Joel and Ren Orans (1995), "The use of area-specific utility costs to target intensive DSM campaigns," *Utilities Policy 5*, number 3-4 (UK: Elsevier, 1996): 185.

160 EIA (1995), "US electric utility demand-side management": 13.

161 *Ibid.*, 4-15.

162 *Ibid.*, 4.

163 CEA, "Electric Power in Canada: 1995," 143.

164 *Ibid.*, 146-147.

165 *Ibid.*, 168-170.

Other provincial utilities, such as Hydro-Québec and BC Hydro, offer attractive pricing and contractual arrangements, depending on their need for external capacity. For the most part, pricing is calculated using avoided-cost principles, thereby providing the utilities with added resources at or below the cost of future generation by their own facilities.

In the future, Canadian utilities anticipate some increase in energy purchases from NUGs. The amount of NUG generation is relatively small, particularly compared to NUGs in the United States. But there appears to be a greater willingness on the part of electricity planners to incorporate NUG generation into long-range expansion plans, especially where NUG capacity would be provided by renewable resources, waste-to-energy plants, or using technologies more efficient than the average for the utility's resource base.[166]

According to industry projections presented by the CEA, capacity provided by minor utilities and IPPs (not including industrial generators) is expected to grow by 43 percent between 1995 and 2000, and an additional 8 percent between 2000 and 2010, with the majority of the growth (66 percent) during the latter period occurring in hydro installations (primarily small-scale) and cogeneration (22 percent). The remainder would be made up of non-cogenerating thermal capacity (6 percent) and non-hydro renewable capacity (5 percent). Generation by minor utilities and IPPs would increase correspondingly, with growth between 1995 and 2000 estimated at 39 percent to 21,380 GWH, or 3.7 percent of the total forecast. Generation from these two classes of producers is expected to increase another 8.3 percent between 2000 and 2010, providing the same share of total generation.[167]

Demand-Side Management. DSM activities in Canada have for decades been well-known to utilities and industrial consumers in the form of interruptible rates and research into lighting efficiency. Canadian utilities have increased activities in this area since the 1980s. A range of utility programs and partnerships with the federal authorities have developed. In 1995, estimated savings in capacity were equivalent to 4,942 MW, roughly 4 percent of total installed capacity and 5.7 of total peak demand.

Hydro-Québec was the leader in capacity savings, reporting 2,940 MW in peak load reductions in 1995, followed by Ontario Hydro with 771 MW, and Alberta with 466 MW.[168] The savings represent 9 percent of peak demand in Quebec, 3.3 percent in Ontario, and 4.4 percent in British Columbia.[169] In the future, Canadian utilities expect that capacity interruptible load initiatives will provide most of the capacity savings, followed by load shifting programs, such as Hydro-Québec's dual-energy program in which customers switch from electricity to another source during peak-load periods.[170] By 1994, total spending on DSM programs in Canada totaled C$344 million, with Ontario Hydro accounting for C$163 million of the total, followed by Hydro-Québec with C$113 million, and BC Hydro with C$50 million.[171]

Hydro-Québec's program has achieved significant results compared to other provincial utilities with higher unit costs of electricity (the average price per kWH for all customer classes in Quebec was 3.6 US cents per kWH, compared to 5.6 US cents/kWH in Ontario and 3.8 US cents/kWH in British Columbia[172]), and with lower outlays. However, this success in Quebec does not call into question the assertion that lower electricity prices necessarily lead to reduced gains in energy efficiency, since Quebec's unusually high dependence on electricity for energy (at 41 percent, it is more than twice the national average in Canada[173]) opens up far more opportunities for savings than in other jurisdictions. Indeed,

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[166] *Ibid.*, 145.

[167] *Ibid.*, 149.

[168] *Ibid.*, 149.

[169] *Ibid.*, 52.

[170] *Ibid.*, 137.

[171] *Ibid.*, 138.

[172] Hydro-Québec (1997), *Plan Strategique 1998-2002* (Montreal: HQ): 14.

[173] Anthony DePalma, "Storm exposes Quebec's 'power' politics," *New York Times*, 15 January 1998.

Hydro-Québec's efforts have focused on load shifting and load building more than on end-use efficiency improvements, but they are testament to the power of economic incentives and sweeping standards programs[174] to induce changes in customer-load patterns, even with relatively low prices for basic service.

As part of its nuclear-replacement program, Ontario Hydro will increase its DSM activities. A recent RFP calls for bids from within and without Ontario for end-use efficiency improvements as well as replacement power.

B. Physical Infrastructure

Physical infrastructure, with the attendant environmental impacts, is an important limiting factor in determining the potential impact of restructuring on electricity markets in North America,. Most broadly, the potential trade in electricity created by the confluence of NAFTA's overall competitiveness and procurement provisions with restructuring has been inhibited in the short term by major constraints on interties and transmission capacity. However, there are signs that these constraints will be overcome in the medium term, with very little if any additional stress on the natural environment.

Physical infrastructure limits and shapes the international trade that flows from NAFTA liberalization in several ways. At a micro level, it affects how widely throughout the NAFTA region the electricity generated by alternative technologies and fuel sources can be distributed and sold. Evidence of the impact of NAFTA-associated trade comes from patterns of and pressures for new transmission capacity and corridors that are evident on a transborder basis and in the domestic lines that feed transborder systems, as well as in those operated for purely domestic purposes. New electricity generation infrastructure seems to be clustering in states adjacent to the border, especially along Mexico's northern frontier and in Texas. In the case of electricity transmission, despite unused capacity and technological improvements to existing lines, some increase in transmission capacity is needed, and planned, between the United States and both Mexico and Canada in the medium term. There are also many new projects, often involving joint ventures among US, Mexican and Canadian firms, for new transborder gas transmission and distribution systems, in part to fuel electricity-generation plants.

1. Electricity

Infrastructure growth in the electricity sector in North America will occur in the areas of generation, transmission and distribution. In the case of generation infrastructure, there appears to be a pronounced geographical distribution pattern that coincides reasonably well with the pattern of demand and consumption growth on a continent-wide basis. New generation capacity, which has more favorable environmental impacts than existing sources, appears to be taking place in locations where it will relieve environmental stress.

a. Generation

Growth in total generation capacity is expected to occur most rapidly in Mexico, followed by the United States and then Canada. In Mexico, the CFE plans to add over 13,000 MW of new capacity between 1998 and 2005, equivalent to a 35 percent rise relative to its installed capacity of 33,037 MW as of early 1996.[175] In the United States, by 2005, net winter capacity is expected to have increased by 6.1 percent, or 44,585 MW, over the 1996 figure of 719,897 MW.[176] In Canada, installed generating capacity in 2005 is expected to total 120,622 MW, up 4.2 percent from the 115,781 MW recorded in 1996.[177] In general, the distribution of new investment in generation capacity shows substantial growth in northern Mexico, the southeastern and central United States, and, in Canada, in the Atlantic provinces, Quebec, British Columbia and the Northwest Territories.

174 Hydro-Québec, *op. cit.*: 16.

175 See SE, *Documento de Prospectiva del Sector Eléctrico*: 28.

176 Net winter capability is larger than net summer capability, both are lower than nameplate capacity. See EIA, I*nventory of Power Plants in the United States – 1995,* Table 17.

177 CEA, *Electric Power in Canada*: 1995: 124.

In Mexico, 60 percent of new capacity is planned for the northern part of the country, primarily in the states of Tamaulipas, Nuevo León, Chihuahua and Baja California Norte. Other regions where capacity expansion is expected include states across the central region of the country (Durango, Michoacán, Querétaro, Nayarit and Veracruz) and the southeastern states of Tabasco, Campeche and Yucatán (see Appendix F). In Canada, the areas showing the most rapid increases in generating capacity through 2005 include British Columbia, Nova Scotia, the Northwest Territories, and Prince Edward Island. With the addition of another 2,616 MW of hydroelectric capacity by 2010, Quebec will also experience double-digit growth relative to 1996 (see Appendix F). In the United States, the results of an EIA survey of US utilities suggests that large increments in generating capacity ("lumps" of over 1,000 MW, equivalent to 2 percent of the total projected capacity expansion through 2005) will occur in the following states: Alabama, Florida, Georgia, Virginia and the Carolinas in the southeast; Wisconsin, Illinois, Missouri, Tennessee, Kentucky and Ohio in the Ohio-Mississippi Valley region; Maryland and New Jersey in the mid-Atlantic region; and Texas, which could account for as much as 14 percent of new capacity additions (see Appendix F).

b. Transmission

Investment in domestic transmission capacity is likely to become an important part of overall utility capital expansion programs in the United States and Canada as restructuring occurs and utilities as well as independent producers of electricity compete for markets beyond their regulated service territories. Mexican investment in transmission capacity is similarly important, though more from the perspective of guaranteeing system reliability and power quality, accommodating the increase in capacity, and reducing the cost of operating the interconnected system.

(i) Mexico

In Mexico, according to the *Documento de Prospectiva* for 1996, the national system included over 69,800 km of transmission lines at 69 kV to 400 kV and substations with a capacity of 132,000 MVA. Planned capacity expansions would add almost 14,500 km of new lines between 69 and 400 kV, and another 27,900 MVA in substation capacity, equivalent to growth of 20 percent and 21 percent, respectively.[178]

(ii) United States

In the United States, there is a total of over 250,000 circuit-miles (400,000 km) of transmission lines in the 69 kV to 765 kV range. Data showing the total planned increase in transmission lines between 1996 and 2005 are not limited to the US segments alone, since the data are gathered by the NERC regions, which incorporate much of Canada and the small part of the Mexican system in Baja California that is part of the WSCC. At this level, however, some estimates show an additional 10,120 circuit-miles (16,200 km) of new transmission capacity being installed through 2004. By comparison, Canada's transmission network comprised over 157,000 circuit-km in 1995.

Investment in transmission infrastructure in the United States is planned to meet NERC reliability criteria. Under FERC orders 888 and 889, transmission providers must offer "available transfer capability" (ATC) to power producers, thereby increasing the demand for greater capability in the transmission system. Transmission operators must meet existing obligations and provide new capability to transfer other producers' power through the transmission system. This has set new standards for system reliability and capability.

It is likely that US utilities will embark on substantial investment in transmission capacity as they prepare for and adapt to the restructuring at both the state level and in Canada. Investment may take the form of line upgrades to increase transfer capacity, new metering systems to facilitate billing for increased sales outside a given service territory, or entirely new transmission lines. The latter category may be complicated by requirements for permits and opposition to the lines in the communities where they are expected to be located. One example of how restructuring will encourage

[178] See SE, *Documento de Prospectiva del Sector Eléctrico*: 35, 59.

investment in this area is provided by the announcement from eleven investor-owned utilities (IOUs) in the upper Ohio River valley that they will create an independent regional transmission entity.[179] Representing a collective investment in transmission capacity of roughly US$6 billion, the objectives of member utilities are to eliminate the pancaking[180] of rates within and between transmission entities and to achieve efficiencies of scale in transmission.[181]

Recent transmission investments will meet the short-term increases in transmission demand in the NERC regions. In ECAR, the anticipated completion of the 765-kV American Electric Power Wyoming-Cloverdale transmission project in 2001 will substantially increase the capacity in this region and reduce transmission constraints from the midwest to the east coast. The line will also reduce transmission constraints from MAIN to the east coast. Transmission in ERCOT is moving to an Independent System Operator (ISO), but no new transmission line projects are under consideration as the current system will meet short-term future demand. In MACC, a new 500–230-kV substation was to come on line in 1997 to reinforce supply in the region's eastern area. Otherwise no new transmission line projects are scheduled. The MAIN transmission system will meet short-term future demand. The 345-kV Burnham-Taylor line in downtown Chicago, finished in 1996, will increase reliability in that area.

The MAPP region has added several transmission lines in order to meet future demand. A 120-mile conversion from 115 kV to 161 kV will strengthen the interface between MAPP and MAIN. Another interface between MAPP and MAIN, in Iowa, is planned to be ready in 1998. In Nebraska, a new 345-kV line will relieve stability constraints in that area. In MAPP Canada, 485 miles of new 230-kV line will be added. In the NPCC, 160 miles of over-230-kV line will be built in the United States and 330 miles of 230-kV line will be built in Canada to meet the NERC transmission criteria. In the SERC region, projects building 1,476 miles of 230-kV lines and 367 miles of 500-kV lines between 1996 and 2005 will meet NERC reliability requirements.

In the SPP, no substantial transmission lines will be constructed in the next ten years, as only small local upgrades are needed to meet NERC transmission requirements. In 1995, an intertie to ERCOT went into service, allowing 820 MW of transfer capability between the two regions. In the WSCC, several new transmission lines will strengthen the system's transfer capability. In the WSCC's Northwest Power Pool Area, local voltage-collapse problems exist in the Puget Sound area but have been repaired with undervoltage load relays. Otherwise, no large transmission projects are necessary to meet NERC reliability criteria. In the WSCC-Canada area, the transmission system is operated by a Transmission Administrator but is still a regulated monopoly. The system will meet NERC criteria and has no new projects planned. In the Rocky Mountain Power Area, intra-regional lines are planned, such as the 230-kV Yellow Creek-Osage line, but no inter-regional lines that will increase transfer capabilities are planned in the next ten years.

In the Arizona-New Mexico Power Area, projects are planned to increase bulk electricity transfer capability. Three lines of 500 kV are in different stages of development: a line from Phoenix to Las Vegas; an interconnection in north-central Arizona; and a line from Las Vegas to the Four Corners area. In the California-Southern Nevada Power Area, two lines have increased bulk electric transfer capability and strengthened reliability. The 500-kV Mead-Adelanto line and an additional 500-kV line between Las Vegas and Los Angeles have increased intra-regional ties. No other major lines are scheduled as the current system is anticipated to meet future increased demand.

In general, there appears to be little additional environmental stress arising from the need to construct new electricity transmission lines from new corridors in the United States.

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179 The utilities involved are: Consumers Energy, Detroit Edison, Duquesne Light Co., The Illuminating Company, Ohio Edison Co., Pennsylvania Power Co., Toledo Edison Co., Virginia Power, Allegheny Power / Monongahela Power Co., The Potomac Edison Co., and the West Penn Power Co., with combined service territories covering 108,500 square miles of southern Michigan, northern and central Ohio, western Pennsylvania, West Virginia, Maryland and Virginia. The group has combined sales of 259 TWH and some 30,000 miles of transmission lines.

180 Pancaking refers to the levying of several transmission tariffs for one transaction that crosses several different service territories.

181 "Electric companies explore creation of independent regional transmission entity," *Daily Power Report*, 10 December 1997.

(iii) Canada

In Canada's transmission system, north-south (international) links are more extensive than east-west (inter-provincial) links. Whereas inter-provincial transmission capacity totals about 10,145 MW, total US-Canada transmission capacity is almost twice that, at 18,900 MW. Further, just over half of the inter-provincial total is located between Quebec and Newfoundland, handling power from the Churchill Falls complex. As of late 1995, only one new inter-provincial connection was planned, for a 44-km link between Alberta and British Columbia.[182]

(iv) United States-Mexico and United States-Canada Interconnections

With respect to cross-border trade in electricity, the number of US-Mexican interconnections is smaller than the number of links between the United States and Canada, and the average capacity of the US-Canadian lines is greater. Based on a general assessment of the relative levels of line loading for the United States-Canada interconnections and United States-Mexico interconnections, in aggregate terms, it appears that the level of capacity utilization is relatively high, but by no means at the economic ratings for the interconnections.[183] For example, US-Canada interconnections have a design capacity of almost 19,000 MW,[184] which suggests an aggregate average line loading of 32 percent for total two-way transactions of about 52,700 GWH in 1996. US-Mexican transfer capability is about 900 MW,[185] which suggests an aggregate average line loading of 33 percent for total two-way transactions of about 2,580 GWH the same year. Transfer volumes could be increased to yield capacity utilization levels of between 40 and 45 percent without requiring any increase in capacity. Assuming that transfer capability has not changed in the last three years, earlier transfer volumes registered between the United States and Mexico, such as the 3,411 GWH in exchanges recorded in 1995, would have implied capacity utilization factors of between 39 and 43 percent.

Based on expectations of increasing cross-border exchanges, some augmentation in transmission capacity between the United States and both Mexico and Canada is necessary in the near to medium term (three to five years into the future). Depending on the extent to which actual line loading factors vary from one interconnection to another (some corridors may be registering factors much closer to 50 percent at present), the capacity enhancements may be necessary even more quickly. Indeed, it appears that some expansion in transmission capacity is planned on both the United States-Mexico and United States-Canada borders.

In the case of the Mexican-US links, several different paths are under consideration by CFE and its counterpart utilities in California, Arizona and Texas, but it is unclear at this stage which lines are likely to be built. For example, according to officials at San Diego Gas & Electric, the company is considering upgrading its interconnections with CFE along the San Diego-Tijuana stretch of the border, but it has not made the firm decision to do so. The SDG&E transmission line upgrades, if undertaken, would double the 408-MW transfer capability currently in place.[186] In many instances, the transfer capability immediately at the border is limited by interconnections leading up to the border, especially on the US side, where border utilities have to interconnect with systems further inside the United States. Thus, upgrading the border interconnections requires further investments elsewhere in the vicinity in order to permit using the extra cross-border capacity.

In the case of US-Canadian ties, one planned interconnection between New Brunswick and Maine is in the planning phase. The proposed 345-kV line would have an estimated transfer capability of 600 MW and would be completed in 1998.[187]

[182] *Ibid.*, 92-99.

[183] The economic capacity of a transmission line will be less than its design, or thermal, capacity, since increases in the current going through a line generate rapidly increasing losses, and hence rapidly diminishing economic returns. Generally, economic capacity is roughly 50 percent of design capacity.

[184] CEA, *Electric Power in Canada*: 97.

[185] CFE and Salt River Project, *op. cit.*: 66.

[186] Remarks of S. Ali Yari, Supervisor of Transmission Planning, SDG&E, "Unleashing the Potential," 24 October 1997.

[187] CEA, *Electric Power in Canada*: 93.

It thus appears that NAFTA-associated growth in cross-border trade in electricity is generating a need for new cross-border transmission lines and corridors. However, the extent and location of such corridors, as well as their immediate environmental impacts, are thus far largely unknown.

2. Natural Gas

As discussed in the context of trends in investment, there is a notable movement in the electricity sector in each country toward the use of natural-gas-fired generation technologies, with a corresponding reduction in the use of petroleum-based fuels and their associated emissions. While this trend does not imply large retirements of coal-fired capacity in the United States or Mexico (where coal-fired capacity is relatively limited) it could mean that some coal-fired capacity in Canada will be retired. Complementing this trend toward more use of natural gas is new investment in gas transmission and distribution infrastructures, particularly in Mexico, through projects that are either in progress or in the planning stage. Such transmission has a variety of site-specific impacts on land and water along its routes but promises broader environmental gains as it displaces dirtier fuels in more distant markets.

a. Canada

An important new gas-related project in Canada involves the development of the Sable Island offshore gas fields in Newfoundland and the transportation of the new production to markets in Quebec, Ontario and the New England states. The total volume of gas delivered to market depends on the pipeline option that is finally built, with the larger of the two lines promising to handle 600 BCF annually for 20 years.[188] Currently, four major pipeline projects are being reviewed by the National Energy Board. These pipelines are primarily being built to service export markets.

Sable Island and the Maritime 7 Northeast Pipeline Project. The Sable Island Offshore Energy Project and its associated Maritime and Northeast Pipeline Project (M&NPP) were approved by the NEB in December 1997. The projects, which will result in the first commercial gas production in Atlantic Canada, will produce 459 MCF per day. The gas will be processed on shore and then shipped 558 km to the US border, through a 76.2 cm pipeline. The Sable Island Offshore Energy Project is a consortium consisting of Mobil Oil Canada Properties Limited, Imperial Oil Resources and Nova Scotia Resources Limited. The consortium intends to develop six offshore fields that have a recoverable gas reserve of 2.978 TCF. Gas will be delivered through a submarine pipeline to onshore facilities and piped 208 km to a gas-processing plant at Goldboro, Nova Scotia.

Environmental concerns associated with this pipeline include the impact of 260 watercourse crossings and their potential impact on fish and fish habitat. There are also concerns about the exposure of acid-generating rock as a result of blasting and excavation. As part of the approval decision, the NEB recommended that the proponents mitigate potential impacts on watercrossings, acid-generating rock and construction techniques.

Trans-Quebec and Trans Maritime Pipeline Project. Trans-Quebec and Maritime Pipeline Inc. (TQM) has proposed an alternative pipeline and route to deliver the Sable Island gas for use in Quebec and the US northeast. Under this proposal, Trans Maritime Gas Transmission (TMGT) would construct a 642-km pipeline from the on-shore facilities, through Nova Scotia and New Brunswick, where it would connect with TQM facilities at the New Brunswick-Quebec border.

[188] The competing routes are being advanced by North Atlantic Pipeline Partners (NAPP), which would carry 12 TCF over 20 years, and the Maritimes and Northeast (M&NE) route, which would carry approximately 3 TCF over the same period. The Joint Public Review Panel for the Sable Gas Project recently approved the M&NE proposal, but this ruling has been challenged in the Federal Court of Canada by NAPP. Canada Newswire, 25 November 1997. Internet: www.powermarketers.com.

On 26 June 1997, TQM applied to the NEB for approval to construct a natural gas pipeline from Saint-Nicolas, Quebec, to the New Brunswick border. The TMGT facilities and the TQM pipeline extension form the TransMaritime Pipeline Project. TQM also applied for approval to construct a 213.2-kilometre pipeline to move gas to the Canada-United States border near East Hereford, Quebec. The TMGT pipeline is expected to cost US$629 million and is expected to be in service by November 1999. The estimated cost of the TQM portion from New Brunswick to Quebec is C$305.3 million and it is also planned to be in service by November 1999. The portion from TQM's interconnect to the US border is estimated to cost C$270 million and is expected to be in service by November 1998.

Alliance Pipeline Project. The Alliance Pipeline Project is a proposal to move 1.06 MCF per day of gas from British Columbia and Alberta to markets in the Chicago area. The Canadian portion of the project consists of approximately 1,565 km of pipeline and related facilities. The US portion, which is to be constructed by Alliance Pipeline L.P., includes approximately 1,430 km of pipeline from the border to Chicago, Illinois. The capital cost of the Canadian portion of the project is estimated at C$1.9 billion. The pipeline is expected to be in service by late 1999.

TransVoyageur Natural Gas Pipeline Project. TransCanada Pipelines Limited has applied to the NEB to expand its system of gas transportation facilities across Canada. The expansion is known as the TransVoyageur Natural Gas Pipeline Project. The project consists of a 1,000-km pipeline from Empress, Alberta, to Emerson, Manitoba. The TransVoyageur system would parallel TransCanada's existing system from Empress to either Brandon or Portage La Prairie, Manitoba. The company is examining two potential routes for the pipeline, one of which may require a comprehensive study under the Canadian Environmental Assessment Act. The project would increase existing west-to-east pipeline capacity by up to 2 TCF per day. The project has a planned in-service date of 1 November 1999.

b. Mexico

The Energy Regulatory Commission of Mexico (CRE) has administered the issuance of permits to private sector gas transmission and distribution companies to serve specific cities and regions throughout the country since 1995. Concessions have been granted for Mexicali, Chihuahua, Hermosillo and Toluca. In 1997, the CRE issued tenders for nine more zones. In November 1997, the CRE launched the bidding process for the permit to provide service to each of two regions in Mexico City. The *Secretaría de Energía* estimates that for the next five years, private business investment in gas distribution could reach US$1.4 billion, with Mexico City and the Bajío Region (León, Salamanca, Celaya and Irapuato) being the largest markets.

In addition, private entities may construct pipelines to carry gas over longer distances to serve specific needs, as opposed to the regional concessions issued by the CRE. The first such permit is to build a 24-inch gas line between Alemán City and Monterrey Nuevo León (148 km) to help meet future demand for gas in Monterrey. Other pipeline projects that may be undertaken in the short and medium terms are Cd. PEMEX-Mérida, Mérida-Valladolid, San Agustín-Valdivia-Samalayuca-Chihuahua, Palmillas-Toluca, and Hermosillo-Guaymas.

Private participation in transmission and distribution is now possible, although PEMEX remains the sole producer of natural gas and is expected to concentrate its efforts on expanding dry gas supplies. One such project is the intensive exploration and subsequent drilling of and production from the Burgos Basin. Located across the Río Grande-Río Bravo from the Texas District 4, in the states of Tamaulipas and Nuevo León, Burgos currently produces 450 MCF per day, but PEMEX believes the field can increase output to 2,200 MCF per day by 2001. PEMEX is also planning to construct industrial plants for processing wet gas, sweetening sour gas (i.e., desulfurizing high-sulfur material) and recovering the sulfur, and liquid fractionation in order to avoid future production bottlenecks. The two primary gas-transportation projects planned by PEMEX in the medium term are the El Paso-Samalayuca pipeline and the rehabilitation of the Reynosa line.

As indicated in the previous section on transborder investment, Mexican and foreign firms from the United States, Canada, Spain, Japan and Europe, benefiting from NAFTA's guarantees on foreign direct investment, have joint-ventured to participate in various bids for obtaining authorization for the distribution of gas in those areas designated by the CRE. These firms continue to participate in bids irrespective of whether they have won a previous authorization. The firms participating in gas distribution projects are as follows:

- Chihuahua-Anáhuac-Delicias, Chihuahua: *Distribuidora de Gas de Mexicali*, a joint-venture of Pacific-Enterprises-Enova of the United States and a Mexican distribution company
- Hermosillo-Guaymas-Empalme, Sonora: US-based KN Energy Inc. in a joint venture with *Compañía General de Combustibles*
- Mexicali: *Distribuidora de Gas de Mexicali*
- Río Pánuco: NorAm Energy of the United States in a joint venture with *Grupo Gutsa*, a Mexican construction firm
- Nuevo Laredo, Tamaulipas: Repsol of Spain, with experience in gas transportation and distribution in Spain and Argentina
- Saltillo-Ramos Arizpe-Arteaga, Coahuila: Repsol
- Toluca, Mexico State: Repsol
- Mérida-Progreso-Cancún, Yucatán Península: *Gutsa* in a joint venture with TransCanada Pipelines (a Canadian firm with a 45 percent share of gas markets in North America) and InterGen (active in the electricity project of Samalayuca). The consortium is organized under the heading *"Energía Mayakan"*
- San José Iturbide, Guanajuato: Igasamex

New regions are being defined for private sector distribution projects, including the Federal District and an adjacent area of the States of Mexico. Firms from North America, Europe and Japan, including Shell Energy, Tenneco, West Coast Energy, and Mexican joint-ventures and subsidiaries of other foreign firms, are participating in these projects.

c. United States

In 1995, US inter-regional pipeline capacity increased by only one percent. This relatively slow overall growth reflects the pipeline system's surplus capacity in most regions. Three new interstate projects that entered into service in 1995 were the 110-MCF/D California-Nevada Tuscararoa pipeline, the 250-MCF/D Crossroads project between Indiana-Ohio, and the 250-MCF/D Bluewater pipeline between Michigan and Ontario. Two expansion projects in the southeast will increase deliveries to this growing regional gas market. A 115-MCF/D pipeline was completed in North Carolina and a 535-MCF/D expansion pipeline will increase availability in Florida. Several other intrastate projects in Texas and New Mexico will also increase gas transport capacity. El Paso's 300-MCF/D San Juan pipeline, serving supplies in New Mexico's San Juan Basin, will also increase available supplies and decrease capacity bottleneck in the area. Proposed projects focus on system bottlenecks and areas where excess supply can be redirected to high-demand markets. Two projects discussed above will expand deliveries from Canada to the United States.

Constraints on physical infrastructure are currently limiting the speed with, and thus scale on, which NAFTA's provisions and restructuring combine to increase competitive pressures throughout North America. These constraints, however, are starting to be overcome through new investment, particularly in Mexico and Canada. Although the infrastructure itself, and the fuels it privileges, may well be relatively environmentally friendly, the broader competitive pressures it creates generates potential environmental costs to which social actors and government regulators are now starting to respond.

C. Social Organization

Citizens in all three NAFTA countries are concerned about how restructuring will affect growth, employment and the environmental programs of the existing integrated monopoly, and how the NAFTA mechanisms might be mobilized to mitigate harmful effects. However, the form, and environmental impact of changes in the electricity sector in the United States and Canada is being more actively shaped by the activities of four types of social organization: consumer, environmental, subfederal and electricity-sector bodies. Consumer organizations have sought regulatory changes that ensure strong consumers' rights and protections, disclosure of information regarding electricity purchases and the choice of sources. Environmental groups have supported these goals, while promoting energy efficiency, national environmental objectives, and transborder air quality initiatives. Organizations based on subfederal governments can foster communication and coordination in environmentally supportive ways. And electricity-sector organizations, traditionally concerned with reliability and security issues, could broaden their mandate to include improvements in environmental performance. Together, the activity of consumer and environmental groups is having an environmentally supportive impact, while that of subfederal government and electricity-sector organizations could do so in the future.

Private organizations concerned with the environmental impacts of the electricity sector are far stronger in Canada and the United States than in Mexico. Such entities have had, and will continue to have, an important impact on policy, especially as deregulation is considered at the federal level in the United States. Environmental organizations and consumer organizations in the United States and in Canada have been active participants in debates and processes regarding electricity industry restructuring and direct access to power suppliers. US public interest groups have been active participants in the process of regulatory change at the state and federal levels. Issues addressed by such entities include concerns such as the following:

- requiring all power generators to face full and fair competition;
- ensuring universally reliable and quality service through strong consumer rights and protection;
- expanding the use of energy efficiency and renewable energy resources;
- ensuring the fair allocation of the benefits and costs of electric restructuring;
- ensuring that restructuring results in the operation of the industry in a manner that promotes the achievement of national environmental and public-health objectives;
- acknowledging and strengthening appropriate state and regulatory authority;
- requiring electricity suppliers to disclose information regarding electricity purchases; and
- assuring environmental mitigation and consumer protection in the operation of federal facilities used by US Federal Power Marketing Administrations.[189]

An important trend in the US and Canadian electricity markets where consumer choice is a part of the deregulation program is the emergence of "branded" energy services that permit consumers to choose electricity generated using renewable resources. Such choice enhances the very considerable power that consumers possess, whether as individual purchasers or members of consumer organizations.

[189] The groups supporting this legislative agenda include: Alliance for Affordable Energy, American Council for an Energy Efficient Economy, American Rivers, American Solar Energy Society, American Whitewater Affiliation, Biomass Energy Advocates, Citizen Action, Citizens Action Coalition of Indiana, Center for Energy Efficiency and Renewable Technologies, Conservation Law Foundation, Environmental Defence Fund, Environmental Law and Policy Center of the Midwest, Iowa SEED Coalition, Izaak Walton League of America, Minnesotans for an Energy Efficient Economy, National Center for Appropriate Technology, National Consumer Law Center, Natural Resources Defence Council, New England Flow, Northwest Conservation Act Coalition, Nuclear Information and Resource Service, People's Action for Clean Energy, Project for Sustainable FERC Energy Policy, Public Citizen, RENEW Wisconsin, River Alliance of Wisconsin, Solar Energy Industries Association, Southern Environmental Law Center, Sustainable New-Wealth Industries, 20/20 Vision, Union of Concerned Scientists and Wisconsin's Environmental Decade.

Environmental organizations have also played an instrumental role in promoting cross-border initiatives, as in the case of the efforts of the Environmental Defense Fund leading to a US-Mexican agreement creating the International Air Quality Management Basin (IAQMB) in the El Paso-Ciudad Juárez airshed.

Beyond environmental advocacy groups, other organizations encompassing state governments in the United States, provincial governments in Canada, and even state governments in Mexico, can play an important role in promoting dialogue and coordinating policy at the subfederal level in each country. In the United States and Canada, entities such as NESCAUM, as well as the Grand Canyon Visibility Transport Commission, have played an important role in guiding federal environmental policies.

The electricity-sector organizations designed to promote the reliability and security of electricity systems in North America—NERC and the regional councils—have traditionally worked within narrow institutional mandates that have not included environmental performance issues. In the future, such groups could also promote improvements in environmental performance, provided that member utilities approve an expansion of these entities' mandates.

Thus far, the NAFTA institutions have done little to reinforce the capacity of such social organizations, or to combine them into trilateral, transnational networks. There is considerable potential for initiative in this domain.

D. Government Policy

The heavily regulated and state-owned character of the electricity and natural-gas input industries give national and subfederal government policy a major role in determining how NAFTA's forces are transmitted into environmental effects. Of central interest is the move to electricity deregulation, begun in Alberta in 1993 and California in 1994, and Mexico's 1993 opening of generation to private investors in four limited areas. A second important process is the intensification of natural gas deregulation begun in Canada and the United States in the 1980s, and initiated in Mexico, for transmissions and distribution, in 1995. US deregulation of rail transportation is also relevant to coal. Also important are environmental policy changes: internationally, for climate change at Kyoto in December 1997; in the United States, in the November 1996 proposals for particulate matter and ground-level ozone; in Mexico, in the December 1994 INE standards on sulfur dioxide and nitrogen oxides for stationary sources and fuels; and in Canada, for environmental assessment and British Columbia's November 1997 greenhouse gas emission credits trading system.

In no cases were these policy changes clearly a direct result of the anticipated or realized NAFTA. However, many of these changes are required to take full advantage of NAFTA's provisions for trade, investment and procurement. Some, such as California's 1994 restructuring, may have been a response to NAFTA-created pressures to lower input costs. Others, such as Mexico's 1993 change in generation, took place in parallel to NAFTA and were manifestations of the same economic philosophy. Still others, such as Mexico's 1995 natural gas changes, were not only consistent with the spirit and terms of NAFTA, but also depended on NAFTA's provisions (guaranteeing the rights of foreign direct investors) to take full effect.

These largely independently initiated federal and subfederal government policy changes promise to have an environmentally enhancing effect in several ways. As indicated above, California and several proposed US federal bills allow consumers the choice of pursuing electricity generated from renewable sources. New Mexican gas consortia with foreign investors use environmentally friendly combined-cycle gas turbines and also bring in international efficiency and safety standards, expertise on high efficiency, low-emission consumer equipment and compressed natural gas vehicles, and safe and efficient network systems. Furthermore, they institute the treatment of contaminated soil. US railroad deregulation has reduced the cost, increased the relative use and geographically broadened the base of environmentally less damaging low-sulfur coal from the western United States. US particulate and ozone and other NAAQS standards will reduce emissions from US generation plants and increase the impetus to address "grandfathered" facilities, while the rising number of non-attainment areas, combined with the expanded ability to import power from afar, should reduce concentration and stress in highly impacted areas. Mexico's 1994 regulations and Canada's environmental assessment laws have a similarly favorable effect. Emissions credit trading systems could maximize environmental benefits on a region-wide basis and help offset the pressures for the low-cost, environmentally unfriendly electricity that NAFTA's intensified competitive pressures might bring.

Assessing the electricity sector's policy baseline at the time of the development and implementation of NAFTA is difficult, given the fact that dramatic changes in the sector began at about the same time in all three countries. The natural-gas sector is different, since changes initiated in the United States and Canada in the 1980s had largely taken hold by the 1992-1993 "NAFTA phase-in" period. Similar change in Mexico's natural-gas sector began in 1995, after NAFTA took effect. The role of NAFTA as a direct and isolated cause of the change in Mexico's natural-gas industry is not clear. This section includes a discussion of federal regulatory developments regarding natural gas in all three countries.

1. Electricity

Concurrently with the development and implementation of NAFTA, there have been numerous independent initiatives to deregulate the electricity sector in the United States, Canada and Mexico. Although the scope of change implicit in the US initiatives has captured much public attention, it is important to note that Alberta took the lead in 1993 in deregulation by deciding to establish the continent's most competitive wholesale spot market for electricity generation. More detailed information regarding state and provincial regulatory initiatives in the United States and Canada (but not Mexico, as all energy-sector regulation is federal) is presented in Appendix H. The relevant trends in regulations governing Mexico's electric sector are reviewed in this section.

a. Canada

As in the state jurisdictions of the United States, provincial regulators in Canada play an important role in setting the pace of deregulation. The federal National Energy Board (NEB) regulates the export and inter-provincial trade of electricity, while a separate federal regulatory agency (the Atomic Energy Control Board) administers issues related to nuclear energy. Provincial authorities govern pricing mechanisms for generation, transmission and distribution, issue permits for new construction in intra-provincial systems, and administer intra-provincial markets.

Even prior to implementing restructuring initiatives to introduce competition into Canadian electricity markets, all electric utilities in Canada had policies for purchasing power from independent non-utility generators. In general, these power purchases were priced according to each utility's estimate of the long-term cost of power. Since the majority of Canada's electric utilities, excluding those in Alberta, are owned by provincial governments, these policies reflected government policy respecting the development of private, independent power supplies for domestic use and for export.

Until the advent of open wholesale markets in the United States, with a requirement for reciprocal treatment by participating utilities, independent power producers that built for export had to deliver power to a provincial utility, or a subsidiary, which could then export to the United States. In order to retain opportunities in the export market in the face of restructuring in the United States, provincial utilities in several jurisdictions have adopted wholesale transmission tariffs and policies that reflect a wholesale competitive market. These, and other changes in provincial government policy in Quebec, Manitoba, British Columbia and Alberta, will allow independent power producers to build for export and pay a cost-based tariff for both transmission and the support of ancillary services.

b. United States

In April 1994, California followed Alberta's lead with an ambitious proposal, later embodied in legislation, to phase out its retail electric monopolies and offer all customers direct access to competitive generation markets. California's initiative followed from then recent changes in federal law (the underpinnings for open access are contained in the Energy Policy Act [EPAct] of 1992), as well as pressure for reductions in California's high electricity prices. Moreover, an April 1996 ruling by the Federal Energy Regulatory Commission (FERC) based on the EPAct forced all private owners of transmission to offer competitors access to their grids on the same terms afforded the owners' own generating units.

By late 1997, ten US state legislatures had formally signaled an end to their integrated utility monopolies, and the US Congress was considering numerous proposals for industry-wide restructuring.[190] Several of the federal bills would set a deadline for giving all US customers what residents of California will achieve in 1998: the opportunity to choose their electricity supplier over a transmission system that is operated with complete independence from every generation owner.[191]

The restructuring of the electricity industry also had roots in earlier domestic initiatives, such as the US Public Utility Regulatory Policies Act of 1978 that helped launch a diverse, competitive electric-generation sector that was independent of the traditional utility monopolies. A steadily expanding three-nation transmission grid encouraged advances in international cooperation well in advance of NAFTA, including the North American Electric Reliability Council, the WSCC, the western Committee on Regional Electric Power Cooperation and the Western Systems Power Pool.

With competition, the need to open up new markets becomes stronger. The prospect of direct sales to a customer group as potentially lucrative as the large-volume industrial customers has encouraged the development of independent power producers (IPPs) and utilities wishing to export power. As restructuring occurs in the United States, trade interests on both sides of the US-Canadian border are becoming increasingly more involved in the process.

c. Mexico

Regulatory change in Mexico has proceeded at a different pace from that in the United States or Canada. The emphasis of the legal changes initiated in 1993 is not to establish competition in the generation market. Rather, emphasis has been on opening up generation to private investment through four clearly delineated means: independent production; cogeneration; small-scale production; and self-supply. It seems that the emphasis of the administration of President Carlos Salinas on privatization, deregulation and trade liberalization was the origin of initiatives such as NAFTA and the parallel deregulation of electricity generation.

Until the 1993 reforms, the Mexican Constitution prohibited private power generators from transmitting power over the grid, a right reserved exclusively for CFE, the owner of the grid. The need to reduce the backlog in supply to meet growing demand, combined with the insufficient financial resources of CFE, led both to its formal commitment to buy back excess power generated by individual industrial cogenerators and to the government providing explicit support for private power schemes.

[190] The states are, in addition to California, Illinois, Maine, Massachusetts, New Hampshire, Rhode Island, Nevada, Oklahoma, Montana and Pennsylvania (see Appendix H).

[191] The beginning date for operation of California's day-ahead power auction, originally set for 1 January 1998, was postponed until 1 April 1998 to permit further systems testing and preparation.

CFE would have preferred the BLT mechanism for private power development rather than external power generation (or independent power production [IPP]) and co-generation, but the latter is a more acceptable scheme from the viewpoint of efficiency. BLTs simply require private investors to finance a power plant with the understanding that it will be leased to and operated by CFE until the owners have recouped their investment. The first project to be financed under a BLT arrangement, currently under construction, is Samalayuca II, in Chihuahua, with 690 MW of generation capacity and an approximate cost of US$650 million.

The regime emerging in the NAFTA era emphasizes IPPs. According to the implementing regulations for the Law on Public Service of Electricity, private companies can invest in power-production facilities with capacities greater than 30 MW. These units are owned and operated by private parties but must sell all the energy they produce to CFE or abroad. The first IPP permit was assigned to an international consortium led by AES of the United States, in conjunction with Japan's Nichimen and Mexico's Hermes. The plant, Mérida III, is a combined-cycle natural gas facility near Mérida, in the state of Yucatán, served by a new gas pipeline that is also being bid on by private investors. The plant's initial net capacity of 484 MW will require an estimated investment of US$227 million. Since the Mérida III bid, the low price for electricity offered by the AES consortium has underscored the advantages of the IPP arrangement, and CFE now plans to open up a large segment of new capacity to IPPs (see Appendix F).

2. Natural Gas

The deregulation of the natural-gas sector in the United States and Canada began in the 1980s, providing the intellectual and practical underpinnings for moves toward deregulation in electricity a decade later. It also provided an important foundation that allowed the impact of restructuring and NAFTA to be reinforced.

a. Canada

The deregulation of natural gas in Canada began in 1985 with agreements that left the pricing of natural gas to market forces, with sales negotiated directly between producers, distributors and large consumers. The agreements also included changes in the arrangements governing the operation and role of inter-provincial and international pipelines, and included terms for short-term NEB export orders (of up to two years) as well as more flexible means for determining the volume of gas available for export.[192]

In 1989, the FTA eliminated several obstacles to trade in gas between Canada and the United States, including the cost-benefit analysis basis for determining gas volumes available for export. In 1993, the NEB lifted the restrictions on gas exports to California that had been imposed in 1992 in the wake of a dispute about short-term sales. In 1987, open-access for federal pipelines was instituted. Open-access was extended to private pipelines in 1995.

b. United States

The Federal Energy Regulatory Commission (FERC), in Orders 491 and 509, provided the basis for open-access to US gas pipelines in 1988. The following year, the FERC eliminated obligatory long-term contracts. In the early 1990s, the FERC ensured improved functioning of the open-access system through fines on gas-line companies that oversubscribed their pipelines, consolidation of the electronic systems for administering gas lines (Order 636 in 1992), and the unbundling of transportation and storage services (Order 636). Subsequently, a clarification of Order 636 addressed the possibility of interconnections between interstate pipeline companies, subject to an approval in which criteria such as market power, treatment of affiliates and impact on consumers would be taken into account.[193]

[192] Secretaría de Energía, *Perspectiva del Mercado de Gas Natural 1997-2006*: 44.

[193] *Ibid.*, 43.

c. Mexico

In Mexico, the deregulation of the transmission and distribution of natural gas began in 1995 in the context of the program of economic and commercial liberalization initiated in the mid-1980s and the investment-promotion program instituted during the economic crisis of 1995. It is consistent with the spirit as well as the terms of NAFTA. Legislation passed in 1995 by the Mexican Congress partially privatized the transport and distribution of natural gas in Mexico, releasing financial resources of the state oil company, PEMEX, from those subsectors and thereby enabling PEMEX to allocate them to increasing natural gas production capacity. Although such changes were not contemplated in NAFTA, they are a logical extension of the NAFTA regime.

The changes allow private participation in the transportation, distribution and storage of natural gas while restricting exploration, extraction and processing activities to PEMEX. According to the new legislation, private parties can use PEMEX's gas lines to transport gas in accordance with their needs. Under NAFTA's investment provisions, private investors from the United States and Canada have access to this sector.

(i) Role of Private Sector Firms in Mexico

As a result of the 1995 legislation, and the security provided by NAFTA's foreign direct investment provisions, firms from North America and Europe are bidding for gas distribution concessions for specific locations in Mexico. Participants are seeking multiple concessions, which are restricted to regions where industrial and residential users are concentrated. Bidder interest in the Mexican gas-distribution sector, therefore, tends not to focus on a single project but rather on multiple projects, reflecting this sector's potential to justify involvement in a number of regions. In addition, firms active in more than one gas-supply region may exploit potential synergies. These include marketing gas to residential users, serving industrial clients active in both areas, and applying knowledge obtained regarding market characteristics and the habits of clients in one location to another.

In the gas-distribution sector, foreign firms possess knowledge and technology that has not been sufficiently developed by the Mexican private sector until now, as this has been a heavily regulated activity. Foreign investment, therefore, contributes a series of business-oriented structures that assure rapid development of gas distribution according to international efficiency and safety standards. Foreign firms participating in the market are providing the following expertise:

- Expertise in gas markets and gas regulation gained in their countries of origin and in developing regional gas markets—as in the case of NorAm Energy or Pacific Enterprises-Enova. The latter has expertise in the California region from Los Angeles to San Diego, which will in the future be key for the increasing integration of the gas and electricity markets of the northwest region of Mexico and those of southern California.
- In cases where a foreign firm participates in the southern US gas-distribution market, it also establishes a link between the Mexican market and the US market that facilitates adaptation to consumer preferences, safety standards and government regulation. This link also facilitates an understanding of regional markets in which the drivers of demand for gas and consumers' preferences are not necessarily as easily understood by a single national producer.
- Expertise in technical advances in gas distribution. These include the real-time measurement of gas flows; remote meter reading; customer-response systems; billing; and customer equipment. The latter includes equipment with low emissions and of high efficiency, as well as compressed natural gas vehicles.
- Although gas distribution (unlike electricity generation) does not involve sophisticated technology, there is always technical progress in adapting existing technology to consumers' needs. On the pipeline side of the business, foreign investors have an integrated view of ducts-mains-service networks. The main goes into the street, and the service goes from the main to the customers' meters. These networks function under tight standards for efficiency, safety and cost.

- Foreign firms have different strengths. European distributors bring the experience of high density urban areas. US investors, particularly those from California, have experience in managing networks designed specifically for high seismic risk. Foreign entities also have experience in building networks on contaminated soil and in using the chemicals that are sometimes necessary in that operation.
- Foreign firms participate in gas distribution, but in some cases they have wider interests than gas in the energy sector. This is the case of Repsol and Shell (although Shell has participated in bids and not yet been part of a winning team). Shell, for example, is a partner of PEMEX in oil refining, at a location in Deer Park, and is a producer of lubricants and products for the petrochemicals industry.
- Foreign firms participating in Mexico also have expertise in managerial techniques for long-term planning, encompassing both cost accounting as well as business strategy vis-à-vis market and economic risks. The gas market faces risks in terms of future prices as well as market growth, depending on the drivers of domestic demand. Managing these risks calls for techniques that have not been available to small Mexican firms, some of which have now become partners of the foreign investors.
- Foreign investors in Mexico are international firms with previous experience in their countries of origin. Their international character, even in those cases in which this is limited to operations in only two countries, facilitates their involvement in markets that will increasingly become integrated across national boundaries. International trade and financial transactions between Mexico and foreign countries will afford international firms an advantage, and their involvement in domestic gas markets will bring such advantages to Mexico in one form or another.

3. Coal

In the case of the United States, changes in interstate transportation policy may have contributed to increased trade in coal. The restructuring of railroad transportation in the United States is widely credited with having reduced the cost of moving coal to US utilities, making it easier and cheaper for them to comply with tighter SO_x emissions implemented under the Clean Air Act (CAA) of 1990 by substituting low-sulfur coal for higher-sulfur varieties. Similarly, since 1995, cheaper rail transportation has also facilitated the exports of US coal to CFE.

The impact of these regulatory changes on coal-production patterns in the United States has been noticeable. As noted in the section on trade in coal, western coal is primarily low in sulfur while most eastern coal has a higher sulfur content. As utilities moved to burn more low-sulfur coal to reduce SO_x emissions, the consumption of western-produced coals increased. Accordingly, coal production in the main western coal-producing state, Wyoming, increased as a share of total production, while most key, eastern coal-producing states declined in market share (see Table 10).

Table 10 Patterns in US Coal Production

State	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Major Western Coal Producers										
Arizona	1.28	1.31	1.16	1.30	1.32	1.22	1.29	1.21	1.07	1.02
Colorado	1.57	1.73	1.84	1.84	1.75	2.06	2.47	2.51	2.25	2.55
Montana	4.24	3.93	3.84	3.80	3.83	3.90	4.02	4.04	3.57	3.60
New Mexico	2.33	2.34	2.37	2.18	2.34	2.74	2.90	2.69	2.35	2.51
N. Dakota	2.93	3.16	2.97	2.93	3.07	3.27	3.25	3.06	2.82	2.70
Texas	5.70	5.46	5.51	5.46	5.46	5.62	5.50	5.03	5.23	4.86
Wyoming	16.73	17.76	17.77	19.29	19.24	20.27	23.00	24.44	25.93	25.81
Major Eastern and Midwestern Coal Producers										
Alabama	2.81	2.85	2.85	2.76	2.61	2.56	2.55	2.26	2.43	2.37
Illinois	6.49	6.52	6.11	6.03	6.16	5.70	4.54	4.75	4.79	4.06
Indiana	3.40	3.28	3.54	3.39	3.20	2.90	3.03	2.78	2.52	2.94
Kentucky	16.69	15.83	16.65	16.27	15.91	16.16	16.18	15.06	14.51	14.23
Ohio	3.58	3.39	3.34	3.21	2.92	2.90	2.93	2.60	2.54	2.74
Pennsylvania	7.51	7.21	7.12	6.48	6.74	6.62	5.98	5.83	6.28	6.45
Virginia	5.00	4.87	4.64	4.38	4.20	4.23	3.92	3.53	3.27	3.35
W. Virginia	4.70	15.75	15.56	16.22	16.69	15.59	14.18	15.89	16.00	16.36

Figures in percent of total US production.

Source: Office of Surface Mining, US Department of the Interior. Data are presented by US fiscal year.

4. Environmental Policy

As of late 1997, the environmental policy development likely to have the most profound impact on the electricity sector in the years ahead is the Kyoto Protocol negotiated by the signatories to the UN Framework Convention on Climate Change (FCCC). At the national level, initiatives intended to improve regional and local air quality are likely to impose the greatest new burden on electricity utilities. In all cases, these policy changes are unrelated to NAFTA.

a. United States

In the United States, there are two major developments to consider in the context of environmental regulation that will affect the US utility industry. The first is the implementation of the emissions trading system at the national level in accordance with the Clean Air Act Amendments of 1990. The second involves efforts by USEPA to tighten emissions standards for particulate matter and ozone precursors.

The EPA proposed and implemented National Ambient Air Quality Standards (NAAQS) for particulate matter and ground-level ozone in November 1996. The rulemaking, which is based on human toxicological and epidemiological data, is expected to have a significant impact on the regulated community. Although the proposal has been subjected to vigorous criticism from various sectors of the affected regulated industries, polling results indicate that there is widespread public support for the new standards, which also have the support of the US president and vice-president. Efforts in Congress to force a vote of disapproval for the measures prior to the end of the legislative session in 1997 were not successful.

(i) Current Particulate Matter and Ozone Standards

Particulate matter (PM), comes largely from combustion from sources like power plants or large incinerators. Precursors to ozone (pollutants that cause ozone to form in the lower atmosphere) generally come from mobile sources, such as car exhausts, and stationary sources such as industrial smoke-stacks and generating facilities.

The PM regulation currently limits ambient concentrations of particles the size of 10 microns or smaller (PM-10) in concentrations of 50 micrograms per cubic meter annually, and 150 micrograms per cubic meter daily. The proposed PM standard calls for limits on particulates of 2.5 microns or smaller (PM-2.5) to concentrations of 15 micrograms per cubic meter annually and 50 micrograms per cubic meter daily. The EPA also proposed maintaining the current standards for PM-10 so that larger, coarse particles would continue to be regulated.

The current ozone standard is 0.12 parts per million (ppm) measured over one hour. The EPA's new standard calls for 0.08 ppm measured over eight hours. The EPA is also seeking comment on several other options, including an ozone concentration of 0.09 ppm measured over eight hours, as well as a range of ozone concentrations from 0.07 ppm measured over eight hours to 0.12 ppm measured over one hour, the current standard. For both new standards, the EPA has also specified the way in which attainment of these standards would be measured. Plans to meet any finalized standards would be due in 2002 for PM, and in 2000 for ozone-control strategies. Deadlines for achieving full compliance would occur several years thereafter for both types of emissions.

Congress specifically named six air pollutants under the Clean Air Act to be regulated by the EPA's national air-quality standards. They are: ozone, particulate matter, nitrogen oxides, carbon monoxide, sulfur oxides, and lead. Congress directed that such standards should be reviewed at least every five years by the EPA to keep up with current science, and that proposals to revise them should be based solely upon the best current scientific opinion on public-health effects, not economic impacts. There is a 60-day comment period on the proposal.

The number of US non-attainment areas is expected to rise from 106 counties to approximately 250, as illustrated in Figure 7. This will lend further impetus to efforts to address the regulatory inconsistencies that currently benefit generating facilities that were "grandfathered" under current clean-air legislation. In addition, the increased number of non-attainment areas will also have a significant impact on the siting and permitting processes for new power generation facilities in the United States.

There will be some new areas within the United States in which the siting of new generating facilities may simply not be viable. Many of the anticipated new non-attainment areas fall within the regions of the country where rapid demand growth is likely to lead to increased capacity requirements, especially in areas where current transmission capability limits the amount of power that can be imported from other regions. The facilitation by restructuring of region-wide imports, plus technological advances, could thus lead to a smaller geographic concentration of generation, with positive environmental effects.

b. Mexico

There are several important policy initiatives in Mexico in the area of energy and environment that will affect the structure of energy consumption in the country, as well as the pattern of energy-related pollutant emissions. These policy initiatives encompass new environmental standards, energy policy directives, and the deregulation of key subsectors of the energy sector, especially in natural gas. This section will address developments in the environmental policy and energy policy areas.

(i) Air Pollution

In December 1994, the National Ecology Institute (*Instituto Nacional de Ecología*, or INE) published two standards with far-ranging implications for air pollution and energy policy in the country. The standards, NOM-ECOL-085-1994 and NOM-ECOL-086-1994, cover permissible emissions of SO_x and NO_x by stationary sources and fuel quality, respectively.

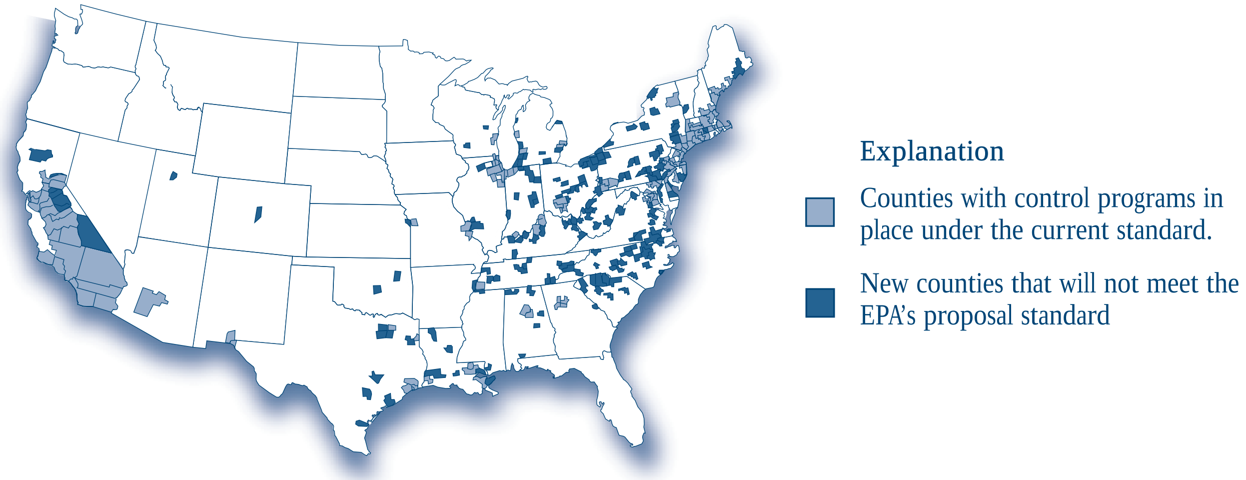
NOM-ECOL-085-1994 establishes a series of geographic zones for which specific emissions levels for both pollutants are specified (see Table 11). NOM-ECOL-086-1994 lays out the specifications of petroleum-based fuels produced by PEMEX for use in stationary and mobile sources of pollution. The specifications include values for various characteristics of gasolines, diesel, natural gas and fuel oil, including lead content, vapor pressure, sulfur content, benzene and olefin content, and ash. Some of the improved fuels have already been introduced into certain regional markets, as in the case of the new super-unleaded gasoline, referred to as Premium.

Table 11 Emissions Limits in Mexico for Criteria Pollutants

Pollutant	ZMCM 1*	Critical Zones**	Rest of Country
1994-1997 (December 31)			
SO_2	1.65	3.30	5.16
NO_x	0.23	0.41	0.59
PM	0.05	0.25	0.39
Beginning in 1998			
SO_2	1.13	2.26	4.53
NO_x	0.16	0.16	0.55
PM	0.04	0.19	0.27

Sources over 110,000 MJ/hour, liquid fuels. Figures in pounds per million BTU input. *Source: NOM-ECOL-085-1994, Tables 1 and 2.*
* ZMCM refers to Metropolitan Area of Mexico City. **The critical zones are: metropolitan Monterrey and Guadalajara, Ciudad Juárez, the Coatzalcoalcos-Minatitlán corridor, the Irapuato-Salamanca-Celaya corridor, the Tula-Vito-Apasco corridor, the Tampico-Cd. Madero-Altamira corridor, and Tijuana.

Figure 7 Existing and Anticipated Non-Attainment Zones under EPA Ozone Standards[194]



Counties not meeting the EPA's ozone proposal standard (8-hour, average 3rd maximum, 0.08 ppm).
Source: EPA, 1996.

[194] See <http://ttnwww.rtpnc.epa.gov/naaqspro/ozone2.gif>, for a color image of this map.

c. Canada

(i) Federal-Provincial Cooperation

Due to Canada's system of federal-provincial jurisdiction, provincial and federal governments jointly develop environmental policy. In many instances, the federal government develops a policy to implement the nation's obligations under international or regional agreements. However, provincial governments will develop the programs and regulations necessary to achieve compliance. Recent examples include the Canada-United States Air Quality Accord and the NO_X/VOC Management Plan, which was developed as part of the United Nations Economic Commission for Europe Convention on Long-Range Transboundary Air Pollution. New agreements, such as the Kyoto Protocol, will require similar cooperative arrangements with provincial governments.

(ii) Environmental Assessment

One of the most significant developments in Canadian environmental policy with regard to electric utilities has been the passage of environmental-assessment legislation in all provinces and at the federal government level. The various pieces of legislation require proponents to engage in a multi-stage process of analysis to determine the cumulative and long-term environmental impacts of their projects and to develop mitigation plans that are considered part of the permitting process. In many cases, there is opportunity for public input and comment throughout the process. In some cases, an environmental-assessment panel may require a full public hearing.

(iii) Greenhouse Gas Trading

In November 1997, the government of British Columbia announced the establishment of a voluntary emissions credit trading system for greenhouse gases. The trading system allows investors in greenhouse gas reductions to acquire reductions at offsite locations as a means of meeting reduction targets, or to hold credits against future regulatory requirements. Under the initial program, trades must involve one party with operations in British Columbia; however, the federal and provincial governments have been invited to participate in the program as co-sponsors. The involvement of other governments would allow the number and variety of potential participants to increase. The program will have ramifications for the development of more efficient generating and conservation technologies, as investors will be able to receive registered credit for investing in green power projects and energy efficiency.

Such trades are occurring elsewhere in Canada, and have even crossed international boundaries within North America. Recently, Ontario Hydro announced that it would purchase 10,000 metric tons of CO_2 from emissions credits created by Southern California Edison (SCE) through its success in reducing emissions even further than its targeted CO_2 emissions reduction of 2 million tons per year by the year 2000. The additional reductions under SCE's Climate Challenge accord with the US DOE will be traded to OH in a demonstration trade.[195] OH's carbon emissions have increased as coal-fired units have made up for nuclear capacity taken off line in August 1997, leading the utility to seek external sources of carbon reductions to meet its own voluntary emissions reduction goals.

[195] "Edison, Ontario Hydro announce CO_2 credit sale," *Daily Power Report*, 15 December 1997.

5. Trends in International Environmental Policy

The Kyoto Protocol provides the basis for what could be important changes in national energy and environmental policies in the United States and Canada, with the potential for significant policy developments in Mexico.[196] The US and Canadian delegations in Kyoto agreed to reduce GHG emissions by 7 percent and 6 percent, respectively, relative to 1990 emissions levels, by the "commitment period" of 2008-2012. All three NAFTA countries supported the inclusion in the Protocol of emissions trading as part of the package of mechanisms to promote emissions reductions—referred to as "certified emissions reductions" (CERs)—achieved under the "clean development mechanism" (CDM), in Article 12. The details of such a system were left to a subsequent meeting of the parties to the Protocol in late 1998 and emissions trading is not yet explicitly sanctioned under the Protocol.[197]

The fluid state of the electricity sector in North America suggests that rapid change will continue for several years before longer-term patterns may be discerned. Indeed, the long-term impacts of deregulation in the electricity sectors of North America depend on policy decisions that have yet to be made or that are being made at the present time. Given the likelihood of rapid change in the environmental impacts of the sector, the following section ("Environmental Impacts and Indicators") helps identify developments that could serve as the basis for ongoing data collection, research and analysis.

[196] *Kyoto Protocol to the United Nations Framework Convention on Climate Change*, 10 December 1997 (FCCC/CP/1997/L.7/Add.1).

[197] One part of the Kyoto Protocol that may be of special interest to the US, Canadian and Mexican governments from this NAFTA perspective is Article 4.6, which provides the basis for regional economic integration organizations to make commitments as a group (under Article 23). As such, a NAFTA commitment could pave the way for a regional emissions trading initiative involving the United States, Canada and Mexico.

V. Environmental Impacts and Indicators

The ambient environment is susceptible to pressures through several media and through the interactions between atmospheric emissions and biota. This section extends the environmental linkages with an analysis of potential environmental impacts and points to specific environmental indicators that could be used for measuring environmental change over time. These indicators include not only the ambient environmental dimensions, and pressures or supports, but their major causes or potential mitigating factors. The relationship between the environmental linkages and the environmental impacts is summarized in Figure 8, which includes four major categories of environmental impacts: air emissions, water pollution, generation of solid waste, and land-use changes (including impacts on biota).

In general, the environmental pressures arising from an increasing demand for and trade in electricity in Canada, Mexico and the United States will depend on two key factors: the level of domestic environmental regulation brought to bear on the operation of existing power plants and the impacts of fuel production resulting from the introduction of newer generation technologies. To the extent that new technologies will displace existing power plants and reduce their use, and hence the environmental pressures, in one area, this change may be offset by increased pressures in other areas, namely production and delivery impacts for fuels that power the new technologies. Environmental impacts in one area, and their displacement to other regions as a result of changes in the geographic distribution of the sector's activities, may be monitored and assessed through the application of environmental performance indicators.

More competitive electricity markets have the potential for both positive and negative environmental impacts. On one hand, they may lead to a decline in environmental quality by prolonging the economic life, and increasing the operating levels, of coal-fired power plants, which are the major sources of air emissions in the United States.[198] Competition can also lead to the abandonment of existing regulatory instruments for achieving energy efficiency and conservation objectives, leading to increased consumption, since the traditional role of economic regulation will focus on the monopoly portions of the system, namely transmission and distribution infrastructure. On the other hand, in the long term, environmental pressures may be reduced since the transition to a competitive market for electricity offers opportunities to improve the existing fleet of power plants by facilitating the earlier introduction of new, cleaner technologies, notably combined-cycle natural gas turbines.[199] In addition, while the end of the economic regulation of power plants reduces incentives for conservation, it also presents an opportunity for social organizations to negotiate better regulatory mechanisms to achieve energy conservation objectives through new institutions.

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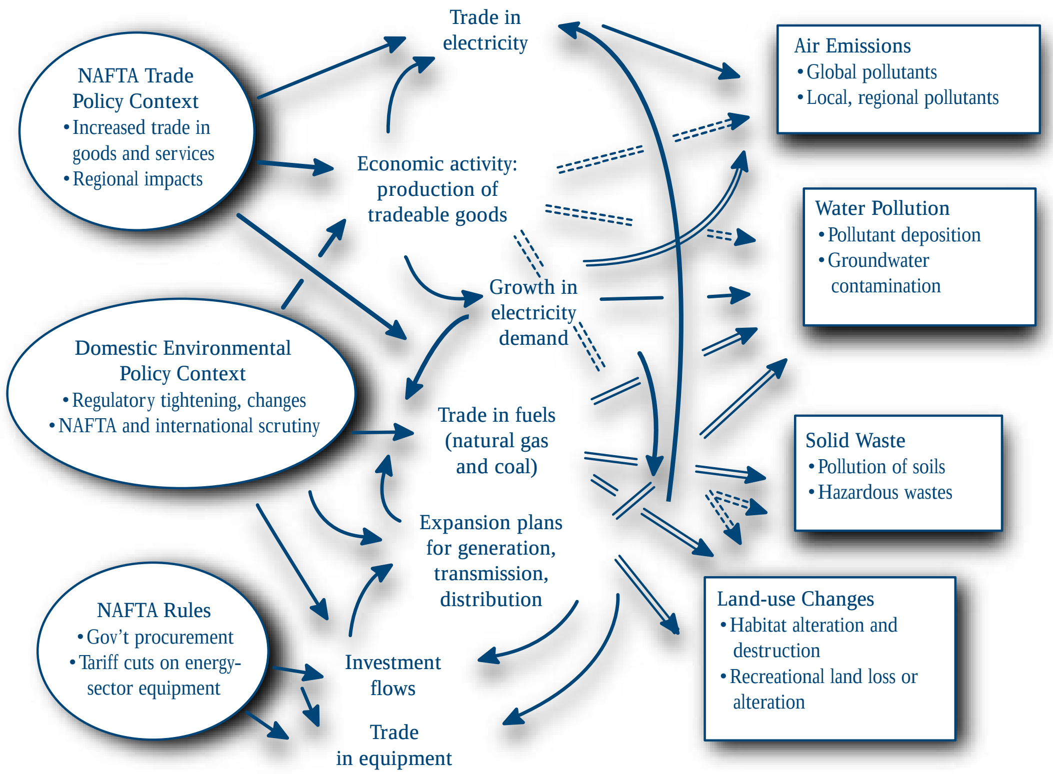
[198] As an indicator of the magnitude of the issue, many old coal-fired generators emit SO_2 at a rate five to ten times that of a new coal plant and emit NO_x at a rate two to three times that of a new coal plant. Natural Resources Defense Council *et al*. 1997 *op.cit*, p. 37.

[199] Natural gas combustion turbines produce 33 percent to 50 percent as much CO_2 as coal-burning facilities.

Figure 8 Trade-Energy Sector-Environment Linkages



Source: EIC

More competitive and integrated electricity markets will likely lead to an increase in demand for natural gas for electricity generation in the United States, Mexico and Canada. The pressures of the competitive marketplace might lead to increased investment in the most competitive new energy generation technologies, especially natural-gas-fired turbines in a combined-cycle configuration. These new units may displace higher-cost units, such as nuclear and oil-fired units, as well as units with comparatively poor environmental performance, such as older coal-fired facilities. These trends would tend to affect emissions of SO_X and CO_2 and NO_X.

Growth in demand for natural gas will lead to the attendant growth in investment in natural gas production, transmission and distribution, and in equipment for consuming natural gas in place of other fuels. Prices for natural gas may tend to rise, widening the gap between gas and coal, thereby creating an incentive to consume coal over gas in dual-fired units and to favor coal-fired capacity over gas-fired units. On balance, however, it seems likely that the overall trend toward the increased use of natural gas will yield environmental benefits, except in those areas where substantial, yet idle, coal-fired capacity is available.

While the production of natural gas does imply substantial environmental impacts, the environmental benefits of gas consumption could offset these costs. Natural gas has higher combustion efficiencies and provides increased opportunities for the beneficial use of waste heat; it also offers reduced carbon and SO_X emissions. However, if combustion is not adequately controlled with NO_X-emissions devices, gas may result in higher emissions of nitrogen oxides, a tropospheric ozone precursor.

The environmental pressures associated with increased trade in natural gas are significant. From 1990 to 1995, GHGs associated with natural gas production in Canada increased from 29,252 kT of CO_2 equivalent to 35,449 kT, an increase of 21 percent.[200] A significant portion of this increase in emissions is directly attributable to increased trade. For example, natural-gas production in Alberta increased by 41 percent between 1990 and 1994, with approximately 65 percent of this increase driven by increased exports to the United States.[201] An analysis of the change in the share of exports in total output of natural gas in Canada shows that exports increased by approximately 90 percent, while domestic use increased by 27 percent, during the period from 1990 to 1995.

Restructuring and some limited privatization in the electricity sector will increase the pressure on utilities to seek competitive positions, reduce costs and expand markets. This might create an incentive to run low-cost and largely depreciated units more heavily than in the past. It may also lead to reduced use of high-cost nuclear and renewable resources. These trends would tend to increase emissions of SO_x, NO_x and CO_2.

Mexico's expansion plans call for a substantial restructuring of generation capacity, with natural gas-fired capacity expanding substantially. This process is being facilitated by access to new technologies through private investment and liberalized trade as well as deregulation in the natural-gas sector.

Trends in trade in electricity between the United States, Canada and Mexico suggest that the total volume of power exchanges may be higher in the future, but substantial variations may occur, reflecting short-term changes in the supply-demand balance. For example, Mexican exports to the United States have dropped sharply in recent years as supplies have tightened; imports from US utilities may increase substantially. Canadian exports could expand to new levels if new generating capacity is made available and if, in the case of Hydro-Québec, local and international opposition to power exports does not limit its ability to expand its share of electricity supplies to the northeastern United States.

The emissions associated with Canadian exports to the United States illustrate the contribution of electricity exports to environmental pressures in Canada. Different emission rates between provinces, based on differences in the fuels used in each region, combined with export levels from each province, permit a rough estimate of the emissions from fossil-fuel generation in Canada dedicated to serve export loads.

Based on these data, the air-emission impacts of exported power in 1995 were some 43,500 metric tons of SO_2; approximately 12,700 metric tons of NO_x; and 7 million metric tons of CO_2. These emissions were equivalent to 1.5 percent of Canada's total CO_2 emissions, 1.6 percent of SO_2 and 0.6 percent of NO_x. In the event that electricity trade were to fully utilize the available transmission capacity linking Canada and the United States, the contribution of export-related air emissions to regional and global environmental pressures could double.

The availability of emission inventories and reporting structures for power-plant operation is essential to be able to confirm the trends. The ability to track environmental indicators over time, along with supplementary data, will also be essential to establishing which environmental trends are becoming a reality.

Limitations on transmission capacity will play an important role in determining the extent to which open-access will lead to increased inter-region and inter-provincial trade in the electricity generated in North America. Substantial demand for transmission capacity, if recorded, will lead "transmission utilities" to invest in new capacity. Such new investment will confront numerous regulatory and other obstacles. In general, there appears to be little additional environmental stress arising from the need to construct new electricity transmission lines from new corridors in the

[200] *Trends in Canada's Greenhouse Gas Emissions*, 1990-1995, A. Jacques, Pollution Data Branch, Environment Canada, Table 2.4

[201] "Greenhouse Gas Emission Trends in Canada and Alberta," Robert Hornung, Pembina Institute for Appropriate Development, November 1995.

United States, and the extent and location of new cross-border transmission lines and corridors and their immediate environmental impacts are, thus far, largely unknown. Preliminary evidence suggests that existing transmission capacity is sufficient to permit some reorientation in power flows to accommodate greater sales of coal-fired generation in the US midwest.

In a more competitive market environment, in the short term, DSM measures might need to meet a far tougher cost-effectiveness criterion since internal competition for investment resources will be stiffer and the reference market price of electricity will be lower. In the longer term, it is likely that DSM will prove a useful strategic tool for utilities seeking to retain their customer bases, in part through a diversification of their product-line to include "integrated" energy services.

It will also be important to monitor the siting and share of the generation of independent power producers to assess their environmental impacts.

The data presented in this study suggested the following four scenarios that guided the development of the analysis.

The first scenario was that open grids—combined with NAFTA guarantees for assured, open, region-wide trade and investment—could improve environmental quality by accelerating capital turnover. This study suggests that a number of jurisdictions are integrating new incentives for energy-efficiency and renewable-energy investment, such as uniform charges on distribution services and minimum-content requirements for generation. Trade in equipment under key tariff classifications appears to be increasing, especially with Mexico. Investment forecasts call for increased natural-gas-fired capacity, in some cases at the expense of coal-fired capacity, as in the case of Canada. Marketing programs for "green power" are emerging, reflecting marketers' desire to distinguish their product based on documented perceptions of some level of consumers' willingness to pay for "clean electricity." On the other hand, industry uncertainty regarding market trends in capacity is accepted as a disincentive to investment. Capacity-expansion projections in the United States and Canada are subject to uncertainties, and there is an unevenness of initiatives favoring renewables at the subfederal levels in the United States and Canada.

The second scenario presented is that trade liberalization could open new markets for cleaner generation technology and fuels. This analysis has shown that trade in equipment under key tariffs classifications appears to be increasing, especially with Mexico. Moreover, investment forecasts call for increased natural-gas-fired capacity, in some cases at the expense of coal-fired capacity, as in the case of Canada. System expansion plans in Mexico include a significant shift toward natural-gas-fired technologies. On the other hand, as in the scenario above, capacity expansion projections in the United States and Canada are subject to uncertainties, and initiatives favoring renewables there are uneven.

A third scenario is that incentives and regulations could benefit end-use efficiencies and renewables. Data presented in this study confirms that North America has at least two decades of experience with the direct governmental regulation of equipment and building efficiency, although the potential for greater savings remains. Coordinating efforts across national boundaries would facilitate higher efficiency levels. Again, initiatives favoring renewables at the state and provincial levels in the United States and Canada are uneven, creating the potential for confusion. A uniform, volume-based charge on transmission, such as one proposed in the US Congress, would be used to match qualifying state-level investments in efficiency and renewables, dollar-for-dollar. At least four bills in the US Congress would mandate renewable-energy content for all generation owners. Industry uncertainty regarding market trends in capacity is a disincentive to investment in DSM. Uniform standards would help reduce this uncertainty. The expectation of continued growth in energy savings from DSM programs, particularly [where there is] competition, leads to the relaxation of regulatory strictures governing rate design. Utility spending is expected to decline slightly, reflecting reduced DSM costs and program changes, while utilities continue to pursue DSM capability.

On the other hand, incentives and regulatory requirements will need to be far greater under deregulation than in the past, since lower prices make energy-efficiency projects even more difficult to justify economically. Renewable energy resources are more difficult to develop because of disadvantages related to the up-front cost of investment and to operational considerations such as reliability.

The fourth scenario is that inconsistent emissions standards and regulatory uncertainty could lead to increased pollution. The analysis shows that older US coal-fired power plants are often permitted to emit four times, or more, the pollution on a per-kWH basis than their newer competitors, and initial indications point to increases in coal-fired generation in the United States. Analyses of the potential impact on pollution of open access and increased trade and investment have evaluated the extent of available transmission capacity and conclude that available capacity, coupled with increased demand due to lower prices, will lead to increased emissions[202] The closure of seven nuclear facilities in Ontario has created a demand for increased coal-fired capacity. It is recognized in Ontario that the incremental demand cannot be served by coal-fired units because of limits on total emissions from those units. Regulatory initiatives at the state and provincial level that would promote the use and construction of renewable energy supplies and/or energy efficiency are important.

However, legislation currently before both houses of the US Congress would phase out current inconsistencies in power-plant emissions standards. There are doubts about the potential availability of transmission capacity between ECAR and MAPP or NPCC. Furthermore, while FERC 888 does include language indicating that transmission providers must build capacity if needed, limitations on that requirement do exist.[203] Analyses showing substantial negative impacts due to restructuring also leave aside the potential, but as yet not quantified, impact of Phase II NO_x controls and the MOU in the Northeast Ozone Transport Region.[204]

In order to monitor the development of these scenarios, a number of indicators from throughout the General Framework can and should be considered.

A. Production Data

The evaluation of long-term trends in the electricity sector throughout North America will require monitoring both the changing composition of the resource bases of each country and operational details such as fuel used and hours of generation. Data collected on plants in operation, generation of electricity and fuel consumption, and inter-regional sales and transmission volumes for each country will provide the basis for drawing conclusions about the environmental impacts of electricity production for the NAFTA region.

B. Investment Data

By monitoring the changes in the composition of each country's fleet of generating plants, further analysis of the linkages to environment will facilitate determinations of the cumulative effects of the electricity trade.

Investments in new cogeneration and combined-cycle facilities, in excess of the levels required to keep pace with demand growth, will provide an indication of the degree to which existing power plants are being replaced. This trend toward replacing existing capacity is clearest in Mexico, where over 4,000 MW of capacity will be converted to natural

[202] See Palmer, Karen and Dallas Burtraw (1996), "Electricity Restructuring and Regional Air Pollution," Resources for the Future, Discussion Paper 96-17-REV2, July.

[203] See EPECO/Enron filings.

[204] See EIA "Electricity prices in a competitive environment."

gas, and where the vast majority of new capacity will also use gas. The close monitoring of investment data and generation-capacity data will permit verification of this projection for Mexico, the United States and Canada.

Decisions on investing in new hydroelectric facilities, in excess of domestic demand, will also indicate the degree to which open competitive markets are affecting the environment. Although it is recognized that distinguishing changes that are market driven from changes that are government directed will require specific policy analysis to interpret the data, the importance of hydroelectric storage reservoirs in a competitive market warrants such an analysis.

Investment decisions regarding DSM and renewable generation technologies will also provide valuable indications of the magnitude of environmental change. Whether or not new institutions arise that provide opportunities to correct for market failures in these areas will provide further indications of change in the electricity market. Whether the market failures themselves disappear will be indicated by the level of investment flowing into these areas.

A further important process to monitor is the way foreign direct investment, encouraged by NAFTA, hastens the international transfer and diffusion of technologies in ways that reduce environmental pressures.

C. Environmental Impact Data

The range of environmental impacts from thermal, hydroelectric and geothermal generation facilities may be measured by a variety of indicators. Such indicators as the flooded area created by dam construction, estimates of GHG emissions from dammed lakes, emissions of gases and underground reservoir indicators at geothermal facilities would contribute to understanding the environmental impacts of these generation resources as well.

1. Air

a. Air Emissions Inventories and Ambient Air Quality Records (SO_x, NO_x and O_3)

In assessing the long-term impacts of electricity restructuring and increased electricity trade on ground-level ozone, SO_x, and NO_x, the operating record, including fuel consumption, emissions inventories and ambient air monitoring data, will provide the greatest opportunity to correlate changes in operation to changes in the ambient environment. Data accuracy and reliability may need to be enhanced through cooperative efforts between the three NAFTA partners.

b. Particulate Matter (PM_{10})

Over time, the development of a baseline analysis of PM_{10} and its specific constituents will provide an indication of the relative contribution of specific precursors to PM_{10}. When this information is combined with operations and emissions data for NO_x and SO_2 from power plants and gas-production facilities, an overall indication of the contribution of electricity generation to PM_{10} levels will be more easily discernible.

c. Greenhouse Gases

As a condition of the UN Framework Convention on Climate Change and the Kyoto Protocol, Annex 1, countries, which include the United States and Canada, are to develop inventories of anthropogenic sources of greenhouse gases. Data provided in these inventories can be disaggregated to indicate changes in operating levels for thermal power plants in the United States and Canada.

Data for Mexico have also been developed through the US Country Studies Program, but may also be derived from emission coefficients, carbon contents of the fuels used and fuel consumption records to indicate changes in greenhouse gas emissions.

d. Mercury

Mercury emissions data are not collected through routine monitoring systems. Currently, these emission estimates are determined from fuel analysis and operating records. Whether these emissions increase as a result of the increased operation of fossil-fuel plants can be determined using the same methodologies.

e. Heavy Metals

Other data for heavy metals, such as arsenic, that are found naturally in some fuel supplies may also be monitored to generate estimates of regional emissions of these pollutants.

2. Water

In relation to new hydroelectric development, the changes in water flow resulting from new diversions can provide an indicator of impacts on rivers and streams. Additional data on areas of newly impounded reservoirs will also serve as an indicator of change.

a. Fuel Treatment and Processing

Changes in the volume of effluent discharge from fuel-treatment and -processing plants, in conjunction with increased or decreased demand for fuels, may provide an indicator of the magnitude of water-quality impacts in response to electricity market changes. To provide a meaningful indicator of change, data should be collected from coal mining and processing, uranium mining, milling and processing, and natural gas and petroleum extraction and processing facilities.

b. Acidified Lakes and Water Bodies

Changes in the current inventory of acidifying lakes in eastern Canada and the United States are a direct indicator of changes in thermal power plant operations over time. Tracking the monitoring records for identified lakes and water bodies and correlating the changes in thermal plant operations will give an indication of the cumulative environmental impact of activity in the electricity sector.

c. Mercury

Collecting data on mercury contamination trends in fish may provide an indication of the changes in operation for coal-fired thermal plants. Should new reservoirs be constructed to meet growing market demand, incidences of mercury contamination in fish will indicate biological impacts.

3. Land

An indicator of new land impacts from opening electricity markets are direct changes in infrastructure, such as the development of new transmission and pipeline corridors to allow increased access to new competitive markets. The impact on land of the addition of new infrastructure may be measured as linear kilometers of new corridors.

a. Waste Disposal

The area of land required for coal and uranium mining waste disposal, as well as for spent fuel and radioactive waste disposal, is an indicator of the impact of these processes on the environment. Correlating changes in volumes of disposed material to changes in operating levels for electricity generating facilities may be difficult due to the potential to export the unused fuel to non-NAFTA countries.

b. Acid Deposition

Current ambient air monitoring and soil sampling will provide an indicator of the changes in acid deposition on land.

c. Reservoirs and Corridors

Measuring the area of disturbed forest and wetland habitat in relation to new hydroelectric development and new transmission and pipeline corridors will indicate potential impacts on biota. Collecting data on changes in migratory patterns for mammals affected by hydro reservoirs and diversions provides an indicator of the level of adaptive response that is caused by altering northern ecosystems.

d. Forest Health

Data on acid deposition in eastern Canadian and US forests will provide an indication of the changes in biota resulting from air emissions.

D. Energy Consumption and End-Use Efficiencies

Changes in the end-use efficiencies of industrial, transportation, residential and commercial electricity consumers are key indicators of electricity use and the associated environmental impacts. These data may be derived from energy consumption and economic production, but other sources, such as mandated as well as voluntary efficiency standards issued by each country, separately or jointly, will also permit an assessment of the rate of efficiency improvement expected in the future.

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Daily Power Report	www.powermarketers.com

Appendix A

Cross-Border Electric Interconnections between Canada, the United States, and Mexico

Table A-1 US-Mexico Interconnections (Holders of US DOE Presidential Permits)

Permittee	FE Permit Number	Export Docket Number	Date Permit Signed	Description of Lines	
ERCOT/Mexico					
Central Power & Light Company	pp-94	EA-94A	92-06-18	69.0 kV	Brownsville, Texas
				138.0 kV	Brownsville, Texas
Comisión Federal de Electricidad	pp-03	E-6137	41-08-26	12.5 kV	(3 phase) Presidio, Texas
Comisión Federal de Electricidad		pp-51	E-7651	71-10-15	7.2 kV (1 phase) Redford, Texas
Comisión Federal de Electricidad	pp-59	E-7972	76-04-16	12.0 kV	Amistad Dam NW of Del Rio, Texas
Comisión Federal de Electricidad	pp-75	pp-75EA	82-08-13	7.2 kV	Comstoc, Texas
Comisión Federal de Electricidad del Golfo Norte	pp-50		49-04-29	138.0 kV	Eagle Pass, Texas
Comisión Federal de Electricidad del Golfo Norte	pp-57	IT-5025	75-01-24	138.0 kV	Laredo, Texas
Rio Grande Electric Cooperative, Inc.	pp-33	E-6868	59-07-28	14.4 kV	(14.4/24.9) KV Health Crossing, Texas
Rio Grande Electric Cooperative, Inc.	pp-53	E-7688	73-01-16	14.4 kV	Lajitas, Texas
Rio Grande Electric Cooperative, Inc.				14.4 kV	Castolon, Texas
Rio Grande Electric Cooperative, Inc.				14.4 kV	Candelaria, Texas
West Texas Utilities Company		EA-3-G	79-03-19		Authorized to use pp-03
WSCC/Mexico					
Arizona Public Service		EA-104			Authorized use of pp-68 & pp-79
Arizona Public Service	pp-106	EA-106	95-11-07	34.5 kV	San Louis, Arizona (Industrial)
Arizona Public Service	pp-107	EA-107	95-11-28	34.5 kV	Douglas, Arizona
Arizona Public Service	pp-108	EA-108	95-12-05	34.5 kV	San Louis, Arizona (Canal)
Citizens Utilities Company	pp-16	E-6431	52-08-08	13.0 kV	Nogales, Arizona
				2.3 kV	Nogales, Arizona
Citizens Utilities Company	pp-40	E-7370	67-12-29	13.8 kV	Lochiel, Arizona
El Paso Electric Company	pp-48	EA-48-1	70-09-30	11 S.0 kV	El Paso, Texas (Ascarate)
El Paso Electric Company	pp-92		92-04-16	115.0 kV	Diablo Substa, Sunland Park, New Mexico
Imperial Irrigation District	pp-90		90-11-29	34.5 kV	Calexico, California
San Diego Gas & Electric Company	pp-49	E-7544	70-12-29	69.0 kV	Tijuana, Mexico
San Diego Gas & Electric Company				12.0 kV	Tijuana, Mexico
San Diego Gas & Electric Company				12.0 kV	Tecate, Mexico
San Diego Gas & Electric Company	pp-68	pp-68EA	81-01-12	230.0 kV	San Diego Co, CA (Miguel-Tijuana)
San Diego Gas & Electric Company	pp-79	pp-79EA	83-12-20	460.0 kV	(2x230) kV Imperial Valley, California
Southern California Edison Company	pp-79SC		56-04-06	161.0 kV	Andrade, California

Source: DOE, 1997.

Table A-2 US-Canada Intereconnections (Holders of US DOE Presidential Permits

Permittee	FE Permit Number	Export Docket Number	Date Pernot Signed	Description of Lines	
WSCC/Canada					
Bonneville Power Administration	pp-10		45-10-27	1000.0 kV	(2x500) Blaine, Washington
Bonneville Power Administration	pp-36		64-09-03	230.0 kV	Nelway, British Columbia
Bonneville Power Administration	pp-46		70-08-29	230.0 kV	Nelway, British Columbia
Glacier Electric Cooperative	pp-18	EA-I8-B	52-07-28	120.0 kV	(120/240) Catway, Alberta
Glacier Electric Cooperative				20.0 kV	(20/240) Del Bonita, Alberta
Marias River Electric Coop Inc.	pp41	IT-6097	68-07-28	6.9 kV	Sweet Grass, Montana
PUD # 1 of Pend Oreille County, WA	p-34		59-11-05	7.2 kV	(1 phase) Pend Orielle Country, Washington
Portland General Electric		EA-97			Authorized to use pp-10, pp-34, pp-46
Puget Sound Power & Light Co.	pp-06-1		81-04-28	25.0 kV	Pt. Roberts, Washington
San Diego G&E Company		EA- 100			Authorized to use pp- 10, pp-34. pp-46
Washington Water Power	pp-86		93-03-08	230.0 kV	Northport, Washington
Western Systems Power Pool		EA-98			Authorized to use pp-10, pp-34, pp-46
MAPP/Canada					
Basin Electric Power Coop	pp-64	IE-78-5	79-11-30	230.0 kV	Tolga, North Dakota
Boise Cascade Corp.	pp-39	pp-39EA	66-11-07	6.6 kV	International Falls, Minnesota
Minnesota Power & Light Company	pp-78	pp-78EA	82-09-30	115.0 kV	International Falls, Minnesota
Minnoka Power Cooperative, Inc.	pp-61	E-9534	76-07-06	230.0 kV	Roseau County, Minnesota
Minnoka Power Cooperative, Inc.	pp-70		80-10-10	12.0 kV	Lake of theWoods County, Minnesota
North Central Electric Corp.	pp-67		79-06-27	12.5 kV	u/g Dunseith, North Dakota
Northern Electric Cooperative Assoc.	pp-28	E-6670	56-12-12	21.6 kV	(3x7.2)Valley County, Minnesota
Northem Electric Cooperative Assoc.	pp-44	E-7465	69-07-02	12.4 kV	St. Louis County, Minnesota
Northem Electric Cooperative Assoc.	pp-60	E-9554	76-07-12	28.8 kV	(2x l4.4) St.Louis County, Minnesota
Northern States Power Company	pp-45-1	E-7482	69-09-19	230.0 kV	Red River, North Dakota
Northern States Power Company	mp-63	EA-63-B	79-03-06	500.0 kV	Roseau County, Minnesota
Roseau Electric Cooperative, Inc.	pp-42	E-8361	68-11-25	7.2 kV	(1 phase) Roseau County, Minnesota
Roseau Electric Cooperative, Inc.	pp-55	E-8361	74-05-09	25.0 kV	(1 phase) Roseau County, Minnesota
ECAR/Canada					
Detroit Edison Company	pp-38	E-7206	66-03-01	345.0 kV	St. Clair, Michigan
Detroit Edison Company	pp-21	E-7206	53-10-12	230.0 kV	Marysville, Michigan
Detroit Edison Company				230.0 kV	Detroit, Michigan
Detroit Edison Company	pp-58	EA-58-E	75-07-25	345.0 kV	St. Clair, Michigan
St. Clair Tunnel Company	pp-99	EA-99	94-12-21	4.8 kV	St. Clair, Michigan

cont'd

Permittee	FE Permit Number	Export Docket Number	Date Pernot Signed	Description of Lines
NPCC/NY/Canada				
Long Sault Incorporated	pp-24		55-06-26	230.0 kV (2-115) Massena, New York
New York Power Authority	pp-25		55-09-26	460.0 kV (2-230) Massena, New York
New York Power Authority	pp-30		58-02-28	230.0 kV Devil's Hole, New York
New York Power Authority	pp-56		74-09- 13	765.0 kV Fort Covington, New York
New York Power Authority	pp-74		81 -09-04	690.0 kV (2x345) Niagara Falls, New York
Niagara Mohawk Power Corp.	pp-13	IT-6078	48-01-31	4.8 kV Hogansburg, New York
Niagara Mohawk Power Corp.	EA-24	56-01-24		Authorized to use pp-24
Niagara Mohawk Power Corp.	pp-31	E-6797	58-02-28	230.0 kV (3 phase) Devil's Hole, New York
Niagara Mohawk Power Corp.				76.0 kV (2x38) Buffalo, New York
Niagara Mohawk Power Corp.				138.0 kV {2x69) Queenstown, New York
Niagara Mohawk Power Corp.				48.0 kV 14-12) 3/c cables-Rainbow Br. New York
Niagara Mohawk Power Corp.				12.0 kV l/c cable-Rainbow Br. (never built)
Niagara Mohawk Power Corp.				138.0 kV (2-69) Devil's Hole, New York
Presley, E.T.	pp-54		73-03-16	4.8 kV (I phase) Wellesley Island, New York
NPCC/NE/Canada				
Central Maine Power Company	pp-62		76-09-29	120.0 kV 2-1/OTriplex Cables (120-240 V) Cobbrun Core, Maine
Citizens Utilities Company	pp-66	EA-66-B	79-06-21	120.0 kV Derby Line, Vermont
Citizens Utilities Company	pp-80	EA-80	83-08-05	25.0 kV Cannan, Vermont
Citizens Utilities Company				25.0 kV Norton, Vermont
Eastern Maine Electric Coop, Inc.	pp-20		53-05-27	6.9 kV Forest City, Maine
Eastern Maine Electric Coop, Inc.	pp-32	E-6853	59-02-05	69.0 kV Calais, Maine
Fairfield Energy Venture & Maine PS Co	pp-83EA			runs over facilities in PP-12 and PP-29
Fraser Papff Limited	pp-11	IT-5952	45-11-20	69.0 kV Madawaska, Maine
Joint Owners of the Highgate Project	pp-82		85-04- 14	345.0 kV Operating at 120 KV-Franklin, Vermont
Maine Electric Power Company	pp-43	E-7534	69-07-25	345.0 kV Houlton, Maine
Maine Public Service Company	pp-12	E-6751	48-01 -03	69.0 kV Limestone, Maine
Maine Public Service Company				69.0 kV Fort Fairfield, Maine
Maine Public Service Company	pp-29			138.0 kV at BM # 62, Aroostock County, Maine
Maine Public Service Company				138.0 kV (2x69) Madawaska, Maine
Maine Public Service Company	pp-81		84-09-21	7.2 kV River-de-Chute, Maine
New England Power Pool		EA-76-C		Authorized to use pp-76
Vermont Electric Cooperative	pp-69		80-10-09	20.0 kV (5-4) Sweby Line, Vermont
Vermont Electric Cooperative				48.0 kV Derby Line, Vermont
Vermont Electric Transmission Co.	pp-76		84-04-05	450.0 kV DC Norton, Vermont
Vermont Electric Transmission Co.				345.0 kV Sandy Pond to Milbury # 3, Vermont
Vermont Electric Transmission Co.				345.0 kV Milbury # 3 to West-Medway Substation, Vermont

Source: DOE, 1997.

Appendix B

Installed Capacity and Generation by Fuel Type in North America

Table B-1 Installed Capacity and Generation: Fossil Fuels, Nuclear, Hydroelectric

	Fossil Fuels					Nuclear	Hydroelectric	
Installed Capacity (MOO)[1]	Fuel Oil	Coal	Gas	Diesel	Subtotal		Conventional	Storage
Canada[2]	8,070	21,118	4,119	-	33,307	16,393	64,770	-
United States[3]	71,908	324,430	152,688	-	549,026	107,896	72,471	18,643
Mexico[4]	15,695	2,250	3,572	129	21,645	1,309	9,329	-
Total	95,673	347,798	160,379	129	603,978	125,598	146,570	18,643
Generation (GWH) in 1996								
Canada[5]	8,174	83,358	16,697	-	108,229	92,306	330,690	
United States[6]	67,346	1,737,453	262,730	-	2,067,529	674,729	348,647	3,088
Mexico	-	-	-	-	-	-	-	-
Total	75,520	1,820,811	279,427	0	2,175,758	767,035	679,337	3,088

Source: CEA, EIA, CFE.

Table B-2 Installed Capacity and Generation: Renewables

	Renewables					Total
Installed Capacity (MW)[1]	Wind	Solar	Biomass	Geothermal	Subtotal	
Canada[2]	-	-	1,035	-	1,035	115,505
United States[3]	1,801	333	10,419	2,842	15,395	763,431
Mexico[4]	2	-	-	753	755	33,037
Total	1,803	333	10,419	3,595	17,185	911,973
Generation (GWH) in 1996						
Canada[5]	-	-	-	-	3,644	534,869
United States[6]	3,517	911	64,074	16,248	71,590	3,162,495
Mexico	-	-	-	-	-	-
Total	3,517	911	64,074	16,248	84,750	3,697,364

[1] Nameplate capacity.
[2] As of December 31, 1995.
[3] As of January 1, 1996.
[4] As of December 31, 1995.
[5] Figures are for 1995.
[6] Fossil generation based on data reported by utilities only. IPPs reported another 213,600 GWH in 1996.

Source: CEA, EIA, CFE.

Appendix C

Electricity Consumption by State/Province in North America

Table C-1 Consumption in Canada

	Consumption (GWH)				Growth (%)		
Canada	1993	1994	1995	1996	1993-94	1994-95	1995-96
Newfoundland	10,909.4	11,036.4	11,188.8		1.16	1.38	
Prince Edward Island	790.1	815.5	764.8		3.22	-6.22	
Nova Scotia	9,930.3	9,978.1	10,051.5		0.48	0.74	
New Brunswick	13,009.3	14,121.2	13,918.0		8.55	-1.44	
Quebec	170,890.3	172,785.9	176,408.0		1.11	2.10	
Ontario	140,269.5	141,007.8	144,016.1		0.53	2.13	
Manitoba	18,007.9	18,437.7	18,974.3		2.39	2.91	
Saskatchewan	13,545.1	15,192.6	15,239.1		12.16	0.31	
Alberta	45,529.4	48,205.7	50,266.3		5.88	4.27	
British Columbia	58,704.6	60,994.0	61,376.6		3.90	0.63	
Yukon	338.4	298.9	346.5		-11.69	15.95	
North West Territories	590.7	578.1	807.9		-2.14	39.76	
Total	482,515.0	493,452.0	503,357.9	516,954.7	2.27	2.01	2.70

Source: Statistics Canada

Table C-2 Consumption in the United States

	Consumption (GWH)				Growth (%)		
United States	1993	1994	1995	1996	1993-94	1994-95	1995-96
Alabama	65,688	67,581.0	70,005.0	72,570.0	2.88	3.59	3.66
Arizona	44,380	47,282.0	48,589.0	51,719.0	6.54	2.76	6.44
Arkansas	32,180	32,619.0	34,669.0	35,487.0	1.36	6.28	2.36
California	209,500	213,684.0	212,605.0	219,803.0	2.00	-0.50	3.39
Colorado	32,760	34,502.0	34,734.0	37,400.0	5.32	0.67	7.68
Connecticut	27,359	28,026.0	27,970.0	28,391.0	2.44	-0.20	1.51
Delaware	9,122	9,299.0	9,580.0	9,750.0	1.94	3.02	1.77
District of Colunnbia	10,374	10,295.0	10,316.0	10,137.0	-0.76	0.20	-1.74
Florida	152,548	159,544.0	167,492.0	170,482.0	4.59	4.98	1.79
Georgia	89,311	89,913.0	96,192.0	100,241.0	0.67	6.98	4.21
Idaho	18,720	19,879.0	19,621.0	21,121.0	6.19	-1.30	7.64
Illinois	120,788	121,490.0	126,231.0	125,109.0	0.58	3.90	-0.89
Indiana	81,929	83,808.0	87,006.0	88,651.0	2.29	3.82	1.89
Iowa	32,144	33,039.0	34,301.0	34,876.0	2.78	3.82	1.68
Kansas	28,810	29,614.0	30,357.0	31,227.0	2.79	2.51	2.87
Kentucky	64,149	72,485.0	74,843.0	75,926.0	12.99	3.25	1.45
Louisiana	67,755	70,132.0	72,729.0	75,055.0	3.51	3.70	3.20
Maine	11,350	11,606.0	11,561.0	11,609.0	2.26	-0.39	0.42
Maryland	53,875	54,752.0	56,159.0	57,733.0	1.63	2.57	2.80
Massachusetts	45,482	46,091.0	46,502.0	47,381.0	1.34	0.89	1.89
Michigan	87,588	91,160.0	94,701.0	96,420.0	4.08	3.88	1.82
Minnesota	49,110	51,155.0	53,958.0	54,692.0	4.16	5.48	1.36
Mississippi	34,749	36,627.0	37,839.0	39,260.0	5.40	3.31	3.76
Missouri	58,620	59,693.0	62,841.0	64,482.0	1.83	5.27	2.61
Montana	12,725	13,184.0	13,418.0	12,413.0	3.61	1.77	-7.49
Nebraska	18,766	19,873.0	20,892.0	21,716.0	5.90	5.13	3.94
Nevada	18,500	2O,036.0	2O,659.0	22,502.0	8.30	3.11	8.92
New Jersey	65,623	66,258.0	66,754.0	66,975.0	0.97	0.75	0.33
New Mexico	14,946	15,859.0	16,416.0	16,823.0	6.11	3.51	2.48
New York	130,259	131,177.0	130,471.0	130,925.0	0.70	-0.54	0.35
New Hampshire	8,761	8,956.0	9,007.0	9,111.0	2.23	0.57	1.15
North Carolina	99,777	99,789.0	104,673.0	108,254.0	0.01	4.89	3.42
North Dakota	7,122	7,681.0	7,883.0	8,345.0	7.85	2.63	5.86
Oklahoma	40,231	41,143.0	41,392.0	43,116.0	2.27	0.61	4.17
Oregon	44,569	44,971.0	45,725.0	47,391.0	0.90	1.68	3.64
Ohio	148,571	154,377.0	158,621.0	157,649.0	3.91	2.75	-0.61
Pennsylvania	119,931	123,045.0	126,251.0	126,997.0	2.60	2.61	0.59
Rhode Island	6,549	6,572.0	6,636.0	6,566.0	0.35	0.97	-1.05
South Carolina	60,233	61,858.0	65,074.0	66,689.0	2.70	5.20	2.48
South Dakota	7,422	7,174.0	7,414.0	7,641.0	-3.34	3.35	3.06
Tennessee	79,832	82,533.0	82,030.0	86,763.0	3.38	-0.61	5.77
Texas	252,084	258,180.0	263,279.0	275,805.0	2.42	1.97	4.76
Utah	18,169	17,847.0	18,434.0	19,824.0	-1.77	3.29	7.54
Vermont	5,016	5,067.0	5,104.0	5,209.0	1.02	0.73	2.06
Virginia	81,372	82,210.0	85,162.0	87,549.0	1.03	3.59	2.80
West Virginia	24,441	24,776.0	25,977.0	26,126.0	1.37	4.85	0.57
Washington	90,493	87,133.0	88,353.0	86,662.0	-3.71	1.40	-1.91
Wisconsin	53,155	55,412.0	57,967.0	58,423.0	4.25	4.61	0.79
Wyoming	11,590	11,696.0	11,198.0	11,624.0	0.91	-4.26	3.80
Contiguous US Subtotal	2,848,428	2,921,083.0	2,999,591.0	3,070,620.0	2.55	2.69	2.37
Alaska and Hawaii	13,093	13,481.0	13,820.0	14,130.0	2.96	2.51	2.24
Total	2,861,521.0	2,934,564.0	3,013,411.0	3,084,750.0	2.55	2.69	2.37

Source: U S. Department of Energy, Energy Information Administration

Table C-3 Consumption in Mexico

	Consumption (GWH)				Change (%)		
Mexico	1993	1994	1995	1996	1993-94	1994-95	1995-96
Aguascalientes	944.9	1,031.9	1,126.9	1,269.0	9.22	9.20	12.61
Baja California Norte	3,855.3	4,293.6	4,560.2	5.245.0	11.37	6.21	15.02
Baja California Sur	671.3	753.7	745.2	868.3	12.27	-1.13	16.53
Campeche	425.2	467.3	481.9	471.5	9.89	3.14	-2.16
Coahuila	4,599.3	4,993.0	5,209.9	5,892.7	8.56	4.34	13.11
Colima	807.6	954.7	1,005.1	1,143.6	18.20	5.28	13.78
Chiapas	1,026.6	1,099.3	1,169.8	1,207.1	7.08	6.41	3.19
Chihuahua	4,526.2	5.013.0	5,278.2	5,598.5	10.76	5.29	6.07
Distrito Federal	11,358.4	11,920.9	11,860.7	11,570.2	4.95	-0.50	-2.45
Durango	1,321.6	1,490.1	1,686.2	1,801.6	12.74	13.16	6.84
Guanajuato	4,399.9	4,562.2	4,711.2	4,951.8	3.69	3.27	5.11
Guerrero	1,485.6	1,576.6	1,650.6	1,629.4	6.13	4.69	-1.28
Hidalgo	1,967.1	2,306.0	2,120.7	2,248.9	17.23	-8.03	6.05
Jalisco	6,163.4	6,638.5	6,616.9	6,955.5	7.71	-0.33	5.12
Estado de Mexico	10,685.9	11,152.6	11,068.6	12,342.3	4.37	-0.75	11.51
Michoacán	3,479.1	3,990.6	4,465.5	4,736.4	14.70	11.90	6.07
Morelos	1,170.8	1,229.9	1,305.1	1,286.9	5.05	6.12	-1.39
Nayarit	510.1	540.4	555.8	581.9	5.96	2.83	4.71
Nuevo León	8,371.2	9,197.8	9,692.2	10,728.9	9.87	5.38	10.70
Oaxaca	1,214.4	1,258.9	1,323.0	1,450.0	3.67	5.09	9.60
Puebla	3,835.2	4,091.4	4,054.6	4,511.2	6.68	-0.90	11.26
Querétaro	1,721.8	1,988.0	2,041.7	2,260.5	15.46	2.70	10.72
Quintana Roo	1,061.7	1,170.9	1,213.5	1,244.9	10.28	3.64	2.59
San Luis Potosí	2,775.2	3,034.1	3,024.3	3,258.5	9.33	-0.32	7.74
Sinaloa	2,472.5	2,695.2	2,745.3	2,867.2	9.01	1.86	4.44
Sonora	5,443.7	5,778.2	6,129.6	6,854.4	6.15	6.08	11.82
Tabasco	1,237.1	1,315.0	1,325.3	1,312.1	6.30	0.78	-1.00
Tamaulipas	3,983.9	4,373.5	4,651.3	4,868.0	9.78	6.35	4.66
Tlaxcala	367.5	804.6	836.4	987.2	118.94	3.95	18.03
Veracruz	6,425.4	6,969.8	7,781.6	8,483.3	8.47	11.65	9.02
Yucatán	1,382.2	1,531.1	1,537.6	1,548.0	10.78	0.42	0.68
Zacatecas	1,186.6	1,310.0	1,390.1	1,396.3	10.40	6.12	0.44
Total	100,876.4	109,532.9	113,365.1	121,571.2	8.58	3.50	7.24

Source: Comisión Federal de Electricidad

Appendix D

Sample US Residential Electricity Tariffs

Table D-1 Tariff Ranks of Sample US Companies

Rank #	Company	State	Residential Rate ($US per MWH)	(%) Change (1986-1997)
1	Long Island Lighting Co.*	New York	151.96	45.0
2	Public Service of N.H.*	New Hampshire	137.86	68.9
3	Atlantic City Electric Co.*	New Jersey	136.22	52.2
4	PECO Energy Co.*	Pennsylvania	135.60	20.3
5	Bangor Hydro-Electric Co.*	Maine	132.59	48.2
6	Southern California Edison*	California	132.12	62.9
7	Boston Edison Company*	Massachusetts	127.73	38.0
8	Pacific Gas & Electric*	California	127.66	42.6
9	Cleveland Electric Illumination Co.*	Ohio	118.79	28.8
10	San Diego Gas & Electric*	California	116.61	-4.3
51	Jacksonville Electric Authority**	Florida	68.15	0.7
52	Georgia Power Co.*	Georgia	67.74	16.4
53	Gulf Power Co.*	Florida	67.34	0.0
54	Electric Power Board of Chattanooga**	Tennessee	65.49	18.9
55	Omaha Public Power District****	Nebraska	64.86	21.3
56	Memphis Light, Gas & Water**	Tennessee	64.57	13.1
57	Union Electric Co.*	Missouri	60.65	-7.6
58	American Electric Power*	Virginia	60.22	-2.5
59	City Public Service**	Texas	56.72	-9.7
60	Seattle City Light**	Washington	48.62	24.4

* IOU7
** Municipal system,
*** Rural electric cooperative system,
**** Federal, state or district system.
# By 1997 residential rate.

Source: Jacksonville Electric Authority, www.jea.com.

Appendix E

Electricity Sector Institutions and Voluntary Organizations

North American Electric Reliability Council (NERC)

The North American Electric Reliability Council (NERC) was formed in 1968 in the aftermath of the 9 November 1965 blackout that affected the northeastern United States and Ontario, Canada. NERC's mission is to promote the reliability of the electricity supply for North America. NERC fulfills this mission by reviewing the past for lessons learned, monitoring the present for compliance with policies, standards, principles and guides for electric system operation and management, and by assessing the future reliability of bulk electric systems.

Membership

NERC is a not-for-profit corporation whose owners are the ten regional councils. The members of these Regional Councils and the one affiliate Council come from all segments of the electricity supply industry—investor-owned, federal, rural electric cooperatives, state/municipal and provincial utilities, independent power producers, customers, and power marketers. These entities account for virtually all the electricity supplied in the United States, Canada and a portion of the state of Baja California Norte, Mexico.

Meetings of the board are attended by observers from the US Department of Energy, the US Federal Energy Regulatory Commission, the National Energy Board of Canada, the National Association of Regulatory Utility Commissioners (NARUC), and several industry organizations: Edison Electric Institute, American Public Power Association, National Rural Electric Cooperative Association, Electric Power Research Institute, the Canadian Electricity Association, the Electric Power Supply Association, National Association of State Utility Consumer Advocates, and the Electricity Consumers Resource Council.

Organization

The activities of NERC are directed by its board of trustees. The board is comprised of about 30 electricity supply industry executives, including the board's officers, two representatives from each regional council, and others as needed to ensure at least two representatives from Canada and at least two representatives from each segment of the electricity-supply industry.

NERC Regions for the United States

Western Systems Coordinating Council

The Western Systems Coordinating Council (WSCC) is committed to being the regional forum for actively promoting regional electricity service reliability by developing planning and operating reliability criteria and policies, monitoring compliance with these criteria and policies, and facilitating a regional transmission planning process.

The Council and its members strive to maintain their self-governance and to unify the coordination and integration of the interconnected transmission system. An important element in WSCC's mission is to assess compliance with established criteria and policies and to administer enforcement where applicable. These objectives go hand-in-hand with developing and maintaining a strong and complementary working relationship with the regional transmission groups, other subregional planning groups and power pools.

Membership in WSCC is voluntary and open to any qualified electricity organization within the region, including independent power producers and marketers whose operation may have an impact on the reliability of the interconnected electricity systems in the western part of North America. Affiliate membership is open to any organization having a legitimate interest in the reliability of interconnected system operation or coordinated planning, including, but not limited to, brokers, environmental organizations, and state and federal regulatory agencies.

WSCC is the largest, geographically, of the ten regional councils. The Council's 1.8 million square-mile service territory is equivalent to more than half the contiguous area of the United States. WSCC was formed in 1967, and at the close of 1996 had a membership of 96 organizations that includes transmission dependent utilities, major transmission utilities, independent power producers, marketers, and a regulatory agency. Members provide reliable electricity service to over 59 million people in all or part of Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington and Wyoming, as well as the Canadian provinces of Alberta and British Columbia, and the northern portion of Baja California Norte, Mexico. The region is naturally divided into four major areas that reflect the varying, and sometimes extreme, geographic and climatic conditions.

The Council's organizational structure includes an executive committee, a board of trustees, a regional planning policy committee, four standing committees (Communications, Environmental, Operations, and Planning Coordination), and numerous subcommittees and working groups. About 500 executives, engineers, and other representatives from WSCC members dedicate time and expertise to these activities.

A permanent staff, located in Salt Lake City, Utah, provides the coordination and support needed to conduct the Council's work in an efficient and timely manner. The staff is responsible for participating in compliance-monitoring reviews, facilitating the preparation of detailed system-disturbance reports, compiling regional data, conducting technical studies, administering a dispatcher training program, publishing the Council's newsletter and annual reports, and coordinating the various committee activities.

System Information

Net generating capacity increased slightly to 157,784 MW. Net independent power producer generating capacity increased by 783 MW, while utility-owned generating capacity increased by 651 MW.

The interconnected transmission system was generally adequate to accommodate desired electricity transfers within the region. Although the transfer levels on the AC/DC entities from the Pacific northwest to California were reduced following the summer outages, Council members continued to derive substantial economic benefits from interconnected system operation.

The 1996 summer electricity demand increased by 5.1 percent compared to the summer of 1995 and was 4.2 percent greater than forecast. Temperatures were generally normal to above normal throughout the region, compared to generally near normal during the 1995 summer.

Hydro conditions in the Northwest Power Pool Area improved significantly, and reservoirs refilled to 99.5 percent of capacity by the end of July. The January-July runoff on the Columbia River, as measured at The Dalles, was 131.5 percent of normal, compared to 98 percent in 1995.

Western Interstate Energy Board

In 1983, the Western Interstate Energy Board, in cooperation with the Western Conference of Public Service Commissioners, created the Committee on Regional Electric Power Cooperation. The Committee includes the governors' or premiers' energy advisors, public-utility commissioners and facility-siting agencies for all major states and Canadian provinces in the Western Interconnection. The Committee is unique in North America in that it includes all the state/provincial government agencies with responsibilities for electricity issues within an entire reliability region.

The Committee is staffed by the Western Interstate Energy Board, which also serves as the energy arm of the Western Governors' Association. The Committee coordinates the appointment of state/provincial representatives to the three regional transmission associations and the Western Systems Coordinating Council and is the focal point for interactions on western regional electric power issues between western states/provinces and the western industry, as well as with the Federal Energy Regulatory Commission. The Committee's primary mission is to identify and resolve issues affecting the efficient operation of the western transmission system. The Committee also provides a vehicle for western states/provinces to share information on recent developments.

Mid-Continent Area Power Pool (MAPP)

The Mid-Continent Area Power Pool (MAPP) is a voluntary association of electric utilities that do business in an area encompassed by the northern borders of Manitoba and Saskatchewan in Canada to the southern borders of Iowa and Nebraska and central Montana to central Wisconsin in the United States. Its members are investor-owned utilities, cooperatives, municipal utilities, public power districts, a power marketing agency, power marketers, regulatory agencies, and independent power producers.

The MAPP organization performs three functions: it is a reliability council, responsible for the safety and reliability of NERC as a whole; a regional transmission group, responsible for facilitating open access of the transmission system; and a power and energy market, where both MAPP members and non-members may buy and sell electricity.

MAPP was first formed in the mid-1960s to plan regional transmission and generation. In 1972, the MAPP Agreement, outlining the provisions of the power pool, was approved by the Federal Power Administration. Members operated under this Agreement until 1 November 1996, when the Restated Agreement went into effect.

MAPPCOR, located in Minneapolis, Minnesota, provides services and maintains the personnel and facilities of the MAPP Center. Its staff includes engineers, technicians, computer programmers and other professionals. MAPPCOR serves as an impartial administrator for the region, approving or denying transmission requests for transactions. It also operates the MAPP OASIS node.

Table E-1 MAPP Statistics for the US and Canada

MAPP Statistics for the US and Canada	
1996 Peak Demand	32,441 MW (Non-coincident Summer Peak)
Geographic Area	890,000 sq. miles
Population	16 million
Projected Annual Growth	1.5%
Miles of Transmission Lines	19,959
Generating Capacity	39,552 MW
Coal	54%
Hydropower	23%
Nuclear	10%
Gas/Oil	12%
Other	1%
Energy Production	
Coal	60%
Hydropower	24%
Nuclear	14%
Gas/Oil	1%
Other	1%

Source: NERC (www.nerc.com).

Northeast Power Coordinating Council (NPCC)

The Northeast Power Coordinating Council (NPCC) is a voluntary, non-profit organization. Its members and associate members currently represent investor- and publicly-owned utilities serving the northeastern United States and central and eastern Canada, and power marketers. In addition, NPCC is working closely with a number of associated organizations such as power pools and control centers. NPCC has 22 full members and 15 associate members.

The area covered by NPCC includes New York, the six New England states, and the provinces of Ontario, Quebec, New Brunswick, Nova Scotia and Prince Edward Island. The total population served is approximately 49 million, of which approximately 20 million are electricity customers. The area covered is approximately 1 million square miles.

National Association of Regulatory Utility Commissioners (NARUC)

The National Association of Regulatory Utility Commissioners (NARUC) is a quasi-governmental nonprofit corporation founded on 5 March 1989. Within its membership are the governmental agencies of the fifty states and of the District of Columbia, Puerto Rico, and the Virgin Islands that are engaged in the regulation of utilities and carriers. The chief objective is to serve the consumer interest by seeking to improve the quality and effectiveness of public regulation in the United States.

The objectives of the Association are the advancement of commission regulation through the study and discussion of subjects concerning the operation and supervision of public utilities and carriers, the promotion of uniformity in the regulation of public utilities and carriers by the several commissions, the promotion of coordinated action by the commissions of the several states to protect the common interests of the people with respect to the regulation of public utilities and carriers, and the promotion of cooperation of the commissions of the several States with each other and with the Federal commissions represented in the Association.

The active members of the Association are the officers of the Association, the commissioners of the commissions of the several states, the federal government and the territories of the United States engaged in the regulation of public utilities or carriers; provided, however, that no more than ten commissions of the federal government shall be represented in the Association at any time.

The associate members of the Association are the staff members of the commissions, the staff members of the Association and its research arm, the commissioners and staff members of other commissions engaged in the regulation of public utilities and carriers who have been approved as members by the Association in annual convention, the members of federal agencies engaged in energy supply, and the members of federal and state agencies engaged in public utility and carrier policy formulation and planning and who are not otherwise entitled to membership within the Association.

In addition to the Executive Committee, the following are standing committees of the Association: Committee on Communications, Committee on Electricity, Committee on Energy Resources and the Environment, Committee on Finance and Technology, Committee on Gas, Committee on International Relations, and Committee on Water.

Appendix F

Planned or Projected Electricity Sector Expansion

Table F-1 Projected Capacity Additions in Canada, by Province

Province	1996	2005	2010	Change (%) 1996-2005	Change (%) 1996-2010
Alberta	8,975	9,281	9,289	3.4	3.5
British Columbia	13,069	14,538	15,454	11.2	18.2
Manitoba	4,912	4,648	4,543	-5.4	-7.5
New Brunswick	4,353	4,414	4,205	1.4	-3.4
Newfoundland	7,435	7,609	7,752	2.3	4.3
Nova Scotia	2,505	2,898	2,898	15.7	15.7
Northwest Territories	218	243	243	11.5	11.5
Ontario	35,768	36,444	36,444	1.9	1.9
Prince Edward Island	121	145	145	19.8	19.8
Quebec	35,209	36,925	39,541	4.9	12.3
Saskatchewan	3,082	3,339	3,339	8.3	8.3
Yukon	134	138	140	3.0	4.5
Total	115,781	120,622	123,993	4.2	7.1

Source: CEA, 1996.

Table F-2 Planned Capacity Additions in Mexico: CFE's Expansion Plan

Project	Location	Type	Probable Date of Bids	Modality of Bidding	Capacity Additions 1998	1999	2000	2001	2002	2003	2004	2005	2006	Total
Under construction														
Samalayucal I (1,2 & 3)	Chih	CC	Awarded	CAT	347.8	173.9								521.7
Mérida III	Yuc	CC	Awarded	PEE			499							499
Marítaro (BLT)	Mich	Geo	1997	CAT		40								40
Bidding underway														
Cerro Prieto IV	BC	Geo	1996	CAT			100							100
Rosarito VIII & IX	BC	CC	1996	CAT			450							450
Chihuahua	Chih	CC	1996	CAT			450							45
Monterrey I, II & III	NL	CC	1996	CAT			450							450
Short-term Action Plan														
Rosarito VII	BC	TG	1997	RP		150								150
Hermosillo I (CFE)	Son	TG	1997	RP		150								150
Río Bravo IV & V (IPP)	Tamps	TG	1997	RP		150								150
Huinalá	NL	TG	1997	RP		150								150
El Saúz	Qro	TG	1997	RP		150								150
External producers (IPPs)														
El Saúz (IPP)	Qro	CC	1997	PEE				450						450
Hermosillo II (IPP)	Son	CC	1997	PEE				225						225
Río Bravo IV & V (IPP)	Tamps	CC	1997	PEE				450						450
Saltillo	Coah	CC	1997	PEE				225						225
Bid packages under review														
LaVenta I & II	Oax	Eol	1996			54								54
Tres Virgenes	BCS	Geo	1996		10									10
San Rafael	Nay	Hid	1997			24								24
Pto. San Carlos III & IV	BCS	CITD	1997					375		375				75
Guerrero Negro (three units)	BCS	CITD	1997			18								18
El Chino I	Mich	Geo	1997			50								50
Bidding modality to be determined														
El Cajon	Nay	Hid	1998									636		636
Tuxpan	Ver	CC	1998						450	450				900
Campeche I	Tab/Camp	CC	1998						225					225
Monterrey	NL	TG	1998						450					450
Altamira	Tamps	CC/C	1998						450		450		450	1,350
Francisco Villa (repowering)*	Chih	CC	1999							249				249
Rosarito X & XI	BC	CC	1999							450				450
Noroeste (Naco-Nogales)	Son	CC	1999							225		225		450
Rio Bravo	Tamps	CC	1999							450	450			900
Laguna I & II	Dur	CC	2000								450			450
Matamoros	Tamps	CC	2001									450	450	900
Oriental	Ver	CC	2001									450	450	900
Valladolid	Yuc	CC	2001									225		225
Baja California Sur (San Carlos)	BCS	CITD	2002										375	38
Baja California Norte	BCN	CC	2002										225	225
Total					358	1,110	1,949	1,388	1,575	1,862	1,350	1,986	1,613	13,189

* Incremental capacity of 150 MW. PEE: IPP. RP: CFE budgeted resources. CAT: BLT.

Source: CFE.

Legend: Modalities: PEE, IPP; RP, CFE budgeted resources; CAT, BLT.
Type: CC, combined cycle; TG, gas turbine; CITD, internal combustion (diesel); Geo, geothermal; Eol, windpower; Hid, hydroelectric.

Location: Chih, Chihuahua; Yuc, Yucatán; Mich, Michoacán; BC, Baja California; NL, Nuevo León; Son, Sonora; Tamps, Tamaulipas; Qro, Querétaro; Coah, Coahuila; Oax, Oaxaca; BCS, Baja California Sur; Nay, Nayarit; Ver, Veracruz; Tab, Tabasco; Camp, Campeche; Dur, Durango.

Table F-3 Planned Capacity Additions in Mexico, by State, 1996-2006

Northern Border	Planned Capacity (MW)
Baja California Norte and Sur	1,516
Chihuahua	1,22 1
Coahuila	225
Nuevo León	1,050
Sonora	825
Tamaulipas	3,750
Subtotal	8,586
Central States	
Durango	450
Michoacán	90
Nayarit	660
Querétaro	600
Veracruz	1,800
Subtotal	3,600
South and Southeast	
Oaxaca	54
Yucatán	724
Tabasco/Campeche	225
Subtotal	1003
Total	13,189

Source: CFE.

Table F-4 Structure of CFE's Current and Planned Capacity, 1995-2006

Technology/FuelType	1995 (MW)	Share (%)	1996 (MW)	Share (%)	2006 (MW)	Share (%)	Change* (%)
Total	33,037.33	100.00	34,790.48	100.00	47,979.68	100.00	37.91
Fossil-Fired Thermoelectric							
Coal	2,250	6.81	2,600	7.47	3,950.00	8.23	51.92
Fuel Oil and/or Gas	13,594.50	41.15	14,294.50	41.09	14,294.50	29.79	0.00
Dual Cycle	2,100	6.36	2,100	6.04	2,100.00	4.38	0.00
Canbined Cycle Natural Gas	1,889.66	5.72	1,911.66	5.49	11,506.36	23.98	501.90
Gas Turbines	1,682.08	5.09	1,674.08	4.81	2,874.08	5.99	71.68
Fixed			1,552.58	4.46			
Mobile			121.5	0.35			
Internal Combustion (Diesel)	128.51	0.39	121.26	0.35	251.76	0.52	107.62
Subtotal	21,644.75	65.51	22,701.50	65.25	34,976.70	72.90	54.07
Alternative Thermoelectric							
Nuclear	1,309.06	3.96	1,309.06	3.76	1,309.06	2.73	0.00
Geothermal	752.9	2.28	743.9	2.14	943.90	1.97	26.89
Hydroelectric	9,329.04	28.24	10,034.44	28.84	10,694.44	22.29	6.58
Wind	1.58	0.01	1.575	0.01	55.58	0.12	3,428.57
Subtotal	11,392.58	34.49	12,088.98	34.75	13,002.98	27.10	7.56

* Change in installed capacity as planned for 2006 relative to 1995.

Source: CFE.

Table F-5 Projected Capacity Additions in the United States, by State

State	Existing* Net Summer Capability	Projected Capacity Additions**	State	Existing* Net Summer Capability	Projected Capacity Additions**
Alabama	20,463	1,413	New Jersey	13,817	2,641
Arizona	15,221	316	New Mexico	5,078	0
Arkansas	9,639	103	New York	32,147	62
California	43,302	446	North Carolina	20,597	4,001
Colorado	6,647	539	North Dakota	4,485	0
Connecticut	6,722	0	Ohio	27,365	3,178
Delaware	2,239	0	Oklahoma	12,928	703
District of Columbia	806	0	Oregon	10,446	0
Florida	35,857	4,100	Pennsylvania	33,698	140
Georgia	22,290	1,069	Rhode Island	442	0
Idaho	2,559	19	South Carolina	16,701	1,063
Illinois	33,139	2,431	South Dakota	2,950	3,070
Indiana	20,712	558	Tennessee	16,144	1,170
Iowa	8,237	63	Texas	64,424	5,878
Kansas	9.675	258	Utah	4,927	8
Kentucky	15,425	1,240	Vermont	1,090	8
Louisiana	17,019	212	Virginia	14,342	2,338
Maine	2,432	43	West Virginia	14,451	0
Maryland	10,957	2,083	Washington	24,277	117
Massachusetts	9,288	0	Wisconsin	11,536	960
Michigan	21,981	2	Wyoming	5,970	0
Minnesota	8,923	20			
Mississippi	7,170	326	Contiguous US Subtotal	702,776	43,058
Missouri	15,724	2,003			
Montana	4,943	0	Alaska and Hawaii	3,334	164
Nebraska	5,529	387			
Nevada	5,556	90	Total	706,110	43,222
New Hampshire	2,506	0			

Figures in Megawatts.

* As of 1996.

** As of 2005.

Source: EIA. "Inventory of Power Plants in the United States—1995," Table 17.

Appendix G

Trade in Equipment and Materials in the Energy Sector

The tables presented here summarize trade in equipment and materials taken from three different sources of data, which are likely to use different methods for aggregating trade figures by tariff codes. Hence, there is not necessarily much agreement between the figures presented here from the different sources. As noted in the text, however, certain general observations do seem warranted, based on these data.

Banco Nacional del Comercio Exterior (Bancomext), Mexico

Table G-1 Mexican Trade with US and Canada, Selected Energy Sector Goods

Trade Flow	1997*	1996	1995	1994	Change (%) 1994-1997
Exports					
Canada	12,498	6,741	19,063	36,296	-65.57
United States	162,210	676,755	161,047	479,649	-66.18
Total	174,707	683,497	180,110	515,945	-66.14
Imports					
Canada	8,230	10,123	6,706	6,049	36.06
United States	485,373	394,561	261,540	366,329	32.50
Total	493,603	404,684	268,246	372,377	32.55
Two-Way					
Canada	20,728	16,864	25,769	42,345	-51.05
United States	647,583	1,071,317	422,587	845,978	-23.45
Total	668,311	1,088,181	448,356	888,323	-24.77

Permanent imports and exports (excludes maquiladora transactions and temporary trade).
Figures in thousands of USD.
* Annualized, based on January - July data.

Source: Banco Nacional del Comercio Exterior.

Table G-2 US Trade with Mexico and Canada, Selected Energy Sector Goods

Trade Flow	1997*	1996*	1995*	Change (%) 1995-1997
Exports				
Canada	6,173,548	5,329,762	5,157,522	19.70
Mexico	2,436,622	1,245,604	1,260,614	93.29
Total	8,610,170	6,575,366	6,418,136	34.15
Imports				
Canada	2,965,982	2,894,208	3,187,360	-6.95
Mexico	1,495,966	1,194,047	1,099,345	36.08
Total	4,461,948	4,088,255	4,286,705	4.09
Two-Way				
Canada	9,139,530	8,223,970	8,344,882	9.52
Mexico	3,932,588	2,439,651	2,359,959	66.64
Total	13,072,118	10,663,621	10,704,841	22.11

Figures in thousands of USD.
* Annualized, based on January - June data.

Source: US DOE, Office of NAFTA.

Bancomext figures for trade with non-NAFTA countries

Table G-3 Mexican Trade with Selected Nations, Selected Energy Sector Products

Country	1997*	1996	1995	1994	Change (%) 1994-1997
China	87,765	341	1,097	524	16649
Finland	498,677	2O,121	131,027	114,467	336
France	2,492,637	5,251,439	12,365,762	13,999,868	-82
Germany	11,362,062	4,579,086	1,752,631	5,380,385	111
Italy	714,668	418,798	4,338,162	464,375	54
Japan	708,327	805,293	666,323	8,660,240	-92
Sweden	1,680	10,405	13,996	22,149	-92
Switzerland	1,002,091	3,157	65,750	79,009	1168
Spain	349,378	1,325,143	131,679	6,198,420	-94

Permanent imports (excludes maquiladora transactions and temporary trade flows).
Figures in thousands of USD.
*January-July data, annualized.

Source: BANCOMEXT.

Appendix H

Background on Electricity Restructuring at State/Provincial Levels in the United States and Canada

This annex presents recent information on electricity-sector restructuring taking place in the United States and Canada, taken from the National Regulatory Research Institute (NRRI) website as well as based on interviews and conversations with regulators in the United States and Canada.

United States

The pace of deregulation in the United States is accelerating as more and more states have passed legislation to restructure electricity markets in the next several years. The list of states that have passed competition legislation increased in November 1997, as Illinois and Massachusetts joined California, Maine, Montana, Nevada, New Hampshire, Oklahoma, Pennsylvania and Rhode Island. California is considered the pace-setter, and will move to retail competition in January 1998.

The table below summarizes recent action in the ten states where restructuring legislation has passed. A map on the page following it provides a national panorama of activity. Lastly, on the subsequent pages the “scorecard” for deregulation in the United States, prepared by the National Regulatory Research Institute (NRRI) is reproduced. The website for the NRRI is <http://www.nrri.ohio-state.edu>.

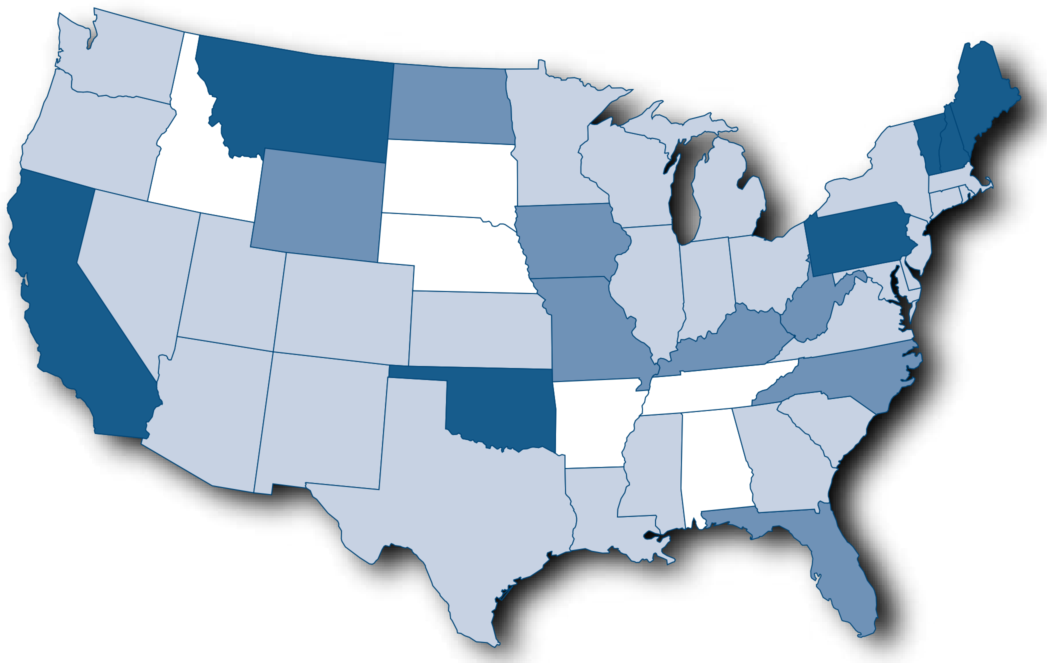
Table H-1 Restructuring Legislation Passed in Ten US States

State	Legislative Action	Regulatory Action	Stranded Costs	Pilot Programs
California	1996: AB 1890 enacted	5/97: CPUC sets 1/98 date for start of competition	9/97: Approval for securing $7.3 billion in stranded costs	
Illinois	1997: retail choice legislation passed			1996: Retail wheeling pilot program for IL (large customers only) and CILCO (all customer classes)
Maine	1997: LD 1804 enacted, providing for retail competition by 2000, with market share cap at 33% in old service area, terms of divestiture and renewables portfolio requirement	Restructuring details are being worked out.	Issue deferred to 1998 legislative session	
Massachusetts	1997: retail choice legislation approved	1996: Legislative proposal, model rules and final order issued	Full recovery over 10 years for costs incurred before March, 1995.	1997: Mass Electric Co. launches 1-year pilot in 4 communities, with "green" power option
Montana	1997: SB 390 enacted, provides for large industrial customers to choose by 7/98, retail customers by 2002, with 2-year rate freeze	PSC to implement SB 390	Allows 2.8-cent per kWH access charge. Securing stranded costs, with rate freeze, secured by customer transition charge	
Nevada	1997: AB 366 enacted, with retail competition by 7/2001	1996: PSC committee adopted 10 principles	Full recovery	
New Hampshire	1996: HB 1392 enacted, with retail choice by 1/98	1997: Final order issued	Full stranded cost recovery not guaranteed	1996: Limited wheeling pilot for 2-years
Oklahoma	1997: SB 500 enacted, with retail competition by 2002	Under study	Stranded cost recovery over 5-7 years as long as rates don't increase	
Pennsylvania	1996: HB 1509 enacted	1997: Final order with guidelines for maintaining customer services at same level	Decision left to PUC, though legislation encourages mitigation, and securitization is under study	1997: Pilot for 5% of PECO customers, through 1999, with retail competition phased-in by 2001
Rhode Island	1997: H 7003 enacted, for securitization of stranded costs, rules due by end of 1997 1996: Retail choice legislation passed, with direct access for 10% of all classes by 7/97	Formal proceedings	Customer transition charge of 2.8 cents per kWH, with recovery through 2009	

Source: EIA, press reports.

The map below summarizes data on state-level activities contained in the table on the following pages. This material is the result of a survey of US state utility regulators undertaken by the NRRI.

Figure H-1 Industry Restructuring in the United States



- Group 1 Restructuring plan adopted or legislation enacted: 7 states, accounting for 20% of the US population.
- Group 2 Legislation under considration or companies filing plans: 27 states, accounting for 60% of the US population.
- Group 3 Restructuring under study: 8 states, accounting for 14% of the US population.
- Group 4 No substantive activity or decision that action not necessary: 6 states, accounting for 6% of the US population.

Source: Ontario Ministry of Finance, "Direction for Change," using data compiled by the NRRI and other sources.

Note: this map was prepared before passage of legislation on deregulation in Illinois and Massachusetts.

Table H-2 US State-level Activities on Restructuring

State	Regulatory Commission Activities									Implementation		Legislative Activities					
	No activity	PUC Forum	Staff Report	Formal Inquiry	Guide-lines	Draft Order	Comm. Hengs	Final Order	Pilot Pgm	Utility Plan	Approve Plan	Legis. Study	Bail Intro	Bail Passed	Failed or Veto	In Court	Exec. Branch Study
AL		●											●			●	
AK		●		●			●						●				
AZ		●	●	●		●		●		●		●	●		●	●	
AR		●								●		●					
CA		●				●		●		●			●	●			
CO		●	●	●									●		●		
CT				●	●							●	●		●		●
DC				●						●							
DE		●	●	●			●			●		●	●				
FL		●										●	●		●		
GA		●		●									●				
HI		●		●									●				
ID		●		●	●	●	●		●			●					
IL		●	●						●			●	●		●		
IN		●	●									●	●				
IA		●	●	●	●		●		●	●							
KS		●		●								●	●				
KY		●											●				
LA		●	●	●	●					●		●	●				
ME		●	●	●	●	●	●			●		●	●				
MD		●	●	●	●							●		●			
MA				●		●	●	●	●	●	●	●	●			●	
MI		●	●			●	●	●	●	●						●	●
MN		●	●	●	●							●	●		●		
MS		●	●	●			●			●		●	●				
MO		●		●					●	●		●			●		
MT		●			●					●		●	●	●			
NE												●					
NV				●	●							●	●	●	●		
NH					●	●	●	●	●				●	●		●	
NJ			●	●	●				●	●	●						
NM		●		●						●	●	●	●				
NY		●			●		●	●	●	●	●	●	●			●	
NC		●		●								●					
ND		●		●		●						●	●				
OH		●		●	●	●				●		●	●				
OK		●		●	●		●					●	●	●			
OR		●				●			●	●		●	●		●		●
PA			●	●	●		●		●	●			●	●			●
RI			●		●					●			●	●			
SC		●	●	●									●				
SD		●															
TN		●															
TX			●	●	●	●		●		●		●	●		●		
UT		●	●	●	●							●	●				
VT		●		●	●	●	●	●		●		●	●				●
VA		●	●	●						●		●	●				
WA				●	●				●								●
WV		●	●	●													
WI		●	●	●	●	●	●			●		●					
WY		●	●		●												
Totals	0	41	22	34	21	13	14	9	12	24	3	31	25	8	10	6	6

As of 25 November 1997. Data believed to be accurate as of this date. Some information has been received from secondary sources and is unverified.This report is a summary of NRRT's database. The full text of the database, over 100 pages, can be retrieved from NRRI's website. For further information, contact <John Hoag.jcht@asu.edu>. Tel: (614) 292-9666.

Source: National Regulatory Research Institute.

In Canada, the drive for restructuring is gaining momentum rapidly, in part due to the impact of US federal actions as well as those of the pace-setting provinces on the issue, especially Alberta. Since 1995, four provinces have moved or are moving to open up provincial energy markets to competition, and it is very likely no accident that the four are among the most important exporters of electricity to the United States: Alberta, Quebec, British Columbia and Manitoba.[205] From among these jurisdictions, the major utilities of Alberta, British Columbia and Quebec have all obtained FERC marketing licenses in the last year.

Alberta

Alberta passed the Alberta Electric Utilities Act in 1995, introducing competition for wholesale electricity markets. As specified in the Act, on 1 January 1996, Alberta's electric system was restructured as a single power pool with transmission controlled by a new independent entity. Under the Act, the three major integrated utilities, TransAlta Utilities, Alberta Power and Edmonton Power, operate their transmission assets through a transmission administrator, known as the Grid Company of Alberta Inc., which applies a regulated cost-based tariff to use of the transmission system.

With the establishment of the pool, all electricity bought or sold in Alberta must go through the pool. All generators bid the daily output of their plants for dispatch on an hourly basis according to the pool price. All imports and exports go through the pool, and parties who wish to import or export must become members of the pool and demonstrate that they have appropriate transmission arrangements for delivery of the power.

Any generator connected to the provincial transmission grid can bid into the power pool and all distributors must receive their power requirements from the pool. There are a number of legislated financial instruments that ensure that low-cost electricity, produced by existing plants for which the province's consumers have already paid, is effectively price-protected for those consumers. In essence, there is a wholesale competitive market for electricity production with consumer protection mechanisms to prevent windfall profits from plants that were built by monopoly utilities. On 10 October 1997, the Alberta Minister of Energy, Steve West, announced that in 1999, all electricity users would be permitted to purchase their electricity from any supplier. Draft legislation governing the market structure will be released in December for consultation purposes, and a bill will be introduced in the spring of 1998.

Manitoba

In June 1997, the provincial legislature approved a law giving other power producers access to Manitoba Hydro's transmission lines, ending the utility's monopoly over the power grid. In preparation for competition, Manitoba Hydro has restructured itself into distinct functional business units and set financial targets, including one to improve its performance according to such financial indicators as its debt-equity ratio.

[205] See Ontario Ministry of Finance, (Ministry of Finance: Toronto, November, 1997): 3.

British Columbia

BC Hydro attempted to take advantage of new opportunities for exports, while at the same time avoiding potential disputes, by gaining admission to US regional transmission associations formed in response to the 1992 federal Energy Policy Act, which expanded FERC's authority to order transmission-owning utilities to provide transmission services to third parties. Because it is not regulated by a US state or federal government, BC Hydro is not required to provide the same access that it enjoys under restructured jurisdictions in the United States; but BC Hydro will not be offered any greater access to transmission by US utilities than it is willing to offer. This runs counter to the national treatment discipline in NAFTA, but BC Hydro appears to be accepting this restriction in exchange for improved access to US wholesale markets. As required by its membership in the Western Regional Transmission Associaton (WRTA), BC Hydro has also filed a wholesale wheeling application with the British Columbia Utilities Commission (BCUC) to grant access to its transmission system to other utilities and IPPs.

In an effort to avoid being left behind by BC Hydro, IPPs in the province actively lobbied the government and appeared before the BCUC to advocate changes to the BC domestic market structure that would permit them to export electricity to the United States directly. While IPPs are limited at present to selling power to BC Hydro for resale by it in the export market if it chooses to do so, the BCUC has approved direct exports by IPPs in a recent decision on wholesale wheeling.

Marketing activities by BC and Alberta producers, including utilities like BC Hydro, across the border provoked complaints from US utilities and producers that they do not have reciprocal access to Canadian markets. The Bonneville Power Administration and large US electricity marketers intervened in proceedings before the BCUC on issues related to transmission services.

In November 1995, BC Hydro applied to the British Columbia regulatory authority for a wholesale tariff that would open up the transmission system for other users. The utilities commission granted approval of the tariff in June 1996, with several conditions that were to be reviewed in a subsequent application. The utility has applied for approval of an updated tariff that addresses concerns expressed by the commission and other intervening agencies. A hearing on the application was scheduled for February 1998. There are only a limited number of small municipal utilities and one privately owned utility, representing approximately 9 percent of BC electricity consumption, that can potentially qualify for purchases through the wholesale tariff. However, in addition to the introduction of wholesale access, the government has appointed an advisor and task force on electricity industry restructuring that is mandated to examine the introduction of retail competition in British Columbia.

In response to public concerns regarding the operation of hydroelectric facilities, in November 1996, the provincial government announced the establishment of a Water-Use Planning process that would review the existing water licenses for British Columbia hydro facilities. The purpose of the planning process is to reallocate water for fish and mitigating measures and resolve long-standing fish issues. The plans are intended to cover non-power issues, such as fisheries, recreation, flood control and irrigation, and will result in amendments to existing licenses.[206]

[206] Response from Canada to Article 14 Complaint under the North American Agreement on Environmental Cooperation, 21 July 1997, III-2

Quebec

In late 1996, the province unveiled a new energy policy that opens Hydro-Québec's transmission grid to outside competitors; sets wheeling rates; and encourages alliances and partnerships to promote Quebec's export potential.

The Loi sur la Régie de l'Énergie also allows for the independent regulation of Hydro-Québec, the provincially owned utility. As of 1 May 1997, the Régie has the authority to set transmission rates for wholesale customers. As in British Columbia, few customers can use the transmission tariff to buy power for use in Quebec. In fact, apart from Hydro-Québec, there are only a handful of municipal utilities, which use about 2 percent of Quebec's electricity.[207]

Ontario

In 1996, the Advisory Committee on Competition in Ontario's Electricity System (known as the MacDonald Committee, after its chairman, Hon. Donald MacDonald), recommended ways to open up Ontario's electricity market to competition.

The provincial government, agreeing with the findings of the committee that change is needed in the energy market and Ontario Hydro, prepared a blueprint for legislative and regulatory change contained in a recently issued report, Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario (November 1997), which proposes that they should: introduce legislation in 1998 to replace the province's Power Corporation Act and redesig the Ontario Energy Board; proceed with preparations for competition in 1999; and introduce competition, including retail choice, in 2000.

The key argument made in this proposal is that electricity restructuring in neighboring jurisdictions in the United States is leading to lower prices for industries that compete with Ontario industries. As stated in the proposal: "Electricity prices in the high-cost northeastern US market are expected to decline, improving the relative economic position of those with whom Ontario competes for investment and jobs."[208]

To keep pace with change outside of Ontario, the proposal includes a blueprint for the radical restructuring of Ontario Hydro, the largest utility in North America. Under the proposal, which the government hopes to implement over the next three years, all electricity consumers would be permitted to purchase their electricity from any generator, including Ontario Hydro's successor company, the Ontario Electricity Generation Company.

Under the new structure, the Ontario Energy Board would have an expanded regulatory role. Existing Ontario Hydro debt, which amounts to $30 billion, would be held by a publicly owned financial holding company, and any new revenues generated through internal efficiencies and rationalization of distribution companies, a new property tax structure and earned returns would be used to pay down the debt.

The white paper includes two options for addressing environmental concerns: a nitrogen oxides emissions cap and trading program for all Ontario-based generation and an emission performance standard for all generators selling power into the Ontario market.

To begin the process of introducing competition as soon as possible, the Ontario government will introduce legislation in 1998 that will replace the Power Corporation Act, Ontario Hydro's governing legislation. In the meantime any supply shortfalls that result from the shutdown of several of Ontario Hydro's nuclear generating plants will be met through the establishment of an independent market operator who will receive bids from within and outside Ontario for replacement power.

[207] Testimony of Ian Goodman, Docket No. ER97-851-000 Federal Energy Regulatory Board Application of H.Q. Energy Services (US) Inc.

[208] Ontario Ministry of Energy Science and Technology, "Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario," November 1997: 4.

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