

Environmental Challenges and Opportunities of the Evolving Continental Electricity Market

Working Draft:
**Background Note for the First Meeting of the Advisory Board
North American Commission for Environmental Cooperation**

16 JANUARY 2001

FIRST MEETING OF THE ADVISORY BOARD

The first meeting of the Advisory Board on Environmental Challenges and Opportunities of the Evolving Continental Electricity Market will take place on Tuesday, 16 January 2001, in Montreal, Quebec, Canada. The Advisory Board to the North American Commission for Environmental Cooperation (NACEC) is chaired by the Honorable Phil Sharp, and is composed of senior officials and experts from Canada, Mexico and the United States.

The mandate of the Advisory Board is to provide guidance, advice and recommendations to the NACEC on its Environmental Challenges and Opportunities of the Evolving Continental Electricity Market initiative, which includes a report. The report, which is being prepared by the Secretariat in accordance with Article 13 provisions of the North American Agreement on Environmental Cooperation, will be prepared during the first eight months of 2001. It is expected that a symposium on specific aspects of electricity restructuring and the environment will be held in late 2001 and that the final Secretariat report will be formally submitted to the Council of the NACEC—whose members are the governments of Canada, Mexico and the United States—in late 2001.

The purpose of this “Note” is to provide an overview of some of the main points covered in the Secretariat’s report and to raise points for possible discussion; it is not intended to be exhaustive. Complete references will be inserted into the final report.

Contents

Part One: Current Issues and Projected Growth of Sectoral Activity.....	1
I. Environmental Significance of the Electricity Sector	1
II. Current Rates of Consumption and Projected Rates of Growth.....	1
<i>Market Status Overview</i>	2
Part Two: Restructuring the Electricity Sector	4
I. The Benefits of Restructuring	4
II. The Experience Thus Far: Efficiency Gains or Dysfunctional Markets?.....	5
<i>The California Example and Lessons for Other Regions</i>	6
Part Three: Environmental Implications of Restructuring	7
I. Supply-Related Issues.....	8
<i>Nonuniform Renewable Portfolio Standards</i>	9
II. Demand-Related Considerations	11
III. Modeling Environmental Effects of Restructuring	12
Part Four: International Trade Patterns and Market Access Issues.....	14
I. Coverage-Related Issues	15
Annex A: Overview of Recent Modeling Work.....	16

PART ONE:

CURRENT ISSUES AND PROJECTED GROWTH OF SECTORAL ACTIVITY

I. Environmental Significance of the Electricity Sector

The electricity sector has a major impact on environmental media in North America. For example, the sector is responsible for 10 percent of total NO_x emissions in Canada, 15 percent in Mexico, and one-third in the United States. The sector is also a significant source of SO₂ emissions—22 percent of total emissions in Canada, 48 percent in Mexico and 70 percent in the United States. As for mercury, the sector accounted for approximately 4 percent of total Canadian releases and 21 percent of total US releases. Estimates suggest that one-third of total greenhouse gas (including CO₂) emissions in North America originate from the sector.

The various stages and segments of the electricity sector—such as fuel extraction, transportation, processing and generation, transmission and final use—give rise to different environmental impacts. and each stage poses extremely complex challenges to environmental policymakers. This note focuses for the most part on air pollution issues—notably NO_x and SO_x—but a broad range of other environmental challenges are inherent in the sector. These range from the impact of transmission infrastructure on land use change and the fragmentation of habitats (a major cause of biodiversity loss) to the environmental impacts of hydroelectric power generation.

The sector is also a main contributor of toxic releases. In the United States, utilities reported half a billion kg of toxic releases, or 22.7 percent of the 2.2 billion kg released from industries. The chemicals that contributed the most to the electric utility sector’s total releases were hydrochloric acid (243 million kg), barium compounds (82 million kg), and sulfuric acid (77 million kg). The majority of the releases of hydrochloric acid and sulfuric acid were to the air; most barium releases were to land on-site.

Meeting the environmental challenges arising from the sector’s existing market structure poses huge challenges for environmental policymakers. These challenges revolve around current levels of emissions, projected rates of growth in demand, as well as fuel and technology options, to name but a few.

Many of these challenges, however, are only now beginning to be understood, because they are emerging from the unprecedented changes under way in the three NAFTA (North American Free Trade Agreement) countries in design, market and pricing structures. The main question to be addressed in the NACEC Article 13 report is one that already has attracted considerable analysis: Will the fundamental changes in the electric power sector in North America make environmental protection easier or more difficult, or will they leave the prospects for environmental policy unchanged?

II. Current Rates of Consumption and Projected Rates of Growth

In 1999, levels of electricity consumption in North America approached 4,000 TWh (see Table 1 for a breakdown of production and consumption).

Table 1: Production and Consumption of Electricity, North America, 1999

Country	Production (TWh)	Total Consumption (TWh)
Canada	555.9	525.7
Mexico	184.9	185.4
United States	3,182.7	3,212.8

Source: International Energy Agency, *Monthly Electricity Survey*, August 2000, 1999 totals.

Projected rates of growth in electricity vary, depending on the economic growth scenarios used. Recent estimates by the US Department of Energy of increases in electricity consumption rates to 2020 are shown in Table 2.

Table 2: Current and Estimated Growth Rates in Electricity Consumption, North America, 2000-2020

	TWh					Annual Growth	Percent Growth
	2000	2005	2010	2015	2020	1997-2020	2000-2020
Canada	495	524	563	601	632	1.25	27.7
Mexico	159	202	254	310	375	3.94	135.8
United States	3,360	3,647	3,909	4,155	4,350	1.24	29.5
Total	4014	4373	4726	5066	5357		33.46

These projections represent an absolute rate of growth in consumption of more than 1,300 billion KWh to 2020, an increase of one-third from current levels. Given the strong relationship between electric power generation and environmental issues, projected increases pose significant challenges to environmental policy making.

Market Status Overview

Canada

- The largest single source of electric power in Canada is hydropower (60 percent), followed by coal (15 percent) and nuclear (13 percent). Natural gas, oil/diesel and other sources make up the remaining 11 percent. With the opening of power grids to competition, however, gas-fired generation is expected to expand strongly in near term.
- In 1997, the existing generating capacity was 10,7898 MW, and estimates suggest that capacity will double by 2010.
- Restructuring has partially begun in half of the Canadian provinces, including Ontario,¹ Quebec,² Alberta,³ New Brunswick and Manitoba. Many provinces are, however, postponing restructuring stages because of the California power crisis.

¹ In October 1998, Ontario passed the Energy Competition Act—Bill 35. The original timetable laid out in the act called for the establishment of a competitive market, including full retail competition, commencing in 2000. This date, however, has been pushed back. The bill calls for dismantling of Ontario Hydro. Thus in April 1999 Ontario Hydro ceased operation and was replaced by several commercial and public sector entities. These include Ontario Power Generation, which assumed ownership and responsibility for power generation; Ontario Hydro Services Company, which assumed ownership and operation of the transmission, distribution and retail business; and the Electric Market Operator, which manages the open and fair access to trading. Other entities created with the dismantling of Ontario Hydro include the Ontario Electricity Financial Corporation, which is responsible for managing and retiring outstanding debt, and the Electric Safety Authority, responsible for electrical inspection duties.

² Since May 1997, the transmission system of Hydro Quebec has been open to any electric power supplier, with the result that several entities have been recognized as authorized clients under Hydro Quebec's transmission system. Also in May 1997, all nine municipal power distribution systems were offered the option of selecting their preferred electric power supplier, opening the market for wholesale electricity in Quebec. In November 1997, in order to position itself in the deregulated US electricity market, H.Q. Energy Services obtained under FERC the status of electric power wholesaler, thereby enabling it, a Hydro Quebec subsidiary, to trade in the US market and become a member of the New England Power Pool (NEPOOL) and PJM Interconnection.

³ In Alberta, the 1998 amendment to the Electric Utilities Act deregulated electricity generators and introduced a phased-in approach beginning in 1999 for large-scale industrial customers, with full deregulation extending to all customers planned for 2001. At that time, all customers will have the option of buying their electric power directly from a selected generator/producer of the Power Pool of Alberta or a selected licensed retailer of electricity, or of continuing with their existing supplier. An independent Power Pool Council will be responsible for operating Alberta's newly opened and

Mexico

- The electricity sector in Mexico is dominated by two vertically integrated state monopolies, the *Comisión Federal de Electricidad* (CFE) and *Luz y Fuerza del Centro* (LFC). These entities are engaged in the generation, transmission and sale of electricity.
- In 1999, Mexico generated 184.9 TWh of electricity. Between 1999 and 2005, demand in Mexico is forecast to grow 6 percent per annum, representing 13,000 MW in new capacities.
- An estimated US \$25 billion, in new generating facilities, will be needed to meet the increased demand, with the projected investment increases concentrated in the natural gas sector. Between 2000 and 2010, many coal-fired generators will likely be converted to gas.
- In 1992, reforms to Mexico's Electricity Law (*Ley del Servicio Público de Energía Eléctrica*) created a partial opening for private investors from both domestic and foreign sources to participate in the electricity sector. Estimates of the contribution private operators are making to Mexico's electric power sector vary widely, ranging from 5 percent to 30 percent.
- In late 1999, the former government introduced more profound changes to the electricity sector, requiring changes to Articles 27 and 28 of the Mexican Constitution. The proposed changes would open up competition in the generating segment; transmission and distribution would remain under state control. The proposed changes also envisage state control over rates.
- In 2000, however, the restructuring plans laid out in the proposed constitutional amendments were put on hold in response to concerns from Mexico's Congress.

United States

- The single largest source of electric power in the United States is coal (52 percent), followed by nuclear (20 percent), gas (15 percent), hydro (8 percent), petroleum (3 percent) and other (2 percent). In certain regions, such as the ECAR (East Central Area Reliability), coal provides over 80 percent of electric power needs.
- The existing capacity for the United States is approximately 3,360 TWh. That figure is expected to reach 4,350 TWh by 2020.
- According to forecasts, the use of coal for power generation will increase, reaching 333,000 MW by 2020.
- Gas-fired generation also is expected to increase, reaching 126,000 MW by 2010 and 212,000 MW by 2020.
- Deregulation of the electric power sector has been under way since 1996. With the issuance of FERC (Federal Energy Regulatory Commission) Order 888 (opens transmission lines owned by shareholder-owned utilities to all suppliers) and FERC Order 2000 (encourages transmission-owning utilities to release control of transmission systems to regional entities by the end of 2001), roughly 60 percent of the US population now lives in states that have enacted open competition and related provisions. The US Department of Energy (DOE) regularly provides updates on the many changes occurring within the restructuring status of each state (http://www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html).

competitive Power Pool, and various provisions—including creation of a market “surveillance expert”—have been created to guard against anticompetitive practices.

PART TWO: RESTRUCTURING THE ELECTRICITY SECTOR

In the late 1990s, the North American electricity sector witnessed the emergence of restructuring legislation. Significant differences exist among the three NAFTA countries—Canada, Mexico and the United States—and within the domestic jurisdictions of each country, on the extent and pace of restructuring. Indeed, the literature must scramble to keep up with the changing restructuring plans.

A key issue that will be examined in the NACEC report is how the current, and increasingly uncertain, trajectory of electricity restructuring will affect environmental quality and environmental policy in North America. Does electricity restructuring create new opportunities for environmental protection, including increased trinational environmental policy cooperation among Canada, Mexico and the United States? Alternatively, does restructuring mean new constraints to effective environmental protection? Or will restructuring leave the current challenges to environmental protection unchanged?

It is widely assumed that restructuring creates new opportunities for environmental protection arising from the unbundling of electric power and the offering of voluntary, third-party green power certification choices to customers. The potential of voluntary green power options, directed primarily at the residential segment, remains uncertain. It is known, however, is that regulatory intervention—notably, market-based measures such as emission caps, performance standards, and traditional command and control technology—together with the more recent introduction of mandatory minimum Renewable Portfolio Standards (RPS)—have decoupled rates of electricity generation from rates of growth in most emissions. In other words, while total electricity generation has increased significantly in North America, several key environmental indicators have declined (such as SO₂) or remained constant (such as NO_x).

Under current regulatory approaches—including Phase II of the Clean Air Act Amendments (CAAA) and the NO_x SIP Call (Nitrogen Oxides State Implementation Plan Call) ~~3~~4 emissions are expected to fall further. The eventual phasing out of regulatory exemptions for older generators—which were allowed on a temporary basis through grandfathering provisions—also are expected to lead to additional reductions in SO₂ and NO_x emissions. Moreover, given the impressive progress being made in demand-side policies—notably energy-efficiency standards for products, more stringent building code standards and the related incentive regimes in place to promote them—it remains unclear how environmental policymakers should approach restructuring.

I. The Benefits of Restructuring

Expectations about the benefits of restructuring and open competition have been high since the idea was put forth in the 1990s. It has been anticipated that open competition will yield several economic and related benefits, including: (1) competition-related incentives that would increase production efficiency; (2) more efficient pricing structures, assuming that private markets are better placed than monopolies to manage price-related risks; (3) market competition that would spur greater innovation, both in technological development and in tailoring end-products to customers' needs. The third benefit is of particular importance for environmental issues because it includes customer-driven preferences for green power.

One of the earlier forecasts about the benefits of electricity restructuring (1996) was that deregulation would yield a 25–30 percent reduction in rates, translating into US \$80 billion in cost savings. A 1997 study estimated that the potential savings in revenue could range from US \$112 billion to \$440 billion

up to 2011.⁴ A July 1998 modeling study by the DOE estimated that the average national price of electricity will be 14 percent lower under competition by 2010. The delivered cost of electricity to all customers in 2010 is estimated to be US \$32 billion less in open competition than under the regulated scenario.⁵ Other analysis has suggested that as monopolies are dismantled, competition will unleash other kinds of currently unforeseen types of innovation that had been stifled by the regulatory agenda.⁶

Three closely related questions pertain to thinking about forecasts of the economic benefits of restructuring. First, are economic projections of increased efficiencies and revenue savings occurring as forecast? Second, assuming economic benefits do accrue, how best can one measure economic benefits against environmental costs? A 1997 report by the Center for Clean Air Policy argues that while the additional costs for NO_x, SO₂ and CO emissions under restructuring would be in a range of US \$16<en>\$140 billion per annum, the economic costs are, as noted above, far greater, leading to significant net cost savings. Third, if economic savings do not accrue as projected from restructuring, what are the implications for the environment of a partially completed deregulatory agenda?

In the early forecasts, the words *restructuring* and *deregulation* were used almost interchangeably. Now, after a few years into this process, especially in the western United States, it is clear that *deregulation* has been a misnomer. The lessons of the telecommunications sector were perfectly clear in this regard: regulatory intervention increased rather than decreased as monopolies in the telecom sector were broken apart. Similarly, breaking up electric power monopolies and unbundling different segments of the sector may require *more*—not less—intervention by regulatory agencies. It was assumed that regulatory intervention would mainly center on access and customer rate issues, similar to that in the telecom sector. It was not anticipated that the intervention would also include price interventions in wholesale markets.

II. The Experience Thus Far: Efficiency Gains or Dysfunctional Markets?

The electric power sector continues to undergo unprecedented changes in parts of Canada, Mexico and the United States, from a situation in which markets were closed and electric power services were bundled, to a situation in which newer forms of competition are being offered. With changes in competition, electric power companies are becoming diversified in terms of both assets and operations, with new suppliers entering the market. Seventy-two mergers and acquisitions have taken place since 1997, and more diversified services are being offered by a larger number of actors.⁷

In the United States, the restructuring of the electric power sector has been under way since New Hampshire first offered a choice to customers in 1996. Since FERC Orders 888 and 889 were issued, 24 states have enacted restructuring legislation. A closer look at the following statistics will reveal one way in which to translate the general trends in restructuring into changing market patterns. By mid-2000, the United States had approximately 92 million IOU (investor-owned utility) customers, and less than 20 million had access to supply choices. To date, less than 1 million customers have opted for an alternative supplier. By the end of 2002, that number is expected to increase to 57 million.

⁴ Center for Clean Air Policy, "Air Quality and Electricity Restructuring: A Framework for Aligning Economic and Environmental Interests under Electricity Restructuring," March 1997, Washington, D.C..

⁵ US Department of Energy, "Supporting Analysis for the Comprehensive Electricity Competition Act," May 1999, Washington, D.C..

⁶ "Comprehensive Review of NW Energy Systems," remarks by Steve Kean, ENRON, 1996.

⁷ The actors in the US electric power market are: 12 federal utilities, 26 state providers, 70 public power districts, 221 shareholder-owned utilities, 700 power marketers (including merchant power generators), 880 cooperatives, 1,886 municipal systems (government owned), and 4,222 non-utility generators. Source: EEI, 2000.

However, it is California, which initiated a staged restructuring process on 1 April 1998, that remains the front-runner and test case for many other states—as well as Canada and to a lesser degree Mexico—in restructuring.

The California Example and Lessons for Other Regions

The transitional period for California's restructuring runs to 31 March 2002. During the transition period, time rates for customers of investor-owned utilities were to be frozen at June 1996 levels. After the transition period, rates are scheduled to be subject to market levels. The contentious issue of stranded costs was addressed by requiring California customers to pay a marginal surcharge.

In 1998, an official with the California Energy Commission noted that among the early lessons of restructuring were likely to be the enormous legal and contractual upheavals that would emerge. Two years later, reeling from these upheavals, California governor Gray Davis described restructuring as “a huge miscalculation” by planners. He claimed that several factors—such as sharp increases in demand, cold, dry weather, sharp increases in the price of natural gas, charges of fuel price gouging, and investor flight linked to regulatory changes that have halted new supply sources—appear not to have been appreciated or anticipated when deregulation was set in motion. Today, California is in the middle of an energy crisis characterized by scarce supplies, outages, price volatility, customer outrage, financial insolvency and open hostility between regulatory bodies.

The argument that is now being sorted out is whether it is deregulation per se that led to the California electric power crisis or the particular path of deregulation the state followed. Attention has focused to a large extent on regulatory intervention and retreat in price controls in the wholesale market. In mid-December 2000, Pacific Gas & Electric (PG&E) noted that the “California wholesale electricity market is broken.”

What has now emerged is an open battle between federal and state regulators. Meanwhile, the two main California utilities—Pacific Gas & Electric and Southern California Edison—are reporting losses of US \$9 billion. In its January 2001 Interim Opinion which authorized a 90-day rate surcharge of between 7 and 15 percent, the California Public Utilities Commission noted that the December 2000 actions by the Federal Energy Regulatory Commission related to price cap interventions in wholesale markets defied “common sense, logic and law,” and that such measures “*expanded the crisis to one that involves not only utility solvency but the very liquidity of the system*” (Public Utilities Commission, Dec. 01-01-018, emphasis added).

The key question remains whether the situation in California represents a problem in the specific sequencing or timing of regulatory change or suggests more fundamental and generic problems. One analysis suggests the former, noting that “the most important impact of the Big Bang theory can be observed in the inability of the market to adapt to instantaneous changes and adjust as conditions warrant.”

The outcome of events unfolding in California is relevant to several of the environmental considerations raised in this report. First and foremost, the situation injects new uncertainty into what once looked like an inexorable march toward restructuring and privatization in the United States and Canada. The effect of the California situation on pending legislation in other jurisdictions may dim or brighten the likelihood of other electricity scenarios other than wholesale restructuring. Essentially, developments in California broaden the range of possible scenarios, which, in turn, multiplies the various environmental issues under consideration. For example, a growing number of environmental advocates have focused increasingly on market-based strategies for augmenting the percentage of

renewables in electricity markets, ranging from labeling and certification schemes and subsidies to lower entry costs into open markets. If the pace or prospects for continued market liberalization are altered, advocates may hedge by concentrating more on regulatory mechanisms, including performance standards, emissions caps and mandated renewable portfolios (also a feature of many so-called deregulated regimes).

Yet others see an opportunity emerging from the California situation, noting that some of the supply problems faced by the state could be remedied by increasing the share of renewables. Such a step would, they assert, help to stabilize overall generation reliability and reduce price volatility. Others see a growing market for nondistributed generation (off-grid) from a new generation of comparatively cleaner sources, including fuel cells and gas-fired cogeneration facilities.

Because the California crisis is far from over, its resolution and lessons for other jurisdictions remain unclear. Undoubtedly, the situation in California will have spillover effects in other jurisdictions facing similar challenges. In Canada, for example, since the announcement of deregulation Alberta has been faced with problems similar to those of California: wholesale prices have tripled, few new generating capacity expansions are in the works, and natural gas prices remain high. In response, the Alberta government introduced—as in California—a rate cap, although it applied only to small retail customers, with public money used to narrow the price difference between wholesale and retail prices. Among the obvious economic effects of creating a two-tier pricing structure is that businesses without offsetting subsidies are placed at a relative competitive disadvantage. As for Ontario, it is widely expected that rates will rise following a five-year freeze. However, given supply capacities and the fuel mix diversity of Ontario, the price-related crisis of Alberta and California is not expected to happen there. Although Ontario has announced it will move fully to a competitive market, the timetable of November 2000 has been set back, somewhat indefinitely.

PART THREE: ENVIRONMENTAL IMPLICATIONS OF RESTRUCTURING

Given the complexity of issues related to the electric power sector and the rate of change within it at the North American level, there is no single best way of approaching how to assess the environmental implications of restructuring. The following is a rough attempt to place these complex issues in three broad categories. Clearly, though, important relationships exist between these categories, beginning with the obvious question of whether technological innovation to meet Renewable Portfolio Standards is driven by customer demand, supply opportunities or an extension of environmental regulations. Moreover, changing indicators of environmental quality—as expressed in changing NO_x, SO_x and mercury (Hg) emissions from utility sources—obviously play an important feedback role in changing supply and demand functions.

Anyone approaching these very complex issues also needs to think about what has been called the “wild card” in the fate of energy renewables and price-based initiatives in relation to the Kyoto mechanisms. Conventional wisdom suggests that commitments to reduce total greenhouse gas emissions under the Kyoto Protocol improves the economic viability of renewables. Although the existing environmental agenda has concentrated on reducing SO_x, NO_x and other emissions, moves to lower CO₂ may radically tilt the economic calculations in favor of renewable energy sources.

In light of the failure of the Conference of the Parties (COP) VI meeting in the Hague in late 2000 to move forward with the operational components of the 1997 Kyoto commitments, the climate agenda remains somewhat on hold. Nevertheless, the reality of a carbon-constrained world has been

recognized by companies and countries worldwide, and actions in this area will inevitably affect investment and pricing-related issues in the electricity sector.

I. Supply-Related Issues

One of the outstanding issues of electricity restructuring is the impact that a dramatic change in regulatory regimes will have on new investment entering the sector. When they were introduced, restructuring plans produced widespread concern about a deep chill in capital investments into the sector. Five years ago, the US Department of Energy forecast a series of bankruptcies among some larger utilities and revenue losses of as much as 30 percent. Moreover, new capital flows into the sector were expected to diminish for two reasons: stranded costs and regulatory uncertainty.

How to best deal with the issue of stranded costs remains the subject of intense work, including that of the environmental implications of subsidizing stranded cost bailouts through add-ons to customer rates. As in any subsidy-related intervention, such actions create a series of price and market distortions. In 1995, US industry stranded costs were estimated at US \$135 billion. In 2000, that figure dropped to US \$10 billion through various measures, including utilities selling approximately \$26 billion in bonds to be paid off through rate surcharges. Thus, although the stranded cost issue has represented the largest hurdle to attracting new capital investment, recent estimates suggest that the problem has been significantly reduced.

The second problem of regulatory uncertainty remains, however, and may even increase after the California power crisis, which has led to the postponement of several jurisdictions. Regulatory uncertainty has been cited as a cause of investor reluctance, which in the end may overshadow the extremely thorny issue of stranded costs. One example of investor reaction to regulatory uncertainty occurred after the April 1994 release of the bluebook proposals; market capital fell by 30 percent in California. Industry complained that in the absence of precise rules governing the operation of deregulated markets new capital was unlikely to move into the sector.

By contrast, Ontario announced in 2000 that roughly C \$3 billion would be invested in new electric generating projects, indicating a high level of investor confidence in that market. At the same time, no other Canadian province has anywhere near comparable investment levels in new projects. And even in Ontario, whose fuel price stability and generating capacities easily meet projected demand increases, some analysts have predicted a 20 percent rate increase between 2001 and 2003 unless clear rules are set that reaffirm investor confidence.⁸ Given this uncertainty, some analysts have also raised questions about whether announced investment will translate into actual new monies.

Given the projected demand increases in all three NAFTA countries, investment flows are crucial to the sector. And it remains critically important whether new capital will be invested in modern, and almost by definition, lower-emission generators or whether investor uncertainty (coupled with the absolute certainty of demand increases) will result in deferred capital investments and therefore extending the life of older and generally dirtier generators.

The environmental implications of extending the life of older generators have been analyzed extensively. Clearly, environmental impacts will largely depend on the regulatory situation in which older generators operate.⁹ For example, analysis by the National Association of Regulatory Utility

⁸ "Canada Wary of the Pitfalls of Electricity Deregulation," *Financial Times of London*, 6-7 January 2001, p. 2

⁹ There is the possibility that "pollution havens" or "pollution halos" spring up where clusters of either relatively dirtier or relatively cleaner generation facilities concentrate in jurisdictions with abundant energy sources and a laxer regulatory climate. At present, structural limitations in the operation of the North American electricity grid, including multiple

Commissioners estimates that if older plants were subject to modern pollution emission standards and if economically suboptimal emission exemption clauses were lifted, the additional emission compliance costs would be US \$9.2 billion a year, translating into a retail rate hike of 4 percent. The environmental benefits of regulatory comparability between old and new plants are estimated to be “huge,” including an estimated 75 percent reduction in SO₂ and NO_x emissions (that is, 7.3 million tons of SO₂ and 3.3 million tons of NO_x).¹⁰

Over and above investments in modern but mainstream generating capacity is the fate of new capital investments in renewable energy sources. Given recent market turbulence, the fate of investments in renewable energy may be unclear. Several US states have introduced regulatory-based Renewable Portfolio Standards, with escalating minimum percentage requirements. Meeting those standards will require new capital investment in renewable technologies such as wind, solar and biomass.

Given that capital costs for most renewable electric power generators tend to be higher than those for nonrenewable forms and given that capital is scarce, one argument is that new capital flows to renewable energy are unlikely. A counterargument, however, is that because a large part of price volatility comes from increases in fuel prices (i.e., outside of regulatory considerations), the prospects for renewables are good given their low or no-fuel costs.

As of December 2000, 163 MW of new renewable capacity had been installed in the United States to serve green power needs; another 290 MW was either under construction or formally announced. Wind power and solar are the most common renewable power sources, with wind power representing a large proportion of total capacity. Ambitious plans have been announced to increase current wind power capacities, and different jurisdictions are supporting mandated RPS requirements in different ways. For example, in mid-2000 DOE announced a plan that called for 5 percent of the nation’s total electricity output to come from wind power. One important part of that plan was that 5 percent of all federal government electricity needs would be met by wind power by 2010.

Nonuniform Renewable Portfolio Standards

Under the Renewable Portfolio Standards, retail electricity suppliers must provide a percentage of their kilowatt-hours from renewable energy resources. Three points are worth noting. First, RPS is not a mechanism directly tied to environmental protection targets—that is, unlike emission caps and other quantitative targets for environmental performance, RPS may deliver relatively cleaner electricity generation compared with that from nonrenewable sources. The extent of environmental benefits depends on the types of eligible renewable energy resources included in provisions, as well as the percent threshold of RPS requirements. Generally, RPS can be viewed as a means of bolstering infant renewable electricity generators. It does therefore appear to be a longer-term environmental policy goal as opposed to a direct environmental quality target.

Second, a standard definition of what constitutes a “renewable” energy does not exist (see Table 3). According to draft guidelines developed by the National Association of Attorneys General, use of green power must conform to certain criteria, including proof:

[A]s to the actual generation and transmission of electricity and the disposal of spent fuels, the product, services or company relies principally (at least __%) on replenishment (sustainable) fuel sources; it releases into the environment no harmful substances; and it poses no other significant concern related to the ecosystem or to land use.

bottlenecks and other infrastructure deficiencies, constrain such theories. However, these considerations may be important in the future as the grid expands.

¹⁰ National Association of Regulatory Utility Commissioners, “Grandfathering and Environmental Comparability,” June 1998.

Table 3: Eligible Fuel Sources within Proposed or Enacted State Restructuring Legislation

	Solar	Wind	Hydro	Fuel Cell	Geo-thermal	Tidal Ocean Wave	Biomass	Landfill Gas	Sewage Digester Gas	Municipal Solid Waste	Waste Tire Comb	Cogen	Other Criteria
Arizona	X	X	<5 MW		X		In-state	X	X				
Arkansas	X	X					X	X		X			
California	X	X	<30 MW		X	X	X	X	X	X ³	X		
Connecticut	X	X	X ²	X			X ⁶	X	X	X			
D.C.	X	X	X		X	X	X		X				
Delaware	X	X	X		X		X	X					
Illinois	X	X	X ³				X ⁷						
Iowa	X	X	<100 MW		X		X			X			
Kansas	X	X	X				X	X					
Maine	X	X	X	X	X	X	X			X		X	All <100 MW
Maryland	X	X	X		X	X	X	X		X			
Massachusetts	X	X	Run-of-river	X		X	Low-emission	X		X			
Michigan	X	X	X		X		X	X		X			
Missouri	X	X					X	X ⁹					Low-impact + sustainable
Nevada	X ¹	X			X		In-state						
New Jersey	X	X	<30 MW	X	X	X	X ⁶	X					
New Mexico	X	X	X	X ⁵	X			X	X				Low/zero emissions
Oklahoma	X	X	X		X		X ⁶	X ⁸		X			
Pennsylvania	X	X	Low-head		X		X ⁶	X ⁸		X			
Rhode Island	X	X	<100 MW ³	X			X ⁶						
South Carolina	X	X	Low-head		X		X ⁶	X ⁸		X			
Texas	X	X	X		X	X	X	X					
Vermont	X	X	<80 MW ⁴				X ⁷	X					All <80 MW

Source: NACEC electricity database.

- | | |
|--|---|
| 1 Except for solar thermal. | 6 Sustainable. |
| 2 Licensed under CWA or CEAA. | 7 Agriculture, crops, silviculture waste. |
| 3 No new construction or expansion. | 8 And mine-based. |
| 4 Licensed and water quality certified . | 9 And lagoon. |
| 5 Non-fossil fuel. | |

Third, RPS requirements vary from one region to another. For example, portfolio requirements in Maine stipulate that no less than 30 percent of its portfolio supply sources for retail electricity sales be accounted for by renewable sources (by 2000). In Arizona, approximately 1.1 percent of the state energy portfolio must be from renewable energy sources (by 2007).

The NACEC is in the process of developing an online, searchable database that compiles information concerning RPS and renewable energy definitions from electricity restructuring legislation <<http://www.cec.org/databases/certifications>>. The database also provides information about the criteria for voluntary, third-party green electricity certification schemes as well as environmental marketing guidelines. Given the amount and diversity of information on renewable energy definitions and portfolio standards, the database is intended to serve as a single-entry information source, by which one will be able compare eligible energy sources, portfolio percentages, and the criteria within the certification schemes.

II. Demand-Related Considerations

As of July 2000, six US states provided green power offerings: California, Pennsylvania, Massachusetts, New Jersey, Maine and Connecticut. Approximately 88 MW of new renewable capacity has been built expressly to supply competitive green markets at both the retail and wholesale levels. Of this total, according to a December 2000 National Renewable Energy Laboratory (NREL) study, about 54 MW supplies California, Pennsylvania, New England and New York, and the remainder is being marketed by Bonneville Power Administration in the northwest. About 82 MW in additional renewable capacities is being planned in the United States to meet demand increases.

In looking at these numbers in the context of competitive markets, the obvious challenge is to sort out the difference between demand- and supply-driven green power offerings. If one assumes that the move to green power at the customer end is demand driven, then the question is whether current rate price volatility generally will have any effect on customer selection of green power.

A guiding assumption about offering the green power option to consumers is that—if available—a measurable percentage of total customers will purchase green power. Numerous market studies are measuring customer interest in, and willingness to pay for, green power. One of the most useful reviews of market research studies can be found in the updates produced by the National Renewable Energy Laboratory, including the fifth edition of those studies (2000). General trends from past surveys suggest a consistently high interest among residential customers in green power options. Surveys also suggest lower interest among business customers.

The findings of market surveys are reinforced by the results of pilot studies of green power. For example, a pilot study of four municipalities in Massachusetts found that 31 percent of residential participants selected the green option compared with 3 percent of business customers.

Green certification schemes are, however, promoting to business customers the institutional procurement opportunities available. Some of the large institutional buyers already meeting a portion of their electricity requirement with green power are: MCI, Toyota, the Los Angeles Airport Authority, Time Warner, the US Postal Service, and the City of Chicago. Anyone looking at patterns of market survey responses should keep in mind the actions of large procurement buyers. For example, in the fifth national opinion poll conducted by the Sustainable Energy Coalition (2000), 62 percent of those polled wanted the US Department of Energy to place a high priority on the funding of renewable energy. Surveys conducted in 1999 and 2000 in North Carolina found that 51 percent of customers polled indicated they wanted to buy clean electricity, and 11 percent said they would be willing to pay \$20 a month more for it.

These are two examples of a growing number of market surveys that indicate that, when offered a choice, customers not only will select cleaner electricity, but also seem willing to pay more for green power. The series of updates on customer market surveys prepared by the National Renewable Energy Laboratory (1999) consistently shows a strong preference among residential users for green power. Some highlights of the NREL report follow:

- Between 50 and 95 percent of residential customers say they are willing to pay a modest price premium for renewable power.
- The relationship between willingness-to-pay and escalating prices suggests the following pattern: 70 percent of customers are willing to pay at least \$5 per month for renewables, 38 percent are willing to pay \$10 per month, and 21 percent are willing to pay \$15 per month. The NREL study notes that it is likely that any survey “will exhibit a similar pattern of results.”
- Crucially, existing data suggest customers are even more willing to pay more for renewable electricity in a competitive market setting like restructuring. The NREL study found that customer responses might be higher when the choice is between forgoing rate decreases—one of the expected outcomes of restructuring—compared with paying a price premium from existing rates for green power.

One of the hard lessons of willingness-to-pay market surveys is the wide gap between what people say they will do and what they actually do in the marketplace. Barbara Farhar (1996) suggests a reasonable rule of thumb: a 10 percent positive response rate from customers on willingness-to-pay translates into a 1 percent switch by customers in signing up for green power.¹¹

Given the gap between consumer responses about willingness to pay, and actual market decisions, it is unclear whether rate price volatility associated with restructuring makes the marketing of green power even more difficult. Put another way, in light of the January 2001 rate increases announced by the California Public Utilities Commission of 7–15 percent, with predictions of further rate price increases after the initial 90-day period, a reasonable assumption is that the prospects of customers paying a price premium over and above the current rate hikes will create new hurdles for green power.

III. Modeling Environmental Effects of Restructuring

A growing body of literature is attempting to estimate the environmental impacts of restructuring using modeling and forecasting tools (see Annex A). Modeling efforts have some common elements, beginning with the observation that electricity restructuring poses few or no significant changes to the environment. Under ideal circumstances, restructuring also may yield positive environmental benefits at low cost. The most common drivers of environmental improvement arise from assumed allocative and other efficiency gains, coupled with offering consumers the choice of purchasing green power.

One of the earlier studies of the environmental effects of restructuring was the Environmental Impact Statement (EIS) released by the US Federal Energy Regulatory Commission in April 1996. Using different scenarios, the EIS concluded that restructuring will result in little or no adverse environmental impacts. As a kind of reference point for subsequent analysis, the findings of the FERC EIS have largely been reconfirmed. However, the EIS has drawn criticism for its underlying

¹¹ This gap closely follows the labeling of green products more generally. Martin Wright has noted that “an oceanic gulf [exists] between what people tell pollsters they’ll do (pay premium prices for greener goods) and what they do in practice (shrug and get the cheap stuff).”

assumptions. For example, because the EIS assumed only that changes in transmission prices, not in transmission capacities, would arise from restructuring, the environmental effects may be understated.

Modeling environmental effects in the electricity sector is difficult for several reasons. First, modelers must examine the economic changes arising from deregulation and infer from these changes in relative prices which may be driven by regulatory changes and/or secondary changes in environmental performance standards. Assumptions about probable pricing effects and market responses are difficult to make given the number of concurrent, divergent and turbulent issues that characterize the sector. These include projected increases in demand; price volatility; the rate and cost of technological innovation; environmental regulatory effects (notably Phase II of the Clean Air Act Amendments, the NO_x SIP Call, New Source Review (NSR) applied to existing plants and Ozone Transport Commission requirements in the United States, their Canadian and Mexican counterparts); changes in the transmission infrastructure, including the pricing of transmission services; the role of ancillary services in a deregulated market and their impact on price. Moreover, models need to incorporate probable changes in nonenvironmental regulatory interventions, including changes in competition policy and tax law issues.

Given the number of variables that have to be juggled, the limitations of modeling work are obvious. Yet models are very useful tools. They help organize very complex data in an internally logical way; and they yield orders of magnitude about the trajectory of environmental change under different assumptions.

Accordingly, the NACEC report will draw on the results of different models to help understand the possible environmental effects of restructuring. An overview of some key findings from existing models appears in Annex A. It is useful to note that modeling efforts yield quite different results. Some find little or no environmental costs in restructuring, but do find some environmental gains through efficiency (for example, the POEMS model, 1998). Others suggest a marginal increase in some emissions, notably NO_x (NESCAUM 1998). However, two common points emerge from the modeling findings:

1. If quantitative emission caps remain fixed, then deregulation should not affect overall environmental quality, at least for those emissions subject to caps. For environmental indicators not subject to caps such as CO₂ environmental impacts are hard to estimate.
2. Several modeling exercises raise concern about potential increases in NO_x emissions that might result from restructuring.

In preparing a literature search and commentary on recent modeling work, including the 2000 exercise supported by the NACEC, it is useful to draw on lessons from recent work that assess the more general environmental impacts of trade liberalization. Among the benefits of including lessons from this area is that it brings to the table insights around the secondary or price-induced environmental effects of market *liberalization*—that is, how does one go about assessing environmental change during a transitional period driven by policy and regulatory changes? A useful framework developed in the environmental arena to weigh dynamic changes is made up of the following categories:

- *Scale effects*: environmental impacts from an absolute increase in economic activity (that is, total electric power generation).
- *Technology effects*: the manner by which advances in generating technologies decouple rates of growth in generating output from rates of environmental change.
- *Regulatory effects*: the role that environmental and other regulations—including competition policy and tax laws—play in sectoral performance and environmental outcomes.

- *Product effects*: the role that demand-side initiatives, including product-based efficiency standards and an increased demand for voluntary, third-party certification schemes, play in environmental quality.
- *Compositional effects*: a more distant consideration related to changes in the gross domestic product (GDP) and how income growth alters the composition of total economic output (for example, from manufacturing to services intensity as a function of growth in GDP per capita).

PART FOUR:

INTERNATIONAL TRADE PATTERNS AND MARKET ACCESS ISSUES

Forecasts call for the cross-border North American trade in electricity to grow over the next two decades. Close ties already exist between the United States and Canada, with over 100 electricity interconnections already in place. Of those, approximately 36 are bulk inter-ties with a total capacity of 18,900 MW. Exports from Canada to the United States are in the range of 45,000 MW per year, and imports from the United States to Canada vary, but are in the range of 7,000–10,000 MW. The majority of grid linkages are between the United States and the Ontario grid. At the organizational level, the Canadian and US electricity systems are integrated through the North American Electricity Reliability Council, and its 10 regional councils.

By contrast, US-Mexico grid connections are limited. The principal exporter in Mexico is CFE, which exports electric power north to California (as well as to Belize). Current interconnection capacities can handle approximately 900 MW of exchange. Synchronization of the grids is difficult because the main part of Mexico's grid is not connected to the northwestern Mexican grid nor the United States. Trade between the US and Mexico is concentrated in the California - Baja California area and from Texas (El Paso Electric Co.). The NACEC report on North American electricity published in 1999 details existing grid connections and includes the challenges in synchronization among the three NAFTA partners.

It is widely expected that as the three North American economies become more closely connected through the North American Free Trade Agreement and other economic and transportation ties, the electricity trade will increase and the prospects of continental electric power interdependence will rise. Some projections (Hill 2000) suggest that electricity exports from Ontario to the United States could rise by as much as 8 TWh by 2002. Other projections suggest Mexico's utility system will become connected to the Texas power pool.

As in any sector, increased international trade raises considerations about market access and rule coverage. Given the pivotal importance of a range of environmental measures that not only affect generation but also may affect or condition access to different grids in the electricity sector, the final section of the NACEC report will examine a series of trade and environment issues.

Article 10(6) of the North American Agreement on Environmental Cooperation includes measures to avoid environment-related trade disputes. It is important to note at the outset that no formal trade issues have arisen among the NAFTA parties involving the cross-border trade in electricity. Yet several issues may warrant consideration. These include (1) the important role that environmental and energy efficiency standards play in Technical Barriers to Trade (TBT) notifications related to product standards; (2) the effects of nonuniform RPS between different jurisdictions, whether such differences can be used to condition market access, and whether such conditioning may raise trade rule issues; and (3) whether experience in international environmental and trade policy related to an upward harmonization of standards has any role in North American sectoral approaches to environmental protection.

I. Coverage-Related Issues

The exact scope of application of the General Agreements on Tariffs and Trade (GATT) and the World Trade Organization (WTO) General Agreement on Trade in Services (GATS) to the electric power industry has yet to be determined. The core question is whether electric power generation constitutes a service or a manufacturing process. Electrical power is intangible, a quality that has traditionally been used to classify items as services. Furthermore, electricity cannot be efficiently stored and must be consumed as it is produced, yet another characteristic of a service.

On the other hand, a power plant materially transforms the energy present in various fuel sources into electrical energy. Such material transformation is typical of the manufacturing process. In a recent study by the US International Trade Commission (USITC) undertaken at the request of the US Trade Representative (USTR), the electric power industry was defined to include core areas, including electric power generation.¹² It is not clear whether this request for classification by the USTR is an indication of the USTR's position on the good/service issue in the GATS negotiations to come.

At this initial stage in the NACEC study, it is nevertheless assumed that electricity is a good. Evidence that electricity is covered by the GATT and that electricity as such is considered a good by many WTO members is borne out by its inclusion in the Schedule of Commitments to the GATT 1994 of most of the major trading partners such as the United States, the European Union and Canada. (It is not, however, included in Japan's and Mexico's schedules.) Those schedules contain the tariff commitments of WTO members for goods. The GATS may currently have some bearing on services related to electricity, but this application is, however, limited. For example, the US GATS schedules currently include only "services incidental to energy distribution" which are included in the sector called "other business services."¹³

Chapter 6 of NAFTA deals with energy and basic petrochemicals. Article 602 on scope and coverage provides in its third paragraph that energy and petrochemical goods and activities are governed by the provisions of NAFTA.¹⁴ The first paragraph of the same article specifies that Chapter 6 "applies to measures relating to energy and basic petrochemical goods originating in the territory of the parties and to measures relating to investment and to the cross-border trade in services associated with such goods. The specific goods subject to the provision are listed in paragraph 2 and include, *inter alia*, electrical energy by reference to its classification under Chapter 27.16 of the Harmonized System."¹⁵ It can therefore be concluded that electrical energy as such is currently considered a good under NAFTA.

¹² "Electric Power Services: Recent Reforms in Selected Foreign Markets," Investigation No. 332-411, USITC Publication 3370, November 2000, p. 1.

¹³ The United States of America, Schedule of Specific Commitments, GATS/SC/90, 15 April 1994.

¹⁴ Article 603, paragraph 3, also refers to Annex 602.3, which introduces reservations and special provisions entered into by Mexico concerning the application of NAFTA to energy and petrochemical goods and activities. The Mexican State reserves to itself several strategic activities, one of which is the supply of electricity as a public service (including the generation, transmission, transformation distribution and sale of electricity). The annex also includes provisions on the activities of and investment in electricity generation facilities.

¹⁵ See Article 602, paragraph 2(h).

ANNEX A: OVERVIEW OF RECENT MODELING WORK

Modeling studies that will be referenced in the NACEC report include:

A. Air Quality and Electricity Restructuring: Center for Clean Air Policy

- Where fixed emission caps are in place, restructuring will not lead to an increase in utility emissions. Quantitative caps will, by definition, avert any increases over and above the cap level. Coupled with emission trading schemes like the SO₂ program, emission targets can be met in a cost-effective way under restructuring.
- If emission caps are not in place, restructuring is likely to increase NO_x emissions. For example, NO_x emissions in New York State are modeled to increase by 11–18 percent during the summer ozone season.
- Increases in generation from uncapped systems, either through increases in the national load or through increased interregional sales—will increase emissions under restructuring. Increased NO_x emissions will result from increased generating from uncapped, higher-emitter, lower-cost generators in the US Midwest.¹⁶
- It makes no difference to net emissions whether competition occurs at the retail or wholesale level.

B. POEMS Modeling Results for Renewable Portfolio Standards (RPS) and Carbon Dioxide Emissions

Forecasting by the US Department of Energy (1998) notes that several environmental benefits are likely to result from restructuring. Highlights of the Policy Office Modeling System (POEMS), which links the National Energy Modeling System (NEMS) and TRADELEC (an electricity model developed specifically to evaluate competitive electricity markets), include the following points related to fuel mixes and environmental outcomes:

- The generation of electricity from RPS-eligible resources will almost triple. The increase is largely government driven, and it assumes that a cost cap provision—setting a limit on the price of renewable energy credits—would be activated. It notes that the administration’s proposal of 7.5 percent RPS coverage would not be met because some retailers would opt for proxy credits. However, RPS targets could be increasingly met if production costs were reduced through technological innovation.

¹⁶ Concern about a possible increase in the emissions of older plants that gain access to the transmission infrastructure through deregulation and are able to compete on price factors alone, has been a central point of debate. For example, the 1999 sectoral study by the NACEC, *Electricity in North America*, cautions:

The most important environmental variable in North American electricity is the fate of more than 300 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....If the competitive advantage associated with lower standards proves decisive [in a competitive marketplace], US coal-fired generation could raise existing production by as much as one-third in response to continued demand growth, access to new markets, and new competitive pressures. Thus, this scenario envisages a near-term surge of production from aging coal-fired plants that overwhelms more tightly regulated competitors.

- Emissions of carbon dioxide will be reduced by 40 percent, or 60 million metric tons carbon equivalent, by 2010.
- Projected NO_x and sulfur dioxide emissions are not modeled, because emissions caps set out in the Clean Air Act Amendments (CAAA) and related measures—including Phase II limits for NO_x, seasonal restrictions set out in the 1998 Ozone Transport Region (OTR), and other measures—must be in place regardless of changes in total generating capacities.

C. NESCAUM: Evidence of Increased Environmental Pressure

A January 1998 study by the Northeast States for Coordinated Air Use Management (NESCAUM) examined the air pollution impacts of increased deregulation in the electric power sector.¹⁷ Highlights of that study include:

- Based on a variety of factors, mainly to do with cross-price elasticities for fuel but including deregulation, the demand for low-cost wholesale power has resulted in increased production by less stringently regulated coal-fired plants in the United States. The study (relying on 1996 and 1997 data) notes that “additional wholesale sales were made possible by increased generation of coal-fired power plants.”
- Significant increases in utility emissions have occurred while electricity restructuring has been under way. The report refers in particular to 1996 NO_x emission data.
- The existing transmission infrastructure is capable of supporting a large increase in electricity transfers, thus allowing low-cost, high-pollution power to flow to new markets.

D. NACEC Model: Increased Emissions

A contrasting set of estimates was produced by a model far less sophisticated and robust than the 1998 POEMS results. The NACEC-sponsored Front of the Envelope (FOE) model provides a relatively accessible tool for weighing selected effects of changes in the regulation of electricity markets in North America, and in particular what those changes might be for environmental quality.

Different parameters are used in estimating environmental impacts. In the NACEC model, three scenarios are applied: minimal, mid-range and full levels of deregulation. And three different energy mixes are used: one in which the energy mix remains the same (status quo); an optimistic scenario in which the share of electricity produced by natural gas-powered generators is increased by 1 percent; and a less-optimistic scenario in which the energy share from coal increases by 1 percent. Numerous other assumptions and constraint parameters are included in the NACEC model. Among the key findings of the NACEC (2000) model are:

- Deregulation increases overall emissions of NO_x, SO₂ and CO₂ in North America, fundamentally because of a shift in the production of energy between regions. Energy production increases in regions where energy prices are relatively low and decreases in regions where they are high. Production is shifted to both relatively clean and relatively dirty regions. However, the increases in the dirty regions is far greater than the decreased emissions caused from a shift to the cleaner regions.
- A shift in the fuel mix to natural gas works to offset increased emissions from deregulation.
- The reduction in emissions becomes smaller as the electricity market becomes more deregulated. An increase of 1 percent in the share of electricity produced by coal generators increases emissions in all regions and in North America as a whole.

¹⁷ NESCAUM, “Air Pollution Impacts of Increased Deregulation in the Electric Power Industry: An Initial Analysis,” July 1998.

- The reduction of the marginal costs increases total generation production and increases emissions. Because the difference between long-run and short-run estimates are simply larger absolute values for demand and supply elasticities, the above-mentioned patterns are simply exacerbated in the long run—that is, deregulation causes emissions to increase more in the long run than in the short run.

E. Ontario Power Generation: Environmental Impacts of Free Trade in Electricity

The modeling work by Hill & Associates relies on two components: the Utility Fuel Economics Model (UFEM) and the National Power Model (NPM). Integration of the models is done sequentially. The NPM models the dispatching of plants in economically optimal conditions (with regulatory and other constraints), and the total generating output is fed into the UFEM. The UFEM then estimates new fuel or clean-up options—including new fuel and technological constellations—which are fed back into the NPM model.

Modeling work by PHB Hagler Baily uses a GE MAPS model to estimate changes in the Eastern Interconnection electricity system of the United States, with Ontario included, for the period 2005–2012. Two scenarios are used:

1. The *Base Case* assumes implementation of Phase II of the Clean Air Act Amendments (CAAA). In 2000, sulfur dioxide was limited to 0.55 kg/mmBTU and NO_x was limited to 0.18–0.21 kg/mmBTU, depending on boiler type. For the eleven states in the Ozone Transport Commission (OTC) further emission reductions were imposed. The Base Case scenario assumes that Ontario imposes an emissions cap of 175,000 metric tonnes for SO₂ and 58,000 for NO_x. (Since the parameters of the study were set, the Ontario government has imposed emissions caps of 158,000 metric tonnes for SO₂ and 55,000 for NO_x.)
2. The *NAAQS Case* assumes more stringent NO_x SIP Call (Nitrogen Oxides State Implementation Plan Call) commitments by states to meet National Ambient Air Quality Standards (NAAQS) targets.

Among the results of the contrasting scenarios run under the model, the NAAQS increases capital and operating costs relative to the Base Case by \$1 billion per year to 2007. (These costs are over and above the mitigation costs of Phase II of the CAAA.) On an aggregate level, this increase will have a marginal impact on total generating costs in the United States. However, the additional costs are concentrated in the coal-dominated Midwest and the southeastern United States.

Focusing on the ECAR (East Central Area Reliability) region, the study notes that even with the advent of Phase II of the CAAA, SO₂ emissions are not expected to fall significantly given the extent of SO₂ banking accumulated under Phase I commitments (about 9 million metric tonnes in 1999). Once banked SO₂ credits are exhausted and new scrubbers are built between 2002 and 2007, the ECAR coal-fired emissions drop in response to Phase II constraints. By contrast, NO_x emissions from coal-fired plants are reduced immediately under Phase II, by approximately 8 percent.

The model suggests that electricity “transfers out” from ECAR to other regions could decrease by more than 50 percent, from a baseline of 28 TWh in 1998 to less than 13 TWh by 2010. The model assumes that the main reason for this decrease is the NO_x SIP Call limits that come into effect before 2005.