Overview of Environmental Policies for Electricity Generation

Report to the IESO

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Disclaimer: The views and opinions expressed in this paper do not necessarily reflect the views of the Independent Electricity System Operator.

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1 Introduction – Environmental Challenges

Over the last half century environmental concerns have led to increasingly strict regulation of a growing list of the side effects of electricity generation and transmission. The environmental concerns facing utilities, including those in Ontario, include several types:

- emissions of traditional air pollutants from thermal plants – particulate matter, SOx and NOx;
- emissions of air toxics from coal-fired plants including mercury, cadmium, arsenic and lead;
- emissions of greenhouse gases from any thermal plants, principally CO2;
- safety and radioactive waste disposal from nuclear power plants;
- aesthetic concerns over transmission lines;
- environmental damage caused by large hydroelectric projects;
- most recently, noise and aesthetic concerns over wind farms.

This paper will focus on the policies that have been used and are contemplated for the control of the air pollutants including greenhouse gases from thermal power plants; for promoting the use of renewable power which is intended to displace thermal generation; and for promoting energy conservation to reduce overall or peak electricity consumption. The purpose of the paper is to identify the choices that are currently available for reducing these environmental risks. Most of the policies reviewed here have been implemented by state or national governments as part of their general responsibility for environmental pollution regulation.

A typical regulatory regime for the traditional air pollutants includes the adoption of ambient air quality standards followed by the adoption of limits on emission rates from major sources that are intended to achieve or move toward achieving these air quality standards. As air quality standards have become more demanding and as the economy and thus the air pollution sources have grown the cost of compliance with these emission rates has grown steadily. Some existing plants have faced very high costs when available control technologies are not compatible with existing plant designs. Emission trading programs emerged in the 1970s and later as a means of providing flexibility for sources and of reducing overall compliance costs for industry. Recent concern over greenhouse gas emissions has raised the prospect of control programs far more expensive than anything undertaken in the past and this has heightened interest in emissions trading and in effluent charges or pollution taxes as means of maximising flexibility and minimising costs. By 2008 we have had some experience with all of these policies, which is briefly summarised below.

2 Environmental Policy Solutions

2.1 Conventional Regulation

Traditionally environmental ministries or agencies have imposed what academics refer to as "command-and-control" regulations on industrial air pollution including electric utility emissions. These include emission limits that are incorporated into the certificate of approval that is granted when the plant is constructed or renovated and other regulatory limits that may be imposed by regulation. These emission limits are generally more stringent for new sources than existing sources – the existing sources are grandfathered for a specified or indefinite period of time. The regulatory limits are usually activity-based, limiting emissions in relationship to the amount of fuel burned or electricity generated. For example, the Canadian federal guidelines for new thermal power generation limit the discharge of sulphur dioxide, nitrogen oxides and particulate matter in kilograms of the pollutant per megawatt-hour of power output.[1] "New" means any generating unit for which commercial operation begins after April 1, 2003. Ontario's guideline for stationary combustion turbines limits nitrogen oxides and sulphur dioxide in proportion to the power output and useful heat recovery of the turbine.[2] Ontario prohibits the burning in boilers of oil or coal with a sulphur content greater than one percent, excepting boilers operated by OPG.[3] New sources are generally regulated more strictly than existing sources. Regulations may also limit the concentration of air pollution allowed at a point of impingement. For example, a regulation under the *Ontario Environmental Protection Act* prohibits discharges that cause SO2 concentrations to exceed 830 micrograms per cubic metre averaged over a half hour.[4]

In some cases the regulation may require the use of "best available technology" or some variation that specifies some balancing of technology and cost. Such standards usually require a general administrative determination of what emission rate is implied by the standard or what specific technology will meet the standard for a particular type of pollution source. This determination is typically difficult and contentious.

A recent example of a regulatory policy that differentiates between new and old sources is outlined in the federal government's "Turning the Corner" document, issued 10 March 2008. This paper, which is a prelude to actual regulations, states that most existing facilities will face one set of rules; that facilities completed between 2004 and 2011 will have to meet more stringent reductions; and that starting in 2012 no new "dirty" coal-fired power plants may be constructed and that all oil sands plants constructed after that date must incorporate carbon capture and sequestration technology. (Canada, 2008, p. 4.) Business commentators have noted that existing oil sands operators might welcome such regulations because they act as a barrier to entry of new competitors without imposing great costs on existing facilities.

Numerous Ontario laws and regulations apply to air emissions from electricity generators including OPG. Section 14(1) of the *Ontario Environmental Protection Act* prohibits the discharge of a contaminant that "causes or may cause an adverse effect." Section 14(2) provides an exception for a discharge authorised under the *EPA*, so long as that discharge "does not cause and is not likely to cause an adverse effect" which exempts discharges that are in compliance with a regulation so long as an adverse effect does not result. Section 6 (1) of the *EPA* prohibits discharges in excess of those allowed by regulations and section 9(1) requires a certificate of

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[1] Environment Canada, CEPA Environmental Registry, "New Source Emission Guidelines for Thermal Electricity Generation," made under the *Canadian Environmental Protection Act,* viewed at: http://www.ec.gc.ca/CEPARegistry/documents/glines/thermal/gl.cfm .

[2] Ontario Ministry of the Environment, "Guideline A-5: Atmospheric Emissions from Stationary Combustion Turbines" (Toronto, MOE, March, 1994.)

[3] O. Reg. 338, *Regulation 338 Boilers*.

[4] O. Reg. 419/05 Air Pollution — Local Air Quality, section 18, schedule 1.

approval for all air pollution sources. The Countdown Acid Rain Program, initiated in the 1980s, limited Ontario Hydro's emissions of sulphur dioxide and nitric oxides through an unusual annual cap on corporate emissions that in 1994 reached 175,000 tonnes/year of SO2 and 215,000 tonnes/year of combined SO2 and nitric oxide.[5] This cap was unrelated to activity. That regulation has been superseded by a cap and trade program initiated through O. Reg. 397/01 in anticipation of a competitive electricity market. See section 3.5 below for a description of this program.

The application of more stringent standards for new or renovated sources than for old sources is a reasonable reaction to the lower cost of reducing emissions when constructing or rebuilding a source but it means that existing sources may continue polluting at high rates for years or decades. If applied aggressively it may provide a cost advantage for the old source compared to the new source.

The use of different regulations standards for classes of pollution sources inevitably means that the cost of pollution control varies considerably among those sources. Studies have shown that the additional cost to reduce emissions by one kg or one tonne may vary greatly from one source to another. If one is concerned only about total emissions from a set of sources this is more costly than necessary – costs would be reduced if the source with the lowest control cost reduced emissions the most. As pollution control requirements have become more strict in the last half century the cost of complying with those requirements has increased, leading industry and agencies to look for more economical methods of regulation.

2.2 Principles of Emissions Trading

Emissions trading can be used to introduce flexibility into a regulatory program, allowing a set of sources to reach the same total emission reduction at a lower total cost. One type of emissions trading involves allowing emission reduction credits "ERCs" or emission offsets in conjunction with conventional regulations. A more radical step is to use a "cap and trade" program instead of imposing more strict emission regulations, with the cap specifying the maximum emissions allowed from a set of sources and trading allowing them to reduce their costs. In either case, emissions trading lets the source that can reduce its emissions at the lowest cost do more of the pollution control while high-cost sources reduce less. Emissions trading saves costs. As pollution control requirements escalated during the last half of the 20th century, achieving environmental goals at the least possible cost became increasingly important. Since electric utilities were subject to some of the most stringent pollution control requirements it is not surprising that the utility industry was among the first to be offered the cost savings of emissions trading. Earlier success with the US EPA's "offsets" and "bubble" trading programs and the lead phaseout program in the 1970's built a base for emissions trading for utilities in the 1990s.

The savings achievable from emissions trading can be illustrated with a simple example involving two pollution sources. Suppose that two sources discharge 1000 kg/day of an air pollutant and that they have very different pollution control costs. Source 1 can reduce emissions at a cost of \$1/kg and source 2 can reduce emissions at a cost of \$2/kg. If the Ministry adopts a regulation requiring each source to reduce its emissions by 200 kg/day the total cost of meeting this regulation will be \$600/day. See Table 1

[5] O. Reg. 281/87, sections 2 and 3 and subsequently O. Reg 153/99.

Table 1. Emissions Trading, Two Sources Example

	Source 1	Source 2	Total
Reg. reduction (kg)	200	200	400
Cost ($/kg)	(1)	(2)	
Total control cost ($)	(200)	(400)	**(600)**
Emission trade (kg)	Sell 200	Buy 200	0
ET revenue (@$1.50/kg)	300	(300)	0
Emission reduction kg	400	0	400
Control cost ($)	(400)	0	400
Net cost with ET ($)	(100)	(300)	**(400)**

While this Ministry regulation achieves the goal of reducing total emissions by 400 kg/day, the cost is higher than necessary. The Ministry could achieve the same total emission reduction goal at a lower total cost if it amended the regulation to allow either source to purchase emission reductions from the other source in order to meet its reduction requirement. If trading is allowed, source 2 would be willing to pay up to $2/kg for source 1 to undertake emission reductions on their behalf because this would save source 2 $2/kg less the price paid. Source 1 would be willing to undertake emission reductions on behalf of source 2 for any price more than $1/kg since the excess over that cost would be pure profit. Suppose that they agree that source 1 will reduce 200 kg extra and sell credits for 200kg to source 2 at a price of $1.50/kg. The results of this agreement are shown in the bottom of Table 1. Source 2 buys 200kg of credits at a cost of $300; source 1 reduces an extra 200 kg at a cost of $200. The total emission reduction is still 400kg so the environmental results is the same as if there were no emission trading. The total control cost for the two firms is only $400 instead of $600, a saving of $200. I have assumed that the firms split the saving equally, as a result of the negotiated credit price of $1.50/kg, so each firm's net cost is $100 less than with the regulation and no trading.

This example shows that emission trading, in the form of emission credits added to a traditional regulation, can achieve the same environmental result at a lower cost for the pollution sources. The savings arise because the pollution sources have different costs of pollution control and trading allows the low cost source to do more pollution reduction, paid for by the high cost source. One use of emission credit trading is the US EPA's "bubble" policy, formalised in its 1986 emission trading model rule.

The example in Table 1 involves two sources that are both subject to regulatory limits on the emission of a pollutant. Similar savings can arise if one source is regulated and the other source is not regulated – because it is in a different industry or even in a different jurisdiction. Suppose that source 2 is required to reduce emissions by 200 kg/day and source 1 is under no regulatory limit. If the MOE allows it, source 2 can still pay source 1 to reduce emissions in the amount of 200 kg/day and negotiate a price lower than source 2's control costs. We might say that source 2 has purchased emission reduction credits of 200 kg/day or we could say that source 2 has purchased emission offsets of 200 kg/day from source 1. The offset means that source 1's emission reduction offsets source 2's emissions to the extent of 200 kg/day. One use of pollution offsets is the Kyoto protocol Clean Development Mechanism under which a source that is required to reduce emissions to comply with Kyoto commitments can pay a source in another country that is not part of the Kyoto protocol to reduce emissions or sequester carbon to offset the regulated source's emissions.

The purchase of emissions offsets raises a special concern, additionality. The purpose of the emission regulation is to reduce total emissions below what would have been discharged in the absence of the regulation, below the business-as-usual scenario. If the regulated limit is below BAU emissions, the environment is improved. Allowing regulated sources to purchase offsets still reduces total emissions so long as the emission reduction that creates the offset is itself additional to any regulatory requirement and also represents a reduction from business as usual. The danger arises if a source makes a process change that can be justified on business grounds alone, perhaps upgrading a boiler to save energy costs, and then sells the resulting emission reduction as an offset to a source that is struggling to meet its regulatory limit. In this case, the selling source's reduction is not additional to business as usual, so selling it allows the buying source not to decrease its emissions and the goal of the regulation has been thwarted. Most emission trading systems that allow the use of emission reduction credits or offsets require proof that the project creating the reduction is additional to any regulatory requirements and that it would not have happened except for the incentive provided by the purchase of the offset credits. Needless to say this is a difficult test to apply in practice, so there is considerable scepticism about the trading of pollution offsets and emission reduction credits.

A very different use of emissions trading arises with a cap and trade program. In cap and trade, the Ministry decides on a total allowed emission rate for a set of sources, presumably well below existing emission rates. Suppose that the total allowed emissions are 1000 kg/day. The MOE allocates to each regulated source of the pollutant some share of the cap so that total allowed emissions are 1000 kg/day. The mechanism for allocation is to distribute allowances to each regulated source, each allowance good for 1 kg/day, with the total allowances just equal to 1000 kg/day. All regulated sources are required to submit to the MOE one allowance for each kg of pollution that they discharge. Once the allowances are distributed the sources may buy and sell them, registering all such sales on the Ministry's registry. The cap determines the total allowed pollution and thus the extent of the reduction from previous emission levels. The trading allows sources to negotiate such that the sources with the lowest cost of control will do most of the controlling, selling allowances to sources with high costs. One use of cap and trade is the US Clean Air Act Amendments of 1990, Title IV which have reduced SO2 emissions from coal-fired power plants by about 50%.

In all cases, the principal achievement of emissions trading is to reduce costs of pollution control. The examples above provide no environmental benefit. The environment is improved by imposing the pollution control regulation or setting the emission cap. The emission trading only reduces the cost of complying with the regulation or cap. When the savings from trading are in the tens of millions of dollars, this is no small achievement. Furthermore if the economies available from emissions trading are sufficiently great, they may allow the Ministry to adopt a more stringent pollution control goal than would have been politically feasible using traditional regulations without trading.

2.3 Pollution Taxes, Effluent Charges

Cost savings similar to those achieved through emissions trading can also be achieved with effluent charges (also called pollution taxes). An effluent charge is a price that must be paid to the government for each unit of pollution discharged by a source. The price for a pollutant is set based on the benefits per unit of pollution reduction or at a level that is expected to achieve the desired degree of pollution reduction. When a source must pay, for example, $1000/tonne for every tonne of SO2 that it discharges, it will implement pollution control measures that cost less than $1000/tonne reduced, since this is less expensive than paying the charge. Each source will start with the most cost-effective control measures and implement increasingly costly measures until the cost of the last measure adopted equals the charge rate, $1,000/tonne in this example. This means that all sources subject to the effluent charge will control until their marginal cost of control is $1,000/tonne, so their marginal costs at all sources are equal. Equating the marginal cost of abatement necessarily minimizes total cost for all sources, so this automatically minimises the cost of achieving the environmental goal. Efficiency is the same as with emissions trading.

The effluent charge differs from the cap and trade system in two fundamental ways. First, the effluent charge sets the price of pollution, in $/kg or $/tonne and the decisions of sources determine the amount of pollution that will be discharged. Once the charge rate has been set the price of pollution is known with certainty but the amount of pollution discharge and pollution control is uncertain, depending on the reactions of sources. In contrast, with cap and trade the government sets the pollution quantity and thus the overall pollution level and the buying and selling of allowances sets the price of pollution. The environmental result is certain but the pollution price is uncertain, depending on the costs of control. Second, with an effluent charge the polluter pays a price for all pollution discharged, so the charge generates revenue for the government and imposes costs for the facilities. Most emissions trading systems to date have distributed allowances for free, so facilities do not pay to pollute unless they purchase allowances in addition to those provided for free. The cost to sources is just the cost of installing and operating the pollution controls.

Industry tends to prefer emissions trading because sources only pay for pollution control and not for the remaining pollution discharge. Environmentalists often also prefer cap and trade because it seems to ensure an environmental result. However setting a fixed cap in a situation where demand for pollution discharge is variable can cause highly variable prices, as occurred in southern California with RECLAIM. Alternatively if the control technology is unproven or uncertain, a cap on emissions may force substantial output reductions in industry, with adverse economic and political consequences. If there are sound environmental reasons not to allow emissions to exceed a specific quantity, perhaps because there is a “safe threshold” of exposure to the substance, cap and trade may be preferred. If, on the other hand, there is no special ambient quality limit but we want to create incentives or pressure to reduce emissions, then a price on pollution may be preferred. There has been extensive discussion of the choice between setting the price or the quantity for pollution control. (Weitzman, 1974.) While the political unpopularity of new taxes has held back effluent charges/pollution taxes in the past, the complexity of emissions trading and the need for more flexibility than a fixed cap allows has led to some effluent charges being imposed and discussed in the last decade. See section 6 below.

3 Conventional Pollutants – Regional Cap and Trade

There are several examples of the use of cap and trade programs to reduce the emissions of conventional pollutants, most of them adopted in the United States in the last 20 years.

3.1 US Clean Air Act Amendments 1990, Title IV, SO2 and NOx Trading

Title IV of the 1990 US *Clean Air Act Amendments*[6] required a 50 percent reduction in SO2 emissions from coal-fired electric utility boilers within the continental United States in two phases between the late 1980s and the year 2000. Phase II allocates 8.95 million tons per year of free allowances to more than 400 utility boilers roughly in proportion to their coal consumption in 1985-87. Utilities must retire one allowance for every ton of SO2 discharged. A utility may sell its allowances, bank them for future use, or buy additional allowances from others. (US EPA, 2001, p. 76.)

No existing regulations were repealed when Title IV was enacted so trading should not make air quality worse than it had been at any location. The trading region for Title IV is the continental United States despite the fact that this is not a single airshed but several unrelated airsheds. The national trading area, over four hundred trading sources plus banking of allowances means that trading is very flexible, resulting in a robust market. Cost savings arising from trading have been estimated at over US $2 billion per year as compared to the same emission reduction without trading. (Ellerman *et al*., 2000.) The flexibility of this market is in marked contrast to the very restricted trading in the RECLAIM program discussed below.

Title IV also limits on NOx emission rates from electric utility boilers and provides that the owner of two or more units may average the actual emissions from those units. This is like traditional activity-based regulation with emissions trading within a corporation, called a "corporate bubble." This aspect of Title IV achieved a 2 million ton per year reduction in NOx emissions by the year 2000. (EPA, 2007, p. 13.)

3.2 US EPA NOX SIP Call: NOx Budget Trading

In October 1998, the EPA required 22 eastern states and the District of Columbia to reduce NOx emissions to meet air quality standards. The EPA developed a model NOx trading rule[7] that applied to large stationary sources, mostly electric utilities, and provided for the trading and banking of allowances. The control period ran from May 1 to September 30. Limits were placed on the use of banked allowances. The electric utility units receive allowances in a year equal to their defined heat input from four years earlier multiplied by 0.15 lbs/mmBTU, with all allocations decreased proportionally if the total exceeds the state cap. A source that closes down loses the right to receive allowances. A new unit may request allowances from a "set-aside" until it can earn allowances under the 4-year rule. The Model Rule allows banking of unused

[6] 1990 *Clean Air Act Amendments* Pub. L. 101-549, Title IV, 42 U.S. Code 7651.
[7] NOx SIP Final Rule, Part 96, 63 Fed. Reg. 57,514 et. seq. [1988].

allowances subject to "flow control." If the sum of all banked allowances exceeds 10% of the annual NOx budget the use of banked allowances is limited or discounted 2:1.

The NOx Budget Trading Program operated from 2003 through 2008, helping to reduce national NOx emissions by over 25% between 2000 and 2006 in combination with the Title IV NOx program. However it did not meet EPA goals and in 2009 it will be superseded by the Clean Air Interstate Rule.

3.3 US EPA Clean Air Interstate Rule – Eastern US SO2 and NOx trading

In 2005 the EPA adopted the Clean Air Interstate Rule (CAIR)[8] which requires 28 eastern states[9] to reduce the emissions of SO2 and NOx to meet the National Air Quality Standards. CAIR includes model rules for a multi-state cap and trade program for annual NOx, for ozone-season NOx, and for SO2. CAIR is directed toward fossil-fuel electricity generating plants larger than 25 MW although states may include other sources. The SO2 reductions of CAIR are achieved using the Title IV allowances and requiring CAIR sources to submit more than one allowance for every ton of SO2 emitted. Vintage 2010 through 2014 allowances will authorise only 0.5 tons of emissions in CAIR states and vintage 2015 allowances will authorise 0.35 tons per allowance. Because Title IV SO2 allowances have already been allocated to coal-fired power plants there is no need to create a new allocation mechanism for CAIR.

For NOx, the EPA proposes that for the first five years the allowance allocation is based on historic baseline heat input. Allowances for 2014 and later years are based on this historic heat input for old units and on recent past heat input for new units. Retired units continue to receive allowances indefinitely. Five percent of allowances are set aside for new sources until 2013, then 3%. There is banking of unused allowances but no flow control.

CAIR reflects the EPA's belief that the only practical and economical way to achieve large emission reductions over a substantial area of the US is through a cap and trade program.

3.4 RECLAIM in California

In 1993, the South Coast Air Quality Management District (the District) adopted the RECLAIM emissions trading program to cause about 40 SOx and 400 NOx sources to reduce emissions by about 75% between 1994 and 2003.[10] Each source was given an emissions allocation, called RTCs, for 1994, in pounds of NOx and/or SOx emitted in a year based on activity (input, output, or energy consumption) between 1989 and 1991 multiplied by an emission factor for the type of source. The emission factors and allocations were steadily reduced between 1993 and 2003. The RTCs are issued twice a year for a specific year and cannot be banked. RECLAIM defines two trading regions: coastal and inland, and limits the sale of inland RTCs to coastal sources. This means that instead of a single trading market there are

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[8] Federal Register, Vol 70, No. 91, Thursday, May 12, 2005, Part II, pp. 25162 to 25405.

[9] States from Minnesota to Louisiana and eastward, excluding Maine, New Hampshire and Vermont, plus Texas.

[10] See AQMD Regulation XX, RECLAIM rules 2000-2020: http://www.arb.ca.gov/homepage.htm .

many separate markets, greatly reducing the cost savings. The market has not operated very competitively. (Ishikida, Ledyard, Olson and Porter, 2000.)

New sources after 1989-91 must purchase RTCs from existing sources by paying them to reduce emissions. New or modified or expanded sources are still required to install Best Available Control Technology for limiting emissions. RECLAIM rules explicitly prohibit production curtailment as a means of demonstrating compliance with a facility's allocation. Electricity generation stations are required to prepare and submit plans for complying with various emission control requirements as well as participating in the RECLAIM trading. Certain sources that are not subject to the RECLAIM cap may reduce their emissions and sell credits to capped sources. An example is a mobile source program that creates credits for scrapping qualifying older high-emission vehicles.

In 2000 and 2001 a drought and heat wave led to increased generation and an increase in demand for NOx RTCs. The price rose from $1 to as much as $30 in 2000 and as high as $60 in 2001. These prices contributed $30, $40 and even $120/mWh to the wholesale price of electricity during the California electricity crisis. (Joskow, 2001, p. 380.) This market gyration led to amendments to the trading scheme, including the creation of a safety valve of extra RTCs that could be purchased as the price rose.

Emissions trading works best for reducing the long-term total emissions from a set of sources without regard to the timing or location of the discharge. However smog is a local pollutant and the policy goal in California is to avoid exceeding a specified concentration at any time, so both timing and location are crucial. This has led to the very restrictive trading regime in RECLAIM, to the continuation of rigorous new source performance standards on participating sources and to debate as to whether the regime has succeeded. Savings have been modest and problems substantial.

3.5 Ontario Emissions Trading, NOx and SOx: O.Regs. 397/01; 194/05

In 2001 the Ontario Ministry of the Environment published O.Reg. 397/01, establishing a cap and trade and credit system for electricity generation facilities. There is a cap on annual emissions of nitric oxides from OPG facilities from 2002 until 2006 and a separate cap on those emissions from independent generation facilities. There is also a cap on sulphur dioxide emissions from OPG facilities and independent facilities. Owners of the capped facilities may trade allowances among themselves. They may also purchase emission reduction credits from sources within Ontario and certain states that are not part of the trading program if those sources have reduced their emissions below a baseline representing the lesser of historic emissions and any regulatory limits and have followed a "standard method" for emission reduction.

In August, 2005, the MOE expanded the program to 30 existing facilities in 7 industrial sectors in Ontario with O.Reg. 194/05. The industry sectors include iron and steel, base metal smelting, cement, pulp and paper and others. There is an industry-wide cap of 47 kilotonnes of NOx by 2015, a 21% reduction from 1990 levels and 192 kilotonnes of SO2 by 2015, a 46% reduction from 1994 levels. The emissions trading rules are identical to those for the electricity sector.

One novelty in O.Reg. 194/05 is that each industrial sector could choose whether facilities would receive NOx and/or SO2 allowances on a fixed basis, with the annual emission tonnage set by the MOE, or on a variable basis, using intensity rates multiplied by actual production data for the facility. Sectors choosing fixed allowances face the prospect that facilities that reduce their production or that close lose the right to some or all of their allowances. (See, e.g. sections 12, 13, O.Reg. 194/05.) New sources and sources that undergo major expansion are entitled to receive allowances based on emission rates derived from "best available technology economically achievable," a standard that has been difficult to interpret and apply in most applications.

Credits from emission reduction projects are discounted by 10% in the year in which they are retired, discouraging the use of emission reduction credits. There are also "flow control" rules limiting the amount of credits that may be applied in any year as a proportion of allowances applied in that year.

The rules for allocating allowances, for creating credits, and for applying credits are more complex than is generally recommended by economists. If little trading takes place, then the system will behave much like a system of traditional activity-based regulations.

4 Greenhouse Gas Emission Trading

4.1 Regional Greenhouse Gas Initiative (RGGI)

Seven states (CT, DE, ME, NH, NJ, VT, NY) signed a Memorandum of Understanding in December, 2005 to create a policy to stabilize and then reduce $CO2$ emissions within the signatory states by establishing a regional $CO2$ emissions budget allocated to states. This will create an emissions trading program within the signatory states covering all fossil fuel-fired electricity generation units having a rated capacity greater than 25 MW. Massachusetts, Rhode Island and Maryland joined in 2007. The regional cap will be about 188 million short tons of $CO2$ per year starting January 1, 2009, which is about 4% above the average emissions for those states during 2000-2004. Base allocations are constant from 2009 through 2014. In 2015 each state's budget will decline by 2.5% and by 2.5% in each subsequent year so that in 2018 the budgets are reduced 10% below the 2009 base.

Allowances are distributed to the states as a negotiated share of the overall cap. Most of the states plan to auction off most of their allowances to sources rather than distributing them for free, a substantial departure from all previous US emissions trading programs. (RGGI, 2007, p. 4.) Unlimited banking of allowances is allowed. Offset allocations may be purchased from sources not capped by the RGGI program, initially including a specific list of project types such as landfill methane capture, energy efficiency improvements and afforestation. (RGGI, 2007, p. 9.) Offsets projects are subject to careful scrutiny for additionality, both regulatory and financial. Offset projects may be anywhere in the US, but projects outside a signatory state are discounted and offsets may cover only 3.3%, 5% or 10% of emissions in any year depending on the market price of allowances. (RGGI, 2007, p. 7.)

Some commentators have complained that it will be too easy for a state to drop out of RGGI if the cost of control is higher than expected, so RGGI may be less effective than it appears on the surface. The proposed extensive auctioning of allowances will be an interesting novelty for emission trading in North America.

4.2 Western Climate Initiative

The Western Climate Initiative (WCI) was started in February, 2007 by the Governors of Arizona, California, New Mexico, Oregon and Washington to develop a regional climate change strategy. In the spring of 2007, the Governor of Utah and the Premiers of British Columbia and Manitoba joined and other states and provinces have joined as observers. As of February, 2008 there is no agreed regional GHG cap nor any enforceable means of emission reduction but there is an agreed goal of reducing economy-wide GHG emissions in the member states to 15% below 2005 levels by 2020. (WCI, 2007a.) WCI produced a set of options papers in February, 2008 to guide further action. Seven of the eight states have adopted specific GHG reduction goals for 2020.

Without any agreement on a regional trading mechanism or on a fixed cap for the members, the WCI is several years behind RGGI as a credible instrument for reducing GHG emissions. Individual states may have rigorous programs but the initiative has so far added little to those programs other than sharing of information and publicity and the development of possible policy options. An interesting aspect of the WCI is the assumption that the members' goals will be achieved by a cap and trade program for major sources, including electric utilities.

4.3 California's Global Warming Solutions Act of 2006

In 2006 the California state assembly adopted AB 32, the Global Warming Solutions Act of 2006.[11] The stated goals are to reduce greenhouse gas emissions from the state of California to 1990 levels by the year 2020 (25% below business-as-usual emission rates) and then to reduce those emissions further to 80% below 1990 levels by 2050. The legislation requires that the California Air Resources Board adopt these goals and then develop a plan and regulations that will achieve them. The plan includes all emissions of GHG from generators outside of California of electricity that is delivered to California. This will require the development of an accounting system for electricity flows in the California area so that the generation mix of electricity destined to California can be determined.

Measures under consideration in 2008 include expanded energy efficiency programs and a renewable portfolio standard for electricity. Other regulations could include direct regulation of GHG emission rates, a cap and trade program for GHG and a carbon fee for all fuels distributed in California. Sequestration of CO2 must be considered. The Air Resources Board is required to define and adopt regulations defining and requiring maximum technically feasible and cost-effective emission reductions by 2012. Given the ambitions of the reductions to be achieved it seems likely that a number of measures will be adopted, including either cap and trade or a carbon tax.

4.4 Kyoto Protocol

The Kyoto Protocol was adopted at the third conference of the parties (COP 3) in December, 1997. Each Annex I Party must reduce its emissions by its commitment amount below its 1990 emission rates during the first five-year commitment period 2008-2012. This reduction is measured in tonnes of carbon dioxide equivalent or assigned amount units (AAUs).[12]

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[11] California Health and Safety Code, section 25.5, sections 38501 *et seq.*
[12] See the United Nations Framework Convention on Climate Change website:

The Kyoto Protocol defines three “flexibility mechanisms” to help to reduce costs:

- Emissions trading (Article 17) allows Annex I Parties to purchase AAUs from other Annex I Parties.
- The clean development mechanism (CDM) (Article 12) allows Annex I Parties to implement projects that reduce emissions in non-Annex I Parties, or absorb carbon through afforestation or reforestation activities, in return for certified emission reductions.
- The Joint Implementation (JI) mechanism (Article 6) allows Annex I Parties to implement an emission-reducing project or a project that enhances removals by sinks in the territory of another Annex I Party and count the resulting emission reduction units towards meeting its own Kyoto target.

The Marrakesh Accords require Annex I Parties to take domestic actions to reduce emissions in a manner that will narrow per capita differences between developed and developing countries. They require that domestic actions rather than the flexibility mechanisms (CDM and JI) constitute a “significant element” of the each Annex I Party’s program to meet its target and that their use of the mechanisms is “supplemental to domestic action” to achieve their targets. (UNFCC, 2008a.)

The UK has developed a set of policies for reducing greenhouse gas emissions and complying with its Kyoto obligations, referred to as the UK Climate Change Programme. Central elements in the program are a climate change levy, associated climate change agreements, both discussed below, and a cap and trade program for greenhouse gases. The UK emissions trading program involves participation in the European Emissions Trading Scheme (EU ETS). The EU ETS covers over 1000 facilities in the UK including electricity generators and representing over 50% of UK CO2 emissions. The UK “cap” on CO2 emissions for Kyoto compliance in 2008-12 has been set and the UK has established the emission trading registry that will keep track of allowances and their ownership. The government has proposed that the entire reduction in emissions by UK sources covered by the EU ETS would be achieved in the electricity generation sector, since it is less subject to international competition than other sources. Some industry sectors that are included in the EU ETS are also covered by the climate change levy and agreements, so the government has taken steps to ensure that facilities cannot double-count their emission reductions in both schemes. (UK DEFRA, 2006, p. 49.)

The European Union member countries have submitted proposed allowances for the 2008-12 period and these have been approved. The assigned amount units have been trading as EU Emission allowances, or EUAs. The price of EUAs is determined by supply and demand, both of which are inelastic, and the price is correspondingly volatile. In 2006 the first verification of EU emissions caused the price of EUAs to drop by 2/3 because the verified emissions were 2.5% less than expected. (Hart, 2007, p. 44.) Prior to 2008 there was uncertainty as to whether Russia and Ukraine would be allowed to sell their allowances in the EUA market. Since both countries have vast allowances based on the highly-polluting industry in the former Soviet Union prior to 1991, they currently have a large supply of excess allowances

http://unfccc.int/essential_background/items/2877.php .

("hot air") that, could drive the price of EUAs to the low single digits. It now appears that the Russian and Ukraine allowances will not be accepted in the EU, and the price of EUAs is trading in the range of €20/tonne of CO2.[13]

In all EU countries the electricity generation sector is covered by the ETS. However a number of member countries have adopted specific programs to encourage the use of renewable energy, such as the German subsidies for solar power and the Danish promotion of wind power.

4.5 Voluntary GHG Commitments

One motive for a corporation to make a voluntary commitment would be to secure public goodwill which may help to market the company's products. Another would be to help forestall government regulation. Still there has been debate whether voluntary commitments will likely achieve significant reductions. (Benedickson, 2002, pp. 294-99.)

Several programs encourage firms to make and to fulfill GHG reduction commitments. These programs promise publicity for successful participants and offer technical support and verification of the commitment and its implementation. For example, the US Environmental Protection Agency operates the Climate Leaders program which works with corporations to develop and implement long-term climate change strategies. Participants ("partners") agree to develop a corporate GHG inventory, to set an aggressive GHG reduction goal for a period of five to ten years, to measure and report GHG emissions, and to publicise their participation in the program. The EPA provides publicity for partners and their achievements, technical support for measuring and reporting emissions, and credibility that comes from EPA verification of the achievements. (EPA 2007b, p. 2.) Over 150 corporations participated in 2007. Electric generating companies participating in the Climate Leaders program include: American Electric Power (GHG 6% less than the 1998-2001 average by 2010); Calpine (reduce U.S. GHG emissions by 4% per mWh between 2003 and 2008); FPL Group (reduce U.S. GHG emissions by 18% per kWh between 2001 and 2008) and Green Mountain Energy (zero GHG emissions in 2005 through 2009). (EPA, 2007c.)

Other voluntary commitment programs include the Business Environmental Leadership Council (BELC) administered by the Pew center and the Chicago Climate Exchange administered by the Chicago Climate Exchange PLC. The BELC program invites corporations to join and to make commitments to GHG reductions. While the Pew Center provides publicity and guidance it appears that it offers less monitoring of member performance than the EPA. The BELC program has 42 members including a number of energy companies, some of which are also partners in the EPA Climate Leaders program. The Chicago Climate Exchange (CCX) operates a voluntary program for reducing GHG emissions and includes as a central feature a trading mechanism for GHG reductions. Members sign legally binding commitments to reduce their GHG emissions below a 1998-2001 baseline and to pursue those reductions either by reducing actual emissions or by purchasing allowances from other members or from offset providers who have reduced their emissions beyond regulatory or voluntary requirements. A major business of the CCX is trading in the allowances and offsets associated with firms complying with their voluntary commitments. More than a dozen electric power generation

[13] Point Carbon, "EUA Price Last 30 Days" http://www.pointcarbon.com/search.php?query=aau+price , accessed 2 March, 2008.

companies are members of the CCX, including firms that participate in one or more of the other voluntary commitment programs.

The Canadian Chemical Producers Association developed a "Responsible Care" program to reduce risks of spills and discharges of harmful chemicals which has achieved significant reductions in emissions and incidents among members of the Association. (CCPA, 2008, p. 4.)

Two examples of electric companies that have made voluntary commitments are Tampa Electric and AEP. Tampa Electric made a commitment to reduce its CO2 emissions to 4% below its average emissions in 1998-2001. In January 2008 the company announced that it had achieved this reduction, signifying a 20% reduction from 1998 emissions, utilising a combination of efficiency improvements, conversion of one plant from coal to natural gas, and operation of an integrated coal gasification combined-cycle plant. (Tampa Electric, 2008, Tampa Electric, 2006.) American Electric Power made a commitment in 2003 to reduce or offset its CO2 emissions to 4% below its average emissions in 1998-2001 in 2006. In 2005 it extended that commitment to an overall 6 % reduction below the 1998-2001 baseline by 2010. These goals are being met by a combination of efficiency improvements, the use of renewable generation, supporting emission reductions elsewhere, and the purchase of credits on the CCX. (AEP, 2007, p. 15.)

In 1995, Ontario Hydro made a commitment to reduce its greenhouse gas emissions to 1990 levels by the year 2000. This commitment was made through Canada's Climate Change Challenge Voluntary Challenge and Registry. That target of 26 million tonnes of CO2 was met in 2000 by a combination of improving energy efficiency internally, generating more renewable power, planting trees (sequestration) and purchasing emission reduction credits from others. (OPG, 2001.) The company has committed to continuing that commitment in subsequent years.

It is significant that many of the electric utilities that have made commitments to reducing or limiting their greenhouse gas emissions have included emissions trading as one element in their plans. The uncertainty of electricity demand and the dearth of emission control technologies for CO2 make the purchase of credits a wise and perhaps essential element in any adoption of a cap on emissions.

4.6 Canadian Policy Proposals

Several proposals have been advanced for reducing greenhouse gas emissions in Canada, each of which would impact the electricity industry. The federal government's 2002 Climate Change Plan for Canada proposed a cap and trade system for greenhouse gases from large final emitters – major individual sources. While this system was never implemented it represented an admission that such a system would be necessary to achieve substantial industrial reductions. Past government programs are described and criticised in Simpson, Jaccard and Rivers (2007). They state that significant CO2 reductions will only occur if the price for CO2 emissions is high. Their first preference is a carbon tax that would start at a low level and grow slowly to a price of $100 to $150 per tonne of CO2 by 2050. (Simpson, Jaccard, Rivers, 2007, p. 207.) After extolling the benefits of the tax approach they note that a cap and trade program could also work so long as it resulted in allowance prices of the same value.

The National Roundtable on Environment and the Economy concluded that Canada would not achieve substantial GHG reductions without making GHG emissions expensive through either a cap-and-trade program or a carbon tax. Setting a goal of reducing GHG emissions in Canada to 65% below current levels (which would be a much smaller reduction from the 1990 Kyoto baseline levels) they recommend a price for CO2 emissions starting at \$20/tonne in 2015 and increasing to \$200/tonne in 2030. (NRTEE 2008, p. 25.) Unlike recent federal programs and proposals the NRTEE program does not give credit for early action nor does it allow international offset credits or offsets for investment in clean technology. Furthermore its carbon price is far above any contemplated by the federal government – federal plans have typically had an escape valve at about \$15/tonne of CO2.

5 Subsidy of Non-fossil Sources

Subsidies of renewable power can take several forms. The Renewable Portfolio Standard mandates that a certain proportion of the power sold must be generated by qualifying renewable sources. The feed-in tariff sets a guaranteed premium price at which renewable generators can sell power to the grid, thus setting a price rather than demanding a quantity. Finally direct subsidies provide tax breaks or cash subsidies to certain types of renewable generation. Examples of these policies and their characteristics are reviewed here.

5.1 Renewable Portfolio Standard

A common method of subsidising renewable generation is to require utilities or retailers to include at least a specified percentage of electricity from renewable sources in the power that they sell in each year. The utility or retailer must generate or purchase the renewable power and roll its cost into the total cost of the electricity that it supplies. So long as the renewable percentage is small, its high cost is largely hidden by the averaging process. RPS is a subsidy because the high cost of the renewable power is averaged in with the low cost of conventional power. For example, suppose that a utility typically generates 1000 mWh of coal power with an average cost of \$50/mWh. It could add another 50 mWh of coal power with the same average cost. Assume that an RPS requires it to add 50 mWh of wind power at a cost of \$150/mWh. The utility's total cost will rise from \$50,000 to \$57,500, and its average cost, and thus its price in a regulated setting, will rise from \$50 to \$54.76/mWh, far below the \$150 cost per mWh of the new expensive wind power.

In the United States, 29 states have implemented RPS requirements (or in a few cases recommendations), with varying definitions of renewable and with percentages ranging from 4% in Massachusetts to 25% in Illinois, Minnesota, New York and Oregon. The dates for compliance range from 2009 to 2025, with most falling in the period 2015 to 2020. Two nearby states plus Texas illustrate typical RPS provisions.

The New York Public Service Commission adopted a renewable portfolio standard in September 2004 with a target of 25% by 2013. Approximately 19.3% of the 25% target will be derived from renewable energy facilities in existence in 2004, which presumably includes hydropower from Niagara Falls, and one percent is expected to be met through voluntary green power sales. The remainder will derive from new, eligible resources centrally procured by the New York State Energy Research and Development Authority (NYSERDA). NYSERDA manages an RPS fund that collects a surcharge on each kilowatt-hour sold by the state's investor-owned utilities. The RPS program purchases power from certain types of renewable generation facilities and subsidises certain customer-sited facilities that are generally limited to the size of the load at the customer's meter.[14]

Pennsylvania's Alternative Energy Portfolio Standard (AEPS), enacted November 30, 2004, requires each electric distribution company and electric generation supplier to retail electric customers in Pennsylvania to supply 18% of its electricity using alternative-energy resources by 2020. Rural cooperatives must offer a voluntary program of energy efficiency and demand side management programs. A minimum percentage of electricity must be generated by photovoltaics (PV), but demand-side management, waste coal, coal-mine methane and coal gasification are also qualifying technologies. The standard calls for utilities to generate 8% of their electricity by using "Tier I" energy sources and 10% using "Tier II" sources by May 31, 2021, all within Pennsylvania or within the PJM regional transmission organization.[15] Perhaps it should not be surprising that a coal-producing state would label its program "Alternative Energy" rather than "Renewable", and that it would include waste coal, coal gasification and "clean coal" technology such as IGCC in its required portfolio.

The Public Utility Commission of Texas adopted in 1999 a set of rules to implement the state's Renewable Energy Mandate, including an RPS which includes a renewable-energy credit trading program so that utilities did not have to actually deliver renewable energy, and renewable-energy purchase requirements for competitive retailers. The goal of the program is to install 2,000 MW of new renewables in Texas by 2009, 5,880 MW by 2015 and 10,000 MW by 2025. The 5,880 target is about 5% of the state's electricity demand. Most existing renewable generation in Texas comes from wind power and this is expected to continue.[16]

Environmental tracking systems are sometimes implemented to ensure that RPS targets are met.[17] These systems are designed to ensure accurate reporting of the actual proportion of electricity being provided by different types of generator. Environmental tracking systems usually include:

- registration and certification of participating facilities to establish the environmental attributes with each MWh of energy generated from the respective facility;
- monitoring of the output the facility;
- reporting and auditing of the aggregate environmental attributes of electricity sold by the regulated entity, based on the certificates to determine if the requirements of the RPS are met.

In some jurisdictions, environmental tracking systems are implemented by the Independent System Operator (ISO) which already collect most of the information required to perform

[14] This description is derived from the Database of State Incentives for Renewable Energy, "New York Incentives for Renewable Energy" http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NY03R&state=NY&CurrentPageID=1 accessed February 22, 2008.
[15] This description is derived from the Database of State Incentives for Renewable Energy, "Pennsylvania Incentives for Renewable Energy," http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=PA06R&state=PA&CurrentPageID=1 .
[16] This description is derived from the Database of State Incentives for Renewable Energy, 2007, "Texas Incentives for Renewable Energy."
[17] Ng Hok and Martin Hastings of the IESO provided this description of tracking systems.

environmental tracking. ISOs currently developing environmental tracking systems include ISO-NE, NYISO, PJM, and ERCOT.

In November 2006, the Ontario government established a Renewable Energy Standard Offer Program (RESOP) to promote the development of small wind, water, solar and biomass power projects of less than 10 MW.[18] Under the RESOP generation is procured by the Ontario Power Authority (OPA) through 20 year contracts at a fixed price that is above current market rates. The long-term, guaranteed contracts and the higher price significantly reduce the risk associated with building the new generation, presumably enabling financing of these small-scale projects. The cost of the program is borne by all Ontario energy consumers as a monthly charge billed on a pro rata basis according to energy consumption. The government has set targets for the quantity of renewable power of various types that it would like to see installed. As of March 2008, the program had 35MW of generation that had reached commercial operation and contracts in place for an additional 1,230MW. (OPA, 2008.)

Ontario's RESOP program is similar to a renewable portfolio standard in that the cost of the more expensive renewable power is borne directly by all electricity consumers in proportion to their electricity use and the government has specified targets for the quantity of installed renewable power. In addition, the target amount of power from each source has been determined by the government. However it differs from a typical RPS in that the government can adjust the target quantity as the cost of renewable power is revealed through the purchase process. In addition, the program is directed at one entity, the OPA, rather than at all retailers and utilities. The set price is more like a feed-in tariff than like an RPS.

5.2 Feed-in Tariffs

The US Public Utilities Regulatory Policies Act of 1978 required, in section 210, that electric utilities purchase all available power from a Qualifying Facility at the utility's avoided cost of production, or marginal cost. Qualifying facilities include renewable sources such as solar, wind, biomass, waste, geothermal, and hydroelectric sources. QFs also include cogeneration facilities. A QF must small or not owned by a utility or meet some other criteria. Some public utility commissions determined avoided cost through administrative proceedings. If the avoided cost was the cost of a new power plant built by the utility the avoided cost could be relatively high, particularly if the likely new plant would be nuclear. In the case of California, the state interpreted avoided cost to be gas-fired generation which led to purchase prices that exceeded actual marginal generation costs for many years. New York also provided favourably high prices to independent QFs. Others states used competitive bidding to determine the marginal cost of generation and thus the price to be paid to power from QFs. (US DOE EIA 2008 d.) During the first decade after PURPA's passage generation from QFs grew rapidly. By 1996, there were 58,000 MW of QF capacity operating. In 1995 FERC specified that avoided cost must be related to the utility's actual avoided cost, which reduced prices paid for renewable power in high-priced states like California and New York. Growth subsequently declined.

California's PUC interpreted avoided cost in 1982 as the long-run cost of power based on forecasts of the price of oil and natural gas, which had just risen dramatically. In fact prices of oil and gas fell during the 1980s so that the feed-in tariffs were greatly above actual avoided

[18] I am grateful to Ng Hok and Martin Hastings of the IESO for this description of the Ontario RESOP program.

costs of the utilities. The CPUC then created "standard offer" contracts for renewable power, providing a fixed price for the first ten years, the price to be determined by avoidable costs thereafter. In 1996, California mandated "net metering" for customers who installed their own renewable power generation, ensuring that they could be paid at the regular electricity price for power that they pumped back into the grid. Other subsidies for renewable power were available in California during the 1990s. (US DOE EIA 2005, p. 10.)

Germany adopted a feed-in tariff in 1991that required utilities to purchase power from renewable generators at a price equal to 90% of the retail electricity price. This price, of course, is significantly higher than the avoided generation cost applied under PURPA. There is no size limit on generators eligible to sell power under the feed-in tariff. In 2000, Germany passed a Renewable Energy Law that set the price which renewable generators must be paid for their power. This has again boosted the renewable sector in Germany. (US DOE EIA 2005, p. 14.)

5.3 Direct Subsidy Programs

The US federal government has two direct subsidy programs for renewable energy, the Renewable Electricity Production Credit and the Residential Solar and Fuel Cell Tax Credit. The electricity production credit provides a tax credit of 2.0¢/kWh (indexed for inflation) for wind, closed-loop biomass and geothermal. Electricity from open-loop biomass, small irrigation hydroelectric, landfill gas, municipal solid waste resources, and hydropower receive half that rate. The duration of the credit is generally 10 years but there are shorter credits for some technologies. Refined-coal facilities and Indian coal facilities receive special subsidies.[19] It is difficult to determine the effect of this program on the share of renewable energy in the total US generation mix.

The residential solar and fuel cell program provides a 30% tax credit up to $2,000 for the purchase and installation of residential solar electric and solar water heating equipment. A 30% tax credit up to $500 per 0.5 kilowatt (kW) is also available for fuels cells. These tax credits have been extended through December 31, 2008.[20] Photovoltaic generation capacity has grown rapidly since the introduction of the credit, but it was growing rapidly beforehand so it is difficult to estimate its effect on the market. The size of the subsidy is large enough, however, so that should have a substantial effect. 259 MW of photovoltaic capacity was installed in 2007, compared to 108 MW in 2005 and 16.8 in 2000, suggesting that the combined effects of available subsidies are substantial, given the high cost of power from both of these sources.. (Earth Policy Institute, 2008.)

6 Pollution Taxes – Effluent Charges

Pollution taxes or effluent charges have been much less commonly used than emissions trading but practical problems with emissions trading programs have led to increased interest in

[19] http://www.dsireusa.org/library/includes/GenericIncentive.cfm?Incentive_Code=US13F&currentpageid=3&EE=0&RE=1 .

[20] http://www.dsireusa.org/library/includes/GenericIncentive.cfm?Incentive_Code=US37F&currentpageid=3&EE=0&RE=1 .

these taxes/charges. This interest is also stimulated by the increasing popularity of the "polluter pays" principle. Several jurisdictions have now adopted serious effluent charge schemes to encourage pollution control.

6.1 The UK Climate Change Levy

The UK Climate Change Programme include a climate change levy, associated climate change agreements and the cap and trade program for greenhouse gases discussed above. The climate change levy, introduced on April 1, 2001, is a tax on fuels purchased by the industrial, commercial and government sectors but not by private individuals, charities or very small businesses. Transport fuels are also exempt, presumably on the grounds that they are already heavily taxed. The rates of the levy are based on the energy content (measured in kilowatt hours) of each fuel: 0.15p/kWh for natural gas; 1.17p/kg (equivalent to 0.15p/kWh) for coal, 0.98p/kg (equal to 0.07p/kWh) for LPG; and 0.43p/kWh for electricity. Oddly, these tax rates result are not equivalent to a uniform tax per tonne of CO2; the rate on CO2 from LPB is half that of natural gas, with coal in the middle. All are less than US $10/tonne of CO2. Beginning in 2007 these rates will increase annually with inflation. Significantly, the levy does not apply to fuels used for generating electricity. (UK DEFRA, 2006, pp. 47-48.) The rationale for this exclusion is that electricity generation is covered by the UK cap and trade system for CO2 that is part of the EU ETS, discussed above, so taxation of fossil fuels used for electricity would be redundant.

The purpose of the levy is to encourage energy conservation and to encourage energy users to agree to specific efficiency targets or greenhouse gas reductions through Climate Change Agreements with the government. Climate Change Agreements provide for an 80% reduction in the levy for sectors that have signed agreements so long as the targets in the agreements are met. (UK DEFRA, 2006, pp. 48-49.) Such agreements have been signed with many industry groups covering a large fraction of firms subject to the levy. Thus the levy serves primarily as a threat to encourage participation in the agreements. The government reduced the national insurance tax by a small amount at the same time that it imposed the climate change levy in an attempt not to increase the overall tax burden on industry. No doubt this also improved the political feasibility of the levy.

6.2 Swedish Energy Taxes

Sweden has imposed a set of energy taxes in an effort to encourage energy conservation and to reduce harmful emissions from energy sources. These taxes include a carbon dioxide tax, introduced in 1991, an energy tax and a sulphur dioxide tax. The taxes were introduced in conjunction with a reduction in both payroll taxes and personal income taxes.

The carbon dioxide tax is imposed on the carbon content of fossil fuels burned in industry or used for highway fuel, with exemptions for energy producers such as electricity generators. Unlike the UK Climate Change Levy the tax is related directly and uniformly to the carbon content of the fuel. The principal impact of the tax is on highway fuels and on industrial boilers, which are largely owned by the forest products industry. The tax rate is linked to the consumer price index, so it is increased regularly in line with inflation. The tax on fossil fuels for industry increased in January, 2008 to 1.01 SEK/kg. (Sweden, 2007.) With the Kroner valued at about 6.25/$US, the increased tax is equivalent to about $161/tonne of CO2. This is a very high rate by current standards, but at present industry pays only 50% of the official tax rate. There is a provision to further reduce the tax payable by 88% for any firm whose tax cost exceeds 0.8% of turnover, intended to protect firms in energy-intensive industries from high costs. (Anderson and Lohoff, 1997, p. 27.) The tax is therefore significantly less effective than would appear from the basic tax rate. It is credited with encouraging the significant production and use of biofuels as an alternative to fossil fuels. Because of Sweden's abundant hydropower and the availability of biofuels from the forest products industry, Sweden does not rely heavily on fossil fuels outside the transportation sector, so the impact of this tax on industrial competitiveness is not as great as it would be in many other countries. The effect of the increased tax on the price of gasoline is about $0.37 US/litre. Consumers of fossil fuels are also subject to the energy tax.

While electricity generators are exempt from the carbon dioxide tax, all electricity consumption is subject to the energy tax. Households and service firms pay a tax of SEK 0.27/kWh in southern Sweden, equal to about $0.043 US/kWh, a big tax.[21] Manufacturing, agriculture, forestry and the fishing industry paid no energy tax until 2004, at which time they started paying SEK 0.05/kWh, equal to about $0.008 US/kWh. The energy tax also applies to burning fossil fuels, so its impact is added to that of the carbon tax.

Nuclear electricity generators are subject to a special tax of SKR 5,514 per MW of capacity per month plus 10 SKR per MWh of actual generation to cover the cost of decommissioning of the reactors plus SKR 1.5/MWh to cover waste management costs. (IEA, 2004, Sweden, p. 32.)

The sulphur tax amounts to SEK 30 /kg of sulphur emissions from coal and peat and SEK 27/cubic metre for each tenth of a per cent by weight of sulphur content in oil. If the sulphur content of a liquid or gaseous fuel does not exceed .1% by weight, no sulphur tax is charged. In addition to the sulphur tax, Sweden provides diesel producers tax rebates of SEK 350 and SEK 150 per cubic meter of diesel used with 0.001% and 0.005% sulphur by mass respectively.

The nitrogen oxides tax was set at SEK 40/kg in 1992 affecting about 120 large energy producing plants. All revenue from the tax is refunded to the facilities paying the tax, but the refund is in proportion to the energy produced. Thus the tax transfers funds from plants with high emissions per mWh generated to those with low emission rates. (NCEE, 2004, p. 17.)

Sweden has accumulated considerable experience with taxation of electricity and air emissions over the last 15 years. When environmental taxes were introduced they reduced other taxes to as an offset. The taxes appear to have reduced the pollution intensity of the economy.

6.3 Norwegian NOX and Carbon Taxes

On 1 January 2007, Norway introduced a NO_X tax of NOK 15 per kg of NO_X emitted or $2.89 US at the current exchange rate of NOK5.19/$US. The tax applies to emissions from ships, aircraft and diesel railways that have a rated output of more than 750 kW (1050 horsepower), and from engines, boilers and turbines in energy plants in the manufacturing industry with rated output of more than 10 kW at a facility. In addition, the tax is imposed on flaring offshore and oil and gas installations onshore.[22] Although the determination of whether a business is taxable is based on installed capacity, the amount of the tax is based on emissions on

[21] Umea Energi, Electricity Prices - a Quick Guide, http://www.umeaenergi.se/default.asp?id=3463 .

[22] Statistics Norway, 2008, "Emissions Of Nitrogen Oxides, NMVOC, Sulphur Dioxide And Ammonia, 1990-2006", at http://www.ssb.no/english/subjects/01/04/10/agassn_en/ .

Norwegian soil or within local Norwegian waters.[23] The tax appears to be part of a larger program to reduce emissions of NOx, volatile organic compounds, sulphur dioxide and ammonia to comply with a regional international agreement, the Gothenburg Protocol.

In January 2008, a NO_X agreement was signed between the Government and 14 trade associations. Companies that endorse the agreement do not have to pay NO_X tax for three years. The members of the trade associations have committed themselves to reduce their emissions by 31,000 tonnes in total by the end of 2011. This will be met by implementing emission-reducing measures. The agreement is expected to encourage comprehensive measures for ship traffic and the fishing fleet, but it also affects the manufacturing industry.[24] Thus it appears that the tax is being used as an incentive to encourage industry to comply with emission reduction targets, specifically those in the Gothenburg Protocol.

In 1991 Norway imposed a tax on fossil fuels based on their carbon content, with the tax rate varying from $15 to $47/ ton of carbon dioxide. (Anderson and Lohoff, 1997, p. 11-25.) In 2005 the tax rate stood at NOK 330/tonne for the offshore oil and gas sector, or about $17 US/tonne. Other sectors face lower tax rates and there are exemptions for some industries to allow them to compete internationally. Some Norwegian studies estimated that in the first decade the tax reduced CO2 emissions by between 2.5% and 11% below business-as-usual rates, the limited effect arising from significant exemptions from the tax and inelastic demand for energy. (IEA, 2005, p. 50.)

6.4 British Columbia Carbon Tax

On February 19, 2008, the government of B.C. announced the implementation of a carbon tax on fossil fuel combustion in the province. Beginning on July 1, 2008 the tax will be levied at the rate of $10/tonne of CO2 equivalent and it will increase annually at $5/tonne until it reaches $30/tonne on July 1, 2012. The tax will be imposed at the wholesale level on all sales of fossil fuels in the province. There are exemptions for inter-jurisdictional commercial marine and aviation fuel and fuel that is to be exported. There are also exemptions for industrial processes such as the production of oil, gas, aluminium and cement. These are energy-intensive sectors and account for about 30% of provincial GHG emissions, but they are to be covered by a provincial cap and trade program. (BC Ministry of Finance, 2008, p. 13.) It appears that electricity generation is covered by the carbon tax. It is noteworthy, however, that only 5% of BC GHG emissions arise from burning coal or coke and less than 20% of electricity generation is from thermal plants, most of which burn natural gas.

The budget includes a commitment that all revenues from the carbon tax will be returned to taxpayers through tax reductions; none will be used to fund government programs. In 2008 the recycling will take place through a refundable tax credit and reductions in the corporate and personal income tax rates. (B.C. Ministry of Finance, 2008, p. 14.) No doubt this guarantee of revenue neutrality is essential to the political success of the program which would otherwise look like a tax increase.

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[23] Ernst & Young, 2007, "New Duty on NOX Emissions" http://www.ey.com/Global/Assets.nsf/Norway/Temaark_-_New_Excise_Duty_on_NOx_Emissions/$file/produktark%20II-%20NOx%20eng.pdf
[24] ibid

The BC carbon tax is important for two reasons. First, it is the first real carbon tax imposed in North America and indeed the first substantial effluent charge on any pollution discharge. Previous economic mechanisms for pollution control have relied almost exclusively on emissions trading with some programs of administrative penalties for environmental offences. In Ontario, municipalities have in the past imposed charges on large industrial water pollution sources, in the form of an "extra strength waste discharge fee." This fee differed in one important respect from an effluent charge – it was based on the cost of operating sewage treatment plants and was designed so that the major source would simply pay its share of the cost of treating its waste. With accounting data from the sewage treatment plant as the basis for the charge it could be sold as a way for the source to pay the municipality to treat its waste instead of treating it at the source. It was a fee for service and could not generate a profit or discretionary funds for the municipality.

Second, the B.C. tax is being imposed at a level that will be comparable to the cost of CO2 control that has been discussed with respect to Kyoto and other serious GHG reduction plans. $30/tonne is twice the "safety valve" built into previous federal plans in Canada, and well above the trading price of CO2 on most exchanges to date. It is comparable to the recent trading price of €20 for EU AAUs cited above. It is unlike the Quebec carbon tax which is at the level of a few dollars per tonne of CO2 and which the Quebec government claimed would be paid not by consumers but by producers, without imposing the price control regime necessary to make this happen.

6.5 Recent Policy Proposals

Economists Tom Courchene and John Allan, in an article in *Policy Options* and summarised in the Globe and Mail (March 17, 2008, p. A15), recommend that Canada adopt a carbon tax that not only reduces our emissions but that encourages other nations to reduce theirs. The proposal is to combine a domestic carbon tax with a "carbon tariff" or "carbon-added tax" that would be imposed on the import of energy-intensive products from countries that did not have GHG policies as rigorous as ours. Such an import tax would avoid placing Canadian producers at a disadvantage compared to foreign producers. It would also encourage other nations to adopt rigorous GHG policies so that they could export products to Canada without bearing the tax. While Canada alone adopting such a policy would have little effect, the more nations follow this path the greater the pressure on the remaining nations. The carbon tax plus tariff would be complemented by a rebate of the carbon tax for exports of energy and energy-intensive products to nations without rigorous policies.

A carbon tax with import and export adjustments would have significant impacts on the electricity industry. The cost of fossil fuel, especially coal, would increase substantially. As a rule of thumb, $10/tonne of CO2 translates in to $10/mWh of electricity generated at a coal-fired power plant. Imports of power from the states to which Ontario is connected would require complex calculations of the implicit carbon content of that electricity and the tax that would therefore be imposed on the import if it came from a state and generator that was not held to the same standards as Ontario generators. On the other hand, Ontario electricity exports would require calculation of their carbon content and would be entitled to a rebate.

7 Conservation Programs

For many years electric utilities and ISOs have engaged in programs to encourage energy conservation by their customers. These programs have pursued one or both of two different goals. The first goal is an overall reduction in mWh of electricity consumed regardless of timing. This goal would be motivated by a desire to reduce the harmful environmental effects such as air pollution of generation from marginal units at all times, or to conserve on non-renewable fossil fuels. The second goal is a reduction in peak-period electricity consumption. This goal would be motivated by a desire to avoid costly investment in additional generation or transmission capacity required for peak periods. This has long been a concern for utilities that face limited reserve capacity and constraints on the construction of new facilities or that simply want to avoid spending large sums on facilities that are used very few hours each year.

As concern about air pollution increases, as the price of natural gas increases, as the likelihood of some effective climate change program in Canada increases, and with Ontario's commitment to cease coal generation by 2014, the importance of energy conservation grows. The same environmental groups that have argued for and end to coal have also advocated energy conservation as a means of making the coal phase-out feasible. Conservations programs have traditionally included public information, appliance labelling, subsidies for scrapping energy-inefficient appliances and much more. I see no reason for any let-up in the pressure to maintain and expand these programs. Studies of the cost-effectiveness of energy conservation programs have produced mixed results, often suggesting that they cost more than they are worth, but these studies themselves are hotly contested. However if carbon trading or carbon taxes are implemented in North America they will force up the price of coal-fired electricity substantially. The BC carbon tax, if implemented in a jurisdiction that was dominated by coal, would increase the wholesale price of power by $30/mWh by 2012. This would likely cause some significant electricity conservation.

With respect to peak load management, there has been more innovation recently with technology that can turn off customer appliances under specified load conditions and with pricing programs designed to discourage peak electricity use. Time-of-use pricing is a blunt instrument for curtailing peak use because the prices and time blocks are pre-specified so the system cannot respond to particular crises. Real-time pricing, in which the customer's price is set at the system marginal cost on an hourly (or less) basis is a more precise instrument for curtailing peak use but customer response has been mixed and there is a political need to blunt the high bill impact of very high prices that last more than a very short time. Critical peak pricing has been applauded for getting customer attention when it is needed without causing excessive bill impacts. Ontario has for many years engaged in studies and pilot projects to examine the customer response to various pricing programs including time-of-use pricing and real-time pricing. Toronto Hydro is currently rolling out smart meters capable of time-of-use pricing to all customers. I expect that the next few years will see more experimentation and development of pricing and control options for cutting peak use in Ontario and elsewhere..

8 Concluding Observations

In May, 2002 Ontario introduced a form of competitive electricity market, converted to a hybrid competitive/regulated market six months later. The competitive element in Ontario should lead to reduced enthusiasm for spending on public programs such as energy conservation and pollution control than was possible for a monopoly utility, since any generator that spends significantly on these programs reduces its competitiveness. In other jurisdictions there has been a reduction in spending on R&D and on demand management programs when competition has been introduced. On the other hand competition tends to increase the diversity of pricing programs, with the introduction of smart meters and ways to assist sophisticated customers in cutting their electricity usage, promoted by marketers or other service providers. The net effect of competition on environmental progress is therefore not clear – it could go either way.

The lessons for Ontario from the experience elsewhere must be tempered by Ontario's situation as a close neighbour interconnected to states for which coal generates a large fraction of the electricity. We must therefore take seriously the problem of leakage – importing pollution if we import electricity as a result of strict domestic environmental policies. This suggests that care must be taken in applying environmental policies to the electricity sector. A carbon tax in Ontario with no adjustments at the border for the generation mix of imported and exported electricity would reduce Ontario CO2 emissions without perhaps achieving much reduction in CO2 emissions caused by satisfying Ontario's demand if we increase imports of coal-fired electricity. On the other hand, Ontario need not be paralysed by this situation; it just requires careful policy design building on experience elsewhere.

Emissions trading has been very successful in reducing costs and stimulating innovation in pollution control in the US and elsewhere. Ontario, however, is a small jurisdiction with a few large sources of some pollutants. A small market raises risks of price volatility and strategic behaviour. Emissions trading within Ontario alone may not perform as well as emissions trading across the US or even the eastern US. An effluent charge avoids the problems of strategic behaviour by individual sources but raises its own problems because of the added cost burden for polluters. Again, careful environmental policy design will be required.

The most difficult decisions today are probably the choice of energy source for new generation to replace aging nuclear plants and retiring coal plants. These investments are likely to be very large, so individual decisions have a major impact. The current policy has the government directing the supply mix and the OPA managing procurement subject to proposals from competitive generators. The mix of environmental policies currently in place may not be the best design to ensure that we meet tomorrow's electricity needs with the desired environmental impact and at a reasonable cost. The good news is that we are not alone in this problem and we can benefit from considerable experience elsewhere as we move ahead with environmental policy for this century.

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