An Economic and Engineering Analysis of Incentive-Based Carbon Dioxide Emission Reduction Policies in the Power Sector

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1. Introduction

The characteristics of an electric power network can strongly influence the effects of environmental policies that are applied to the power sector, because the constraints and flow characteristics of the network determine the extent to which power from lower-emitting power plants can substitute for power from higher-emitting plants in other locations. However, realistic modeling of power networks is challenging.

Actual power networks are “alternating-current” networks. Thousands of constraints on flow, voltage, stability, and power production govern the operation of such a network. Many of these constraints are non-linear and complex. Furthermore, the flows in such a network do not just follow the shortest or most under-utilized route from where power is generated to where it is consumed, but instead flow along all connected lines, including ones that may already be congested, in accordance with laws of physics known as Kirchoff’s Laws.

Because of the complexity of creating and solving a realistic power system model, simpler models have been used instead. These include “direct-current approximations” and “regional-flow-constraint” models. We describe these simpler models in Section 3.

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We use an alternating-current model of the power network in northeastern North America to predict the effects of several different incentive-based carbon dioxide regulations. We use all of the kinds of flow equations and constraints that govern the actual system. To our knowledge, this paper is the first to analyze an environmental policy using an alternating-current model of a power network.

This paper makes three contributions to the environmental and energy economics literature. The first is to demonstrate and further develop the use of alternating-current modeling. The second is to compare the predictions of an alternating-current model with those of a direct-current approximation of the same model and with an unlimited-transmission model of the same region. This comparison is a test of whether our more complex modeling is warranted. The third contribution is to predict the effects of different incentive-based carbon dioxide emission regulations on emissions and total variable cost. Among other scenarios, we simulate a US-only regulation, a Canada-only regulation, the Regional Greenhouse Gas Initiative\(^2\) ("RGGI") in the presence of a drought, the effects of exempting smaller generators from a carbon dioxide regulation (as done in RGGI), and the interaction of incentive-based carbon dioxide and sulfur dioxide regulations. We have not previously seen any of these examined in the literature.

Around the world, there is the potential for one region to adopt an incentive-based carbon dioxide emission regulation without a neighboring region doing so, or for one region to have a more stringent regulation than the neighboring region does. Our simulations of US-only, Canada-only, and RGGI-only regulations examine such situations. A network model is particularly important in simulating such situations because the network determines the amount of emissions “leakage” that can occur. Leakage refers to the increased emissions at generators outside of the regulated region as a result of the increased marginal operating cost for generators inside the regulated region. Leakage can partially or completely offset the emission reductions that result from the regulation.

\(^{2}\) The Regional Greenhouse Gas Initiative is a cap-and-trade program in ten northeastern US states.
As mentioned above, we also simulate the RGGI policy in the presence of a drought. Our purpose in doing so is to examine the potential for permit price volatility under a cap and trade program. A drought reduces hydropower, therefore increasing the need for carbon dioxide-emitting generation and the price of emission permits.

Both an emission tax and a cap-and-trade program operate by creating a price or opportunity cost that each firm incurs for each ton of emissions. As a result, examining the response of the power industry to a price on emissions allows us to predict the effect of both emission taxes and cap-and-trade programs. We will use the term “emission price” to refer generically to either the permit price in a cap-and-trade program or the emission tax rate.

This paper is organized as follows: The second section reviews current and proposed legislation at the national and regional level for regulation of CO$_2$. The third section presents the optimization/simulation model and network used in the analysis and contrasts this work with existing work. The fourth section presents results from the simulation model which allows analysis of the effects of various CO$_2$ prices either from a cap and trade program or a carbon tax on emissions and total variable cost.

2. Current and Proposed Legislation

This section will first describe the currently proposed US national CO$_2$ mitigation legislation, the American Clean Energy and Security Act of 2009 (ACESA) introduced by Henry Waxman and Edward Markey. Then, the various regional initiatives will be identified and one, the Regional Greenhouse Gas Initiative (RGGI), will be described in detail since it forms the basis for part of our case study that is able to contrast regional to national policies.

The ACESA proposes the following greenhouse gas (GHG) reductions over time:

- By 2012: reduce to 1% below 2005 levels
- By 2020, reduce to 17% below 2005 levels
- By 2030, reduce to 36% below 2005 levels
- By 2040, reduce to 55% below 2005 levels
• By 2050, reduce to 73% below 2005 levels

These are the reductions that are proposed through separate cap and trade programs for CO2 and hydrofluorcarbon (HFC). The quarterly auctions are proposed to start in March of 2011 for 2011 allowances and the use of offsets (credits earned from emission reduction activities, such as tree planting or reducing emissions from a facility in another country) is limited to a specified percentage each year determined by formula. For example, in 2013 not more than 15% can come from domestic offsets and not more than 15% can come from international offsets. Banking of allowances is unlimited and next year's allowances can be utilized in the current year without interest. Up to 15% of needed allowances can be borrowed from following years up to five years but 8% interest per year must be paid in the form of purchase of additional allowances.

The ACESA would initially distribute 84% of the permits free of charge in the first year allocating permits as follows:

• 60.5% to Consumer Protection (35% to local electricity distribution companies, merchant coal, and long term power agreements, 15% for low and moderate income households, and the remainder to offset price increases in heating oil and natural gas);

• 14% to Energy Efficiency and Clean Energy (10% to States, 3% to advanced automobiles, and 1% to research and development);

• 9.5% to Other Public Purposes (5% for preventing tropical deforestation, 4% for domestic and international adaptation and technology transfer, and .5% for worker assistance and job training).

The permits allocated to many of these areas phase out over five to ten years starting in 2026, but the allocations to some areas increase and some new areas are added over time. Finally, the bill temporarily (until 2017) prohibits States from running their own cap and trade programs but those holding allowances from the Regional Greenhouse Gas Initiative or California (see below for a discussion of these regional programs) would be compensated with
allowances from the proposed Federal program. Figure 1 shows the greenhouse gas targets of the ACESA.

In addition to this proposed federal legislation, three regional cap and trade initiatives are underway as shown in Figure 2. Note that these three initiatives comprise 37 percent of US emissions. The states in RGGI contain 16% of the US population (Grenfell, 2008) but emit only 10% of US GHG emissions, in part because of the RGGI region’s electricity generation mix that uses relatively more natural gas and less coal than some other areas.

In this study we focus on the Regional Greenhouse Gas Initiative because of the availability of an existing network model that can explore many issues that have been raised concerning CO$_2$ regulation. RGGI has ten member states shown in Figure 3, importantly excluding Pennsylvania that has a substantial availability of coal fired generation. RGGI plans to reduce power-sector CO$_2$ emissions 10% from the 2009 level, between 2009 and 2018. Note that it is significantly less stringent than the ACESA.

![Emission Reductions Under the Waxman-Markey Discussion Draft, 2005-2050](image)

*For a full discussion of underlying methodology, assumptions and references, please see [http://www.wri.org/policy/dec2009]. WRI does not endorse this proposal.*

**Figure 1: The American Clean Energy and Security Act of 2009 Emission Targets.**

*Source: Larsen and Heilmayr April 22, 2009.*
RGGI = 10% of US total GHG emissions
MW = 14%
West = 13%
TOTAL: 37%

Figure 2: Total GHG Emissions of States Participating in Prospective Regional GHG Cap and Trade Initiatives. Source: Damassa, 2007. Notes from source: “GHG emission totals from Canadian Provinces participating in the Midwest Accord and WCI are not included here. MtCO₂e is million metric tons of carbon dioxide equivalent per year. Percentages are of total U.S. emissions.”

In the 2009–2014 interval, emissions will be capped at 2009 levels. From 2015–2019 the cap is reduced by 2.5% per year. Currently, 6 states plan to auction off 100% of their permits. The others are required to auction at least 25% of permits. Auction revenue will be used for consumer benefits including energy efficiency programs. A three-year compliance or “true up” period will be enforced unless the trigger price of $10 is reached in which case this period can be extended. Offset usage is limited to 3.3% unless the trigger price reached, so that, if permits reach $10/ton, there will be no limit on offset use. The first three quarterly auctions have been completed yielding prices per ton of $3.07 (9/25/2008), $3.38 (12/17/2008), and $3.51 (3/18/2009) for 2009 allowances. All of the allowances offered so far for more than 75 million tons of CO2 have been sold.

As noted above, one of the main worries for regional programs is “leakage.” As generators inside regulated areas are forced to pay for carbon dioxide (CO2) permits, the prices at which they can offer to profitably sell power rise compared to the prices at which generators outside of the regulated region can offer to profitably sell power. This may cause emissions to increase outside of the regulated region, partially offsetting the emission reduction inside the regulated region. In what follows, we measure leakage in our simulations of RGGI, US-only, and Canada-only policies. We also demonstrate what happens if all of the Northeastern states and provinces are regulated in a “binational” program. A binational program is also akin to a national program in which leakage is prevented or is small. There is no model of the whole United States that has been aggregated or “reduced” to make it solvable in AC simulations, so what we have the best type of model available for AC modeling of a US or Canadian national policy.

3. The Simulation Model and Network

Several studies of CO2 regulation have been conducted to examine the issue of leakage. First, the ICF (2007) IPM model has been used to examine the leakage issue for RGGI. This is a national model that includes very detailed data on every generator in the United States as well as
emission rates for various pollutants including CO₂. However, it assumes that transmission is unconstrained within regions and constrained by aggregate flow limits between adjacent regions. Thus, it is not a model of even simplified DC flows, but assumes that electricity flows as if through "pipes." This makes the model easier to solve. Similarly, the Resources for the Future Haiku model (Paul and Burtraw, 2002) uses constraints between regions and models generation using hundreds of characteristic "typical" plants including typical emission characteristics. Both of these studies suggest that leakage occurs but is not so great as to defeat CO₂ emission reductions by RGGI. The two models differ in how they treat fuel prices, investment, retirement of plants, etc. These comments should not be taken as critical of these models. Rather, the type of detailed network modeling we are attempting is quite difficult and, simply put, might not be important enough to justify the effort required. One of our goals is to test the hypothesis that it is important to model the network with the added realism of alternating-current constraints and flow equations.

The reason we focus on this issue is that, around the world, electric power systems or “grids” are predominantly alternating-current systems. As noted in the introduction, a complex set of constraints and flow equations governs each such system. One of the most important sets of constraints is voltage constraints: voltage must be maintained within acceptable limits and more expensive plants must often be operated in order to achieve this. Furthermore, rather than flowing on the shortest or least congested path from source to point of use, power flows along multiple lines, potentially including already-congested lines, in accordance with Kirchoff’s Law. The resulting constraints and flow equations affect which set of generation units satisfies electricity demand at the lowest cost in each moment. Consequently, these constraints and flow equations also play a major role in determining the effects of a carbon-dioxide emission regulation on emissions, cost, prices, fuel use, and leakage.

The reason for using a more realistic model of the transmission system is well illustrated by the California experience where markets were designed and introduced on the assumption that transmission constraints were relatively unimportant. In fact, transmission constraints proved
fatal to that market design, making the market much less competitive than economists initially assumed. Another example is the Northeast power outage that occurred in August of 2003. Markets in Ohio (unlike the rest of the Northeast) were not designed to provide incentives for generators to assist in maintaining voltage (a public good). This design flaw, which resulted from a failure to consider the requirements of an AC network, proved to be a major factor in the collapse of the system. Simply put, in a contest between physics and economics, physics wins.

A common simplified method of modeling a power system is to model it as if it were a direct-current system. GE MAPS and PowerWorld are two software packages that use direct-current approximations to model alternating-current power systems. Direct-current models use linear approximations of the non-linear flow equations in an alternating-current system. Direct current systems do not have voltage constraints and do not have the same kinds of stability constraints that alternating-current systems do, so such constraints are sometimes roughly represented by simple flow constraints known as “proxy limits” on transmission lines. These linear approximations and proxy limits are designed to approximate the characteristics of the system under a particular pattern of operation. The more a system departs from that pattern of operation, the less accurate these linear approximations and proxy limits are. Incentive-based emission regulations change the pattern of operation of a power system by making high-emitting power plants more expensive to operate. So, for example, more stringent emission regulations are likely to result in less use of coal-burning power plants and more use of gas-burning power plants. Coal-burning and gas-burning power plants have different geographic distributions, so more stringent environmental regulations may drastically alter the pattern of operation of the power system.

A second deficiency of direct-current modeling of alternating-current power networks is that the transmission prices and locational marginal power prices derived from DC optimal power flows are incorrect and may lead to sub-optimal decisions if those prices are used as incentives or signals for generation or transmission investment.
In this study, MATPOWER, a full AC optimization/simulation framework developed at Cornell University, is used to study the Northeast power system’s response to CO₂ regulation. Like an electricity system operator, MATPOWER minimizes the cost of operating the electric power system subject to the demands and availability of electricity at each node, the transmission capability of the lines in the system, and voltage and stability requirements. Costs of purchasing carbon permits or carbon taxes are incorporated in the optimization. The simulation works by using representative hours and solving the optimization with different CO₂ emission prices. The current study incorporates reliability by requiring that a reserve of extra generation is maintained in each region, so it does not include transmission line outages or other “contingencies” and the only generation units it includes are those expected in 2006 to be operational in summer 2008.

Figure 4: The Formulation of MATPOWER
(Source: Zimmerman and Murillo-Sanchez, 2007)

Figure 4 shows the mathematical formulation of MATPOWER. In that formulation, the optimization variables are labeled $x$. The $x$ variables are the optimal power flow variables, consisting of the voltage angles $\theta$ and voltage magnitudes $V$ at each “bus” or node in the network, and real and reactive generator injections $P_{gi}$ and $Q_{gi}$ at generators $i = 1, 2, 3, \ldots$. The
objective is to minimize the sum of the generation unit real and reactive power production costs $f_{1i}$ and $f_{2i}$ for $i = 1, 2, 3, \ldots$. $P_g$ and $Q_g$ are the vectors of the aggregate real and reactive power injections from generators at each bus. $P_d$ and $Q_d$ are real and reactive power consumed by customers, which are exogenous to our model. $P$ and $Q$ are net real and reactive power outflows at each bus. The first two constraints say that, at each bus, power production minus consumption equals net power outflow at all times. $S_f$ and $S_t$ are vectors of the “apparent power flow” (quadrature sum of real and reactive power) on each transmission line. $S_{\text{max}}$ is the maximum flow a line can accept without sagging to a level at which vegetation or the ground can cause an arc and power failure. The general linear constraints include “branch angle difference limits,” which we will not describe here. The voltage limits require that voltage remain in a narrow range that will not damage equipment. The generation limits require that each generator be producing amounts of real and reactive power that it is capable of producing. Simultaneously satisfying all of these constraints requires constant monitoring and frequent adjustments by the system operator.

We do this for the 2007 power system since complete data are readily available to allow stress testing what is essentially the existing system. Investment in new generation and transmission capacity is a slow process, so it is worthwhile to examine what the existing possibilities are for CO$_2$ reduction in response to emission taxes or cap-and-trade programs.

The optimization problem associated with determining the operation of an AC network has more constraints than a DC system and is non-linear and complex. Consequently, using a simplified representation of the AC network, with dozens instead of thousands of buses, is necessary because it allows us to solve for the operation of the system.

The transmission lines and nodes or “buses” of the physical network representation utilized in the study are shown in Figure 5. The network includes only PJM-East (New Jersey, Delaware, Washington DC, and most of Pennsylvania and Maryland), New York, New England, Ontario, Quebec, and the Maritime Provinces. Allen, Lang, and Ilic (2008) developed this network representation as a simplified version of the northeast power grid, which has thousands
of buses. Their simplified representation aggregates the thousands of actual buses in the
Northeast into 36 buses, and specifies the electrical characteristics of those 36 buses and the
aggregated lines that connect them. The simplified network approximates thermal, voltage, and
reactive power constraints of the real system and “…some of the major intra- and inter-area
congestion patterns are preserved….” Ilic (2008) has reported that in comparisons between the
simplified model and a detailed model of the same region, the simplified model produces results
very similar to those of the detailed model. Given that no completed study of CO₂ regulation
includes an AC network, it is at least reasonable to examine the issues raised by CO₂ regulation
using an available AC network model.

Our geographic representation of RGGI is approximate. One of the buses in the Allen,
Lang, and Ilic model is enormous, and includes parts of states participating in RGGI as well as
parts of states not participating. The RGGI states included in this bus are all of Delaware and
parts of New Jersey and Maryland. We count this bus as being entirely outside of RGGI, in
order to maintain transmission constraints between RGGI and non-RGGI parts of the system.

Our data on generation units, provided by Energy Visuals, Inc, came from the 2006
reliability planning process of the Multiregional Modeling Working Group, the group
responsible for examining the adequacy of the electric power system in the Eastern United States
and Canada under the auspices of the North American Electric Reliability Council. The data
consists of the units projected to be operational in the summer of 2008. There were
approximately 2000 such units in the region we model. For each unit, we have name, maximum
and minimum real and reactive capability, fuel type, fuel use per megawatt-hour (MWh) of
output, fuel price in 2007, longitude, and latitude. From the fuel type, fuel use per MWh, and
carbon content of different fuel types (Energy Information Administration, 2009) we calculated
the marginal cost per MWh and CO₂ emission rate per MWh of each generation unit. We knew
to which of the 36 buses Allen, Lang, and Ilic (2008) had assigned some of the generation units.
We assigned the others by geographic proximity and then scaled their real and reactive power
capabilities so that our totals at each bus matched that of Allen, Lang, and Ilic. We assume that the units offer all of their capacity at the constant marginal cost we calculated.

To estimate the outcomes under each policy option during the course of a year, we simulate the outcomes during sixteen representative hours and then average them. The outcomes depend on the amount of power production by each generator in the system. In all three of the power-system models we compare, the power production by each generator is a control variable in a cost-minimization problem that determines the operation of the system. In this problem, the objective is to minimize the cost of operating the system, where that cost includes the price of carbon dioxide emissions.

Table A4 presents the amount of electricity demanded (“load”) by region in each hour type, as a proportion of the load in Allen, Lang, and Ilic’s model of load during the summer peak hour. Load is highest during the hour that represents the highest-load hours of the summer and is lowest during the hour that represents the lowest-load hours of the fall. Load is assumed to be perfectly inelastic, since few electricity customers face real-time electricity prices. In reality, the quantity demanded is slightly responsive to price in the short term and is more responsive in the long term. This would increase emission reductions from carbon dioxide prices, compared with what we predict below. The higher the carbon dioxide price, the higher the price of electricity, and the higher the price of electricity, the lower would be the quantity of electricity demanded.

Generation units are sometimes not available for operation because of maintenance or repair. Rather than simulate discrete outages, we derate the maximum and minimum real and reactive capability of each unit using an availability rate. Availability is highest in summer and winter because regulators require generators to conduct maintenance during the relatively low-load seasons of spring and fall. Tables A1 and A2 in the appendix show these availability rates, by hour type and fuel type.

The CO₂ prices we consider are $0, $3.51, $25, $50, $100, $175, and $250 per metric tonne. The $175 and $250 prices are much higher than the prices we expect to see under at least
one of the policies we model, the RGGI policy. However, the use of these high emission prices enables us to plot the demand curve of emission permits over a wide range of permit prices.
Figure 5: Physical Network Used in Our Simulation. Source: Allen, Lang, and Ilic 2008.
4. Simulation Results

4a. Two Snapshots of the Effect of Transmission System Modeling

Figure 6 shows carbon dioxide emissions as a function of carbon dioxide price, predicted using three methods: our alternating current (AC) model, our direct current (DC) linear approximation of that AC model, and a model with no transmission constraints at all. It shows that in some instances results can be quite similar with these three models. An increasing carbon dioxide price tends to cause a shift from coal-fired generation units to gas-fired units, which tend to be located closer to customers. Therefore, if the carbon dioxide price is imposed throughout the entire region, the change in the operation of the power system that results from the CO₂ price may not substantially exacerbate transmission constraints.

Figure 6: Emissions as a Function of a Binational, System-Wide Price on Carbon Dioxide Emissions

Figures 7 and 8, in contrast, highlight the importance of modeling the transmission system. Figure 7 shows the predicted effects of the Regional Greenhouse Gas Initiative on

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3 All figures and tables of results in this paper assume a sulfur dioxide price of $700 per metric tonne and a nitrogen oxide price of $2000 per metric tonne, unless otherwise noted. Unless otherwise specified, results are based on our alternating-current model.
carbon dioxide emissions from the electric power sector in the regulated region, using three different models. Each point plotted on this graph is a weighted average of the sixteen representative hours that we model. The DC model predicts larger carbon dioxide emission reductions than does the AC model, and the model with no transmission constraints predicts much larger reductions. Figure 8 is different from Figure 7 in that it shows the predicted effect of RGGI on the sum of emissions inside and outside of the RGGI region, and it shows it as a percentage of the predicted emissions at a carbon dioxide price of $0. At a price of $25, the DC model predicts an increase in total emissions while the AC model predicts a decrease. At a price of $50, the AC model predicts an overall emission reduction twice as large as the reduction that the DC model predicts.

![Graph showing predicted effect of RGGI on carbon dioxide emissions](image)

**Figure 7: Predicted Effect of Regional Greenhouse Gas Initiative on Carbon Dioxide Emissions in the Regulated Region**
Figure 8: Predicted Effect of Regional Greenhouse Gas Initiative on System-Wide Carbon Dioxide Emissions, for Carbon Dioxide Emission Prices Between $0 and $100

4b. “Leakage” Under the Regional Greenhouse Gas Initiative

The top line in Figure 9 again shows the AC model’s predictions of total emissions from the electric power sector in the modeled region, as a function of the RGGI permit price. Figure 9 decomposes this total into emissions within the RGGI states and emissions elsewhere in the modeled region, revealing leakage. For example, at a RGGI permit price of $3.51, which was the price in the March 18, 2009 auction of RGGI permits, our AC model predicts that emissions from power plants within the RGGI states are reduced by 1.6 million metric tonnes per year, but that emissions from power plants in surrounding states and adjacent Canadian provinces are increased by nearly as much, 1.3 million tonnes, for a net reduction of 0.3 million tonnes in the modeled year. However, this is not the end of our story about RGGI. We will consider its cost below.
4c. Universal and Partial Application of a Carbon Dioxide Price

Policymakers can impose a price on all generation units or on just of strict subset of the units. Thus far, we have considered a price applied to all generation units (a “binational” price) and a price imposed only on the generation units in the RGGI region. We will consider these two policies further, along with three other policies: a US-only price, a Canada-only price, and a price applied throughout the modeled region but only to generation units with capacities above 25 megawatts (MW). Many units with capacities of 25 MW or less are exempt from certain emission regulations in the United States. All such units are exempt from the RGGI.

Our US-only policy is not a valid representation of a nationwide US policy, because the power system varies geographically and because much of the United States is farther from Canada or Mexico than the modeled portion of the US is from eastern Canada. Our Canada-only policy is not a valid representation of a nationwide Canadian policy, although the resemblance may be closer since much of Canada’s generation capacity and load are in our model and the portion not included may be similarly well connected to the US. Rather than accurately
representing national policies, our US-only and Canada-only policies roughly represent the effects of nationwide policies within in the modeled region, and also serve as generic examples of policies that apply in one region but not in a neighboring region.

Figure 10 provides the information for our comparison of the five simulated policies. It plots cost versus quantity of emission reductions under each of these policies. We define the cost of an emission reduction policy as that policy’s effect on the total cost of providing the quantity of electricity demanded. We do not include carbon dioxide emission prices in the cost because they are transferred to the government or another party, so they have no net effect on social surplus.4

The curves in Figure 10 are not supply curves, since the vertical axis measures system-wide, aggregate variable cost. We might wish to instead plot supply curves by putting the derivative of aggregate cost with respect to aggregate emission abatement on the vertical axis, but cannot because we know it only for the binational policy. Under the “binational” policy, it is equal to the emission price. For the other policies, it is not, because of leakage.

4 We do however include sulfur dioxide and nitrogen oxide emission prices. If one of these emissions increases or decreases as a result of a policy change, it has health and environmental effects that we do not otherwise consider. Instead of considering it separately, we include it in the objective function by assuming that the marginal damage from these emissions is equal to the price of these emissions, which in our simulation is $700 for sulfur dioxide and $2000 for nitrogen oxides. This has little effect on the results, compared to assuming zero external marginal damages from these emissions.
Figure 10: Aggregate Variable Cost of System-Wide Aggregate Emission Reductions Under Five Policies

The marginal cost of emission reductions is the slope of each line. The average cost of emission reductions at any point on one of the curves is the slope of a ray from the origin to that point. For any quantity of emission reduction, the binational carbon dioxide emission price, which applies to all generation units, achieves that reduction at lowest cost. Even though generation units with capacities of 25 MW or less constitute only 3.7% of fossil-fueled generation capacity in our model, exempting these units increases the cost of achieving any quantity of total emission reduction by approximately 50%, primarily because of emission leakage to these small generators. Similarly, a US-only policy achieves any given quantity of emission reduction at approximately 50% greater cost than does a binational policy.

The cost of achieving any given quantity of emission reductions is several times higher with a RGGI-only or Canada-only policy than with a binational policy, partly because these are
substantially smaller regions and partly because of leakage.\textsuperscript{5} For any given quantity of emission abatement, a policy without leakage normally has an average abatement cost lower than its emission price (since without leakage the emission price is also the marginal abatement cost). However, the average cost of the emission reductions from RGGI is $11 at a permit price of $3.51 and $53 at a permit price of $10. Our model predicts that a Canada-only emission price of $25 actually increases overall emissions in the region because generation in Canada is replaced with more polluting generation in the United States. Of the Canada-only carbon dioxide emission prices we model, the one that achieves emission reductions at lowest average cost is $50. It achieves emission reductions at an average cost of $112 per tonne.

We should warn that our model might overestimate leakage, and hence might also overestimate the costs of emission reductions from the policies that can result in leakage: the RGGI-only, Canada-only, US-only, and large-generators-only\textsuperscript{6} policies. The ideal model would combine both thermal and voltage limits that fully match the real system. Our model has thermal limits on the interfaces where such limits historically have bound most restrictively. However, there could be other thermal limits that in reality will bind in the event Canada-only, US-only, or RGGI-only emission prices, but that are not included in our model. Whether our model accurately predicts leakage or not, policymakers in the country with the more stringent carbon dioxide emission regulation can prevent leakage across the US-Canada border by applying a tariff on imported power.\textsuperscript{7}

4d. Effect of Carbon Dioxide Regulation on Sulfur Dioxide and Nitrogen Oxide Emissions

Figure 11 shows the demand curves for sulfur dioxide emission permits at carbon dioxide prices of $0 and $100. These demand curves assume each unit has a constant sulfur dioxide emission

\textsuperscript{5} An additional reason for the high cost of emission reductions, in the case of RGGI, is that leakage to small generation units may occur because they are exempt from the policy.

\textsuperscript{6} This would affect the analysis of the large-generators-only policy to a lesser extent than it would affect the analysis of regional policies, since small generators are spread throughout the modeled region, making transmission less important for leakage to those generators.

\textsuperscript{7} The RGGI states may be prohibited by federal inter-state commerce laws from addressing leakage from other US states in this way.
emission rate. They are extremely short-run demand curves. In a matter of hours, days, or weeks, generators can change their sulfur dioxide output rate by switching to coal with a different sulfur content. Therefore, over a period that allows for such a fuel change, the curves would be more elastic. Nonetheless, the shift shown in Figure 1 is valid in the longer term as well. It shows that the carbon dioxide emission price can significantly shift the demand curve for sulfur dioxide permits. Under a cap and trade program on sulfur dioxide emissions, a carbon dioxide price would reduce the price of sulfur dioxide permits, which could induce unit owners to switch to higher-sulfur coal and turn off their emission control devices, since the latter are costly to operate. This could be avoided by switching to a sulfur dioxide emission fee or by tightening the cap on sulfur dioxide emissions. If the sulfur dioxide permit price were $700 per tonne with no carbon dioxide price, keeping it there with a carbon dioxide price of $100 per tonne would require reducing the quantity of sulfur dioxide emission permits by 11%, as shown graphically in Figure 11. Even then, if the carbon dioxide regulation were a cap and trade program, fluctuations in the price of the carbon dioxide permits could also cause large fluctuations in the prices of the sulfur dioxide permits.

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8 Generation units with “scrubbers” for flue-gas desulfurization can also turn them off or on. However, the variable cost of operating a scrubber is approximately $150 to $210 per metric tonne of sulfur dioxide removed (Hart, 2009), and our sulfur dioxide permit demand curves in Figure 10 start at a price of $200 per metric tonne, so operators would leave the scrubbers on over all but the extreme low end of the range of the curves shown.
The price of carbon dioxide could similarly interact with the price of nitrogen oxides: keeping the price of nitrogen oxide permits at $2000 while increasing the carbon dioxide price from $0 to $100 would require reducing the quantity of nitrogen oxide permits by 10%.

4e. Emission price volatility under a cap and trade program

A cap-and-trade program is susceptible to price volatility in response to changes in expected permit supply or demand. One type of event that could cause such a change in expectations is a drought, which reduces the amount of hydropower, one of the two largest power types that are associated with virtually zero carbon CO₂ emissions. In the forty-year period ending in 1999, there were four “severe” or “extreme” droughts in the northeastern United States, lasting up to five years, and associated with a reduction in rainfall of approximately 20% or more.

Figure 12 shows the effect of a drought that reduces hydropower production by 20%, estimated using our AC model. In a three-year true-up period of the RGGI policy, if the amount of emission reduction required by the policy is 1.6% relative to business as usual, a drought raises the predicted permit price from the current price of approximately $3.50 (blue curve) to
approximately $20 (red curve). If the required emission reduction is 10% from business as usual, a drought raises the predicted permit price from approximately $20 to approximately $60.

![Marginal Cost of Emission Reductions, With and Without Drought](image)

**Figure 12: The Effect of a Drought on the Demand Curve for Emission Permits Within the Ten RGGI States**

Our analysis ignores two other components of the RGGI policy that should reduce CO$_2$ emissions. First, power plant owners in the RGGI region may satisfy some of the emission reduction requirements by purchasing offsets. Second, the states may use some of the revenues from the sale of RGGI emission permits to fund programs that help energy customers to improve their energy efficiency and consequently to reduce the demand for permits.
4f. *Higher average costs resulting from volatility of permit prices*

A cap-and-trade program is susceptible to permit price volatility. The potential for drought, such as the recent prolonged southeast drought that reduced hydroelectric production by about 50%, is one potential source. Another possibility is the shutdown of multiple nuclear plants because of a threat of terrorist attacks. One of the largest potential causes at the national and binational levels is a change in the price of natural gas.

Permit price volatility increases the average cost of emission abatement. We will see this using Table 1, which presents the emission reductions and average costs of emission abatement under a binational emission reduction policy. If there were an emission tax of $25 per tonne or a cap-and-trade program with a constant permit price of $25 per tonne, the emission reduction would be 2.84 million tonnes per year and the average cost of the abatement would be $11.20 per tonne. If instead there were a cap-and-trade program with a permit price that was $3.51 for 52% of the time and $50 the other 48% of the time, the emission abatement per year would be the same, but the average cost of the abatement would be $23.85 per tonne.

Table 1: Emission Reduction and Average Cost of Emission Reductions Under a Binational Policy

<table>
<thead>
<tr>
<th>Emission price (dollars per tonne)</th>
<th>Emission abatement (millions of tonnes per year)</th>
<th>Average cost of abatement (dollars per tonne)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0</td>
<td>N/A</td>
</tr>
<tr>
<td>3.51</td>
<td>0.26</td>
<td>1.69</td>
</tr>
<tr>
<td>25</td>
<td>2.84</td>
<td>11.20</td>
</tr>
<tr>
<td>50</td>
<td>5.60</td>
<td>24.99</td>
</tr>
<tr>
<td>100</td>
<td>16.22</td>
<td>59.87</td>
</tr>
<tr>
<td>175</td>
<td>40.12</td>
<td>100.06</td>
</tr>
<tr>
<td>250</td>
<td>51.29</td>
<td>117.55</td>
</tr>
<tr>
<td>10000</td>
<td>61.09</td>
<td>165.10</td>
</tr>
</tbody>
</table>

5. Conclusions

To our knowledge, this is the first study that uses an alternating-current model to predict the effects of an environmental policy. Based on this analysis, we draw some conclusions. First,
with the model we used, some of the predictions of the AC simulations were qualitatively similar to those of the DC, linear approximations, while others were qualitatively different. In a model with more severely binding voltage constraints, there may be a larger qualitative difference between the predictions of AC simulations and DC approximations.

Second, the demand for CO₂ allowances under a national cap-and-trade policy is likely to be extremely inelastic. With a binational policy, a $50 carbon dioxide emission price reduces carbon dioxide emissions by 2% and a $100 price reduces emissions by 6%, as can be seen in Figure 6. Note that in order to assess the responsiveness of the power system itself, we have utilized a common power systems approach used to run the system on a day-to-day basis by assuming totally inelastic short run electricity demand. Increasing the carbon dioxide price from $0 to $100 per tonne increases the average wholesale price per megawatt-hour of electricity from $66 to $137 per megawatt-hour, so we would expect that, over the long term, demand would decrease in response to rising electricity prices. Studies of the long run elasticity of electricity demand suggest that the value may be around -1 (see Lafferty, et al. 2001 for a review paper on electricity demand elasticities prepared for the Federal Energy Regulatory Commission). Thus, long-run electricity demand itself is likely to be much more elastic than the short-run demand for permits shown here and a major source of potential CO₂ reduction may be higher electricity prices and demand reduction in the long run. This is consistent with the view of supporters of energy efficiency who have suggested that energy conservation can be a major, low-cost source of emission reductions (Cowart, 2009).

Third, since the demand for CO₂ permits is likely to be very inelastic, price volatility in permit market will likely be a problem as it has been for some previous cap-and-trade programs. This results in an increased average cost of emission abatement, as illustrated in section 4f. In addition, a volatile permit price increases the risk associated with making irreversible investments in CO₂ emission reduction technologies, and therefore makes them less appealing to risk-averse companies even if they have the potential to be relatively low-cost emission reduction options. Of course, banking, multiple year true-up periods, borrowing of future
permits at interest, and permit price ceilings and floors all attempt to reduce this fundamental deficiency in the cap and trade approach compared to emissions taxes.

Fourth, the effect of the CO₂ prices on the demand for SO₂ and NOₓ permits is large. In fact CO₂ prices would possibly reduce demand for NOₓ and SO₂ permits sufficiently that emission control equipment and techniques would go unused. If marginal damages were greater than the resulting prices, then to maintain economic efficiency, caps would have to be revised in the face of rising CO₂ prices to keep permit prices in line with estimated marginal damages. The extreme short-run inelasticity of demand for CO₂ allowances given current markets and technologies makes the CO₂ auction a potential source of additional volatility in the SO₂ and NOₓ markets.

Fifth, incentive-based emission regulations that are not uniform across regions may be relatively expensive if leakage is not prevented. An import tariff on power from the less stringently regulated region can reduce leakage. Another means is system operation or “dispatch” that takes into account the non-internalized or “hidden” environmental cost of generation from the region without the incentive-based emission regulation. Sixth, exempting small generation units from an incentive-based carbon dioxide emission regulation can greatly increase the cost of achieving any given amount of emission reductions.
APPENDIX

A1. Introduction to our sources of data on generation units

The generator data at each bus is a combination of data from Energy Visuals, Inc.; Allen, Lang, and Ilic (2008); and the Environmental Protection Agency (2007). Our data on generation units purchased from Energy Visuals, Inc, came from the 2006 reliability planning process of the Multiregional Modeling Working Group, the group responsible for examining the adequacy of the electric power system in the Eastern United States and Canada under the auspices of the North American Electric Reliability Council. The data consists of the units projected to be operational in the summer of 2008. There were approximately 2000 such units in the region we model. For each unit, we have name, maximum and minimum real and reactive capability, fuel type, fuel use per MWh of output, fuel price in 2007, longitude, and latitude.

A2. Assignment of generation units to buses

We knew to which of the 36 buses Allen, Lang, and Ilic (2008) had assigned some of the generation units. We assigned the others by geographic proximity. Then, at each bus, we scaled the real-power capacities of all fossil units by a constant such that our maximum real-power capacity total at each bus matched the total from Allen, Lang, and Ilic, produced as described above.

A3. Fossil-fueled real-power generation capacity at each bus

Real power output of fossil-fueled generators is determined by the constrained cost-minimization problems described elsewhere in this manuscript. We calculate the total amount of fossil-fueled real-power generation capacity at each bus using data from Allen, Lang, and Ilic (2008). At each of their 36 buses, they report total real and reactive generation capacity (in the second-to-last, fifth, and sixth columns of the generation block of their appendix), total real and reactive generation in the summer peak-load hour that they model (in the third and fourth
columns of the generation block of their appendix), and approximate percentage of that real-power generation coming from each fuel type (coal, gas, oil, nuclear, hydro, refuse, wood, and wind; in their Table VI). At buses with more than 0% of their real-power generation from fossil fuels (coal, gas, and oil), we calculate fossil-fueled real-power capacity as the total real-power generation capacity minus generation from non-fossil sources.\(^9\)

**A4. Availability of Fossil-Fueled Generators in Each Hour Type**

Generation units are sometimes not available for operation because of maintenance or repair. We scale down the maximum and minimum real-power capability of each fossil-fueled generation unit using an availability rate. We start by multiplying the real and reactive power capacity of all fossil fueled units by 0.9613, which is the proportion of the time they were not having unplanned outages in 2006 (North American Electric Reliability Council, 2007). Then we multiply their capacities by an availability modifier specific to the hour type, as shown in Table A1. These availability modifiers bring the average availability of the units to the average reported by the North American Electricity Reliability Council. They differ from one in proportion to the amount by which the load in their hour type differs from the system-wide load in the summer peak hour type.

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\(^9\) This produces estimated fossil-fueled generation capacity of 93,772 MW. If instead we had calculated fossil-fueled real-power capacity as total real-power generation capacity times the percent of generation coming from fossil fuels, the total would have been 92,515 MW.
Table A1: Availability Modifiers of Fossil-Fueled Generation Units, by Hour Type

<table>
<thead>
<tr>
<th>Hour Type</th>
<th>Availability Modifier of Fossil-Fueled Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>FALL (Oct, Nov)</td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>0.93</td>
</tr>
<tr>
<td>High</td>
<td>0.90</td>
</tr>
<tr>
<td>Medium</td>
<td>0.87</td>
</tr>
<tr>
<td>Low</td>
<td>0.83</td>
</tr>
<tr>
<td>WINTER (Dec–Feb)</td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>0.96</td>
</tr>
<tr>
<td>High</td>
<td>0.93</td>
</tr>
<tr>
<td>Medium</td>
<td>0.90</td>
</tr>
<tr>
<td>Low</td>
<td>0.85</td>
</tr>
<tr>
<td>SPRING (Mar, Apr)</td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>0.93</td>
</tr>
<tr>
<td>High</td>
<td>0.90</td>
</tr>
<tr>
<td>Medium</td>
<td>0.87</td>
</tr>
<tr>
<td>Low</td>
<td>0.83</td>
</tr>
<tr>
<td>SUMMER (May–Sep)</td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>1.00</td>
</tr>
<tr>
<td>High</td>
<td>0.94</td>
</tr>
<tr>
<td>Medium</td>
<td>0.89</td>
</tr>
<tr>
<td>Low</td>
<td>0.83</td>
</tr>
</tbody>
</table>

A5. Non-fossil-fueled real-power generation capacity available at each bus

The economics of using or “dispatching” non-fossil fueled generation units (those relying on hydro, nuclear, refuse, wood, or wind) are different from the economics of dispatching fossil-fueled units. For nuclear, refuse, wood, and run-of-river hydropower units, the marginal operating cost of operation is typically close to zero, or else negative. We model non-fossil-fueled units as having marginal cost of zero\(^{10}\), but we adjust their maximum capacities according to the hour type, as shown in Table A2. For the nuclear units, these maximum capacity adjustments primarily represent outages for refueling and other maintenance, which are most

\(^{10}\) A result of having a marginal cost of zero is that the unit generates at its maximum capacity all or almost all of the time.
common in the fall and spring. For the hydro units, these adjustments represent the output decisions that result from water availability, environmental constraints on river flow, and intertemporal optimization of the use of available water. For wind, refuse, and wood, each of which constitutes only a miniscule proportion of total generation capacity, we assume that output does not vary by hour type.

Allen, Lang, and Ilic report the approximate output from each non-fossil generator type at each bus during the summer peak hour that they model, ignoring types that provide less than a few percent of the output at the bus. We take this output as the maximum output in any hour type from that generation type at that bus, since the summer peak hour is the hour with greatest total demand.\textsuperscript{11}

For hydro, the adjustment to hourly demand in Table A2 makes total capacity factor (output divided by capacity) for the year equal to that reported in NERC (2007). The hydro adjustment factors deviate from 1 in proportion to the amount by which load during the respective hour type deviates from load during the summer peak hour type.

For nuclear, the adjustment to hourly demand in Table A2 makes total capacity factor for the year equal to the weighted equivalent availability factor\textsuperscript{12} of 0.8899 reported in NERC (2007). The nuclear adjustment factors are the same for all hour types of a season because nuclear plants generally have constant output when they operate. They deviate from one in proportion to the amount by which the load in the seasonal peak hour type deviates from the load in the summer peak hour type. Allen, Lang, and Ilic report the amount of non-fossil-fueled (hydro, nuclear, wind, refuse, and wood) generation during the summer peak demand hour that they simulate. In our simulation, real power output of the non-fossil-fueled generators is simply a function of hour type. For nuclear, wind, refuse, wood, and run-of-river hydropower units, this

\textsuperscript{11} For the hydro units taken together, this output is approximately 63% of the output that the units can produce when they all have an abundance of water. Sometimes, in reality, they do together produce more than this amount of power, but much of the variation in water availability does not correlate with our hour types. Average hydropower output per month is close to being constant. Even in the spring, when snow is melting, northeastern hydropower output is only about 5% higher than output in other seasons. Our model does not represent this seasonal difference, but its effect on the results would be small.

\textsuperscript{12} Roughly speaking, an “availability factor” indicates the proportion of the time a unit is not out of operation for maintenance or repair.
is because the marginal operating cost of these generators is typically close to, or less than, zero. For hydro units with dams, this is because the output per hour is a result of water availability, environmental constraints on operation, and intertemporal optimization of the use of available water, rather than simply a function of marginal operating cost as for fossil-fueled units. Table A2 below shows how we adjusted the output of non-fossil-fueled generators in each hour type, after first multiplying each by another constant.

Table A2: Real Power Output of Non-Fossil Fueled Generators by Hour Type, as a Proportion of Summer Peak Output

<table>
<thead>
<tr>
<th>Hour Type</th>
<th>Hydro</th>
<th>Nuclear</th>
<th>Wind, Refuse, Wood</th>
</tr>
</thead>
<tbody>
<tr>
<td>FALL (Oct, Nov)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>0.97</td>
<td>0.73</td>
<td>1</td>
</tr>
<tr>
<td>High</td>
<td>0.96</td>
<td>0.73</td>
<td>1</td>
</tr>
<tr>
<td>Medium</td>
<td>0.95</td>
<td>0.73</td>
<td>1</td>
</tr>
<tr>
<td>Low</td>
<td>0.93</td>
<td>0.73</td>
<td>1</td>
</tr>
<tr>
<td>WINTER (Dec–Feb)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>0.98</td>
<td>0.84</td>
<td>1</td>
</tr>
<tr>
<td>High</td>
<td>0.97</td>
<td>0.84</td>
<td>1</td>
</tr>
<tr>
<td>Medium</td>
<td>0.96</td>
<td>0.84</td>
<td>1</td>
</tr>
<tr>
<td>Low</td>
<td>0.94</td>
<td>0.84</td>
<td>1</td>
</tr>
<tr>
<td>SPRING (Mar, Apr)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>0.98</td>
<td>0.75</td>
<td>1</td>
</tr>
<tr>
<td>High</td>
<td>0.96</td>
<td>0.75</td>
<td>1</td>
</tr>
<tr>
<td>Medium</td>
<td>0.95</td>
<td>0.75</td>
<td>1</td>
</tr>
<tr>
<td>Low</td>
<td>0.93</td>
<td>0.75</td>
<td>1</td>
</tr>
<tr>
<td>SUMMER (May–Sep)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>1.00</td>
<td>1.00</td>
<td>1</td>
</tr>
<tr>
<td>High</td>
<td>0.98</td>
<td>1.00</td>
<td>1</td>
</tr>
<tr>
<td>Medium</td>
<td>0.95</td>
<td>1.00</td>
<td>1</td>
</tr>
<tr>
<td>Low</td>
<td>0.93</td>
<td>1.00</td>
<td>1</td>
</tr>
</tbody>
</table>

A6. Reactive power capacity

The reactive power capacity at each bus has two parts. The first is a constant reactive power injection that represents the amount of reactive power that the transmission system
produces or absorbs at each bus. In the reduced model, many of these constant injections are negative and have large magnitudes, as a result of the model reduction. The second part of the reactive power capacity is the reactive power capabilities of the generation units. Each unit has a range of reactive outputs it can produce, with a maximum that is typically positive and a minimum that is typically negative. We scale the capabilities of the fossil fueled units so that the total maximum and minimum reactive capacity at each bus, including the fixed injection and the reactive capabilities at the non-fossil-fueled units, is 10% farther from the fixed reactive power injection than the reactive power capacity totals in Allen, Lang, and Ilic (2008). We make the the total reactive power ranges wider than in Allen, Lang, and Ilic’s model in order to represent relatively inexpensive opportunities for providing reactive power that are not otherwise represented in our model, such as the installation of capacitors and inductors.

We assume that a generation unit can provide reactive power up to its maximum limit or down to its minimum limit costlessly if that unit is on. The only units we turn off in the optimization are coal-fired units, as part of the unit commitment process. Therefore, a need for reactive power can contribute to keeping a coal-fired unit on.

A7. Carbon dioxide emission rates of the generation units

From the fuel type, fuel use per MWh, and carbon content of different fuel types (Energy Information Administration, 2009) we calculated the CO2 emission rate per MWh of each generation unit.

A8. Nitrogen oxide and sulfur dioxide emission rates of the generation units

The US Environmental Protection Agency reports nitrogen oxide and sulfur dioxide emissions and generation output of most fossil fueled generation units with capacities over 25 MW. We matched the units in the EPA data with units in the Energy Visuals data based on name or owner name, fuel, and generation capacity. We used latitude and longitude to verify the matchups. For units not included in the EPA data, we assigned the following emission rates,
which are the average emission rates of the units that appear in both the EPA and Energy Visuals data.

**Table A3: Assumed Emission Rates for Units without Known Emission Rates (Metric Tonnes per Megawatt-hour)**

<table>
<thead>
<tr>
<th>Fuel</th>
<th>SO$_2$ rate</th>
<th>NO$_2$ rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>0.006202</td>
<td>0.000824</td>
</tr>
<tr>
<td>Diesel Oil</td>
<td>0.000133</td>
<td>0.000927</td>
</tr>
<tr>
<td>Pipeline Natural Gas</td>
<td>0</td>
<td>0.000136</td>
</tr>
<tr>
<td>Residual Oil</td>
<td>0.000632</td>
<td>0.000504</td>
</tr>
</tbody>
</table>

**A9. Amount of electricity demanded, or “load”**

Table A4 presents the amount of electricity demanded (“load”) by region in each hour type, as a proportion of the load in Allen, Lang, and Illic’s model of load during the summer peak hour. Load varies from one hour type to another, but is assumed to be perfectly inelastic in a given hour type, since few electricity customers face real-time electricity prices. The second column of Table A4 indicates the number of hours each hour type represents. For example, the fall “peak” hour type represents the 73 hours of October and November with the highest aggregate loads. The fall “high” hour type represents the 366 hours of October and November with the next-highest aggregate loads. Each hour type uses the average load in each region during the corresponding hours.
Table A4: Electric Load as a Ratio of Load in Summer Peak Hour, by Hour Type and Region

<table>
<thead>
<tr>
<th></th>
<th># of hours</th>
<th>New York</th>
<th>PJM-East</th>
<th>Ontario</th>
<th>Maritimes</th>
<th>New England</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>FALL (Oct, Nov)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>73</td>
<td>0.68</td>
<td>0.67</td>
<td>0.74</td>
<td>0.90</td>
<td>0.69</td>
</tr>
<tr>
<td>High</td>
<td>366</td>
<td>0.63</td>
<td>0.59</td>
<td>0.70</td>
<td>0.90</td>
<td>0.64</td>
</tr>
<tr>
<td>Medium</td>
<td>586</td>
<td>0.56</td>
<td>0.52</td>
<td>0.64</td>
<td>0.86</td>
<td>0.57</td>
</tr>
<tr>
<td>Low</td>
<td>439</td>
<td>0.45</td>
<td>0.42</td>
<td>0.53</td>
<td>0.74</td>
<td>0.43</td>
</tr>
<tr>
<td><strong>WINTER (Dec–Feb)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Peak</td>
<td>108</td>
<td>0.73</td>
<td>0.72</td>
<td>0.85</td>
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<td>0.76</td>
</tr>
<tr>
<td>High</td>
<td>540</td>
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<td>0.65</td>
<td>0.79</td>
<td>1.08</td>
<td>0.70</td>
</tr>
<tr>
<td>Medium</td>
<td>864</td>
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<td>0.58</td>
<td>0.71</td>
<td>1.01</td>
<td>0.62</td>
</tr>
<tr>
<td>Low</td>
<td>648</td>
<td>0.50</td>
<td>0.48</td>
<td>0.60</td>
<td>0.91</td>
<td>0.49</td>
</tr>
<tr>
<td><strong>SPRING (Mar, Apr)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>73</td>
<td>0.67</td>
<td>0.67</td>
<td>0.80</td>
<td>1.09</td>
<td>0.72</td>
</tr>
<tr>
<td>High</td>
<td>366</td>
<td>0.62</td>
<td>0.57</td>
<td>0.72</td>
<td>0.97</td>
<td>0.63</td>
</tr>
<tr>
<td>Medium</td>
<td>585</td>
<td>0.56</td>
<td>0.52</td>
<td>0.65</td>
<td>0.91</td>
<td>0.57</td>
</tr>
<tr>
<td>Low</td>
<td>439</td>
<td>0.46</td>
<td>0.43</td>
<td>0.55</td>
<td>0.84</td>
<td>0.45</td>
</tr>
<tr>
<td><strong>SUMMER (May–Sep)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>184</td>
<td>0.87</td>
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<td>0.87</td>
<td>0.87</td>
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<tr>
<td>High</td>
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<td>0.75</td>
<td>0.72</td>
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<td>0.84</td>
<td>0.72</td>
</tr>
<tr>
<td>Medium</td>
<td>1469</td>
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<td>0.57</td>
<td>0.65</td>
<td>0.79</td>
<td>0.59</td>
</tr>
<tr>
<td>Low</td>
<td>1102</td>
<td>0.48</td>
<td>0.44</td>
<td>0.53</td>
<td>0.69</td>
<td>0.45</td>
</tr>
</tbody>
</table>
REFERENCES


