Estimating Power Sector Leakage Risks and Provincial Impacts of Canadian Carbon Pricing

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Abstract

Carbon pricing systems have emerged in Canada at provincial and federal levels to reduce CO_2 emissions. However, cross-border electricity trade with the U.S. is already extensive, and although Canada is currently a net exporter, policy changes could alter these trade dynamics. Since CO_2 emissions are currently unregulated in most U.S. states, there is a concern that this incomplete regulatory coverage will lead to emissions leakage, as electric generation and emissions shift toward these unregulated regions. This paper examines potential power sector emissions leakage and distributional implications across provinces from Canadian carbon pricing. Using an integrated model of electric sector investments and operations with detailed spatial and temporal resolutions, the analysis demonstrates how emissions leakage through trade adjustments can be non-trivial fractions of the intended emissions reductions even in the presence of leakage containment measures. Magnitudes of long-run leakage rates from Canadian carbon pricing depend on market and policy assumptions (e.g., natural gas prices, timing of future U.S. CO_2 policy), ranging from 13% (high gas price scenario with border carbon adjustments) to 76% (lower gas price scenario without antileakage measures), which are higher than reported literature values for national policies. When leakage containment measures are implemented, net emissions and leakage rates decrease, but gross emissions in Canada and policy costs increase. Leakage persists in alternate scenarios with constrained transmission expansion, higher natural gas prices, and U.S. adoption of carbon pricing, but leakage rates decrease under these conditions.

Keywords: climate policy; economic geography; emissions leakage; energy-economic modeling; market integration; trade

JEL: F18, L94, Q28, Q42, Q48

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1. Introduction

Carbon[1] pricing systems have emerged in Canada at provincial and federal levels to reduce carbon dioxide (CO_2) emissions. However, cross-border electricity trade with the U.S. is extensive, and although Canada is currently a net exporter, policy changes could alter these trade dynamics. Since emissions are currently unregulated in most U.S. states, there is a concern that this incomplete regulatory coverage will lead to emissions leakage, as electric generation and emissions shift toward unregulated locations.

Leakage refers to any regulatory-induced shift in production (and consequently emissions) toward uncovered or less stringently regulated sources. Market linkages make leakage a potential issue for regionally or nationally differentiated policies, since policy design choices in one jurisdiction influence economic conditions and the environmental integrity of the system as a whole. Channels for leakage are typically challenging to identify and quantify ex ante, but can be of first-order importance in evaluating impacts of policy alternatives (Caron, Rausch and Winchester 2015).

Despite subnational and unilateral emissions policies receiving greater policy focus in light of stalled cooperative action, many questions remain about potential electric sector implications of regional and international interactions from energy and climate policies. There are extensive theoretical and applied economic literatures on emissions leakage (Cosbey, et al. 2019). The empirical and modeling literatures on emissions leakage have largely focused on quantifying international leakage mechanisms, rates, and trade impacts, especially for trade-exposed industries with migration risks (Böhringer, Balisteri and Rutherford 2012, Babiker 2005, Droege 2011). Most studies examine international or global leakage and not subnational adjustments (or between adjacent countries), where the connectedness increases the potential for reallocating production across a physically linked network. This latter dynamic is applicable for Canada and the U.S. given existing transmission links and geographical proximity. The limited studies of North American leakage and carbon pricing have principally looked at existing policies in California and Regional Greenhouse Gas Initiative (RGGI) states (Caron, Rausch and Winchester 2015, Fowlie 2009, Chen 2009). These analyses indicate that subnational policies could lead to leakage rates between 9 and 57% depending on the region and policy provisions. International leakage rates tend to be lower than those for subnational policies, with rates commonly between 0 and 20% (Böhringer, Landis, et al. 2017), due to greater market integration at state and regional levels. In particular, the leakage literature has limited coverage of existing or prospective power sector carbon pricing for interconnected regional and national markets. Bistline and Rose (2018) is one of the only papers to investigate prospective unilateral carbon pricing across different U.S. regions for a range of stringencies. The assessment finds that emissions leakage is likely, ranging from negative 70% to over 80%, and quantifies how leakage mitigation provisions like power import constraints likely reduce leakage but can result in lower net emissions reductions and larger price increases. Other papers look at leakage in the United Kingdom and Ireland (Curtis, Di Cosmo and Deane 2014), California (Caron, Rausch and Winchester 2015), and RGGI states (Fell and Maniloff 2015, Chan and Morrow 2019).

[1] This article uses "carbon" as shorthand for carbon dioxide (CO_2). All prices and emissions values are presented in CO_2 terms.

This paper assesses potential power sector leakage from Canadian carbon pricing and the geographical incidence of impacts across provinces. This analysis is the first to investigate possible emissions leakage between Canada and the U.S. under unilateral carbon pricing using an integrated model of electric sector investment, dispatch, and trade decisions with detailed spatial and temporal resolutions, as described in Section 2.1, Appendix A, and EPRI (2018). Earlier studies simulate changes in dispatch with fixed generation without capacity or transmission investment (Chen 2009, Sauma 2012), use stylized models with restrictive assumptions about the possibility of endogenous trade (Winchester and Rausch 2013), or adopt static trade models instead of intertemporal optimization frameworks (Eichner and Pethig 2015). This study focuses on power sector leakage owing to its significant cross-border integration and due to previous work indicating that electricity trade can be the primary leakage channel for carbon pricing (Bistline and Rose 2018). A unique contribution of this research is to quantify emissions leakage using a power sector model with long-run investment and short-run operational detail, including both the temporal detail (to capture the economics of trade and variable renewables) and spatial coverage (to represent U.S. states and Canadian provinces). This study also quantifies the economic and environmental impacts of three proposed instruments to reduce emissions leakage: border carbon adjustments, trade constraints, and output-based pricing systems.

The analysis finds that power sector emissions leakage through trade adjustments is likely under Canadian carbon pricing and can erode non-trivial portions of intended emissions reductions. Magnitudes change depending on assumed market and policy assumptions in the future (e.g., natural gas prices, timing and stringency of U.S. policy), but positive leakage persists and ranges from 13% (in the high gas price scenario with border carbon adjustments) to 76% (in the lower gas price scenario without antileakage measures). There is a net decrease in aggregate emissions from the U.S. and Canada due to carbon pricing even after accounting for leakage, but these benefits are partially eroded by electricity generation leaking from Canada to U.S. through integrated electricity markets, especially when fossil-fuel-based generation is on the margin and transmission expansion is possible. These results suggest that policy analysis is incomplete if it does not account for benefits and costs across geographical boundaries. Leakage reduction measures like import tariffs and local generation constraints can reduce leakage rates but may simultaneously change costs and net emissions, suggesting tradeoffs between economic and environmental outcomes. The distribution of policy costs is linked to relative mitigation efforts across provinces and competitiveness of gas-fired generation in the absence of carbon pricing.

2. Analytical Framework and Scenarios

2.1. Model

This analysis uses the North American Regional Economy, Greenhouse Gas, and Energy (NA-REGEN) modeling framework to evaluate leakage risks and province-level impacts. REGEN is a state-of-the-art capacity planning and dispatch model of the electric sector that provides an intertemporal optimization of planning pathways given assumptions about policies, technologies, and markets. The model uses an innovative algorithm to capture hourly joint variability in load, wind, and solar output in a multidecadal model (EPRI 2018, Blanford, et al. 2018). REGEN makes linked decisions about new generation investments and hourly system dispatch across U.S. and Canada while co-optimizing transmission investment and trade flows. The detailed intra-annual temporal resolution and regional heterogeneity are critical for representing power system operations and trade, as many other models do not represent endogenous import and export decisions (Santen, et al. 2017, Bistline, Santen and Young 2019). More information about the model's structure, assumptions, and data can be found in Appendix A and the detailed model documentation (EPRI 2018), and additional applications of REGEN can be found at http://eea.epri.com.

NA-REGEN can be configured to consider any combination of the contiguous U.S. states and Canadian provinces. The regional aggregation used for this analysis is shown in Figure 1.

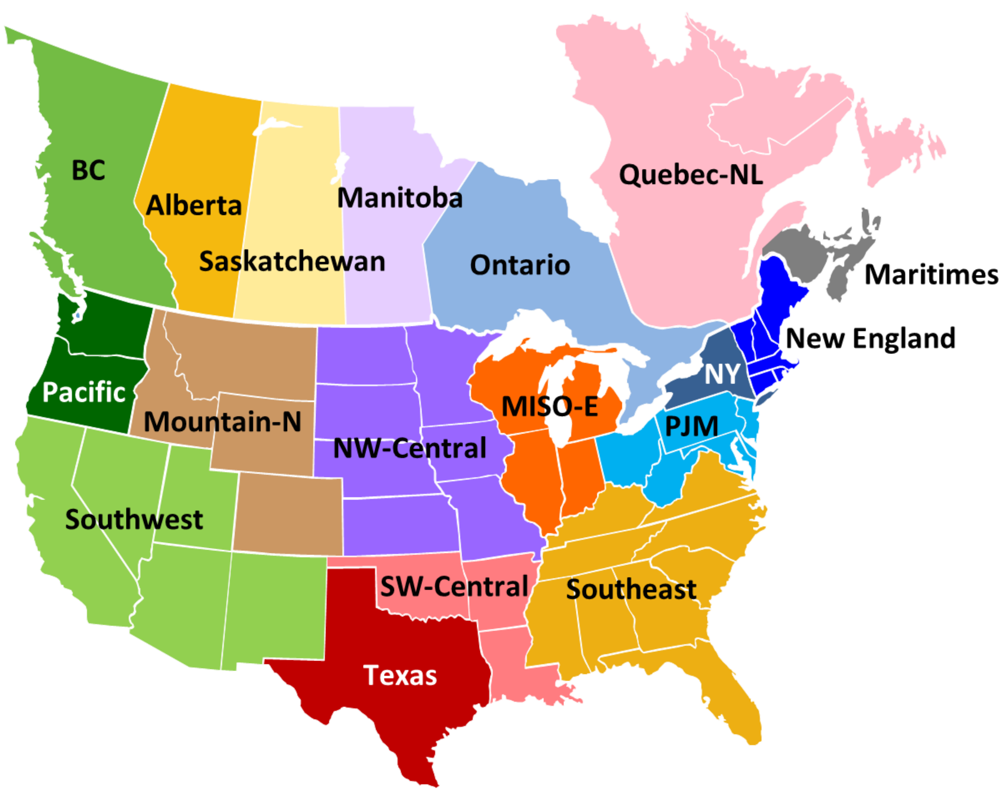

Figure 1. Default regional configuration of the North American REGEN model. U.S. state and Canadian provinces are grouped into the model regions above unless otherwise specified.

Cross-regional exchange of electricity in a given hour is constrained by net transfer capacities of transmission between regions (zonal), which can change over time as new inter-regional transmission investments are made. Hourly electricity prices by region are Lagrange multipliers on the load-balance equation in the cost-minimization electric sector capacity planning and dispatch optimization problem. Hourly renewable output and resource potentials are based on analysis and data by EPRI, AWS Truepower, and NASA's MERRA-2 dataset (Blanford, et al. 2018, EPRI 2018, Young and Bistline 2018), which give synchronous time-series values with load.

In light of the motivating research questions on leakage and cross-border trade, there are a few considerations in selecting an appropriate analytical approach. The prominence of renewables across these scenarios requires a modeling framework that can evaluate electric sector investment and operational decisions simultaneously. In particular, the focus on variable renewable energy requires a model that can capture temporal and spatial variability in a computationally tractable manner (Mai, et al. 2018). NA-REGEN is unique in its temporal granularity and was designed to capture the distinctive economic and operational characteristics of renewables as well as the policies that support them. Specifically, a novel "representative hours" approach more accurately captures correlations between hourly load, wind, and solar time-series data across regions (Blanford, et al. 2018). Additionally, the questions in this analysis center on trading electricity with neighboring regions through integrated electricity markets, which requires a model with regional detail and intra-annual temporal granularity. NA-REGEN's detailed temporal resolution make it especially well-suited for capturing these dynamics. Finally, the forward-looking nature of the research questions suggests that structural optimization models are more appropriate than statistical frameworks, especially in light of expected changes in technologies, markets, and policies.

All monetary values in the analysis are presented in U.S. dollars unless otherwise stated.

Note that this analysis uses an electric sector only version of the REGEN model, so end-use sectors (and their interactions with load shapes) are not modeled explicitly. Annual load over time is exogenous in these scenarios and is based on values from U.S. Energy Information Administration's *Annual Energy Outlook 2018* (U.S. Energy Information Administration 2018) for U.S. states and the National Energy Board's *Canada's Energy Future 2016* (National Energy Board 2016) for Canadian provinces. The version of REGEN used in this analysis omits unit commitment costs and constraints (Bistline 2019).

2.2. Scenarios

Table 1 lists the primary policy variants in this analysis and provides descriptions of key assumptions. Section 3 focuses on four types of outputs: generation, CO_2 emissions, economic impacts, and regional policy impacts. Given uncertainties about policy implementation, model results should not be interpreted or used as forecasts. The results reflect fundamental economic drivers, and details in policy and market design may lead to different outcomes.

Table 1. Core policy scenario list and assumptions. Additional detail is provided in Appendix B.

Policy Scenario	Description
Reference	The reference scenario assumes a "business-as-usual trend estimate" with all on-the-books federal and provincial/state policies apart from Canadian carbon pricing, including renewable mandates, the U.S. federal tax credit for wind and solar, and Canadian coal phase-out intensity targets. This scenario includes U.S. Clean Air Act (CAA) § 111(b) CO_2 performance standards for new fossil units.
Tax	This scenario assumes Canadian carbon pricing with the federal backstop in provinces without qualifying plans. These policies are layered on top of other U.S. and Canadian policies from the "Reference" scenario. The U.S. policy landscape does not include a federal climate policy.
Tax (BCA)	This scenario assumes the same policies as the "Tax" scenario but includes a border carbon adjustment (BCA) that taxes electricity imports into Canada at the respective CO_2 price.
Tax (Local Gen)	This scenario assumes policies in the "Tax" scenario and adopts constraints on cross-border electricity trade to prevent leakage. This local generation constraint assumes that 90% of provincial generation must come from in-province resources.
Tax (OBPS)	This scenario assumes the same policies as the "Tax" scenario but includes an output-based pricing system (OBPS) modeled after the proposed Canadian federal backstop as part of the *Greenhouse Gas Pollution Pricing Act* (Government of Canada 2018).

To evaluate the impact of Canadian carbon pricing, the analysis begins with a counterfactual reference scenario with all other on-the-books policies and regulations (e.g., coal phaseouts, renewable mandates). All scenarios except for the "policy equivalence" scenario assume that the U.S. follows its current patchwork approach to policy at the state and regional level (e.g., California's clean energy mandate and economy-wide emissions targets, Regional Greenhouse Gas Initiative (RGGI), state renewable mandates) but does not implement a federal climate policy. The reference scenario assumes load growth from the U.S. Energy Information Administration's *Annual Energy Outlook 2018* (U.S. Energy Information Administration 2018). No additional environmental regulatory costs or constraints are included. Production tax credits for wind and investment tax credits for solar are included per their December 2015 updates. As discussed in Appendix A, technology costs come from EPRI's Generation Options report. Hydropower is assumed to remain at currently installed capacities and planned projects (e.g., Site C Dam in British Columbia, Lower Churchill Project in Labrador) owing to higher costs and environmental concerns. Given the potential benefits of hydro, particularly in scenarios with carbon policy across North America, relaxing this assumption and investigating the role of future large-scale hydro development will be an important area of future work.

Results in this scenario can be compared with the carbon pricing scenario ("Tax"), which assumes that provinces implement CO_2 policies as proposed (including the federal backstop for provinces that do not adopt their own pricing systems). The stringency and timing of the CO_2 levy are shown in Figure 2.

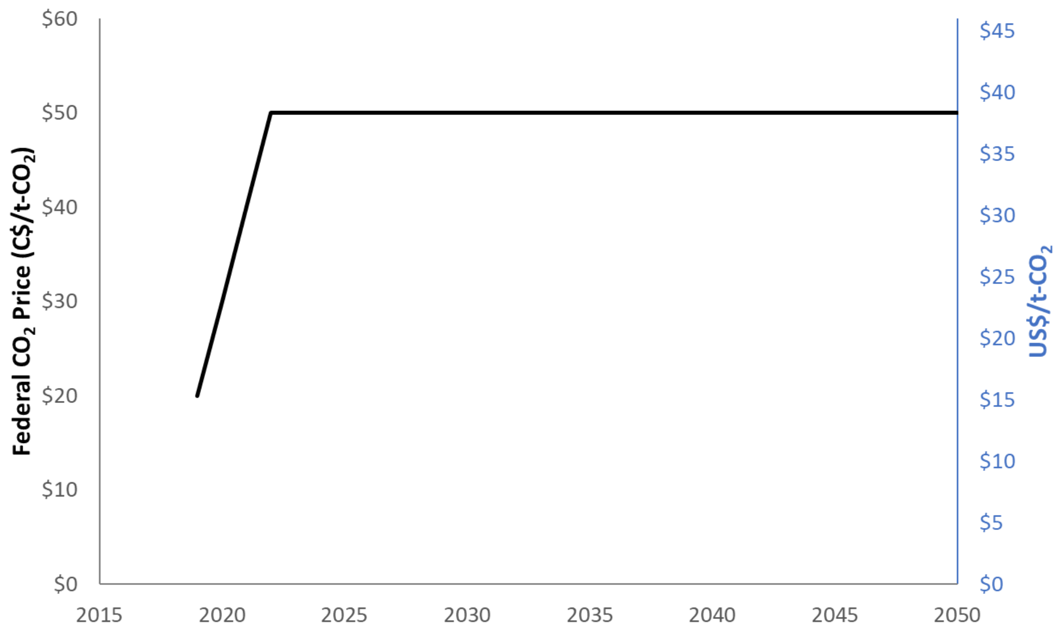

Figure 2. Current federal Canadian backstop CO_2 price over time. Values are expressed in Canadian dollars (left axis) and equivalent U.S. dollars (right axis).

The analysis also examines scenarios with three mechanisms for limiting leakage. The first leakage mitigation measure imposes a border carbon adjustment through an import tariff. Border carbon adjustments are intended to level the playing field between jurisdictions with divergent carbon prices by aligning prices faced by consumers in the regulated region based on the carbon content of domestic goods relative to imported ones (Cosbey, et al. 2019). The tariff rate is dynamically updated over time based on Canadian carbon price and emissions rate from a new natural gas combined cycle (NGCC) unit. Since there are many methods for evaluating emissions intensities of imported power and other complicated regulatory tradeoffs associated with border carbon adjustments, Appendix C briefly surveys the strengths and shortcomings of different approaches and provides a calculation demonstrating how the administratively simple assumption in this scenario aligns with the modeled marginal emissions intensity of U.S. generation. The second leakage mitigation provision includes an autarky constraint to enforce local generation in individual provinces to be at least 90% of load in each hour. This stylized self-sufficiency constraint mimics possible trade restrictions imposed by policymakers, system operators, or other stakeholders to achieve goals like ensuring reliability, minimizing leakage, and/or encouraging local development.[2] The third antileakage measure is an output-based pricing system (OBPS) for large emitters based on the proposed Canadian federal backstop as part of the *Greenhouse Gas Pollution Pricing Act*. Under this proposal, firms receive subsidies based on their output and the difference between their emissions intensity and fuel-specific benchmarks. The emissions intensity benchmark for coal-fired generators starts at 0.8 t-CO_2/MWh in 2019, decreases to 0.65 t-CO_2/MWh in 2020, and then declines linearly to 0.37 t-CO_2/MWh by 2030. Gas-fired generators are subject to a flat benchmark of

[2] For instance, the 2007 British Columbia Energy Plan lists "electricity self-sufficiency" as a goal in light of broader objectives to decrease emissions through strategies like electrification while ensuring that the province has sufficient capacity to meet its needs (https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/info/pdf/2008_ltap_appendix_b1.pdf).

0.37 t-CO_2/MWh across the time horizon.[3] An OBPS depresses wholesale electricity prices relative to other approaches, and although dampening price signals may be attractive from a political economy perspective, these dynamics also lower firm responses to carbon pricing, which *ceteris paribus* increases emissions relative to the scenario without antileakage measures.

Since transmission investments and changes in trade are two important degrees of freedom in planning that can simultaneously contribute to leakage, we attempt to isolate the contributions of these drivers by conducting a sensitivity that includes Canadian carbon pricing but does not allow new transmission additions. Net transfer capacities between Canadian and U.S. model regions (Figure 1) are constrained to their base year levels.

A final sensitivity investigates the impact of the U.S. adopting a federal carbon price with equivalent stringency to the Canadian federal policy (Figure 1).[4]

All policy scenarios in Table 1 are tested with two natural gas price trajectories from the U.S. Energy Information Administration's *Annual Energy Outlook 2018* (U.S. Energy Information Administration 2018). The "Reference" and "High" price trajectories are shown in Figure 14, where the former are relatively flat in real-dollar terms over time (just above \$3/MMBtu) and the latter increase steadily (and reach about \$5/MMBtu by 2050).

2.3. Leakage

Leakage results in this paper use a cumulative CO_2 leakage metric, which is specified through a particular time T. A cumulative emissions metric aggregates temporal effects and offers a more comprehensive characterization of environmental impacts than an annual leakage value. The undiscounted cumulative leakage rate is defined as follows:

$$\lambda_T = -\frac{\sum_{t=t_0}^{T} \Delta_U}{\sum_{t=t_0}^{T} \Delta_C} \tag{1}$$

where λ_T is the cumulative leakage rate (%) through time T, Δ_r is the difference in emissions between the Canadian carbon pricing policy and the equivalent scenario without the policy for region r (where U stands for the U.S. and C is Canada), t is the set of all time periods, and t_0 is the initial policy period.

In summary, the leakage rate is the change in emissions in all regions outside of the regulated area (in this case, U.S. regions) divided by the expected/modeled decrease in regulated emissions in the Canadian power sector. This analysis follows convention in the literature that an increase in unregulated emissions is referred to as "leakage," and a decrease is referred to as "negative leakage." Note that

[3] This stylized scenario assumes that the OBPS applies to all provinces. Note that Alberta has different performance benchmarks in its large-emitter plan that are uniform for all generators, which includes subsidies for zero-emitting generators.
[4] Note that this scenario and the "Tax (Local Gen)" scenario require separate counterfactual "reference" scenarios to evaluate the incremental impact of a Canadian carbon pricing policy (the focus of the analysis) in a true *ceteris paribus* experiment.

leakage rates measure policy-induced changes relative to the baseline when the unilateral policy is not pursued in Canada, which accounts for trends in both the regulated and unregulated regions.

3. Results

3.1. Generation and Emissions Impacts

Figure 3 shows Canadian generation by technology across the five core scenarios. In the reference scenario, as coal exits the generation mix (per the 2030 phaseout) and demand increases, generation and capacity are increasingly provided by new NGCC units and wind. Existing hydropower dominates generation across all scenarios, even as hydro's share decreases over time owing to expansion of other resources to meet increasing load. Nuclear output reflects refurbishments and planned retirements. Variable renewable generation comes largely from wind owing to its higher revenues than lower-cost but still lower capacity factor solar (Figure 13). With Canadian carbon pricing and no leakage containment measures ("Tax"), Canada's net trade position changes, and imports from the U.S. displace gas generation in Canada, as coal capacity retires earlier in the model horizon. All Canadian carbon pricing scenarios include higher wind generation and NGCC with carbon capture relative to the reference, alongside decreases in NGCC output. The three policy scenarios with leakage mitigation entail higher gas and wind generation in Canada as the net trade balance narrows, though export volumes are smaller than reference levels (though long-run trade with the OBPS is close to reference levels).

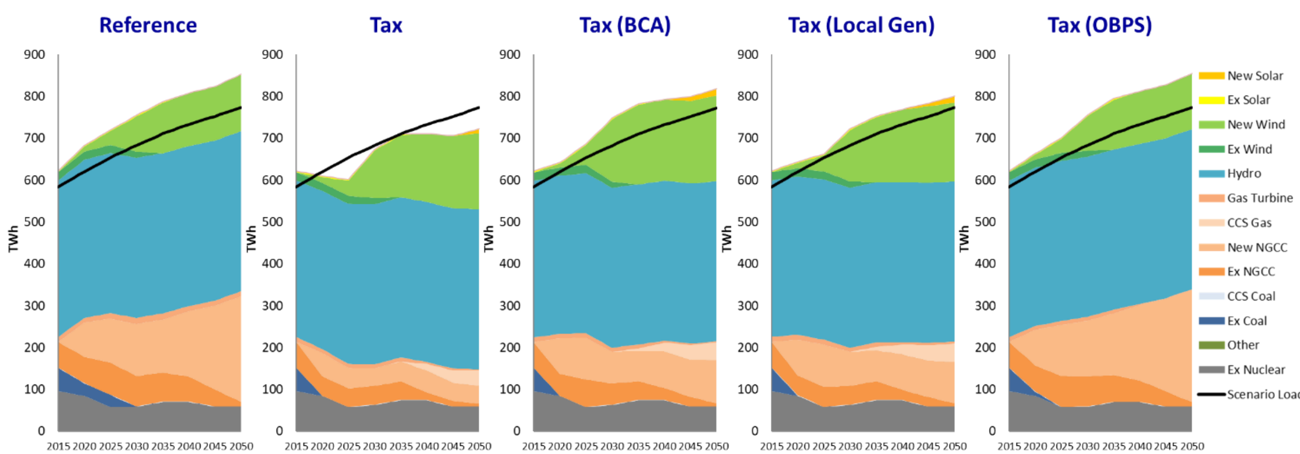

Figure 3. Canadian generation (TWh) by technology and scenario under reference natural gas prices. Detailed descriptions of the scenarios are provided in Section 2.

Model results suggest that CO_2 emissions leakage through trade adjustments from Canadian carbon pricing is likely, though the magnitudes vary based on assumptions about future market and policy conditions. Without antileakage measures, carbon pricing reduces cumulative CO_2 emissions in Canada through 2050 by 61% relative to the reference, lowering cumulative emissions by 2.0 million metric tons (mmt) CO_2 (Figure 4). However, U.S. emissions simultaneously rise by 1.5 mmt-CO_2, and the resulting leakage rate of 76% is on the higher end of the published literature (Bistline and Rose, 2018). Even the presence of carbon pricing in northern U.S. states like RGGI is not enough to disincentivize leakage, as electricity price differentials are still significant enough for U.S. states to reduce dependence on lower-CO_2 but higher-cost imports from Canadian provinces.

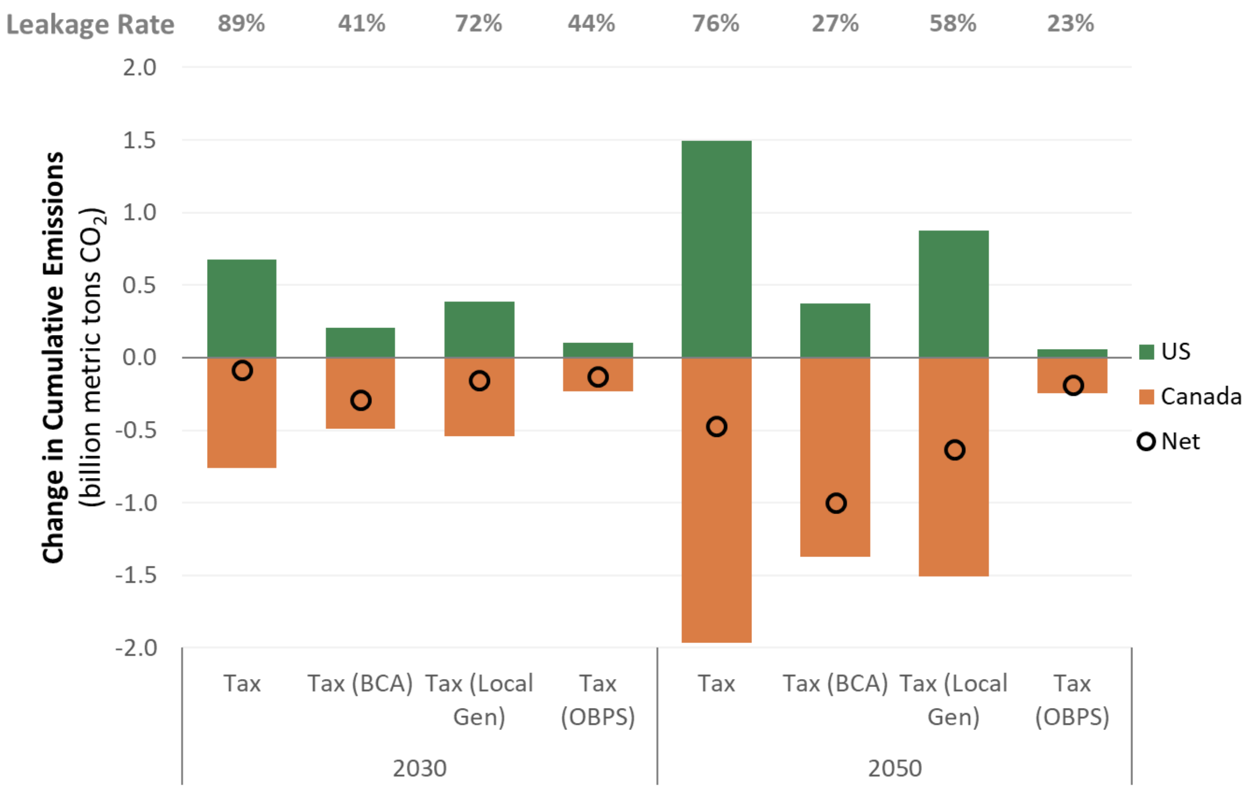

Figure 4. Change in cumulative CO_2 emissions through 2030 (left) and 2050 (right) by scenario relative to the reference case. Leakage rates shown above the bar chart are defined by Equation 1. Cumulative emissions reductions are undiscounted.

Time-series data for emissions by scenario are provided in Appendix D.

Leakage mitigation provisions lower emissions in unregulated regions but can raise gross emissions in the regulated regions (and costs, as discussed in the next section). As shown in Figure 4, Canadian emissions increase when antileakage policies like border carbon adjustments and local generation constraints are added. Leakage through trade adjustments is observed even in the presence of containment measures, but these policies can reduce leakage rates and net emissions across the U.S. and Canada (Figure 4). Leakage rates through 2050 decrease from 76% to 27% with border carbon adjustments, to 58% with autarky constraints, and to 23% with output-based subsidies.[5] BCA-induced emissions reductions are more significant in this context with extensive cross-border linkages and high leakage relative to estimates in multisector international modelling contexts, where BCA measures reduce leakage rates by approximately 33% (Böhringer, Balisteri and Rutherford 2012). The OBPS approach in particular leads to lower leakage; however, long-run emissions are similar to reference

[5] Leakage rates in 2030 are qualitatively similar across scenarios as the 2050 rates. The high leakage rates in 2030 also indicate that leakage is problematic even with anticipated but delayed future U.S. policy, though the absolute leakage magnitudes after 2030 indicate that earlier policy harmonization could lower cumulative emissions.

levels (Figure 18) due to output subsidies lowering the effective emissions penalty faced by NGCC units (Figure 3).[6]

In part, positive leakage persists owing to Canada's net trade position as an exporter in the reference scenario. With Canadian carbon pricing, U.S. generation becomes more competitive, and even though leakage containment measures can prevent the net trade balance from switching (i.e., prevent Canada from becoming a net importer), the narrowing of the trade gap remains since the U.S. is not obligated to purchase above-market-price power from Canada. Note that export subsidies would be a mechanism for preventing this leakage, but the legality of such measures is subject to controversy (Cosbey, et al. 2019, de Cendra 2006).

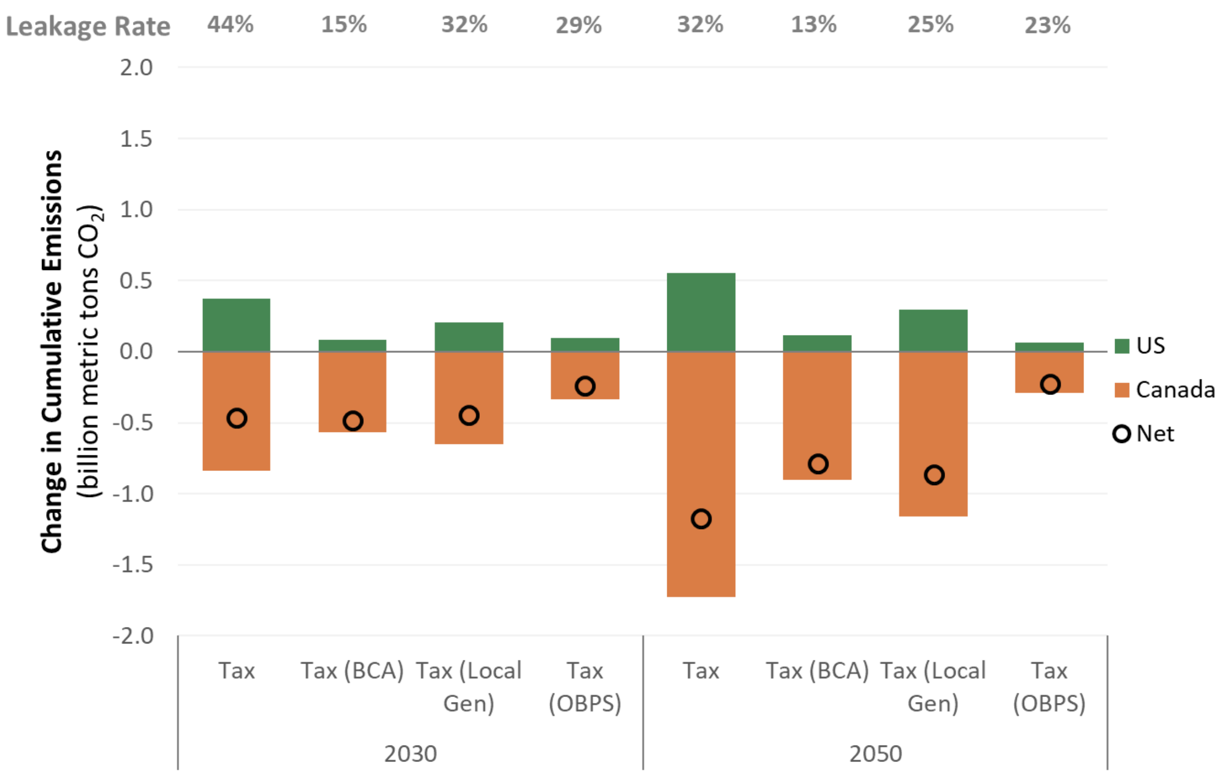

Figure 5. Change in cumulative CO_2 emissions through 2030 (left) and 2050 (right) by scenario relative to the reference case with higher gas prices. Leakage rates shown above the bar chart are defined by Equation 1. Cumulative emissions reductions are undiscounted.

With higher natural gas prices, NGCC generation shares are lower across all scenarios, and gas is displaced primarily by wind generation (along with limited increases in imports and solar), as shown in Figure 15. Figure 5 demonstrates how leakage persists with higher natural gas prices, though magnitudes of leakage rates decrease. Without antileakage measures, Canadian carbon pricing primarily increases U.S. NGCC generation under reference gas prices with some near-term coal expansion from existing plants, as shown in Figure 6. However, with high gas prices, the supply response from U.S.

[6] The higher coal generation before 2030 in the OBPS scenario also leads to higher cumulative SO_2 and NO_x emissions relative to the tax scenario without antileakage measures.

generation shifts toward a mix of NGCC and wind based on their relative competitiveness in exporting regions. This shift leads to lower leakage rates under high gas price conditions in Figure 5 relative to Figure 4. These results underscore how leakage rates can change depending on market assumptions like natural gas prices owing to adjustments on the extensive margin, which makes it important to evaluate leakage in a model with investment and dispatch changes.

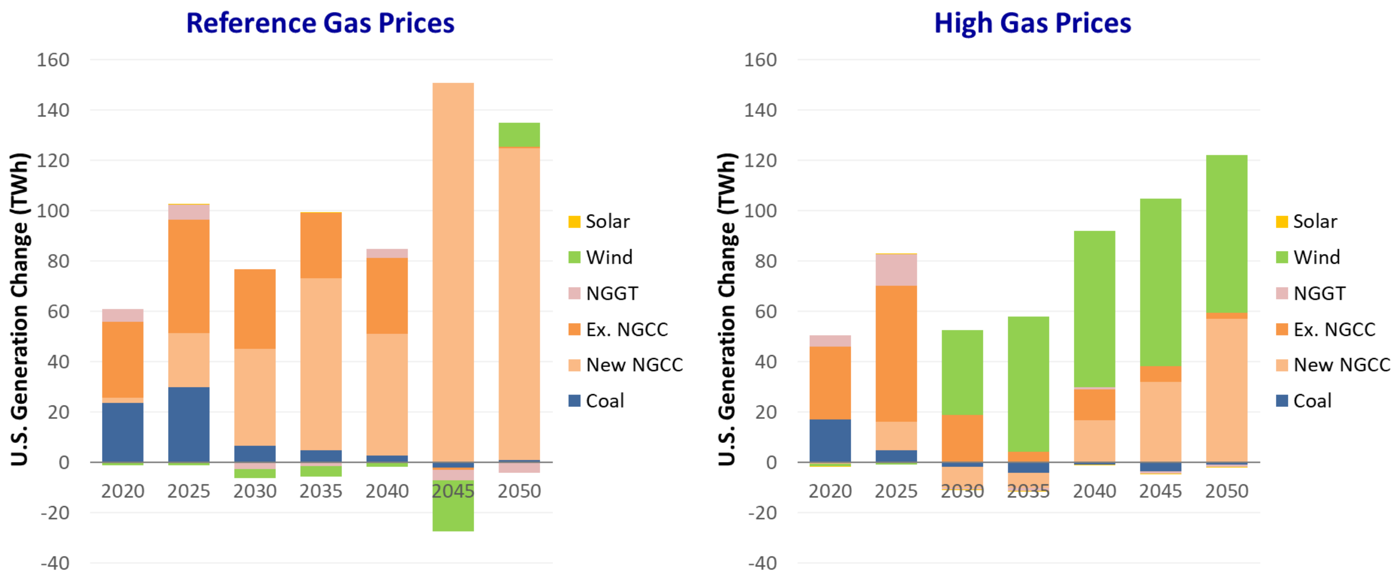

Figure 6. Change in composition of U.S. generation by technology over time. Values represent differences between the Canadian carbon pricing scenario and the corresponding reference. Panels compare values with reference gas prices (left) and high gas prices (right).

Results thus far assume that changes in transmission investment and trade are possible based on the economic drivers in a given scenario. Both factors can contribute to leakage. Figure 7 shows the sum of cross-border transmission capacity between the U.S. and Canada in 2050 and net exports from Canada. Transmission capacity is highest in the Canadian carbon pricing scenario without antileakage measures, though all scenarios entail growth from base year levels (about 11.3 GW). Net exports exhibit greater variation than transmission capacity, and the largest deviation occurs in the policy scenario without leakage containment measures.

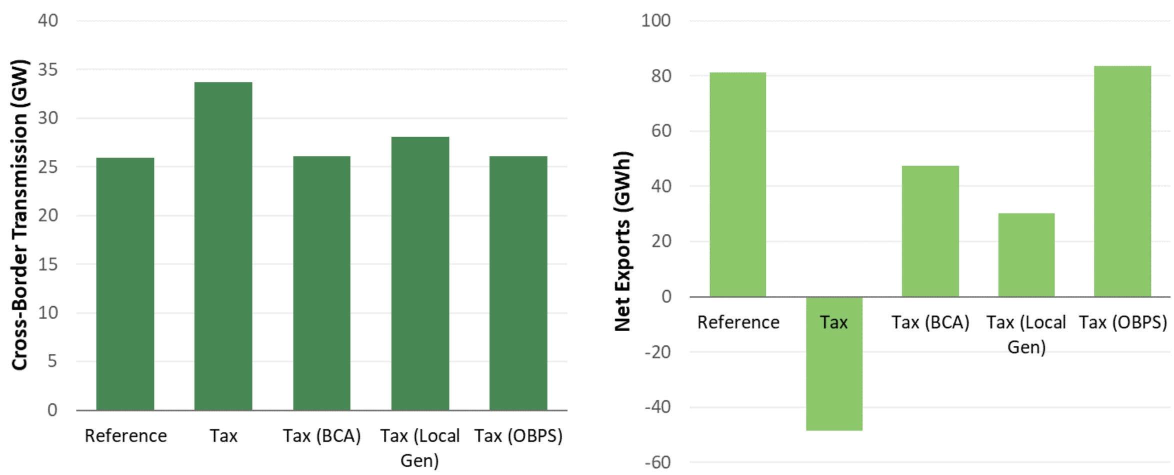

Figure 7. 2050 cross-border transmission capacity (left) and net exports from Canada to the U.S. (right) by scenario. Values are shown with reference gas prices.

To isolate the relative contributions transmission and trade, a sensitivity is conducted that includes Canadian carbon pricing without new transmission. Figure 8 suggests that fixing transmission at base year levels may lower leakage rates but that leakage is still possible. Constraining transmission capacity has a larger impact on long-run leakage (decreasing leakage rates from 76% to 27% in 2050) than on short-run rates (lowering rates from 89% to 48% in 2030). Combined with Figure 7, these results indicate that emissions leakage is driven by a combination of changes in trade and cross-border transmission capacity. Constraining either trade or transmission investments can lower leakage rates, but existing transmission infrastructure suggests that trade adjustments (when incentivized by cross-border price differentials) can lead to emissions leakage, though the magnitude depends on markets and policies.

Figure 8. Change in cumulative CO_2 emissions through 2030 (left) and 2050 (right) by scenario relative to the reference case. The "Tax (NoTr)" scenario assumes no new transmission additions are possible.

Leakage rates shown above the bar chart are defined by Equation 1. Cumulative emissions reductions are undiscounted.

Overall, the porous border between the U.S. and Canada, which already has extensive cross-border trade and transmission linkages, invites leakage across a range of conditions. Long-run leakage rates from Canadian carbon pricing span a wide range from 13% (high gas price scenario with border carbon adjustments) to 76% (lower gas price scenario without antileakage measures). Note that these leakage rates are generally higher than reported literature values for national policies, which are typically between 0 and 20% but vary appreciably across different system contexts, policy stringencies, and leakage provisions (Caron, Rausch and Winchester 2015, Böhringer, Landis, et al. 2017).

3.2. Economic Impacts

In addition to environmental impacts, potential economic impacts through changes in electric sector costs are an indicator of potential broader societal impacts and a salient metric for policymakers.[7]

Figure 9. Incremental electric sector cost changes (billion $ net present value to 2050) for Canada by category scenario. Incremental electric sector costs are relative to the appropriate reference scenario and include changes in all operating, fuel, trade, and capital costs. Tax revenues and subsidy payments are not shown.

Figure 9 shows policy costs (i.e., the incremental net present value of the cost of power procurement across the time horizon) across the four Canadian carbon pricing scenarios. Overall policy costs are low relative to the total system cost. For instance, summing across all electric sector expenditures (including capital costs, fuel costs, trade, operation and maintenance costs), the NPV of total system costs

[7] Note that a metric like changes in macroeconomic consumption, for instance, would be a more comprehensive metric for societal economic impacts but requires a computable general equilibrium model to evaluate. Such assessments are left for future work along with distributional impacts of carbon pricing and leakage reduction provisions across households.

increases about $2.6 billion in Canada with carbon pricing, which is about 1% of reference scenario costs. Although national costs are low, economic impacts vary across provinces, as discussed in Section 3.3. As shown in Figure 3, carbon pricing leads Canada to switch its net trade position, and the combined loss in export revenue and increases in import purchases lead the largest policy-induced costs in Figure 9. Lower gas-fired generation and higher wind deployment in the "Tax" scenario result in higher net investment costs and lower fuel expenditures.

Leakage mitigation measures are second-best policy instruments, which means that potential environmental gains (as discussed in the previous section) should be compared with possible distortions in other outcomes. In the case of leakage measures, one of the most salient tradeoffs is between emissions reductions, leakage attenuation, and changes in abatement costs. Results in Figure 9 indicate that border carbon adjustments increase policy costs in Canada by 83%, while local generation constraints and output subsidies decrease policy costs in Canada by 40 and 76%, respectively. Recall from Section 3.1 that the tax scenario with BCA had the lowest net emissions of the four scenarios (Figure 4), which means that differences in cost correspond not only to differences in policy design but also to cumulative abatement effort. Similarly, the OBPS scenario, which shows the lowest net costs in Figure 9, involves the highest emissions as shown on Figure 4.

3.3. Regional Impacts

Policy impacts vary significantly by province. Figure 10 shows incremental policy costs for each Canadian model region. Impacts are most significant for provinces with higher natural gas shares in the reference scenario, which varies by province and scenario and underscores the importance of identifying the counterfactual reference scenario (Section 2.2). Although costs change with leakage measures, the spatial distribution of impacts is similar, and potential regional inequalities in mitigation cost are not exacerbated by border carbon adjustments, local generation constraints, or output-based subsidies.

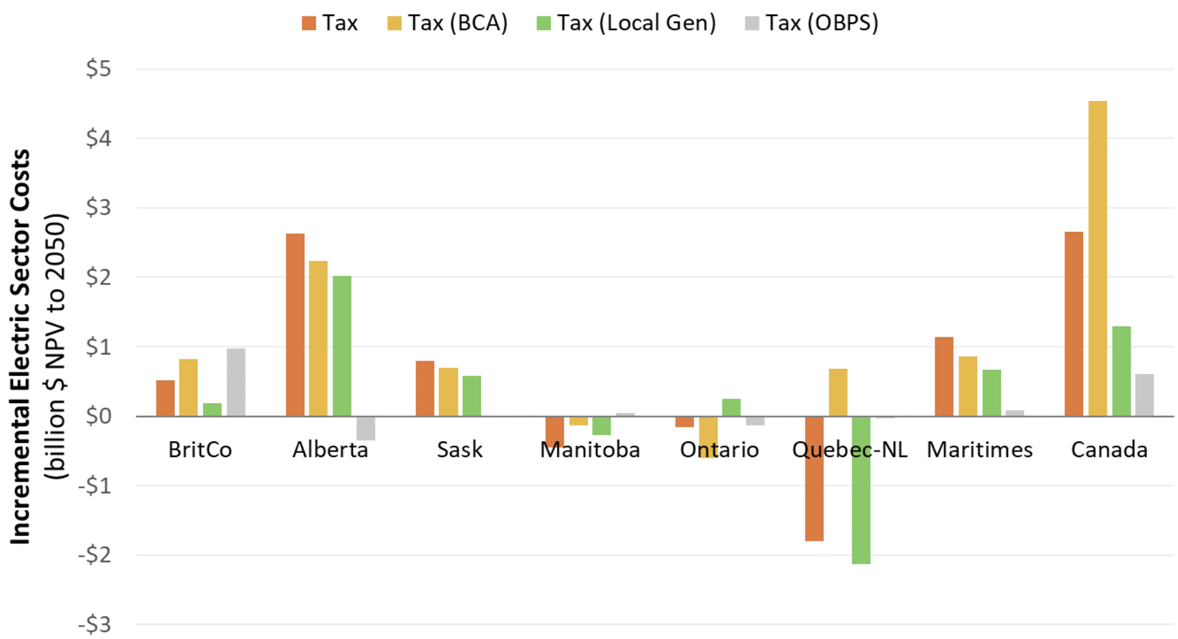

Figure 10. Incremental electric sector costs (billion $ net present value to 2050) by province and scenario. Incremental electric sector costs include changes in all operating, fuel, and capital costs, as well as imports (net of exports), but exclude tax revenues.

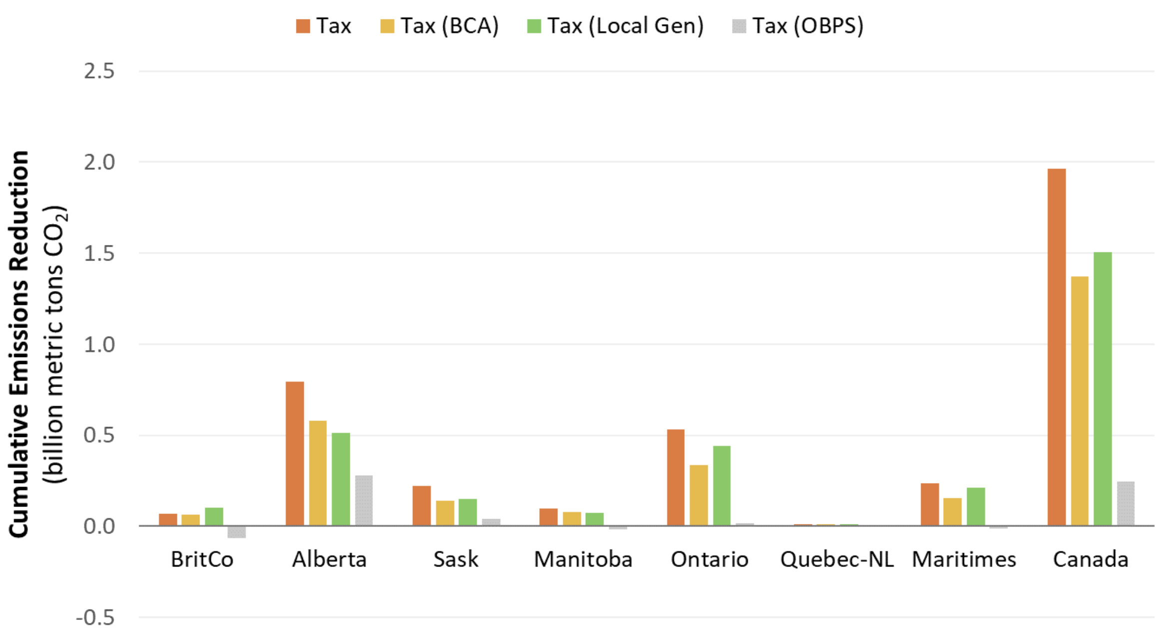

Figure 11. Cumulative emissions reduction (billion metric tons CO_2) by province and scenario. Emissions reductions are undiscounted.

Figure 11 illustrates how the distribution of policy costs is linked to relative mitigation efforts across provinces. Alberta contributes 40% of cumulative emissions reductions for Canada relative to the reference scenario, so it is not surprising that it bears the highest cost burdens as well. As existing capacity retires, Alberta replaces generation from retiring units with natural gas and wind in the reference scenario but relies on imports when carbon pricing is added. Note that Alberta is one of the largest regional grids in demand and cost terms (only Quebec and Ontario are larger), which also contributes to differences in impacts.

3.4. Effects of U.S. Carbon Pricing

Earlier scenarios assume that Canada adopts federal carbon pricing while the U.S. only adopts state-level policies. This section discusses a scenario where the U.S. adopts a federal carbon price with an equivalent stringency to the Canadian federal policy (Figure 1).

When the U.S. imposes a carbon price, adding a Canadian policy leads to significant reductions in Canadian emissions (especially since Canadian gas generation increases in response to a U.S. unilateral policy) but also increases in U.S. emissions, as U.S. imports from Canada decrease (Figure 20). However, since U.S. marginal generation has a higher fraction of renewables relative to gas when a federal CO_2 policy is in place, net and percentage leakage are lower than if the U.S. does not adopt a federal policy.

4. Discussion

Leakage – the reallocation of emissions from covered entities, sectors, and jurisdictions to uncovered or less stringently regulated ones – has become a more salient consideration for policymakers as difficulties with policy coordination and diverse preferences for regulation have given rise to subnational and subglobal policies. This analysis suggests that power sector emissions leakage from Canadian carbon pricing is likely and that it can be significant, especially when transmission investments and cross-border trade respond to economic drivers in the absence of leakage containment measures. Magnitudes of leakage vary based on assumptions about the market context (e.g., natural gas prices) and can range from 13% (in the high gas price scenario with border carbon adjustments) to 76% (in the lower gas price scenario without antileakage measures). Border carbon adjustments are shown to be an effective means of reducing leakage rates and may be even more effective in settings with extensive cross-border linkages like the U.S. and Canada than other international contexts. However, focusing on leakage rates alone ignores broader tradeoffs between economic and environmental outcomes, especially given how leakage mitigation provisions may increase electric sector costs or lead to higher Canadian emissions.

These results have several implications for policymakers, analysts, and other stakeholders. First, the analysis indicates that changes to Canadian electric sector policy will not significantly alter aggregate North American emissions (Figure 19). Not only does international leakage offset a fraction of domestic reductions, but the scale of Canada's emissions and its low power sector CO_2 intensity suggest that additional U.S. policy ambition and changes in Canadian emissions beyond the power sector would be necessary for North America's emissions trajectory to be more consistent with the Paris Agreement (Rose 2017). The low emissions intensity of generation in Canada across all scenarios facilitates electrification strategies for economy-wide decarbonization, which is left for future work.

Second, the finding that leakage containment measures can increase costs is more broadly indicative of tradeoffs between environmental and economic outcomes in policy design. Energy-economic modeling can help to quantify these tradeoffs, but stakeholders inevitably must settle on appropriate and acceptable compromises across these competing objectives. Models can quantify cost premia associated with non-first-best policies for emissions reductions and suggest policy design elements that should be considered to enhance cost-effectiveness (or to avoid unintended consequences). Note that this analysis focuses on border adjustment as a means to reduce emissions leakage and does not investigate competitiveness considerations (Kuik and Hofkes 2010, Cosbey, et al. 2019). For instance, the Green New Deal resolution proposes, "enacting and enforcing trade rules, procurement standards, and border adjustments with strong labor and environmental protections to stop the transfer of jobs and pollution overseas and to grow domestic manufacturing" (Ocasio-Cortez 2019).

Finally, the non-trivial emissions leakage observed in this analysis across scenarios (between 13% and 76% of the expected long-run decrease in regulated emissions) suggests that quantifying policy-induced economic and environmental impacts of Canadian carbon pricing requires consideration of potential cross-border impacts and a modeling framework that can evaluate endogenous changes in investment and dispatch in the U.S. and Canada. Evaluating and accounting for leakage effects in benefit-cost analysis is becoming ever more important as states and other subnational jurisdictions enhance their climate and energy policy ambitions unilaterally or with limited cooperation.

Future work should examine economy-wide responses to unilateral Canadian carbon pricing policies (EPRI 2018) and uncertainty about future policies and fuel prices (Bistline, Comello and Sahoo 2018). It is prima facie unclear whether the current analysis over- or under-estimates economy-wide leakage, though the assumed carbon pricing levels likely have incremental impacts on non-electric sectors.

Acknowledgments

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Appendix A: Model Description

The electric sector only version of EPRI's North American Regional Economy, Greenhouse Gas, and Energy (NA-REGEN) model represents detailed capacity planning and dispatch decisions simultaneously with state-based regions (Figure A.1). Each customizable-length time step (often five-year intervals) includes capacity investment, retrofit, and retirement decisions as well as dispatch for installed capacity over representative intra-annual hours. The intertemporal optimization structure of NA-REGEN determines investment and operational choices through 2050 while representing regional resource endowments, costs, inter-regional transmission, demand, and regulations. This appendix summarizes the main features and assumptions of the model, especially those relating to the experiments in this paper. Additional detail about the NA-REGEN is provided in EPRI (2018).

NA-REGEN provides customizable state or regional resolution, accounting for regional differences in policy, transmission, and demand. The regional configuration used for this study is shown in Figure 1. Although the model includes endogenous investments in inter-regional transmission and segment-level electricity trade across regions, NA-REGEN does not represent intra-regional transmission constraints.

Hourly renewable output and resource potentials are based on analysis and data by EPRI, AWS Truepower, and NASA's MERRA-2 dataset (Blanford, et al. 2018, EPRI 2018), which give synchronous time-series values with load. Figure 12 shows Canadian wind speed data on the MERRA-2 grid (0.625° longitude by 0.5° latitude).

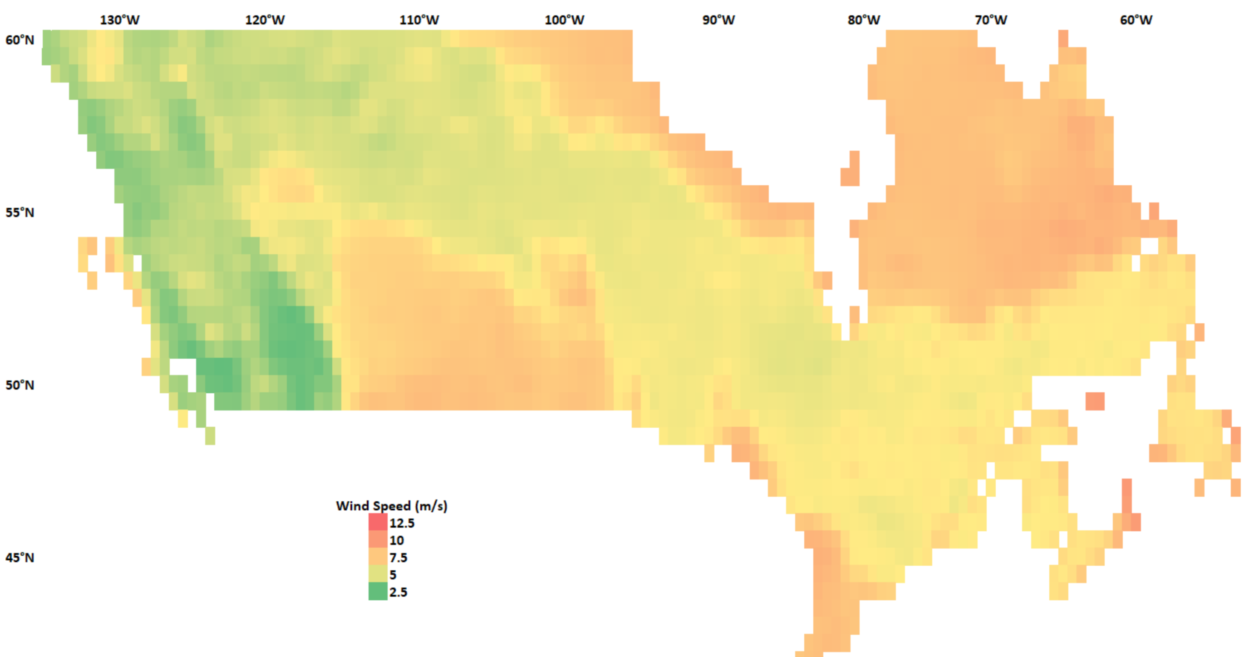

Figure 12. Average onshore wind speed in Canada at 100 meters between 1980 and 2016. Values based on analysis of NASA's MERRA-2 reanalysis dataset.

Technological cost and performance assumptions come from EPRI's Integrated Generation Technology Options report with more frequent updates for technologies like solar and wind. Default capital cost assumptions are shown in Figure 13, and other cost assumptions are detailed in the REGEN documentation (EPRI 2018).

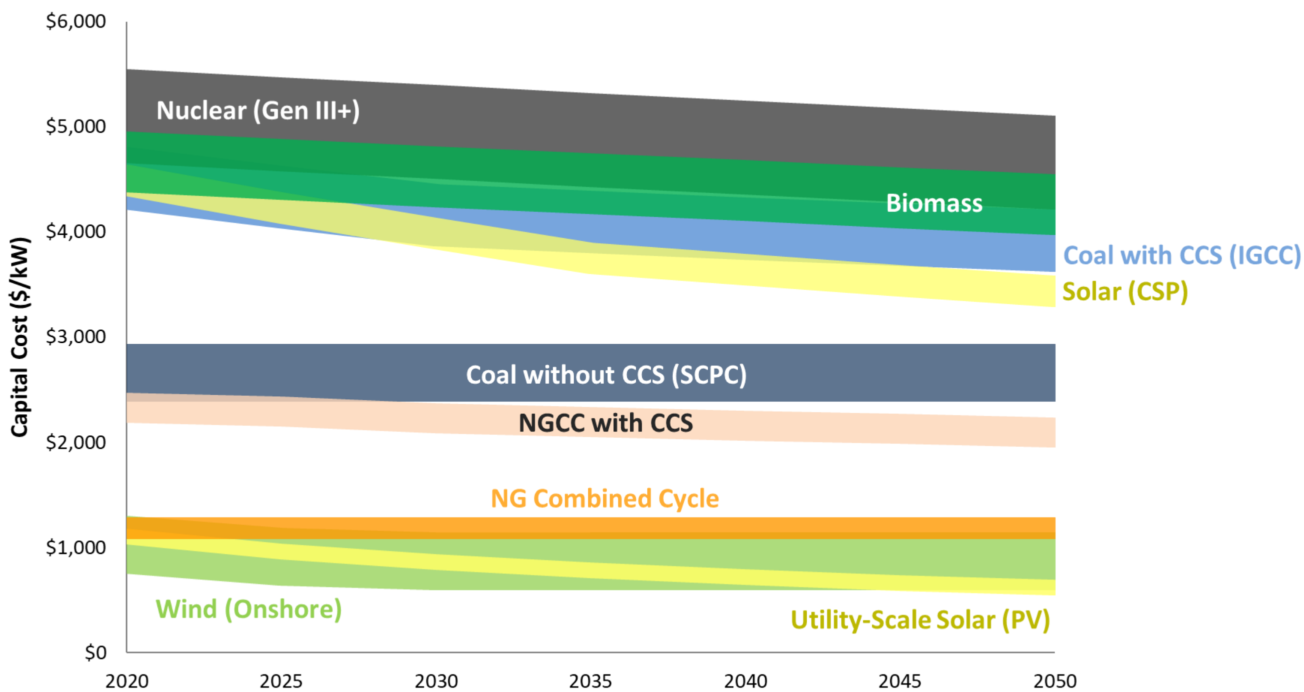

Figure 13. Capital cost ($/kW) trajectories over time in NA-REGEN. Ranges represent region-specific differences in cost.

NA-REGEN uses a bottom-up representation of capacity grouped into technology blocks within a region based on heat rates and dispatches these blocks across a range of intra-annual time segments. Joint variation in load, wind, and solar across regions is captured through the selection of so-called "representative hours" using an approach described in Blanford, et al. (2018). This novel feature more accurately captures the spatial and temporal variability of power systems, which are critical for evaluating asset investments and operations especially under higher renewable deployment scenarios. Power plant data come from the ABB Velocity and were last updated in June 2018, which includes projects in the development pipeline like variable renewable projects and the Site C Dam in British Columbia. Announced retirements for plants in the U.S. and Canada are also included. REGEN includes a reserve margin constraint, where the sum of firm capacity must be greater than or equal to the peak residual load plus a reserve margin (which is set at 15% by default). Contributions from renewable resources and dispatchable technologies vary by hour and season, and residual load (i.e., grid-supplied load less variable renewable output) is determined endogenously and varies by region, load shape scenario, and levels of wind and solar deployment.

Note that this analysis uses an electric sector only version of the REGEN model, so end-use sectors and their interactions with load shapes are not modeled explicitly. All hourly time-series data, including load and variable renewable resources, come from 2015. Annual load over time is exogenous and is based on values from U.S. Energy Information Administration's *Annual Energy Outlook 2018* (U.S. Energy Information Administration 2018) for U.S. states and the National Energy Board's *Canada's Energy Future 2016* (National Energy Board 2016) for Canadian provinces.

Appendix B: Scenario Assumptions

This appendix provides additional detail about scenario assumptions.

Fuel price trajectories come from the U.S. Energy Information Administration's *Annual Energy Outlook 2018* (U.S. Energy Information Administration 2018). Fuel prices are not responsive to changes in demand for these runs, though such feedbacks are possible using the integrated version of NA-REGEN. Delivered gas prices in the model include region-specific adders, which are calibrated to observed 2016 values and assumed to decline over time.

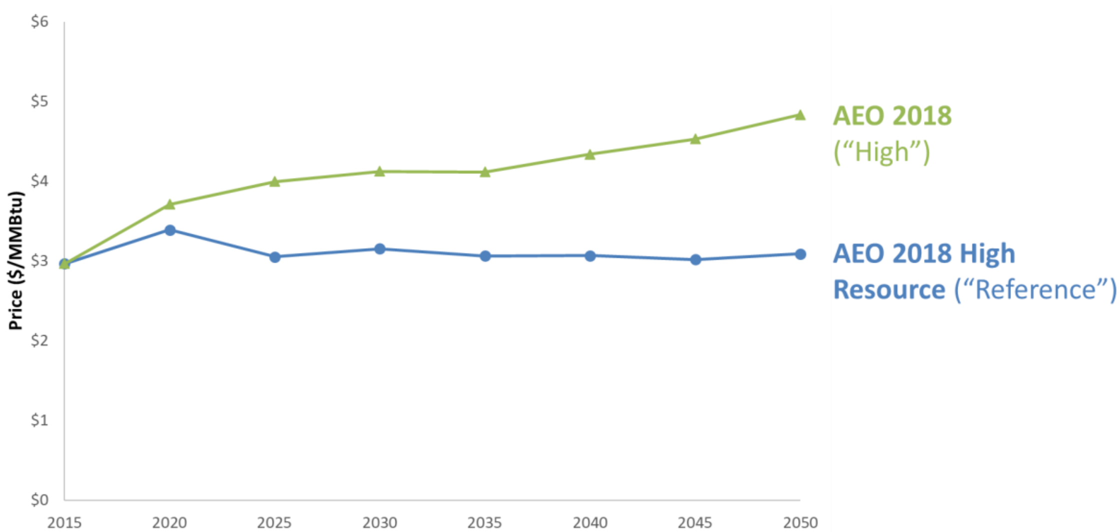

Figure 14. Henry Hub natural gas price sensitivities used in this analysis. Values shown are the average power producer's gas price in U.S. dollars per MMBtu.

Transmission between regions can be endogenously added with an assumed cost of $3.85 million per mile for a notional high-voltage line to transfer 6,400 MW of capacity. Note how, due to changes in flows across regions (with associated transmission losses) and different levels of new transmission investments, total national generation may vary across scenarios.

The Canadian federal carbon pricing backstop is implemented as a carbon levy on upstream fuels (Environment and Climate Change Canada 2017). For Canadian nuclear units (primarily in Ontario), announced retirement and refurbishment schedules are incorporated into the analysis. All Pickering units retire by 2025, and Bruce units 1 and 2 retire in 2043. Refurbishment schedules are taken from IESO data (Indepedent Electricity System Operator 2018), and refurbished units are assumed to unavailable during these years.

Appendix C: Emissions Intensity Calculation for Border Carbon Adjustments

Many measures have been proposed to reduce leakage associated with climate policy. The principal measures are border carbon adjustments, where imports from non-regulated (or under-regulated) jurisdictions are taxed at the emissions price of the regulated region (Hoel 1991). Border carbon adjustments are often relied on as tools when production in unregulated regions have higher emissions intensities and when a regulated region is a net exporter (Fell and Maniloff 2015). Other measures to reduce leakage include trade constraints, output-based allocations, and exemptions for trade-exposed industries. The literature suggests that it is difficult to rank order these anti-leakage measures, since their effectiveness is highly context-dependent and depends on considerations like relative emissions rates, elasticities of substitution, and consumption volumes (Fischer and Fox 2012). Border carbon adjustments can be attractive in leakage reduction and cost-effectiveness terms, which comes at the expense of equity considerations (Böhringer, Carbone and Rutherford 2012).

As described in Section 2.2, the leakage mitigation sensitivity that imposes a border carbon adjustment uses a tariff rate that is dynamically updated over time based on Canadian carbon price and emissions rate from a new NGCC unit. There are many methods and considerations for calculations emissions intensities on imported power, including whether marginal versus average rates are used (the former more accurately represent emissions rates, but the latter are simpler to calculate), dynamic versus static rates (the former adjust over time based on changing conditions, while the latter are easier to calculate), and temporal granularity for assessment (regardless of the method chosen, emissions intensities could be calculated on a sub-hourly basis, hourly basis, or something more aggregated). Different combinations for the above conditions are possible, but most entail tradeoffs between accuracy and administrative simplicity/cost (Cosbey, et al. 2019). An additional question is whether to include export subsidies in addition to import tariffs. The border carbon adjustment used here includes only import tariffs given the uncertain legal status of export subsidies under the World Trade Organization's General Agreement on Tariffs and Trade (GATT) (Cosbey, et al. 2019, de Cendra 2006) and due to the fact that the literature indicates measures with import adjustments only capture most of the BCA leakage reduction benefits (Böhringer, Balisteri and Rutherford 2012, Fischer and Fox 2012).

A uniform benchmark based on a new NGCC plant emissions rate is administratively simple and, as suggested by the calculations below, aligns with the marginal emissions intensity of U.S. generation. Table 2 shows changes in U.S. emissions and emissions intensity between the reference case without Canadian carbon pricing and the treatment scenario with Canadian policy. The marginal CO_2 intensity of power imports is the ratio of incremental U.S. CO_2 emissions to incremental U.S. generation between these two scenarios. Increased exports from the U.S. to Canada are mostly be supported by incremental NGCC output under reference gas prices, as shown in the left panel of Figure 6. An implicit assumption in this scenario is that U.S. exporters do not adjust the composition of generation to lower emissions liabilities associated with trade to the regulated region as firms might if exposed to the import tariff in the scenario with the border carbon adjustment.

Table 2. Change in U.S. emissions, generation, and CO_2 intensity over time. Values represent differences between the Canadian carbon pricing scenario and the corresponding reference.

	2020	2025	2030	2035	2040	2045	2050
U.S. Emissions Change (million tons CO_2)	40.2	59.2	31.7	38.3	33.9	47.0	41.30
U.S. Generation Change (TWh)	74.8	118.0	78.1	77.3	92.11	119.5	133.3
Import Intensity (ton/MWh)	0.54	0.50	0.41	0.50	0.37	0.39	0.31

Note that using the NGCC-based benchmark means that the intensity does vary across time (supporting a dynamic adjustment) and is in some cases higher than the NGCC intensity. Figure 6 shows that a portion of Canadian imports in early years are supported by coal and combustion turbine generation in addition to NGCC, which leads to higher intensities in 2020 and 2025. However, increased NGCC output represents the bulk of the response in the near years, and almost all the response in the out years. Thus, using an intensity based on the emissions rate from a new NGCC unit to set the benchmark captures ex-post values well and is considerably easier to administer than a dynamically updated intensity calculated in real time.

Appendix D: Additional Results

This section provides additional reporting related to the analysis.

Figure 15 shows Canadian generation by technology over time across the five core policy scenarios under high gas price conditions. Relative to the reference gas price scenario (Figure 3), Canadian NGCC generation falls, while generation from renewables rises.

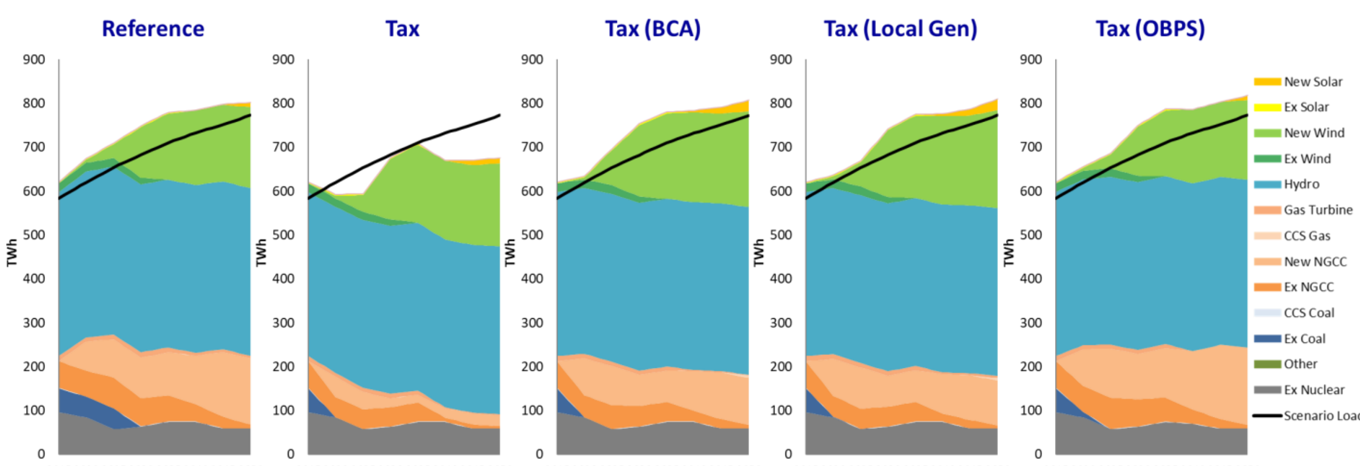

Figure 15. Canadian generation (TWh) by technology and scenario under high natural gas prices. Detailed descriptions of the scenarios are provided in Section 2.

Figure 16 shows the U.S. generation mix across the five main scenarios assuming reference gas prices. Canada's CO_2 emissions intensity of generation is roughly a third of U.S. values in 2015. New capacity additions over time are dominated by natural gas units (specifically NGCC without carbon capture), wind, and solar. Figure 17 shows the same scenarios with higher gas prices, which leads to higher wind and solar generation.

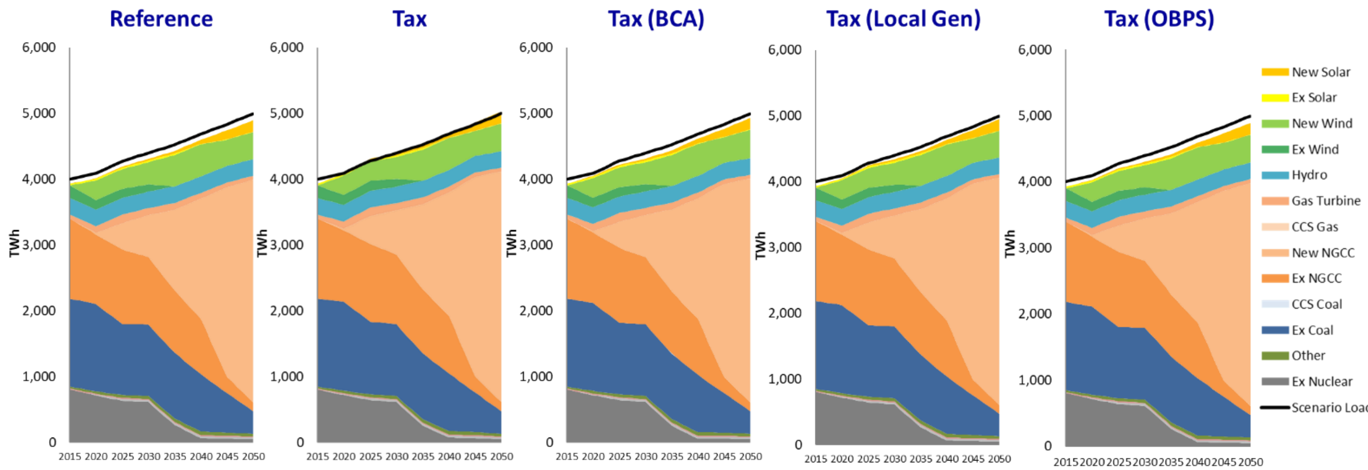

Figure 16. U.S. generation (TWh) by technology and scenario under reference natural gas prices. Detailed descriptions of the scenarios are provided in Section 2.

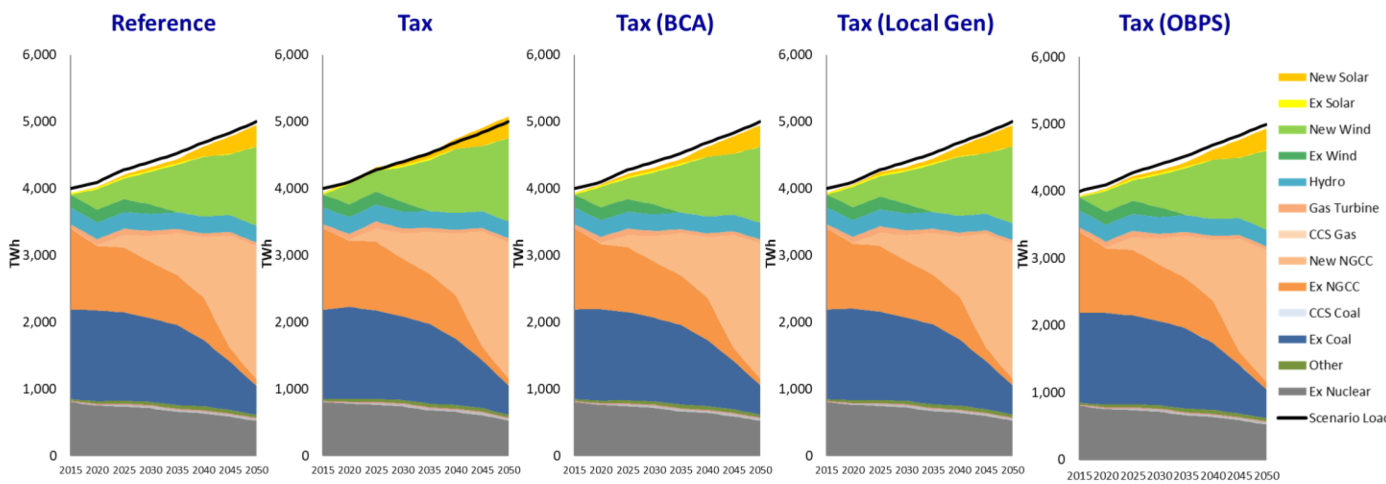

Figure 17. U.S. generation (TWh) by technology and scenario under high natural gas prices. Detailed descriptions of the scenarios are provided in Section 2.

The main text focuses on cumulative emissions metrics over time. Figure 18 and Figure 19 show CO_2 emissions trajectories over time by scenario for Canada and the sum of Canada and U.S., respectively.

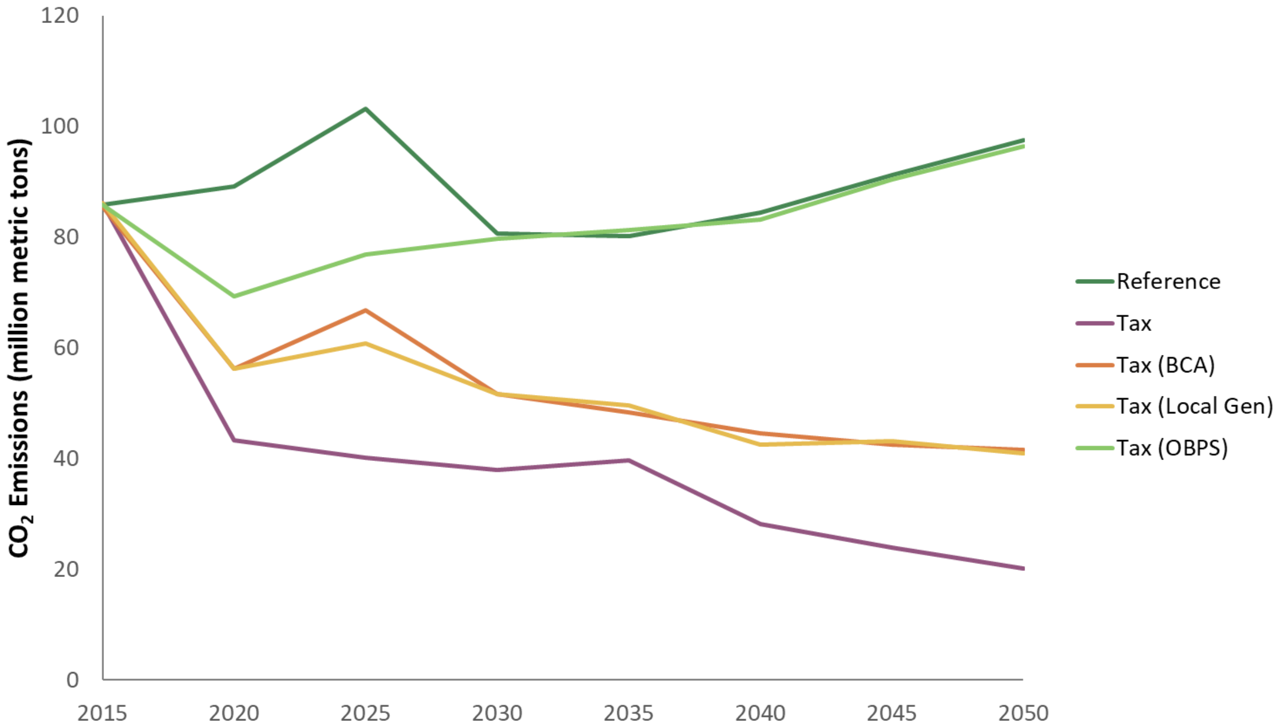

Figure 18. Canadian CO_2 emissions by scenario under reference natural gas prices.

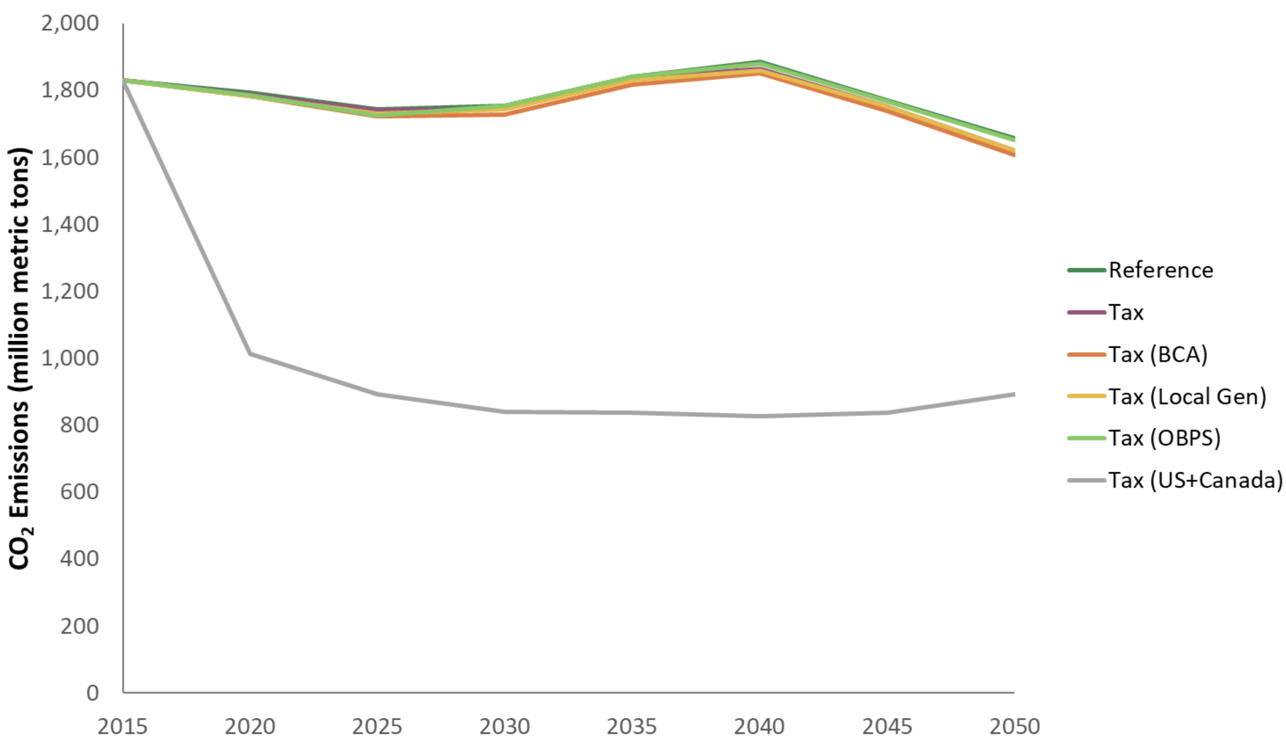

Figure 19. U.S. and Canadian CO_2 emissions by scenario under reference natural gas prices.

Figure 20 shows cumulative CO_2 emissions changes and leakage under cases without and without U.S. federal carbon pricing.

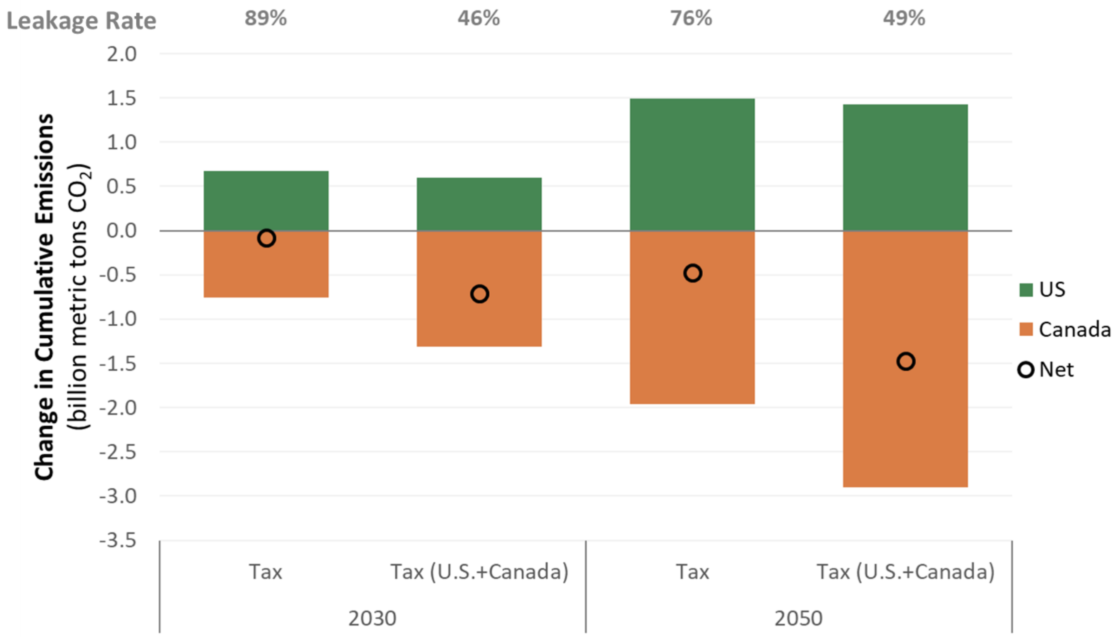

Figure 20. Change in cumulative CO_2 emissions through 2030 (left) and 2050 (right) by scenario relative to the reference case. Leakage rates shown above the bar chart are defined by Equation 1. Cumulative emissions reductions are undiscounted.