WHEN THE PRICE IS RIGHT

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How B.C.'s carbon tax could cost-effectively reduce methane pollution in the oil and gas sector

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EXECUTIVE SUMMARY

British Columbia's carbon tax works, but it is not being applied to harmful emissions from the province's largest industrial polluter. Cutting methane emissions from the oil and gas industry is one of the cheapest, fastest, most effective climate solutions, readily available with identified technology.

This report models two feasible approaches to applying British Columbia's carbon tax to methane emissions from oil and gas to drive down emissions. Our results show that these emissions reductions can be achieved more cost-effectively than in other sectors of the economy and without imposing a substantial competitive disadvantage on the province's oil and gas industry.

Recommendations include:

1. Forming a technical committee or scientific review panel to provide more detailed advice on how B.C.'s carbon tax can be implemented to control methane emissions
2. Allocating funding to improve the accuracy of oil and gas provincial inventory data and to independent direct monitoring of emissions using vehicle-based, aerial, and/or emerging measurement technologies
3. Applying B.C.'s carbon tax to methane emissions using an inventory-based approach
4. Retaining regulations as an essential methane mitigation tool to work alongside the carbon tax
5. Phasing the application of the tax to the sector's methane emissions over three to six years, in increments of \$5 to \$10/tCO_2e per year and set implementation date in B.C. budget 2020 and fiscal plan
6. Tying the conversion from methane emissions to tCO_2e using the most recent and more accurate IPCC estimates for the warming potential of methane

This report builds on recent research conducted by St. Francis Xavier University and the David Suzuki Foundation, published in the peer-reviewed journal *Atmospheric Chemistry and Physics*, which found that methane emissions from the oil and gas industry are a much bigger problem than reported.

Reducing methane emissions offers large, cost-effective climate mitigation benefits over the short term because methane has a global warming potential 84 times greater than carbon dioxide over a 20-year time frame. The International Energy Agency reports that taking global action to reduce these emissions would have the same climate benefit by 2100 as eliminating all coal plants in China.

British Columbia and Canada have committed to reducing methane emissions in the oil and gas sector by 40 to 45 per cent by 2025. In 2017, the B.C. government committed to expanding the carbon tax to include methane emissions. B.C. has an opportunity to demonstrate its climate leadership if it chooses to take on this innovative approach to turning down the dial on methane pollution.

INTRODUCTION

This report focuses on evaluating how British Columbia's carbon tax might be applied to methane emissions from oil and gas to drive emissions reductions.[1] It is intended to support provincial efforts to reduce B.C.'s greenhouse gas emissions.

Broadening the carbon tax to cover methane emissions would complement recent regulations focused on reducing methane emissions from the upstream oil and gas industry. It supports the CleanBC blueprint for reducing the province's GHG emissions while supporting a strong and diversified low carbon economy.[2] It supports Canada's commitment to reduce methane emissions from the oil and gas sector by 45 per cent by 2025. Lastly, one further motivation for this study is the 2017 Confidence and Supply Agreement between the Green Party and the NDP, which enabled the current provincial government's mandate. This agreement requires that the government expand the B.C. carbon tax to cover fugitive emissions.[3]

Reducing methane emissions offers large, cost-effective climate mitigation benefits over the short term because methane has a global warming potential 84 times greater than carbon dioxide over a 20-year time frame.

The Province of British Columbia acknowledges the urgency of addressing climate change and has legislated emissions targets that include a 40 per cent reduction from 2007 levels by 2030 and a 60 per cent reduction by 2040.[4] Climate change is already affecting B.C.'s ecosystems, with extreme weather events becoming more common and coastal communities having to grapple with rising sea levels. In recent years, British Columbia has suffered from floods, droughts and forest fires exacerbated by climate change.[5] As a province with a deep cultural attachment to the Pacific Ocean and important fishing and tourism industries, the increased stress faced by marine ecosystems resulting from higher ocean acidity and lower oxygen levels is of particular concern.[6]

Reducing methane emissions offers large, cost-effective climate mitigation benefits over the short term. Unlike carbon dioxide, which resides in the atmosphere for over a century, methane is a short-lived climate pollutant that disappears from the atmosphere more quickly but has a global warming potential

1 Note that this report is narrowly focused on the oil and gas sector's methane emissions and does not consider other sources of methane, such as emissions from landfills or livestock.
2 Clean B.C. section 2.4.4 Reducing methane emissions from natural gas production, offers insight into key provincial concerns: "Using new and upgraded technologies and leak detection and repair programs, methane emissions can be reduced while keeping natural gas production economic for companies." "…we will be able to calibrate our response to ensure we capture the most methane for the least cost, keeping the sector economic while reducing carbon pollution from major emitters."
3 See section 2a(i) of the Confidence and Supply Agreement.
4 See Section 2(1) of the Climate Change Accountability Act.
5 Ministry of the Environment (2016)
6 Ministry of the Environment (2016)

84 times greater than carbon dioxide over a 20-year time frame, and 34 times greater on a 100-year time frame.[7] The concentration of methane in the atmosphere has risen from a pre-industrial 722 parts per billion to above 1,860 in 2019.[8] Because of its potency, methane is currently responsible for 20 per cent of already observed changes to Earth's climate, even though it is emitted in smaller amounts than carbon dioxide.[9]

B.C.'s oil and gas sector has grown rapidly in recent years, especially natural gas production, which has risen from 31.9 billion cubic metres in 2007 to 58.9 billion in 2018. The province has also been encouraging development of an LNG export industry. If this industry comes online as projected around

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2025, accelerated development of B.C.'s natural gas fields can be anticipated.[10] Recent research suggests methane emissions from the oil and gas sector are much higher than reported in the official inventory.[11] If methane emissions are higher than about three per cent of produced gas, then power produced using natural gas has a climate impact equivalent to or worse than a modern coal plant.[12]

Commitment to reduce methane emissions

In March 2016, the governments of Canada and the United States committed to reduce methane emissions from the oil and gas sector by 40 to 45 per cent of 2012 levels by 2025. This commitment was reaffirmed in the Pan-Canadian Framework on Clean Growth and Climate Change,[13] of which B.C. is a signatory. The Government of B.C.'s reduction target is 45 per cent by 2025, relative to 2014 levels.

To meet these targets, the federal government put in place regulations in 2018 under the *Canadian Environmental Protection Act* aimed at cutting methane pollution from the oil and gas industry by 40 to 45 per cent by 2025.[14] The federal regulation allows provincial governments to draft their own regulations to achieve the same or better results, such that once an equivalency agreement is reached with

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7 Throughout this report, we use warming potentials for methane drawn from the IPCC's Fifth Assessment Report, accounting for interactions with increased CO_2 concentrations.

8 Dlugokencky (2019)

9 Per the IPPC's Fifth Assessment Report: https://ar5-syr.ipcc.ch/topic_observedchanges.php#figure_1_6

10 See page 27, National Energy Board (2016)

11 Atherton et al. (2017); Johnson et al. (2017); Sheng et al. (2017)

12 Alvarez et al. (2012)

13 See page 21: "1. Reducing methane and HFC emissions: The federal government will work with provinces and territories to achieve the objective of reducing methane emissions from the oil and gas sector, including offshore activities, by 40-45% by 2025, including through equivalency agreements."

14 *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* SOR/2018-66

the province, the provincial regulations apply. The B.C. Oil and Gas Commission deposited its methane regulations in December 2018.[15]

At the time of writing, it is not clear which set of regulations will eventually apply because Environment and Climate Change Canada is currently evaluating equivalency, and the necessary regulatory steps to stand down the federal regulations have not been fulfilled. For the purpose of analysis, we have assumed that the provincial regulations will apply. In our view this is the more conservative case, since the BCOGC regulations set less stringent requirements for leak detection and repair (LDAR).[16] Furthermore, as discussed in detail in later sections, this study recommends implementing methane pricing only in addition to these regulations, not as a replacement for them.

The British Columbia carbon tax

The B.C. government introduced North America's first broadly applicable carbon tax in 2008. The tax was initially set at $10 a tonne and increased $5 per year until 2012 when it was frozen at $30 a tonne. In 2017, annual $5 increases resumed, and it has now reached $40 a tonne and is scheduled to reach $50 a tonne in 2021.[17]

While the tax is broadly applied throughout the economy, covering about 70 per cent of the province's emissions, it does not apply to the oil and gas sector's methane emissions. Consequently, prior to the announcement of regulations, there has been limited pressure or incentive for the sector to reduce its emissions.

It should be noted that one incentive to mitigate methane emissions was the ability for projects that reduced methane emissions in B.C.'s oil and gas industry to generate offsets for use in the British Columbia Greenhouse Gas Emission Offset Portfolio (to meet carbon-neutral government requirements).[18] A second initiative to spur mitigation was the ability of firms to apply under a competitive process for royalty credits that could offset up to 50 per cent of the cost of eligible projects in methane mitigation under the Clean Infrastructure Royalty Credit Program.[19]

To protect industry competitiveness in the face of a rising carbon tax and to promote innovation in low-emission technologies, in 2017 the province announced the CleanBC Program for Industry.[20] This program is intended to recycle the portion of the carbon tax above $30 a tonne back to large regulated industrial operations in a manner that retains the incentive to reduce emissions. As described by the province, the program has two initiatives:

15 B.C. Reg 286/2018, made under the *Oil and Gas Activities Act*, amends the provincial *Drilling and Production Regulation.*

16 Comments on the Draft Equivalency Agreement for the B.C. Methane Regulations, David Suzuki Foundation, Clean Air Task Force, Environmental Defence, Environmental Defense Fund, Pembina Institute: https://davidsuzuki.org/science-learning-centre-article/comments-on-the-draft-equivalency-agreement-for-the-b-c-methane-regulations

17 For further details regarding the B.C. carbon tax, see: https://www2.gov.bc.ca/gov/content/environment/climate-change/planning-and-action/carbon-tax

18 Government purchases and retires such offsets at a value of below $25/tonne CO_2e – see: https://www2.gov.bc.ca/gov/content/environment/climate-change/industry/offset-projects

19 In 2018, $9.7 million in royalty credits were available to defray the costs of investments that would reduce the venting of methane emissions – see: https://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/oil-gas-royalties/clean-infrastructure-royalty-credit-program

20 Initially, the program was named the Clean Growth Incentive Program. It was renamed in 2019.

- an Industrial Incentive that reduces carbon-tax costs for operations meeting world-leading emissions benchmarks, and
- a Clean Industry Fund that invests some industrial carbon tax revenue directly into emission-reduction projects, helping to make our traditional industries cleaner and stronger.[21]

This study evaluates the application of the carbon tax to oil and gas methane emissions while accounting for how the CleanBC Program for Industry will mitigate the sector's overall costs of reducing emissions, since some of the carbon tax proceeds will be made available to industry to defray the costs of investments in mitigation.[22]

Converting a carbon price to a price on methane

One important consideration for applying B.C.'s carbon tax to methane emissions is the conversion factor from CO_2 emissions. We note that B.C.'s Provincial Greenhouse Gas Inventory uses an outdated 100-year warming potential of 25, which is drawn from the IPCC's Fourth Assessment Report. This report uses an updated 100-year warming factor of 34 from the IPCC's Fifth Assessment Report, which better reflects the consensus of current climate science. In other words, the best available scientific evidence suggests converting one tonne of methane to 34 tonnes of CO_2-equivalent (tCO_2e) emissions, if we care about warming impacts over the next century. As the science surrounding the climate impacts of methane is likely to evolve, this report strongly recommends tying the conversion factor used for a methane tax (and for the Provincial Greenhouse Gas Inventory) to the most recent IPCC estimate.[23] Presently, this conversion factor implies that for every $5 per tonne CO_2e increment to the carbon tax, the price of methane per tonne rises by $170 (34 x $5), rather than $125. At B.C.'s current carbon tax of $40 a tonne CO_2e, the carbon tax if applied per tonne of methane would be $1,360. The social cost of a tonne of methane emitted to the atmosphere has been estimated at an order of magnitude larger than its market price as natural gas.[24]

The economic argument for taxing methane emissions

There is a general consensus among economists that pricing greenhouse gases is the most cost-effective approach to driving emissions reductions.[25] A price on emissions — either in the form of an emissions tax or permit trading program — gives firms and households an incentive to reduce emissions and allows them the flexibility to find the most efficient means to do so. It also encourages innovation in technologies

21 See page 40 of Province of British Columbia (2018)

22 Note that for this analysis, we consider sector-wide impacts of the CleanBC program for industry, rather than the impacts on individual firms. This is because firm-level impacts will be difficult to predict: some firms with leading practices and/or innovative emissions reductions projects will stand to gain more of the benefits from the program and the recycled carbon tax revenues, while firms lagging on environmental performance or lacking qualifying projects may see fewer benefits.

23 While an argument could be made for adopting the 20-year warming factor, which is significantly higher, using the most recent 100-year warming factor provides a less disruptive (but still scientifically accurate) starting point for the first wave of policies regulating methane emissions.

24 The social cost of one tonne of methane is about $1,800 using the EPA's estimate for the social cost of carbon and using the latest IPCC warming potential of 34. The wholesale value of one tonne of methane is about $180 assuming the average B.C. gas price over the past five years of $118/10^{3}m^3, and converting to a per tonne equivalent using the density of methane as 0.6557 kg/m^3 (if 1000 m^3 weighs 655.7kg and has a value of $118, one tonne is worth $118 * 1000 / 655.7 = $180).

25 Nordhaus (2019); Stern (2007); Pearce (1991)

that have lower emissions. As of 2017, more than 65 jurisdictions were pricing greenhouse gas emissions, covering about 15 per cent of total global emissions, and this proportion is growing.[26]

Putting a price on pollution is consistent with the "polluter pays" principle. It gives companies the incentive to pursue innovative solutions and it favours increased efforts to maintain and repair equipment without dictating the use of specific technologies or processes. Expanding the carbon tax to the oil and gas sector's methane emissions would also increase fairness because it would treat this sector the same as other sectors of the economy.[27] Furthermore, the cost of mitigation per tCO_2e of methane is relatively inexpensive compared to other mitigation options in the economy, implying that effective climate policy should take advantage of this low-hanging abatement fruit.[28] Unlike other greenhouse gases, methane is also an energy source. It is the primary constituent of natural gas. When the upstream oil and gas industry reduces the amount of methane lost to the atmosphere, it can recover part of the costs by selling the product. Firms have a monetary incentive to avoid emitting even in the absence of an emissions tax.

Over the past few years, wholesale gas prices in B.C. have averaged around $118 per thousand cubic metres, which works out to about $5 per tonne of CO_2-equivalent emissions.[29] This means it is worthwhile for firms to expend up to $5 to prevent one tCO_2e of methane from escaping into the atmosphere if they can thereby sell the conserved gas. According to standard economic theory, abatement measures that cost less than $5 per tCO_2e of captured gas will be undertaken by firms, while those that cost more than $5/$tCO_2e$ will not be undertaken. However, B.C.'s carbon tax is $40/$tCO_2e$ as of writing and will reach $50/$tCO_2e$ in 2021. If this tax is applied to methane emissions, firms will then be incentivized to capture all potentially emitted gas that can be abated for less than the sum of the market value of conserved gas plus the carbon tax, or $55/$tCO_2e$.[30] Various assessments of the techno-economics of abatement have shown that there are many mitigation opportunities below both the federal price on carbon in backstop jurisdictions ($20/tonne CO_2e as of 2019) and the provincial price.[31]

Methane regulations passed by the Government of Canada and/or those put in place by the B.C. Oil and Gas Commission are intended to result in a 45 per cent reduction in methane emissions from the oil and gas sector. However, recent economic and engineering studies predict that about 75 to 80 per cent of methane emissions from natural gas infrastructure could be cost-effectively mitigated.[32] These studies directly model firms' flexibility to implement different equipment upgrades and improved operational practices to reduce emissions on a facility-by-facility basis, which is representative of the effect of an emissions tax.

26 See: https://carbonpricingdashboard.worldbank.org
27 Note that there are legitimate reasons to offer some form of relief from carbon pricing (e.g., the federal Output-Based Price System is designed to address competitiveness concerns for emissions intensive, trade-exposed sectors, while ensuring carbon emissions are priced at the margin). See: https://institute.smartprosperity.ca/content/technical-design-federal-output-based-pricing-system
28 An anonymous reviewer noted that the regulatory approach has prevailed until now due to data uncertainties. We agree with this assessment, but also observe that capabilities to detect and measure methane have greatly improved in recent years, enabling governments to deploy economic instruments to accelerate mitigation.
29 Given average wholesale prices of $118/1000m^3 and converting given a density of methane of 0.6557 kg/m^3 and the IPCC's conversion factor of 34 for methane to CO_2e, the cost to industry of emitting natural gas in terms of lost revenue is equivalent to a carbon tax of $180/tonne of methane or $180/34 = $5/tonne CO_2e.
30 While the general economic principle that decision-makers (such as firms) balance marginal costs with marginal benefits is well-established, in practice, there are a number of potential market failures that could cause a divergence from theoretically optimal behaviour.
31 E.g. ICF (2015); McCabe et al. (2015)
32 Marks (2019); Tyner & Johnson (2018); Mayfield et al. (2017)

To offer a concrete example, the regulations require firms to install zero-emitting pneumatic pumps at wells beginning operations in 2022 or later. It is likely that existing wells will be excluded because the cost of requiring firms to replace pneumatic pumps at *all* existing wells may exceed the benefits. However, for many existing wells with high output and/or high emissions, this equipment upgrade may be highly cost-effective. By adjusting firms' incentives to mitigate emissions to incorporate external climate costs, then allowing them flexibility to abate only where it is efficient to do so, an emissions tax can achieve additional cost-effective abatement beyond the scope of traditional regulations.

A price on emissions — either in the form of an emissions tax or permit trading program — gives firms and households an incentive to reduce emissions and allows them the flexibility to find the most efficient means to do so.

Understanding the oil and gas sector's methane emissions

According to provincial figures in the Provincial Greenhouse Gas Inventory, the oil and gas sector emitted 74.5 kt of methane in 2016, which corresponds to 1.86 Mt of CO_2e under the warming potential for methane used by the inventory.[33] However, several lines of evidence suggest that the provincial GHGI underestimates or does not capture some emissions sources.[34] The oil and gas sector's methane emissions can be placed in three main categories:

- **Fugitive (unintentional) emissions:** leaks from equipment (e.g., leaky valves or hatches stuck in open position).
- **Vented emissions:** methane released because of equipment design (e.g., pneumatic valves that use gas pressure in the course of operation or vented from tanks after flashing out of oil due to the drop in pressure when oil is moved to the tank) or due to operational procedures (e.g., well completion and maintenance).
- **Incomplete combustion:** methane used as a fuel or that was routed to a device to destroy it (e.g., a flare or heater), but lost to the atmosphere due to incomplete combustion.

A further factor that requires attention in evaluating the application of the carbon tax to the oil and gas sector is that monitoring has shown that a small number of facilities can be classified as super emitters, whereby abnormal process conditions lead to large, unintentional releases to the atmosphere. Such sites — 20 per cent of surveyed sites in one study of the Red Deer region in Alberta — can be responsible for the majority of overall emissions from facilities in the region.[35]

33 See: https://www2.gov.bc.ca/assets/gov/environment/climate-change/data/provincial-inventory/2016/2016_provincial_inventory.xls – Note that 25 is the warming potential multiplier used in the provincial inventory. This warming potential is lower than reported in the most recent scientific literature, which suggests 34 or more, implying 2.53MT of CO_2e.
34 Werring (2018); Atherton et al. (2017)
35 Zavala-Araiza (2018)

A number of technologies for mitigating emissions are available to the industry. These are described and evaluated in detail in other studies.[36]

HOW TO APPLY B.C.'S CARBON TAX TO METHANE EMISSIONS

If implemented, the application of B.C.'s carbon tax to methane emissions could substantially reduce the province's greenhouse gas footprint. Additionally, as we demonstrate in the following section, it could achieve this without imposing a substantial competitive disadvantage on the province's oil and gas industry. However, methane emissions from the natural gas supply chain are qualitatively different from the CO_2 emissions from fossil fuel combustion currently covered by B.C.'s tax. This would be a pioneering effort to use emissions pricing to manage this emissions source, which means that B.C. has an opportunity to demonstrate its leadership in addressing climate change and that designing the tax effectively requires special attention.[37] In this section, we will begin by describing a key consideration for designing an effective tax and proceed to outline two potential approaches for applying a tax to this unique emissions source.

Overcoming the measurement challenge

For an emissions tax to achieve efficient pollution abatement, there must be a sufficiently accurate and verifiable measure of emissions to tie it to. For carbon dioxide emissions from fossil fuels, this is relatively straightforward: CO_2 emissions from power plants and factories can be tracked using continuous emissions monitoring sensors placed in smokestacks, and CO_2 emissions from vehicles can be assessed to fuel suppliers based on the carbon content of the fuels they sell.

Unfortunately, because methane emissions are emitted from many different sources in a variety of different ways, comprehensive and continuous monitoring is prohibitively costly at this time.[38] However, this does not imply that taxing methane is impossible until measurement costs decline. Here, we identify

36 I.e. ICF (2015)
37 Under Alberta's recently revoked carbon levy, methane was taxed as if it were CO_2 (i.e. a 1:1 conversion that did not reflect actual global warming potential), greatly diluting the price signal. Note that fugitive emissions from the oil and gas sector were not subjected to the levy. Alberta's carbon pricing system for large industrial emitters, the Carbon Competitiveness Incentive Regulation, applied to methane emissions for producers of 100,000 tonnes of CO_2e (see Gorski and Kenyon, 2018). Although a tax on methane emissions has not yet been attempted in the U.S., a number of recent studies have explored this policy in the context of the U.S. gas industry, including Mayfield et al. (2017) and Munning & Krupnick (2017).
38 "Measurement" or "monitoring" in this context means quantifying emissions, as opposed to simply detecting large sources (which is considerably less costly, but would not be useful for emissions pricing).

two potential approaches for applying an emissions tax in the face of this measurement challenge: an inventory-based approach and a sampling-based approach.[39]

OPTION 1: An inventory-based approach

Under an inventory-based approach, the carbon tax would be assessed based on facility-level estimates of emissions constructed using equipment counts, characteristics and emission factors, and records of firm activities in well completion, processing and maintenance.[40,41] The current inventory of methane emissions in British Columbia is the provincial GHGI.[42]

The biggest advantage of this approach is that it would be built on an existing program, which may reduce administrative costs of implementation. Although there are many ways in which B.C.'s current inventory might be improved, the basic legal framework surrounding how emissions are reported is already in place. Furthermore, verifying which types of equipment are installed at a facility would make auditing fairly straightforward. To the extent that emissions are captured effectively by the inventory, this approach would access the efficiency benefits of emissions pricing.

The biggest disadvantage with this approach is that current inventories are known to systematically underreport actual emissions. For example, a recent scientific measurement study of methane emissions from oil and gas infrastructure in B.C. estimated emissions to be 2.1 times greater than the level reported to the provincial GHGI.[43,44] While certain components of the inventory could be improved (for example, by updating equipment emission factors), other emission sources are inherently hard to capture using this methodology (for example, failure to properly seal a storage tank hatch). Generally speaking, inventories do a fairly good job of capturing most types of expected process emissions from equipment such as pneumatic controllers and compressors but struggle to effectively capture emissions from unintentional leaks, including the more substantial equipment and operational failures that lead to "superemitting" facilities.[45]

Additionally, for those sources it did cover, applying the carbon tax based on an inventory approach would only partially capture the efficiency benefits of emissions pricing. Rather than being incentivized directly to reduce their emissions by any means available to them, firms would instead be incentivized to install equipment that has lower official emission factors and engage in emission-reducing behaviours that

39 A third approach would be applying the tax based on output — in other words, tying the tax to production at a well or throughput for a compression station/processing plant multiplied by a common assumed emission factor for each facility type. This approach would effectively incentivize firms to produce less natural gas without incentivizing them to engage in cost effective methane abatement, which runs counter to the intended efficiency benefits of emissions pricing. We therefore strongly recommend against taxing methane based on facility output.

40 "Facilities" in this document refer to individual wells, multi-well batteries, gathering infrastructure sites, processing plants or compression stations.

41 This approach is similar to the "Tax with Default Leakage Rates" option proposed by Munnings and Krupnick (2017). Their approach additionally allows firms to petition the regulator to demonstrate lower emission rates at their facilities, which may be worth further consideration if this strategy is pursued in B.C.

42 The current threshold for reporting for most facilities is 10,000 tCO_2e/year, with auditing for facilities over 25,000 tCO_2e/year. We do not assess whether these same thresholds would be appropriate under an inventory-based methane tax in this report.

43 Atherton et al. (2017)

44 Another recent study estimated that the U.S. EPA's Greenhouse Gas Inventory, which is based on a more thorough inventory methodology than the B.C. inventory, understates true emissions by about 60 per cent (Alvarez et al., 2018). That study concluded that underreported emissions are primarily due to equipment malfunctions, highlighting the need to impose strong mandates on leak detection and repair if an inventory-based approach to taxing methane is implemented.

45 Zavala-Araiza et al. (2017)

are incorporated into the inventory. Whether firms are actually undertaking cost-effective abatement measures would therefore depend on the accuracy with which regulators are able to identify and quantify available abatement opportunities. For abatement through investments in lower-emitting equipment, emission factors would need to be accurate under real operating conditions for as many different equipment types as possible. Abatement through improved operating practices (such as increased frequency of LDAR or procedures for double-checking hatches and seals) would either be captured very roughly by an inventory framework or excluded altogether.

Despite these shortcomings, an inventory-based approach would almost certainly result in a substantial amount of cost-effective abatement beyond what can be achieved using conventional regulations alone. Potential abatement measures that are likely to be effectively incentivized by this approach include retrofitting wet-seal compressors with dry seals, replacing pneumatic devices with instrument air devices in locations that have access to grid power, choosing lower-bleed pneumatic devices when instrument air is not available, and installing vapour-recovery systems for compressors and storage tanks.

Under an inventory-based approach, the carbon tax would be assessed based on facility-level estimates of emissions constructed using equipment counts, characteristics and emission factors, and records of firm activities in well completion, processing and maintenance.

While these emission sources are now partially addressed by the recently introduced equipment mandates and performance standards, an inventory-based approach would increase their deployment to closer to the optimal levels. And because firms are given significant flexibility, this can be achieved without the risk of accidentally setting an unreasonable standard or requiring equipment that turns out to be much more costly than anticipated.

With this in mind, we recommend considering an inventory-based approach to applying B.C.'s carbon tax to methane emissions — with a few caveats:

- Ongoing effort should be applied to update the provincial GHGI to capture more emission sources and to more accurately and completely characterize available abatement technologies, especially in the early years of implementation.
- With a monetary incentive tied to the inventory, firms will have a strong incentive to underreport, necessitating robust monitoring and enforcement.[46] Along these lines, we caution that with a financial stake in the inventory, oil and gas firms and firms that produce the equipment they use would have an incentive to distort the process by which emission factors and other relevant inputs are decided.
- We recommend exploring ways to incentivize abatement activities that are not well captured by the inventory approach, such as offering firms tax credits for LDAR performed in excess of what is required by the regulations.

46 Ambient methane monitors could be useful in this context for identifying regions where actual emissions are inconsistent with reported inventory emissions.

OPTION 2: Sampling-based approach

Another potential approach would be to construct firm-level estimates of emissions by performing direct measurements at a randomly chosen subset of each firm's facilities. As long as the facilities are selected randomly, these measurements can be used to develop a robust firm-level estimate of emissions with a known level of statistical uncertainty. With only a fraction of facilities getting measured, this approach would cost only a fraction of the price of comprehensive monitoring.[47] Measurement could either be carried out directly by B.C. Oil and Gas Commission staff or by a certified third party.[48]

To illustrate, suppose a gas production firm operates 400 wells. The regulator determines that a sample size of 40 is sufficient and each year randomly chooses 40 wells to perform measurements at.[49] As a random sample, these 40 wells will on average be representative of emissions at all 400 wells for a given year.[50] In the simplest implementation, the regulator could appropriately tax the firm by estimating that its emissions are 10 times the total measured quantity of emissions. In this case, although each individual well only has a 10 per cent probability of being sampled, if it is sampled, its contribution to the total amount of taxes the firm must pay will be 10 times larger. The firm's expected benefit of reducing emissions at any given well would therefore be exactly the same as it would be in a case where emissions were measured with certainty (and not scaled up).

Perhaps the biggest advantages of this approach is that it covers all potential emissions sources, including sources that are difficult to capture using inventory methodologies. Because this mechanism is completely ambivalent about how emissions are generated, the incentive to reduce emissions would apply equally both intentional venting and unintentional leaks. Furthermore, it offers full flexibility in how firms choose to reduce their emissions. Rather than being constrained by established abatement technologies and emissions factors used by an inventory, firms would be able to use any technologies and practices they know to be most effective,[51] and would not be incentivized to use potentially inefficient technologies that may have been accidentally misspecified by the inventory framework. Lastly, firms would have a direct incentive to develop novel technologies and strategies for reducing emissions, which could have positive externality benefits of reducing methane abatement costs in other jurisdictions around the world.

While this approach has a number of important advantages over using an inventory measure, it also faces more substantial challenges for its implementation. First, while the statistical nature of this approach is appropriate for production firms with hundreds of wells, special considerations would need to be made

47 One example of a viable direct measurement technology that would be cost prohibitive for comprehensive monitoring but would likely be affordable for measuring a small percentage of facilities is downwind tracer flux. The biggest cost advantage for the sampling approach is that measurement equipment can be moved from site to site rather than permanently installed.

48 I.e., a private company could perform measurements and report them directly to BCOGC, subject to the same certification and accountability standards as other contracted auditors. Although requiring firms to self-report under this system could potentially lower costs by creating a market for measurement services, we recommend caution here. The effectiveness of a sampling-based emissions tax depends critically on the sampled facilities being truly randomly chosen and unknown to the firm before measurement. A monetary relationship between the firm and a third-party measurement service creates an incentive to manipulate the site-selection process, and it may be difficult for the regulator to ensure such manipulations do not take place.

49 To prevent firms from gaming this methodology, the timing of measurements would need to be effectively random as well, without alerting the firm before visiting. For larger facilities such as processing plants, it may be optimal to measure all facilities one or more times each year, with the timing of the measurement being random.

50 This is true under the intuitive and well-established statistical theorem, the "Law of Large Numbers."

51 For example, there are likely to be various kinds of subtle emission-reducing behaviours firms may begin requiring their workers to adopt if the cost of emitting increases.

for smaller emitters. For a firm with only a handful of wells, constructing a robust firm-level estimate of emissions would require sampling almost all facilities. One potential way to handle this challenge would be to set a threshold for the number of facilities, below which firms could be assigned a default emissions rate. Another option (which would better preserve firms' incentive to abate) would be to give firms with a limited number of facilities an option to request resampling if they can establish that the samples taken are not representative. This would prevent situations where measurement circumstances could cause a single superemitting facility to severely impact the tax burden faced by a smaller firm. A final option is to sample all facilities for operators with a small number of them.

Second, there is some uncertainty surrounding the costs of currently available measurement technologies. So far, direct methane measurement technologies have only been used in academic research projects, and formal data on costs are not publicly available.[52] However, we have obtained rough cost estimates from three scientists who have been involved in these studies, which range from $500 to $4,000 per site. To offer a back-of-the-envelope calculation of how these costs would scale to B.C.'s natural gas infrastructure, if measurements were performed each year at 10 per cent of B.C.'s roughly 10,500 wells, processing plants and compression stations, the total cost would be $525,000 to $4,200,000. This range is well below our estimates of the tax revenue that would be collected under a methane tax (approximately $25,000,000) and over an order of magnitude below the social benefits of avoided climate damages (approximately $65,000,000). However, we note that the cost structure for scientific studies is likely to be different than that of a government or third-party undertaking.[53] Furthermore, the most accurate direct measurement technologies require specific road-access conditions. While this is unlikely to be an issue for processing and transmission facilities, many B.C. production facilities are in remote areas with limited road access.[54]

Finally, and perhaps most importantly, because there is some possibility that as a result of the sample taken firms may be taxed for more emissions than they are actually generating, the direct measurement approach could be subject to legal challenges. With this in mind, if this approach is pursued, we recommend providing sufficient leeway to firms to ensure there is a low probability that they would be taxed for more than they are emitting. This could be accomplished either by charging firms based on a lower bound of a confidence interval for their estimated emissions, or by reducing the amount of the tax that would be paid per unit of emissions based on expected error. Fortunately, because marginal abatement cost curves for methane emissions start out relatively flat and then become very steep at higher marginal costs — indicating that the majority of abatement would take place under very low emission prices — even if the final charge somewhat underestimates actual emission volumes, the price signal it provided would still be sufficiently strong to achieve nearly the full amount of efficient abatement.[55]

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52 For example, the most accurate direct measurement technology currently available is downwind tracer flux, which involves placing a source of an inert tracer gas at an emitting site and driving a vehicle equipped with measurement equipment nearby. For an overview of recent scientific studies of methane emissions that have used direct measurement technologies, see Alvarez et al. (2018).

53 While various factors may influence this in either direction, larger-scale projects typically imply lower average costs (i.e., economies of scale).

54 Facilities that are infeasible to measure using downwind sampling could be measured using handheld optical gas imaging and high-flow sampling equipment. However, because this approach does not effectively capture very large leaks, special considerations would need to be made to address superemitting facilities.

55 As illustrated in Figure 1, in both Marks (2019) and Mayfield et al. (2017), a $40 tax is predicted to achieve almost as much abatement as a $50 tax. The marginal abatement cost curve estimated by Tyner and Johnson (2018) for methane emissions from venting and flaring in Alberta similarly demonstrates that most abatement occurs at very low emission prices.

IMPACTS OF TAXING METHANE EMISSIONS IN B.C.

Just how big are the potential gains from applying the B.C. carbon tax to methane? To answer this question, we developed a model of emissions and abatement potential specific to British Columbia. Our model accounts for methane regulations recently introduced in the province and evaluates the impact of applying B.C.'s carbon tax on top of those regulations. We draw on recent economic studies of methane abatement costs and utilize data from a variety of government, academic and industry sources. Our model also incorporates predictions about the growth of B.C.'s oil and gas sector over time, examining outcomes over a 10-year period from 2020 to 2030, with the tax being introduced in 2022. Although our analysis relies on limited data and makes a number of simplifying assumptions, we believe it correctly captures the approximate size of the expected costs and benefits of implementing emissions pricing in the province.

Marginal abatement cost curves

The primary tool we use to estimate the impact of taxing methane is a "marginal abatement cost curve." This shows the relationship between the cost of abating each unit of emissions and the total amount of abatement. In general, the first units of abatement are "low-hanging fruit" that can be achieved at very low costs. As total abatement increases, so does the per-unit cost of achieving additional abatement. For methane emissions, one example of a low-cost abatement measure would be retrofitting a wet-seal compressor with a vapour-recovery system. An example of a more costly abatement measure that would be found further up the MACC is replacing pneumatic pumps with solar-powered pumps in areas where grid electricity is not available.

Costs depend not only on the type of abatement activity but also on various characteristics of the site where it is employed, such as how accessible it is, what condition the current equipment is in and how long the site is expected to continue operating. As discussed in detail in the previous section, unlike conventional regulations such as equipment mandates, an emissions tax gives firms full flexibility in how they achieve reductions. Firms consider all information available to them when deciding which abatement measures to implement at which sites, allowing them to achieve the desired level of abatement at the lowest possible cost. By ordering all possible abatement opportunities from least-costly to most-costly, an MACC identifies how much abatement can be achieved below any particular per-unit cost. This reveals how much abatement firms will engage in at any particular level of an emissions tax.

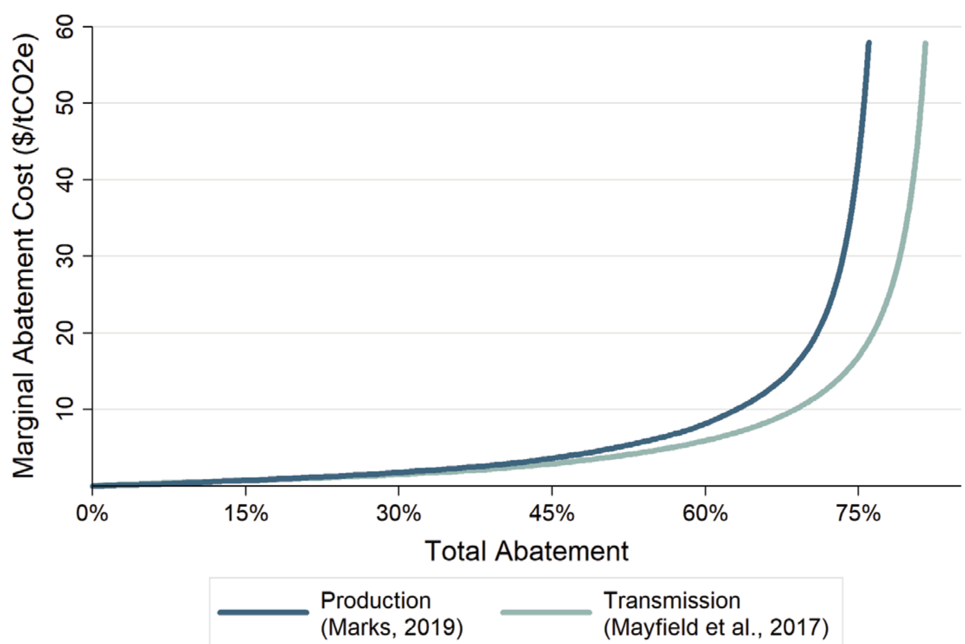
Our analysis begins by separating British Columbia's oil and gas industry into production and transmission segments.[56] We then use MACCs drawn from two recent academic studies focused on these two respective segments in the United States to independently estimate emissions reductions in each. For

56 We group emissions from the processing segment of the natural gas industry into the production segment. This decision is unlikely to be consequential, as processing only represents about 2.3 per cent of total methane emissions from the B.C. oil and gas industry.

the production segment, which consists of wells and infrastructure for gathering and processing gas, we use an MACC estimated by Marks (2019). For the transmission segment, which consists of long-distance pipelines and the compression stations used to pump gas along them, we use an MACC estimated by Mayfield et al. (2017). Although these two studies use different economic approaches, both are expressly designed to model the impacts of an emissions-pricing program such as an emissions tax, making them well-suited for our application.[57]

Figure 1 illustrates these two MACCs. We note that both are steeply convex at marginal costs above about \$20/tCO_2e. This implies that, at least over the short to medium term, higher carbon prices have minimal additional abatement impacts (though they would increase tax revenue).[58] However, over a longer time horizon, these MACCs are likely to flatten at higher marginal costs as new abatement technologies are developed. It is likely that many types of abatement technologies with higher marginal costs have not yet been explored because it has been uneconomical in all practical cases to invest in these technologies when only the private cost of emitting methane is considered. This would mean that over a longer time horizon, greater abatement would be achieved at lower cost than what is predicted by our model.

FIGURE 1: Marginal abatement cost curves adapted from Marks (2019) and Mayfield et al. (2017). Under an emissions tax, firms are incentivized to abate all emissions that have a marginal abatement cost less than the amount of the tax.



Note: We convert abatement costs from USD to 2019 CAD and abatement quantities to percentages. For the MACC from Mayfield et al. (2019), we take an average of their 100 simulations.

57 For additional detail on the MACCs used in this study, see Appendix A2.

58 Note that some marginal assets may be shut in and some marginal production may not be developed as a result of the carbon tax. However, this would occur because producers will longer be able to externalize costs into future climate damages by emitting methane into the atmosphere, ultimately making society as a whole better off. Government may wish to strengthen policies to ensure marginal operators do not default and increase the number of orphaned wells in the province (see Ho et al., 2016).

Predicting emissions under the carbon tax

We model a phased introduction of the tax in increments of either \$5 or \$10. We focus in the main text on the intermediate scenario where the tax is introduced at \$10/tCO_2e in 2022 and increases \$10/tCO_2e per year over the following four years, and present results for the other \$5/year scenario in the appendix. Additionally, we model a baseline scenario with only the recently introduced regulations as a point of comparison for understanding the additional effect of applying an emissions tax on top of those regulations.[59] Finally, to account for growth in the province's oil and gas sector over time, we also model emissions under a hypothetical "business-as-usual" scenario without regulations or a tax.[60,61]

As shown in Figure 1, the MACCs from Marks (2019) and Mayfield (2017) predict a \$10/tCO_2e tax will result in roughly 63 per cent and 69 per cent abatement for the production and transmission sectors, respectively.[62] This corresponds to a reduction of about 2,120,000 tCO_2e of emissions in the first year of tax implementation, versus only about 1,354,000 tCO_2e of abatement under a regulations-only scenario.[63]

Although this may seem like very large amount of abatement for a relatively modest tax, it is consistent with the large differential between current abatement costs and the social cost of methane emissions. Converted to tCO_2e, average natural gas prices in B.C. over the last five years are close to \$5, which means firms have only been incentivized to spend up to \$5/tCO_2e to prevent emitting methane. A \$10/tCO_2e tax on methane would effectively triple firms' opportunity cost of allowing gas to escape from their operations into the atmosphere, which is consistent with the reductions predicted in this analysis.

Figure 2 demonstrates how emissions evolve over time in our model. After the regulations have fully realized their abatement potential, the additional abatement from implementing an emissions tax continues to grow. By 2025, for example, we estimate that the tax would reduce emissions by an additional 1,131,000 tCO_2e beyond what will be achieved through the regulations alone. Our model predicts that instead of achieving only a 45 per cent reduction in emissions by this target date, an emissions tax could enable B.C. to achieve a 77 per cent reduction. Assuming a social cost of carbon of \$50/ton,[64] this additional abatement represents a climate mitigation benefit of \$65,500,000.

59 For the regulations-only scenario, we use estimated emissions over the period of interest provided by BCOGC, but we scale their estimates to match total emissions from the 2016 Provincial Greenhouse Gas Inventory for consistency. We note that some changes were made to the regulations after these estimates were constructed; however, these improvements were relatively minor and should not significantly impact this portion of the analysis.

60 We assume methane emissions start at 3,154,513 tCO_2e, which is the reported emissions from the Provincial Greenhouse Gas Inventory for 2016 (adjusted to reflect an updated warming potential of methane of 34 from the IPCC's Fifth Assessment Report). We estimate how baseline emissions are projected to increase over the next decade using data from BCOGC. For more detail on how we model the time path of baseline emissions, see Appendix A3.

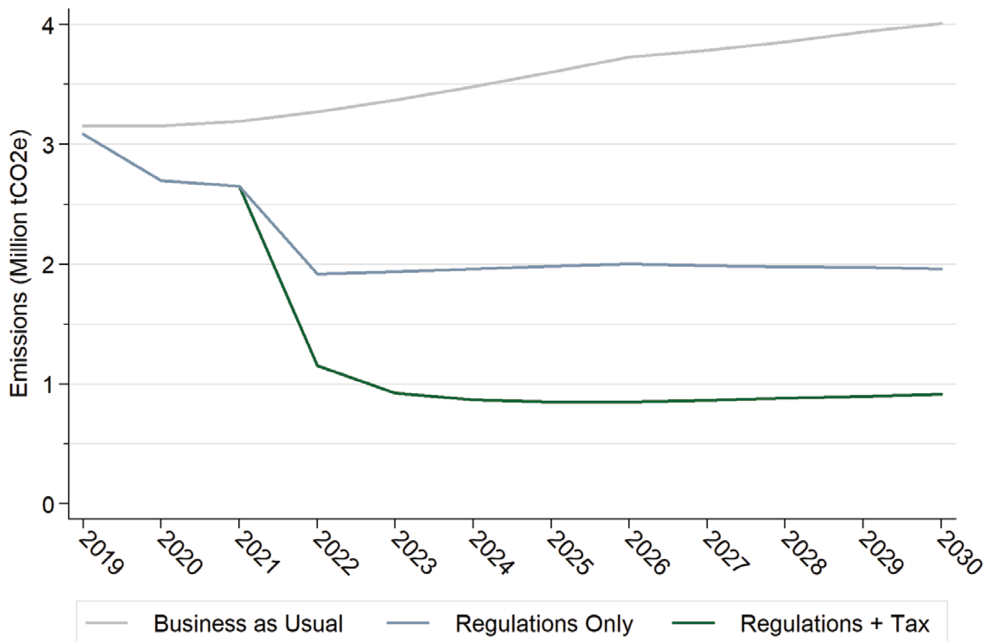
61 Because we rely on the inventory estimates for emissions, our analysis is most directly applicable to an inventory-based methane tax. However, if the tax is implemented using a sampling-based approach, or if steps are taken to substantially improve the accuracy of the inventory, total abatement would be even greater than the predictions in this report.

62 Results are also presented in table form in Appendix A1.

63 Here, we note that one shortcoming of our analysis is that it does not fully capture real-world frictions that would prevent firms from fully responding to the tax in the first year of its implementation. Although in an idealized setting, it may be optimal for firms to reduce their methane emissions by two-thirds in the first year, factors such as supply constraints for lower-emitting equipment or not having access to enough skilled employees to install the equipment or conduct LDAR may result in delays in practice. This is part of the reason a phased approach may be preferred. However, over a period of a few years, firms and labour markets would have time to adjust to the tax and real-world abatement would converge to the predictions of our model.

64 CAD 50/tCO_2e is slightly below the EPA-estimated US\$42 social cost of carbon assuming a three per cent discount rate.

FIGURE 2: ESTIMATED EMISSIONS OVER TIME UNDER A TAX THAT IS PHASED IN BY $10 PER YEAR UNTIL REACHING $50/TCO$_2$E IN 2026.



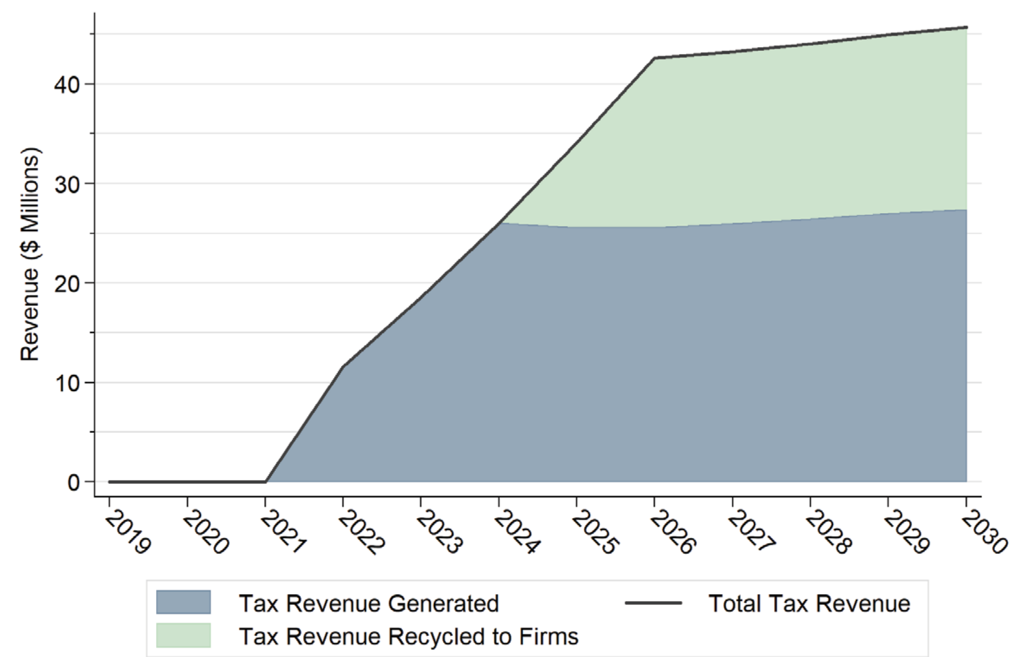
Estimating costs under the carbon tax

We turn now to estimating the additional cost of applying an emissions tax on top of existing regulations. These costs can be broken into two types. The first is the tax on the sector's unabated methane emission. While these revenues would be recycled to the B.C. economy (e.g., the Climate Action Tax Credit for low income households, revenues for government programs, potential to reduce other taxes) and therefore do not represent lost value, they nonetheless affect the B.C. oil and gas industry's competitiveness. Tax revenues are straightforward to calculate as the estimated level of emissions in the presence of the tax times the per-tonne amount of the tax. We estimate that in 2025, firms would pay about $34,000,000 in taxes on just over 850,000 tCO_2e of emissions for which the abatement cost exceeds $40/t$CO_2$e.

However, it is important to note that under the recently introduced Clean Growth Incentive program, revenues from carbon taxes in excess of $30/tonne are recycled back to industry, either through direct transfers or investment in green technologies (such as the abatement technologies the tax would induce).[65] The effective cost to industry of paying these taxes would therefore be closer to $25,500,000.[66] Figure 3 illustrates this breakdown in tax revenues over time.

65 Ministry of Finance (2018)
66 While recycling some revenues reduces the effective tax burden to firms, it does not dampen their incentive to undertake abatement activities with marginal costs up to the level of the full amount of the tax, provided the industry sector is not highly concentrated (Fischer, 2011).

FIGURE 3: TAX REVENUE GENERATED UNDER A PHASED $10/YEAR IMPLEMENTATION.



By internalizing the external greenhouse gas consequences of using natural gas for energy, firms' investment decisions in natural gas exploration and production will better account for society's long-run interests. That said, as we will show in the next few pages, the overall impact of the tax on total natural gas production in the province is likely to be small.

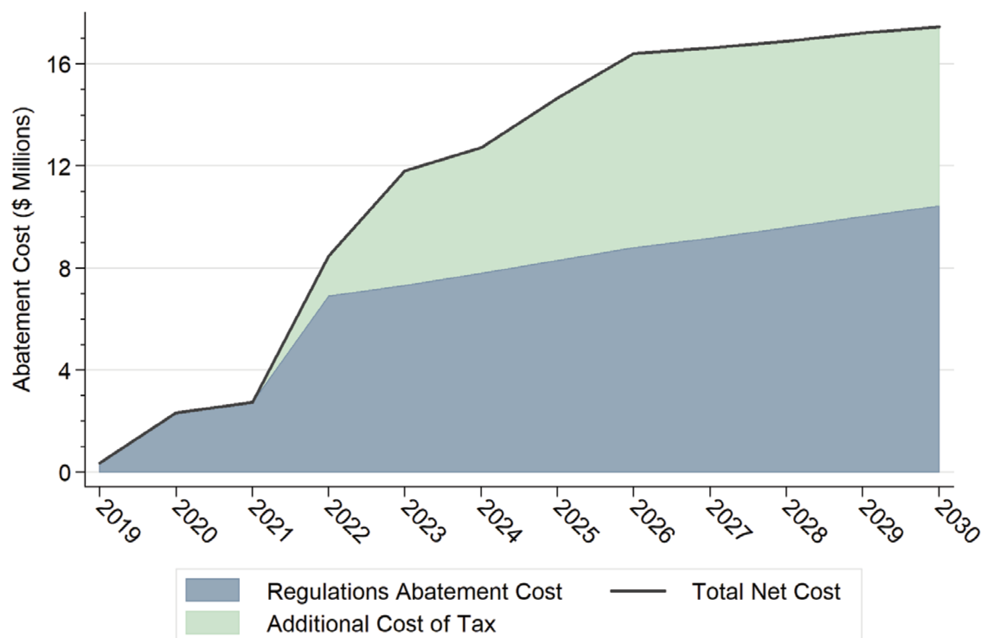
The second component of the cost of implementing a tax on methane is the amount firms will expend to achieve abatement when it is efficient to do so; i.e., abatement that can be achieved at a per-unit cost of less than the amount of the tax. In other words, this is the physical cost of purchasing equipment that leaks less, installing vapour-recovery systems, hiring more workers to perform LDAR, etc. We calculate total abatement cost (i.e., due to the conventional regulations and the tax) as the area under the MACCs for the transmission and production industry segments, scaled to be representative of these segments in B.C. We then subtract the portion of that cost that would be incurred by the conventional regulations in the absence of the tax, which we estimate using data from BCOGC, BCMECCS and ICF.[67,68] Lastly, we account for the value of the gas that stays in the pipeline rather than being emitted, which firms can sell at market prices.

67 We estimate the cost of the conventional regulations by combining estimated reductions from various abatement types from BCOGC with abatement costs drawn from ICF (2015). A detailed overview of how we calculate costs of the BCOGC regulations is provided in Appendix A4.

68 Our methodology assumes abatement costs of complying with the BCOGC regulations would be lower than $50/tCO$_2$e (or the current tax level in phased scenarios) in all instances in which abatement measures are implemented. Because the regulations were chosen to try to target low-cost abatement opportunities, this is likely to be true in most cases. However, because abatement costs can vary greatly due to site-level conditions, there are likely to be some instances where the regulations cause firms to expend greater than $50/tCO$_2$e. To the extent that this is true, additional real-world abatement due to the tax would be even greater than what our model predicts, and additional abatement costs from the tax would be lower.

Figure 4 illustrates how physical abatement costs evolve over the study period, net of the value of conserved gas, broken down into abatement required under the recently introduced regulations and abatement that would be induced by the tax. Focusing again on 2025, we estimate that the cost to firms of additional abatement induced by the tax would be about $10,800,000. However, at a gas price of $88/10^{3}m^3,[69] the market value of the additional 1,131,000 tCO_2e (or 50,575,000m^3) of gas captured by firms is about $4,400,000, meaning the net abatement cost of the tax is only about $6,400,000. On average, this works out to about $5.63/t$CO_2$e of avoided emissions, which we note is low relative to abatement costs in other sectors of the economy.[70]

FIGURE 4: ABATEMENT COSTS OVER TIME DUE TO RECENTLY INTRODUCED REGULATIONS AND THE ADDITIONAL ABATEMENT COST UNDER THE TAX (PHASED IN AT $10/YEAR), NET OF THE VALUE OF CONSERVED GAS.



Considering both the physical abatement costs and the taxes paid, total cost to industry would be about $31,900,000 in 2025. Using projected B.C. gas production from the National Energy Board, this works out to only about $0.64/10^{3}m^3 of gas produced in the province. Current gas prices in the province are close to $45/10^{3}m^3, which would mean the cost increase due to the tax would represent only about 1.4 per cent of firms' total revenues. This suggests that taxing methane emissions would have a relatively minimal impact on the natural gas industry's productivity.

69 We use the average gas price over the past five years for the West Coast Station 2 Hub, which we collect from S&P Global, and adjust this price downward by 25 per cent to account for royalty payments and fees following ICF (2016). For sensitivity analyses, we show results for a low gas price and high gas price in Figure 5. Although the net cost to firms is clearly dependent on future gas prices, results are broadly similar in character to those presented in the main text.

70 For example, a recent study by researchers at the University of California, Berkeley estimated that in the electricity sector, abatement costs associated with installing new wind generation capacity (accounting for the offset power production) are between US$25-105/t$CO_2$e and between US$43-90/tCO_2e for solar (Callaway et al., 2018).

CONCLUSION AND RECOMMENDATIONS

This study shows that applying British Columbia's carbon tax to methane emissions from the oil and gas industry can substantially reduce the province's greenhouse gas footprint. Our results also show that these reductions can be achieved much more cost-effectively than greenhouse gas abatement in other sectors of the economy. This policy would fill a significant gap in the current coverage of B.C.'s carbon tax to ensure the oil and gas industry in the province faces the same incentives for long-run sustainability as other sectors. That said, our results indicate that the total cost to industry of complying with the tax would be relatively small.

Although there are real challenges associated with taxing a pollutant that is difficult to monitor, we believe these challenges are not insurmountable, and we have outlined two possible approaches for overcoming them. We believe either approach could be effective. In general, an inventory-based tax would likely be more straightforward to implement but would have a more limited impact in accurately capturing all possible cost-effective abatement opportunities. A sampling-based tax would likely have a greater impact in covering more sources and more fully realizing the efficiency benefits of emissions pricing but would require more effort to design and implement.

For either policy, we recommend implementation only in addition to the recently developed conventional regulations; i.e., not as a substitute for them. While we have shown pricing methane emissions has very large potential benefits, it is also new regulatory territory, and accordingly there may be unforeseen complications. The BCOGC regulations are similar to regulations already proven effective in other jurisdictions, and the abatement measures they require were generally chosen to be cost-effective, so they are likely to be consistent with the abatement measures that would be incentivized under the tax. We also advise a phased implementation of the tax (for example, in increments of $10/t$CO_2$e per year, with the conversion to CO_2e tied to the most recent IPCC estimates for a 100-year time horizon). This would give firms time to adjust to the policy in the face of market frictions in acquiring the personnel and equipment necessary to achieve the abatement incentivized by the policy.

While we have identified two potentially viable strategies for implementing a tax on methane, we recognize there could be other options we have not yet considered. Given the substantial payoffs for mitigation estimated in the previous section, we encourage the B.C. government to prioritize further study of how best to technically implement an effective tax on methane emissions. We note that even if the B.C. government ultimately elects not to employ a tax on methane, our results still imply there are substantial cost-effective abatement opportunities available in this sector that could be addressed by expanding existing regulations.

Lastly, we encourage the B.C. government to allocate additional resources to monitoring methane emissions from oil and gas infrastructure. Regional methane monitoring sensors and site-specific measurement exercises would have a number of benefits, including improving estimates of the province's total emissions, improving the detection of superemitting facilities and providing more accurate data for future studies on methane abatement.

Although methane emissions from the oil and gas sector have historically received less attention than carbon dioxide emissions from fossil fuel combustion, they account for a large portion of total greenhouse gas emissions in natural gas–producing regions such as British Columbia. Furthermore, they are a highly efficient emissions source to prioritize for near-term greenhouse gas abatement. An emissions tax can realize these efficient abatement opportunities without imposing additional abatement that would not be cost-effective, and we recommend utilizing this tool to manage methane emissions in B.C.

TO SUMMARIZE, WE RECOMMEND:

1. **Forming a technical committee or scientific review panel to provide more detailed advice on how B.C.'s carbon tax can be implemented to control methane emissions**
2. **Allocating funding to improve the accuracy of oil and gas provincial inventory data and to independent direct monitoring of emissions using vehicle-based, aerial and/or emerging measurement technologies**
3. **Applying B.C.'s carbon tax to methane emissions using an inventory-based approach**
4. **Retaining regulations as an essential methane mitigation tool to work alongside the carbon tax**
5. **Phasing the application of the tax to the sector's methane emissions over three to six years, in increments of \$5 to \$10/tCO_2e per year set implementation date in B.C. budget 2020 and fiscal plan**
6. **Tying the conversion from methane emissions to tCO_2e using the most recent and more accurate IPCC estimates for the warming potential of methane**

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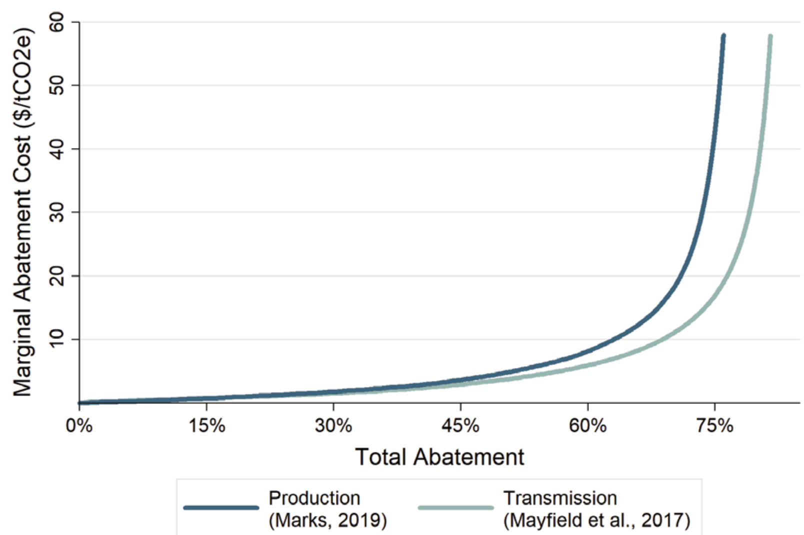
Figures

FIGURE 1: Marginal abatement cost curves adapted from Marks (2019) and Mayfield et al. (2017). Under an emissions tax, firms are incentivized to abate all emissions that have a marginal abatement cost less than the amount of the tax.



Note: We convert abatement costs from USD to 2019 CAD and abatement quantities to percentages. For the MACC from Mayfield et al. (2019), we take an average of their 100 simulations.

FIGURE 2: Estimated emissions over time under a tax that is phased in by $10 per year until reaching $50/tCO$_2$e in 2026.

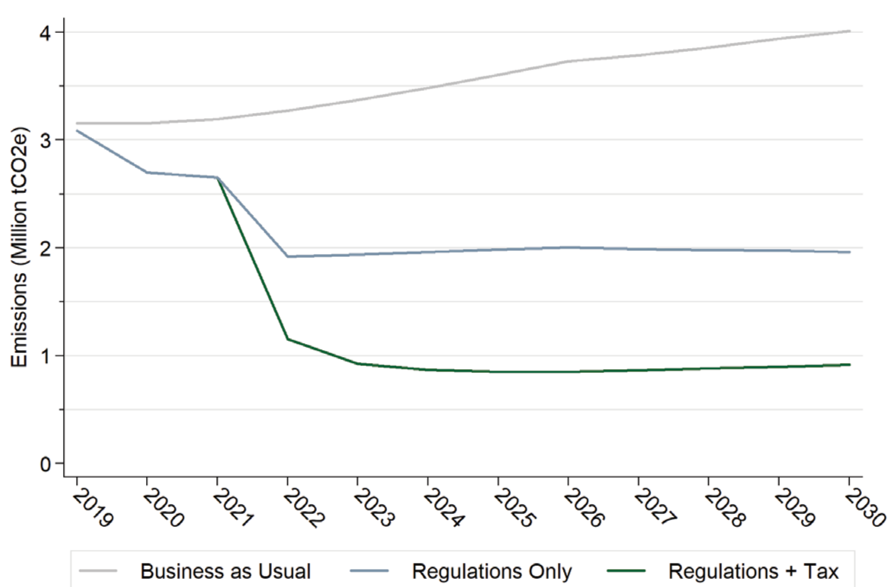


FIGURE 3: Tax revenue generated under a phased $10/year implementation.

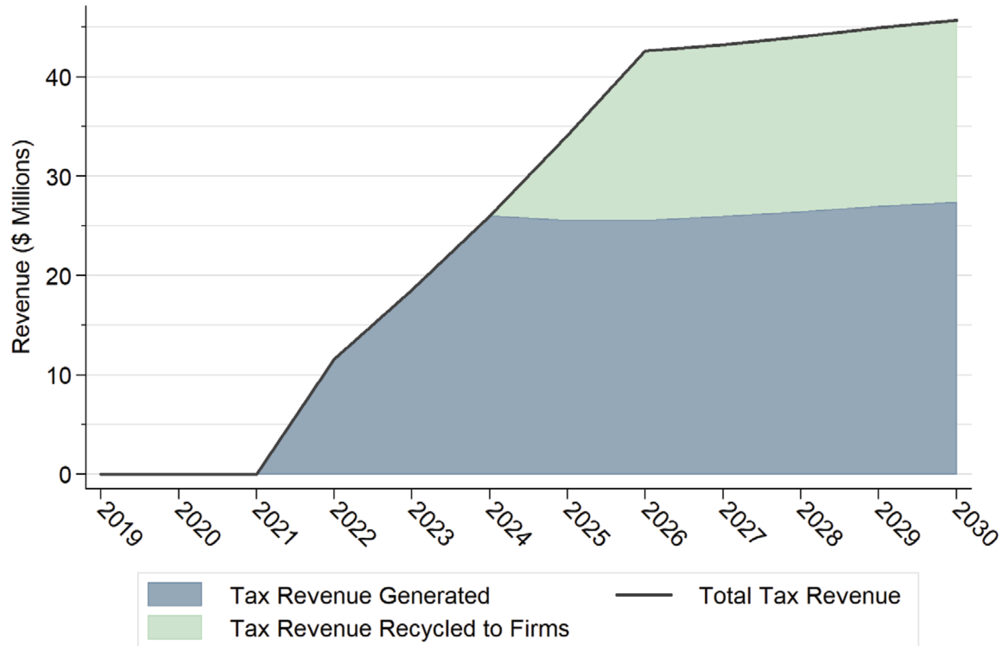


FIGURE 4: Abatement costs over time due to recently introduced regulations and the additional abatement cost under the tax (phased in at $10/year), net of the value of conserved gas.

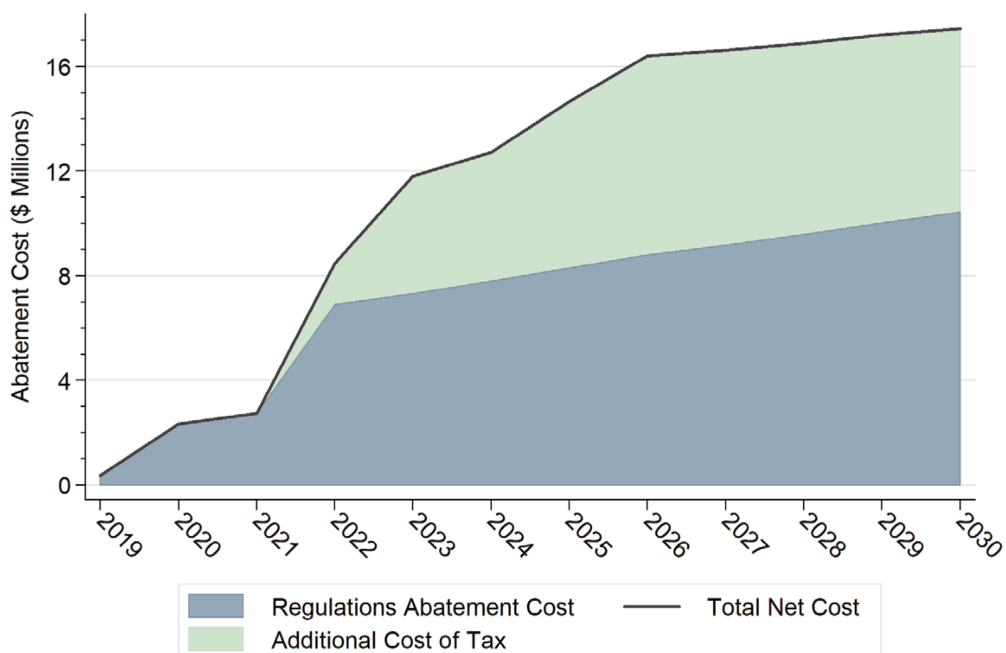


FIGURE 5: Average net abatement cost under a $10/year phased implementation of the tax considering the value of conserved gas under low gas price ($34/10^{3}m^3) and high gas price ($127/10^{3}m^3) scenarios. These scenarios were chosen as the minimum and maximum average annual gas prices at B.C.'s West Coast Station 2 Hub over the past five years, while the baseline scenario uses the average price over that period.

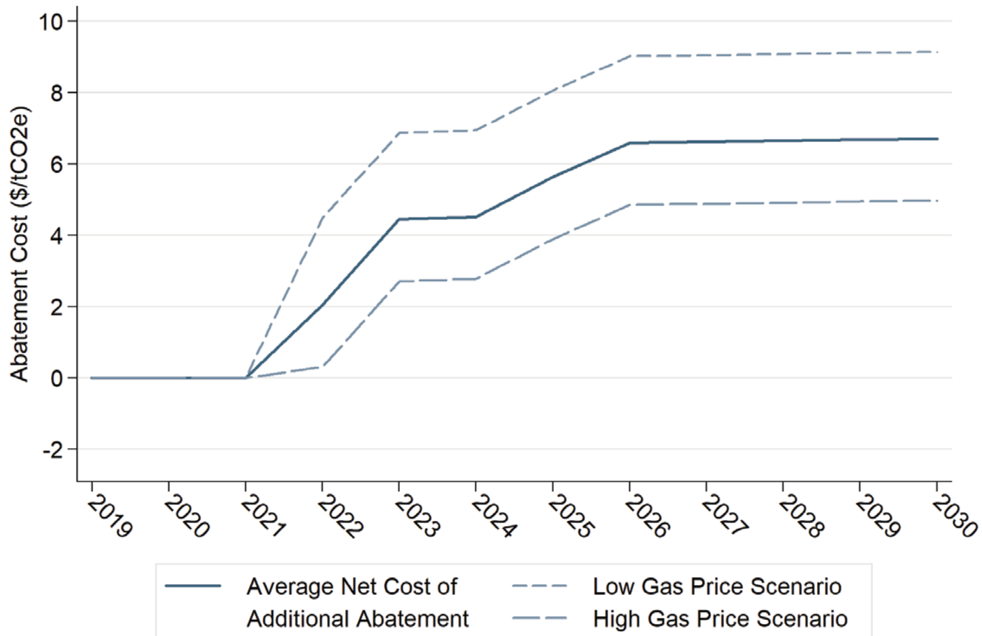


FIGURE 6: Estimated emissions over time in a scenario where the tax is phased in with increments of $5/t$CO_2$e.

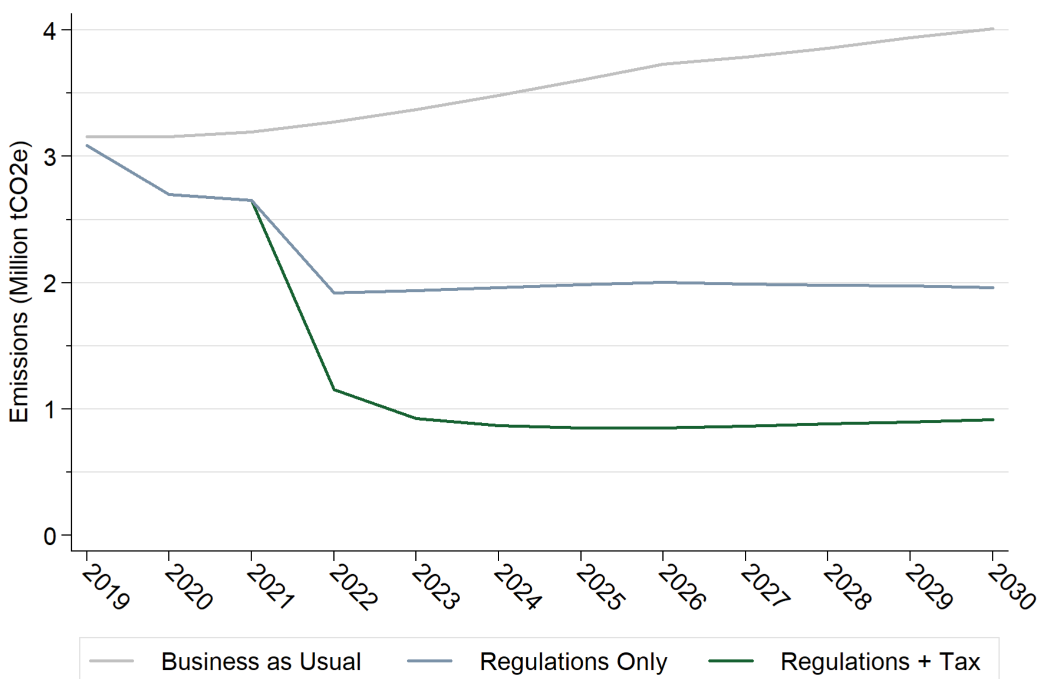
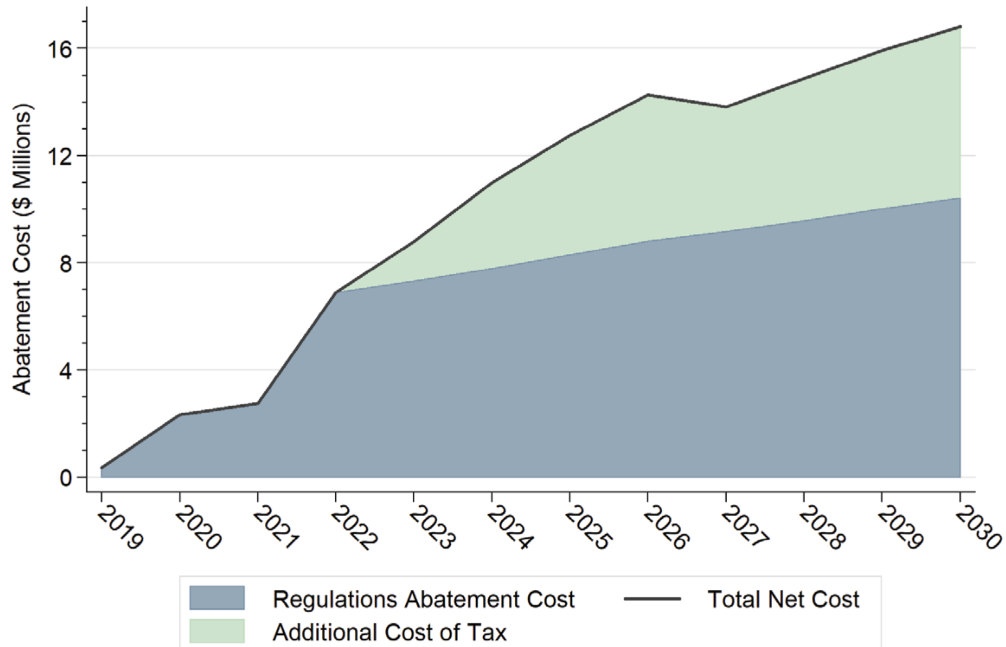


FIGURE 7: Estimated abatement costs under an emissions tax that is phased in with increments of $5/tCO$_2$e.



Appendix

A1. Numerical Results from Simulation

Year	Tax Level ($)	Modeled Baseline Emissions (tCO2e)	Abatement from Regulations (tCO2e)	Abatement from Tax (tCO2e)	Net Abatement Cost of Regulations ($)	Net Abatement Cost of Tax ($)	Average Cost of Tax ($/tCO2e)	Total Tax Revenue ($)	Tax Revenue Recycled to Industry ($)	Average Cost to Firms $/1000m^3 of Production)
2019	0	3,155,000	70,000	0	359,000	0	0.00	0	0	0
2020	0	3,155,000	456,000	0	2,330,000	0	0.00	0	0	0
2021	0	3,191,000	539,000	0	2,751,000	0	0.00	0	0	0
2022	10	3,275,000	1,354,000	766,000	6,908,000	1,571,000	2.05	11,556,000	0	0.27
2023	20	3,373,000	1,435,000	1,011,000	7,327,000	4,497,000	4.45	18,528,000	0	0.47
2024	30	3,485,000	1,526,000	1,092,000	7,793,000	4,934,000	4.52	26,024,000	0	0.63
2025	40	3,606,000	1,623,000	1,131,000	8,294,000	6,372,000	5.63	34,091,000	8,523,000	0.64
2026	50	3,728,000	1,723,000	1,153,000	8,811,000	7,603,000	6.60	42,607,000	17,043,000	0.66
2027	50	3,788,000	1,797,000	1,125,000	9,179,000	7,449,000	6.62	43,257,000	17,303,000	0.66
2028	50	3,858,000	1,878,000	1,100,000	9,581,000	7,316,000	6.65	44,031,000	17,613,000	0.66
2029	50	3,941,000	1,966,000	1,076,000	10,023,000	7,196,000	6.69	44,946,000	17,978,000	0.67
2030	50	4,009,000	2,049,000	1,046,000	10,431,000	7,020,000	6.71	45,675,000	18,270,000	0.67

A2. Additional detail on marginal abatement cost curves

The MACC from Marks (2019) is estimated by examining real-world abatement undertaken by natural gas production firms in the United States in response to changes in natural gas prices. This approach makes use of the economic principle that profit-maximizing firms will choose a level of abatement that sets the marginal cost of capturing one unit of gas equal to the marginal private benefit of being able to sell that unit of gas, which is given by the gas price. Because with methane emissions the pollutant is also a priced commodity, it possible to map an estimated relationship between emissions and price to a relationship between emissions and cost, which is the basis of an MACC.

The MACC from Mayfield et al. (2017) is constructed by using engineering cost estimates of various potential abatement activities as inputs to a simulation model where a social planner implements the lowest-cost abatement opportunities first. This approach generates the exact same results as an emissions tax, which similarly incentivizes firms to choose the lowest-cost abatement options first. Their model incorporates uncertainty in emission factors, operating hours and abatement costs.

We acknowledge that neither of these MACCs is an ideal fit for the B.C. context, as they rely on data from the U.S., where the distribution of facility types, equipment types and emission sources are different. However, these MACCs are the best available tools for estimating the impacts of methane emissions from B.C.'s oil and gas industry.

Another MACC that we considered using for the production sector in our analysis is found in Tyner and Johnson (2018). This MACC is also constructed using an economic optimization approach that facilitates predicting the impacts of emissions pricing. While this MACC has the advantage of using data from Alberta rather than from the U.S., it only considers abatement from primarily oil-producing wells that also produce some associated natural gas, which is not representative of B.C.'s oil and gas infrastructure. Relatedly, it is limited in scope by only considering abatement through alternative venting and flaring practices. However, we note that for the emission sources it covers, the MACC estimated by Tyner and Johnson predicts roughly 75 per cent abatement at a \$50/tCO_2e carbon price, which is highly consistent with the predictions from Marks (2019) and Mayfield et al. (2017).

Other MACCs, such as the one estimated by ICF (2015) that specifically focuses on Canada, are not as directly useful for predicting the impacts of emissions pricing because they don't flexibly model a decision-maker implementing the least-costly abatement options first. Instead, they identify a set of potential abatement technologies, assume abatement costs are the same for all applications of a particular technology, and evaluate abatement and cost at just one potential level of deployment of each technology. This results in a blocky MACC that does not characterize flexibility in utilization levels of different abatement technologies. The usefulness of these studies for predicting firm responses to an emissions tax is further limited by not considering more costly abatement options that firms would undertake at emissions taxes on the order of British Columbia's current carbon tax.

A3. Modelling baseline emissions

We assume methane emissions from the oil and gas industry in B.C. start at the 2016 Provincial Greenhouse Gas Inventory estimate of 3,154,513 (2,371,842*34/25 to adjust for updated warming factors) and model a time path of emissions in the absence of any methane regulation or tax using projected facility counts from BCOGC. In particular, we group facility types into compression stations, processing plants, multi-well batteries, single-well batteries, single conventional wells, single tight gas wells and single oil wells, and calculate per-site emissions generated by each. We then combine per-site emissions with estimated facility counts over the period from 2017-2030 to project emissions over that period, then separate emissions into the production and transmission segments. Because we don't have facility counts available for 2016 (the last year for which Provincial Greenhouse Gas Inventory data is available), we assume no change in facility counts between 2016 and 2017.

A4. Estimating costs of abatement under regulations

We model abatement costs under the scenario with regulations only by combining estimates of predicted abatement from BCOGC with abatement costs drawn from ICF (2015), an engineering cost study specifically calibrated to the Canadian oil and gas industry. We use ICF's estimated costs without "credit" for the value of conserved gas, as we build this into our model separately using more recent gas prices. We also convert all dollar amounts in the ICF study to 2019 dollars.

We separately estimate costs for five categories of abatement that are used by BCOGC in their estimates: LDAR, pneumatics, compressors, dehydrators and venting.[71] We combine the 10-year abatement percent-

71 We group together the "Venting" and "Surface Casing Vent Flow Venting" categories used by BCOGC, since both are addressed by similar abatement technologies (i.e. vapor recovery systems). Each of these categories accounts for only 2% of predicted abatement, so this simplification is unlikely to affect final results.

ages for each category from BCOGC with our estimated time path of baseline emissions, which effectively assumes that these percentages are constant over our study period.[72]

Emissions from pneumatic devices are the category predicted to be most heavily impacted by the regulations, accounting for 55 per cent of total abatement over a 10-year period. For this emissions source, we were able to incorporate preliminary data from a recent field count equipment study conducted by BCMECCS. In particular, we used B.C.-specific data to determine the ratio of pneumatic pumps to other types of pneumatic devices, then separately apply ICF cost estimates for abatement technologies for these two types of emissions sources. We use ICF (2015) assumptions regarding the percentage of high-bleed pneumatic devices that can be switched to zero-bleed instrument air devices in Canada and the percentage that can be replaced with low-bleed devices. Taking a weighted average based on the ratio of emissions from pumps and other devices in the BCMECCS, we estimate that the average abatement cost of the recently introduced regulations on pneumatic devices is \$8.64/tCO_2e.[73]

Emissions from LDAR are expected to account for 26 per cent of abatement under the regulations over a 10-year period. ICF (2015) estimates costs and effectiveness of LDAR performed either once per year or four times per year, separately for wells, gathering, processing and transmission. However, because the BCOGC regulations require LDAR either once per year or three times per year depending on the facility type, we impute a three-per-year LDAR scenario by adjusting the variable cost component of ICF's cost calculation.[74] We directly use this estimate for the cost of 3x/year LDAR for transmission (\$3.85/tCO_2e), and construct the cost of LDAR for the production segment (\$12.79/tCO_2e) as a weighted average of the cost of 3x/year LDAR for processing and 1x/year or 3x/year LDAR for production, based on the relative share of emissions coming from facilities covered under either inspection regime.

For emissions reductions from compressors (15 per cent of the total estimated reductions), we follow ICF's assumptions about the applicability of various potential abatement technologies, including replacing rod packing, vapour recovery and retrofitting wet seals with dry seals. We separately calculate abatement costs for the production (\$7.11/tCO_2e) and transmission (\$0.81/tCO_2e) sectors as weighted averages of the costs of these potential abatement measures. For emissions from venting and dehydrators, which collectively make up six per cent of expected reductions, we directly use cost estimates from ICF (2015) (with a conversion from Mcf to tCO_2e and from 2015 Canadian dollars to 2019 Canadian dollars).

We multiply per-tCO_2e abatement costs by the predicted time path for abatement under the regulations at the year-emission category level, then sum those values to determine the total cost of abatement required by the recently introduced regulations in a given year. In 2025, for example, we predict that regulations would reduce emissions by 1,622,964 tCO_2e at a net cost of \$8,293,725 (accounting for the value of conserved gas).

72 In practice, the shares that different categories contribute to total abatement under the regulations will change over time. Unfortunately, estimated time paths of abatement broken out by category were not available at the time of publication of this study, necessitating this simplifying assumption.

73 We note that the abatement cost estimates we develop for most categories are substantially lower than those predicted by BCOGC. For example, their estimate for abatement costs from pneumatics is \$23/tCO_2e. BCOGC cost estimates are substantially higher than any found in previous studies on methane abatement costs, including ICF (2014, 2015, and 2016), Warner et al. (2015), Mayfield et al. (2017), and Marks (2019).

74 We assume the effectiveness of 3x/year LDAR in reducing emissions is halfway between the effectiveness of 4x/year LDAR and 1x/year LDAR.