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Policy Forum: Alberta's Specified Gas Emitters Regulation

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CONTENTS

INTRODUCTION

Over the past decade, many policy options have been proposed to limit greenhouse gas (GHG) emissions from industrial activity in Canada. The purpose of this article is to introduce one specific example, Alberta's Specified Gas Emitters Regulation (SGER),[1] and to compare and contrast the incentives provided by this program with those provided by comparably priced carbon taxes. The results show that, unlike a carbon tax policy that prices all emissions reductions identically, the SGER program provides vastly different rewards for emissions reductions achieved in different ways within the same facility. Despite this, it is not accurate to say that the SGER systematically underprices emissions reductions relative to a carbon tax; in many cases the

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1 Specified Gas Emitters Regulation, Alta. Reg. 139/2007, as amended (herein referred to as "the SGER").

implicit incentives provided by the two policy options are identical, and in some cases the SGER would reward better performance where a carbon tax would not.

The SGER was the first GHG pricing policy in Canada when it came into force in July 2007—a full year before a carbon tax was implemented in British Columbia, and a few months before a less stringent carbon price was implemented in Quebec. The SGER affects most energy projects in Alberta, and thus a large share of the provincial economy; the energy sector accounted for over 30 percent of Alberta's gross domestic product in 2008.[2] Facilities covered under the SGER account for roughly half of GHG emissions in Alberta, and Alberta accounts for 34 percent of Canada's GHG emissions, according to the most recent national inventory report.[3] Thus, the policy applies a carbon price to more than one-sixth of all GHG emissions in the country.

Despite being the first carbon-pricing policy enacted in Canada, the SGER has been the subject of significant criticism, mostly centred on two aspects of its design. First, the program is based on emissions intensity, implying (according to critics) that it will not generate reductions in absolute emissions. Second, the program allocates the majority of emission permits at no charge, based on production, leading to low average costs and thus (according to critics) undermining incentives for emissions reduction.

This article uses examples of actual facilities operating in Alberta as well as prototypical examples to illustrate how the SGER functions and to compare and contrast the emissions reduction incentives it provides with a prototypical carbon tax. The results show that it is generally true that, for a given carbon price, the SGER would generally provide equivalent or weaker incentives to engage in emissions reductions than would a carbon tax. However, the reverse may be true for innovations that increase productivity per unit of emissions later in the project life cycle. For example, while an innovation that reduced emissions per unit of output (production) would provide the same reward under both the SGER and a comparable carbon tax, an innovation that increased output per unit of emissions after the third year of operation would provide a smaller reward under the carbon tax than under the SGER. Decisions to reduce output in response to emissions policies would provide greater rewards under the carbon tax than under the SGER. Perhaps more importantly, it is shown that the SGER provides very different financial incentives for emissions reductions derived through different actions or changes. This runs counter to the equimarginal principle, since the policy either undervalues or overvalues certain types of emissions reductions, which are perfect substitutes for each other from a GHG abatement perspective.

2 Statistics Canada, CANSIM database, table 379-0025, "Gross Domestic Product (GDP) at Basic Prices by North American Industry Classification System (NAICS) and Province."

3 Environment Canada, *National Inventory Report 1990-2010: Greenhouse Gas Sources and Sinks in Canada* (Ottawa: Environment Canada, 2012), the Canadian government's submission to the United Nations Framework Convention on Climate Change.

Finally, this article illustrates the importance of considering two separate measures of policy stringency, the marginal cost (or costs, in the case of the SGER) and the average cost. The average cost of the SGER tends to be very low, so it will have less effect on the overall financial viability of new and existing investments than a comparable carbon tax. However, this does not, in and of itself, imply that a smaller reward is provided for changes that reduce emissions from a facility, since these are determined by the marginal cost or benefit associated with considered changes.

BACKGROUND

In October 2006, the federal government announced in the *Canada Gazette*[4] that it intended to regulate GHGs under the Canadian Environmental Protection Act, 1999[5] (CEPA). Specifically, the government would address emissions from large final emitters—facilities with emissions over 100,000 tonnes per year (t/yr)—by implementing a regulatory approach as part of an overall policy package that would include "intensity targets that are ambitious enough to lead to absolute reductions in emissions and thus support the establishment of a fixed cap on emissions."[6] The expectation stated at the time was that this would, in the long term, lead to "an absolute reduction in GHG emissions between 45 and 65% from 2003 levels by 2050."[7]

Since this would be the first national GHG policy imposed in Canada, there were questions as to the federal government's constitutional authority to regulate in this area. Hogg[8] discusses four plausible underpinnings of constitutional authority to regulate GHGs at the federal level: peace, order, and good governance; taxation; spending; and criminal law. The federal government at the time seemed to favour the criminal law route, via an update to CEPA, as the means by which it would regulate GHGs, but its authority to tax and spend also would have been potentially invoked as part of the implementation of its *Turning the Corner* action plan,[9] the public face of the notice of intent to regulate GHGs.

The implementation of GHG regulations by the federal government was of concern to Alberta. For the most part, this concern was rooted in the potential for significant wealth transfers out of the province as a result of the federal policy. In Alberta, compliance costs (financial or otherwise) would be deductible from both income taxes and royalties, implying that provincial coffers would be affected by

4 Canada, "Notice of Intent To Develop and Implement Regulations and Other Measures To Reduce Air Emissions" (2006) 140:42 *Canada Gazette Part I* 3351-61.

5 SC 1999, c. 33.

6 "Notice of Intent," supra note 4, at 3359.

7 Ibid.

8 Peter W. Hogg, "Constitutional Authority over Greenhouse Gas Emissions" (2009) 46:2 *Alberta Law Review* 507-20.

9 Environment Canada, *Turning the Corner: An Action Plan To Reduce Greenhouse Gas Emissions and Air Pollution* (Ottawa: Environment Canada, 2007).

federal GHG policy. It was felt that the federal government would be unlikely to supersede provincial regulation of GHGs provided that the provincial policies were of similar stringency. As a result, Alberta saw an opportunity to hedge the potential risks from federal policy by developing and implementing a provincial GHG policy before the federal policy was finalized.

Alberta introduced its GHG policy, in the form of the SGER, in March 2007. This regulation, applicable to large facilities with annual emissions of over 100,000 t, would come into effect on July 1 of the same year. The regulation had four principal components:

1. a formula by which facility-level emissions-intensity targets would be established;
2. provisions to allow for trading of emissions allocations between firms;
3. an offset system through which facilities not covered by the emissions-intensity targets may certify and sell credits for emissions reductions; and
4. a flexibility mechanism through which covered facilities may achieve compliance with the regulation by contributing to a fund, which would be used to invest in emissions-reduction projects.

When the SGER was introduced, it was widely panned by environmentalists, for several reasons. First, it was thought to be insufficiently stringent to generate real emissions reductions. This criticism was validated by the October 2008 report of Alberta's auditor general, which stated that "[t]he 14% reduction target [from 2005 levels by 2050] in [Alberta's Climate Change] Strategy is based on actions that are more stringent than the actions the Strategy chose."[10] Second, it was thought that the SGER's reliance on emissions-intensity targets implied that it could not be expected to generate reductions in absolute emissions. For example, in a study of GHG policy options sponsored by Alberta's Pembina Institute, Demerse and Bramley pointed out that "intensity targets can be met while absolute emissions rise if production grows rapidly."[11] Third, it was thought that the allocations were too generous and the compliance price was too low, so that the program would not generate sufficient benefits from emissions reductions for firms. Therefore, Demerse and Bramley concluded, "Alberta's regulatory policy (unless it is strengthened or supplemented with complementary policies) is virtually guaranteed to fail the test of environmental effectiveness."[12] Finally, in a critique that is borne out by the results presented in this article, policies based on emissions-intensity targets, including the SGER, were panned on economic efficiency grounds. According to Demerse and Bramley, "inten-

10 Alberta, Auditor General, *Report of the Auditor General of Alberta* (Edmonton: Auditor General of Alberta, October 2008), at 99.

11 Clare Demerse and Matthew Bramley, *Choosing Greenhouse Gas Emissions Reduction Policies in Canada* (Drayton Valley, AB: Pembina Institute, October 2008), at 34.

12 Ibid., at B-10.

sity targets (and/or the use of offset credits) will result in different types of reductions being priced differently."[13]

Since 2007, the GHG policy environment has shifted considerably. The United States is no longer moving forward with economy-wide carbon pricing, as had been proposed under the American Clean Energy and Security Act of 2009[14] (the so-called Waxman-Markey bill); the bill was passed by Congress but not by the Senate. Within Canada, only British Columbia with its carbon tax has implanted a more broadly based and/or more stringent price on carbon emissions than Alberta's SGER. This notwithstanding, many myths remain about the emissions-intensity system, its design, and its implicit incentives for GHG reduction. In this article, I first introduce the regulation in detail, then discuss the results of the program during its first three years of implementation, and finally examine the validity of criticisms with respect to the low price, the emissions-intensity basis, and the allocation of emissions rights.

HOW THE SGER WORKS

The SGER has five key provisions. These respectively

- determine coverage,
- establish allocations of emissions rights,
- provide for trading,
- allow for the certification and sale of offsets, and
- allow firms to achieve compliance through payments into a fund rather than through direct emissions reductions.

Facilities with annual emissions greater than 100,000 t of GHG emissions, measured in tonnes of carbon dioxide equivalent (CO_2e), are subject to the SGER. For facilities in operation before January 1, 2000, an emissions-intensity baseline was established as the average emissions intensity (GHG/unit of output) over the years 2003-2005. For newer facilities, the emissions-intensity baseline is based on the facility's third year in operation.[15]

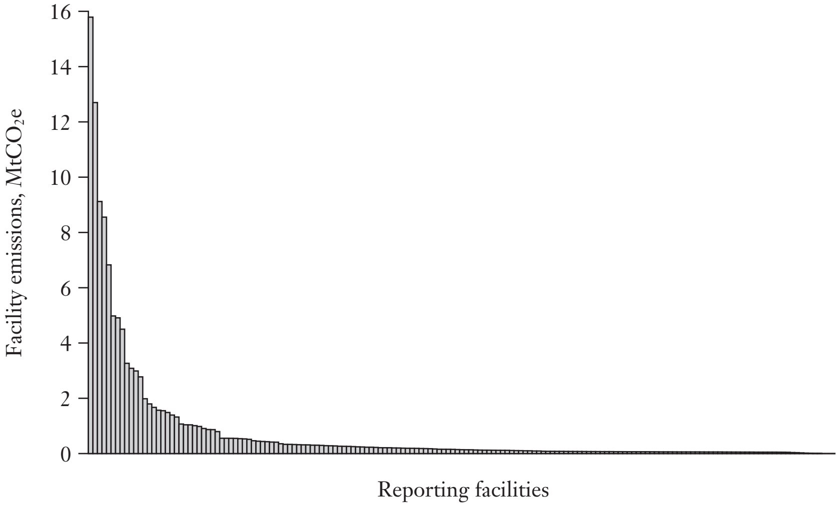
Alberta requires GHG reporting by all facilities with emissions totalling over 50,000 t/yr. Data from 2010 show total reported emissions of 122.5 million tonnes (Mt) from 165 facilities, with 97 facilities reporting emissions over the SGER threshold of 100,000 t/yr. Emissions from these facilities accounted for 114.9 Mt. As shown in figure 1, emissions are highly concentrated in the largest facilities: the 10 largest facilities account for approximately 60 percent of reported emissions, while the 30 largest account for over 80 percent of reported emissions. Accordingly, the

13 Ibid., at 36.

14 HR 2454, American Clean Energy and Security Act of 2009, 111th Cong., 1st sess. (2009).

15 Emissions per barrel tend to be higher in the first months of operation. Alberta is moving to an approach based on the third through fifth years of operation for new facilities. (This information is based on personal communication with Alberta government officials.)

FIGURE 1 Greenhouse Gas Emissions Reported by Facilities in Alberta, 2008



$MtCO_2e$ = Million tonnes of carbon dioxide equivalent

Source: Alberta Environment (2012) (http://environment.alberta.ca/02166.html).

SGER threshold is set such that changing it would not have a significant impact on covered emissions; reducing it by half or doubling it would change covered emissions by less than 10 percent.

Under the SGER, facilities are allocated emissions rights on the basis of their qualifying production in each year. Facilities are allowed an emissions intensity of 88 percent of their baseline level, and any emissions over and above that threshold (referred to as the facility's "allowable level") would require the facility to take additional action to achieve compliance with the regulation.

Facilities that are not responsible for emissions reductions under the SGER may still profit from emissions reductions through the offset protocol. Under these rules, facilities that undertake verified emissions reductions through various activities receive emissions offset credits that they can sell to firms covered by the SGER. The offset program is of particular interest because of both what it includes and what it does not. First, the only facilities eligible for participation are those in Alberta, thus restricting the pool of available emissions reductions. Second, the offset protocol initially allowed credits to be issued for projects that were begun as early as 2002, well before the SGER was announced, thereby opening the pool to emissions reductions not directly induced by the regulation.[16] Allowing projects begun before the regulation was announced seems to contradict the spirit of "additionality," defined in the offset project development protocol as the assurance that "the activity being

16 As of January 1, 2012, the Alberta government has amended the offset system such that crediting for historic reductions achieved before the SGER was implemented is no longer permissible.

credited is additional and results in emissions reductions that would not otherwise have occurred."[17]

A facility covered under the SGER has four means of compliance with the regulation. First, and most obviously, the facility may comply directly by reducing its emissions intensity by 12 percent, to its allowable level, or more. If a facility reduces its emissions intensity below its allowable level, each additional tonne of emissions reduction would generate an "emissions performance credit," which can be banked for future years or transferred to another facility.

Facilities with emissions above their production-based allowable levels can choose one of three means of ex post compliance. First, they can purchase emissions performance credits, as described above, from another covered facility. Second, they can purchase offsets, also described above, from an Alberta-based provider, or they can obtain compliance credits or generate their own offsets from the implementation of certain technologies, such as carbon capture and storage (CCS) or electricity and steam/heat cogeneration. Finally, they can contribute to the Climate Change and Emissions Management Fund (CCEMF) at a rate of $15/t of compliance credit required.

The creation of the CCEMF (similar to a proposed technology fund at the federal level) allows firms to offset emissions above their facility-specific target by making monetary contributions based on a specified rate. The CCEMF is administered by the Climate Change and Emissions Management Corporation (CCEMC),

> an arm's-length organization independent from government that is responsible for investing money collected in the Fund into initiatives and projects that support emission reduction technologies and improve our ability to adapt to climate change in Alberta.[18]

The contributions made to the CCEMF are transferred each year in the form of a grant to the CCEMC. Since the inception of the SGER, the fund has collected over $300 million and the CCEMC has committed over $125 million to emissions-reduction projects.[19]

Compliance with the SGER in 2011 was accomplished through direct facility-level compliance (1.5 Mt), payments into the CCEMF (3.7 Mt), offset purchases (5.3 Mt), and the retirement of emissions performance credits (1.0 Mt).[20] Facilities were also granted credits for the use of cogeneration, but these are attributed before compliance obligations are calculated and so are not included here.

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17 Alberta Environment and Water, *Technical Guidance for Offset Project Developers: Specified Gas Emitters Regulation* (Edmonton: Alberta Environment and Water, February 2012), at 19.

18 Alberta Environment and Sustainable Resource Development, "Climate Change and Emissions Management Fund" (http://environment.alberta.ca/02486.html).

19 Ibid. The latter figure is a combination of two publicly available data points. As of September 2011, the CCEMC reported having received $257 million, and the Alberta government reported an additional $55 million in contributions to the CCEMF for the 2011 compliance period.

20 Oil Sands Information Data Library (http://environment.alberta.ca/apps/OSIPDL/Dataset/Details/18).

Example of a Covered Facility

To build understanding of how the SGER works in practice, I introduce the following specific example, which I will use in assessing the incentives provided by the program.

The Athabasca oil sands project's Muskeg River mining complex (operated by Shell) is subject to the SGER, given that it generates emissions of well over 100,000 t/yr. As shown in figure 2, in 2008 the total on-site emissions for the complex were 1.7 $MtCO_2e$, including both the cogeneration unit and emissions related to bitumen production. For SGER purposes, the mine and electricity cogeneration facilities report separately, and we can decompose their respective compliance activities as follows.

The mine has an emissions performance benchmark of 0.048 tonnes per barrel (t/bbl) of bitumen, from which it was required, in 2008, to reduce emissions by 4 percent since it was in the second year of coverage under the policy.[21] Accordingly, its allowable emissions were 0.046 t/bbl. Emissions from the mine in 2008 were 566,910 t on 7.35 million cubic metres of total bitumen production, at an intensity of 0.077 t/bbl. As a result, the facility faced a compliance gap of 228,969 tCO_2e.

To achieve compliance at the mine site, the facility had three remaining options, and Shell's decisions in this regard are shown in figure 2. Shell retired emissions performance credits equivalent to 120,460 tCO_2e and made contributions to the CCEMF at the rate of \$15/tCO_2e, which offset 108,534 tCO_2e of emissions.[22] The cogeneration site, which operated below its performance standard, generated 250,220 tCO_2e of emissions performance credits, which will be usable in future years.[23]

Cogeneration facilities are assessed via a complex compliance calculation under the SGER. First, any emissions attributable to incremental electricity generation are not counted either for benchmarking or for compliance purposes. Second, the facility is granted credits for cogeneration efficiency, based on the emissions that would have been required to generate the heat and power separately net of the emissions of the cogeneration plant.[24] With these two treatments in place, the cogeneration facility exists as a regulated entity in and of itself within the SGER. If its emissions intensity, net of the treatment for electricity emissions and the credits for cogeneration efficiency, is lower than its compliance benchmark, it generates emissions performance credits, as was the case for the Muskeg River Cogeneration Station in 2008.

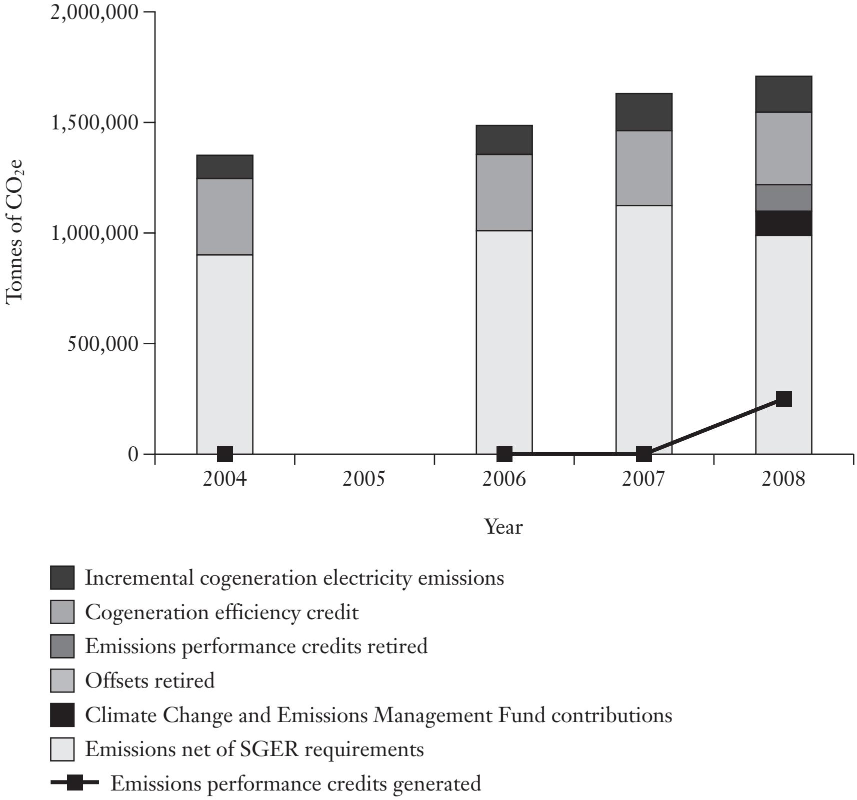
21 New facilities are required to reduce emissions intensity incrementally by 2 percent per year up to the maximum of 12 percent.

22 Figures are sourced from Alberta Environment compliance data, supra note 20. There are some differences in the figures reported here because of rounding.

23 See supra note 22.

24 Alberta's cogeneration protocol bases the hypothetical emissions against which cogeneration emissions are judged on 80 percent boiler efficiency and a natural gas combined cycle generator (0.418 tCO_2e/MWh).

FIGURE 2 On-Site Emissions and SGER Compliance Activity for the Muskeg River Mine and Cogeneration Complex, 2004-2008



SGER = Specified Gas Emitters Regulation
CO_2e = Carbon dioxide equivalent

Notes: The first period of mandatory reductions for established facilities was July 1 to December 31, 2007. Details of the method of compliance for the 2007 half-year period are currently unavailable. All subsequent compliance cycles cover entire calendar years.

Source: Oil Sands Information Library (http://environment.alberta.ca/apps/OSIPDL/Dataset/Details/18).

HOW DOES THE SGER COMPARE WITH A CARBON TAX OR A CAP-AND-TRADE REGIME?

Alberta's SGER puts a price on carbon emissions, but it does so in a way that is different from a carbon tax charged on every tonne of emissions or, equivalently, a cap-and-trade regime in which permits are auctioned. Below, I consider the effect of these policy mechanisms, each with a price of \$15/t, on existing facilities and on potential new entrants.

Existing Facilities

Using the Muskeg River example from above, and concentrating only on the mine, the 2008 annual emissions from that facility would yield a carbon tax liability of approximately $8.5 million (566,000 t × $15). By contrast, under the emissions-intensity approach of the SGER, the 228,969 t compliance gap would cost slightly over $3.4 million if all compliance were achieved financially through contributions to the CCEMF or through the purchase of comparably priced offsets. This implies an average cost of emissions of $6.05/t for the SGER and $15/t for the carbon tax.

This lower average cost of emissions under the SGER relative to a carbon tax is often confounded with significantly lower incentives to reduce emissions. For example, a report by the Pembina Institute stated that "[t]he incentive to undertake emission reductions by lowering the output of an industrial activity is at most $1.80 per tonne (12% × $15) because of the SGER's intensity targets."[25] Further, a recent report from the David Suzuki Foundation stated that "Alberta's $15/tonne partial carbon price (Specified Gas Emitter Regulation) applies to only 12 per cent of emissions from large industrial polluters reducing the equivalent incentive for clean energy (carbon price) to less than $5/tonne of emissions."[26] This hypothesis seems to permeate much of the criticism of the SGER, but it does not accurately express the economic incentives created by the policy. The average cost in the Muskeg River case is higher than the $1.80/t often cited for the SGER because the facility is operating above its benchmark level, and therefore paying the carbon charge on a larger proportion (approximately 40 percent) of its emissions.

Under a policy based on emissions intensity and/or one that allocates a significant number of emissions credits, the incentives to reduce emissions will differ from those created by a carbon tax, but it is not accurate to say that such a policy systematically values emissions reductions at a lower implicit price. In fact, for many potential emissions reductions, the payoff will be equivalent under the Alberta system to that under a similarly priced carbon tax. In other cases, the Alberta system may provide either more or less reward to emissions reductions than that which would be provided under a carbon tax.

Using the example above of the Muskeg River facility, we can consider three types of reductions in emissions.

1. a direct reduction in emissions, which might be accomplished, for example, by the deployment of emissions reduction technology such as CCS;
2. a reduction in emissions resulting from a reduction in output, whether or not the reduction in output is related to GHG concerns; and

25 Matthew Bramley, Marc Huot, Simon Dyer, and Matt Horne, *Responsible Action? An Assessment of Alberta's Greenhouse Gas Policies* (Drayton Valley, AB: Pembina Institute, December 2011), at 13.

26 Miranda Holmes, with contributions from Paul Lingl, Dale Marshall, Ian Bruce, Morag Carter, and Faisal Moola, *All Over the Map 2012: A Comparison of Provincial Climate Change Plans* (Vancouver: David Suzuki Foundation, 2012), at 23.

3. a reduction in emissions intensity resulting from increased productivity, whereby the same quantity of emissions produces a higher level of output.

These types of reductions in emissions intensity are expected to be seen with the deployment of solvent-aided extraction technology in oil sands, for example. The results of this comparative statistical analysis are shown in table 1.

How would the installation of technology that, all else being equal, reduced GHG emissions by 100,000 t change the compliance cost for Muskeg River? A reduction in emissions without a corresponding change in production is a perfect substitute for achieving compliance through the CCEMF, so the value of such a reduction would be $1.5 million, or 100,000 t at $15/t. If the same innovation were contemplated by a firm facing a $15/t carbon tax charged on every tonne of emissions, the payoff in terms of avoided carbon tax payments would also be $1.5 million. So, for innovations that reduce emissions intensity, the payoff between Alberta's SGER and a similarly priced carbon tax regime would be identical.

The second possibility is to reduce emissions through a reduction of output, the type of emissions reduction described in the quotation from the Pembina Institute report above.[27] Here, we do see significant differences between the SGER, which rewards reductions in emissions intensity, and a carbon tax, which rewards reductions in emissions regardless of the means by which they are achieved. Assuming that the facility reduced production by 10 percent, and that emissions decreased proportionately (a simplifying assumption), the facility's emissions intensity would not change, so its carbon liability per barrel of oil produced would also remain constant. The reduction in production would, in addition to its forgone value, reduce the facility's total GHG liability by +/−10 percent, depending on the assumptions made with respect to the cogeneration facility. Given that the facility is producing above its benchmark emissions intensity, the average savings per tonne of emissions reduced through an output reduction is higher than it might otherwise be, at $6.05/t. If the facility were producing at its historic benchmark emissions intensity, the savings from a reduction in output would be $1.80/t, as cited by the Pembina Institute report above. The incentive to reduce emissions through reductions in output will be lower under the SGER, but clearly there is no upper bound of $1.80 on this incentive.

Since the incentive to reduce emissions through a reduction in output is a point of contention with respect to the SGER, a more formal analysis of this option is required. The incentive to reduce production will depend on the state of the facility with respect to its current emissions per barrel and its historic benchmark. Let B represent the benchmark, and E represent the current emissions per barrel from production. The compliance gap on every barrel produced is $(E - B)$, with an associated compliance cost per barrel of $t(E - B)$ where t is the compliance fee. If no

27 See supra note 25 and the accompanying text.

TABLE 1 Changes in Emissions and Compliance Costs for an Existing Facility Under the SGER and a Hypothetical Carbon Tax

		SGER		Carbon tax	
	GHGs (t)	Compliance costs ($ million, annual, assuming all compliance achieved through the CCEMF)	Compliance cost per tonne of emissions ($/t)	Costs ($ million, annual)	Cost per tonne of emissions (undiscounted $/t)
Base case	566,000	3.4	6.05	8.5	15.0
Changes in emissions and compliance costs					
100,000 t decrease in emissions, production held constant	(100,000)	(1.5)	(15.0)	(1.5)	(15.0)
10% reduction in output holding emissions intensity constant	(56,600)	(0.343)	(6.05)	(0.849)	(15.0)
10% increase in production holding emissions constant	nil	(0.507)	na	nil	na

t = tonne
SGER = Specified Gas Emitters Regulation
CCEMF = Climate Change and Emissions Management Fund

baseline emissions intensity is allowed, equivalent to $B = 0$, the incentives are identical between a tax and the SGER. Only where $B = 0.88E$ will the incentive to reduce emissions through a reduction in production have an average reward of \$1.80/t. If E is exactly equal to B, then there is no compliance cost and thus no gain from a reduction in production. If $E < B$, the facility is generating permits, so there is a cost to reducing emissions through a reduction in production. The implicit reward for reducing emissions through a reduction in production is bounded from above by \$15, and has no lower bound.[28]

The third considered change is one that yields higher productivity, increasing production while holding emissions constant. This case is analogous to the first case considered. Suppose that Muskeg River can increase production by 10 percent while maintaining the same emissions. With this innovation, the facility would increase its GHG allocation by 33,794 t (allowable emissions of 0.046 t/bbl in the current year × 734,910 new barrels of production), which would in turn reduce its compliance liability under the SGER by \$506,911, to just under \$8 million, while GHG emissions remain constant. In the case of the carbon tax, the constant GHG emissions would imply a constant liability, so no direct GHG advantage would result from the improved technology. In both cases, the facility would still benefit from the value of the increased production.

To summarize, the above analysis shows that for existing facilities,

- the incentives to reduce emissions per unit of output are equivalent for the SGER and a carbon tax,
- the incentives to improve productivity per unit of emissions are stronger with the SGER, and
- the incentives to reduce emissions by reducing production are stronger with the carbon tax.

New Facilities

The section above considers the impact of the three emissions pricing policy options on emissions at individual facilities, or the intensive margin. This section considers the extensive margin, and asks how each of those policies would affect the decision to build a new facility. The results are summarized in table 2, and discussed below.

Here, we consider a new 20,000 barrels per day (bbl/d) oil sands facility,[29] with expected emissions per barrel of production in the range of 108 kilograms per barrel

28 Theoretically, the cost of reducing GHG emissions by reducing production is bounded from above by infinity, since a facility that had reduced emissions to zero after the benchmark was imposed would be forgoing emissions performance credits but having no impact on emissions by reducing production. The division of the amount of forgone permit revenue (>0) by the amount of emissions reductions (0) is undefined, but the limit is positive infinity.

29 I assume that 20,000 bbl/d is the average annual production, not the nameplate capacity, for the purposes of these calculations.

TABLE 2 Base Case Compliance Costs and Changes in Emissions and Compliance Costs Attributable to Changes in Project Emissions and Production Dynamics

		SGER		Carbon tax	
	GHGs (Mt)	Compliance costs (NPV, $ million)	Compliance cost per tonne of emissions (undiscounted $/t)	Costs (NPV, $ million)	Cost per tonne of emissions (undiscounted $/t)
Base case	27.59	6.9	1.47	115.30	15.0
Changes in emissions and compliance costs					
10% decrease in emissions per barrel	(2.76)	(0.69)	(1.47)	(11.5)	(15.0)
10% increase in production	2.76	0.69	1.47	11.5	15.0
Annual 1% improvement in GHG/bbl	(4.21)	(6.15)	(12.54)	(8.7)	(15.0)
Annual 1% improvement from year 4 onward	(3.54)	(6.13)	(15.0)	(6.13)	(15.0)
10% increase in production holding emissions constant	nil	nil	nil	nil	nil
10% increase in production holding emissions constant from year 4 onward	nil	(6.77)	na	nil	nil

t = tonne
SGER = Specified Gas Emitters Regulation
NPV = net present value
GHG/bbl = greenhouse gas emissions per barrel

(the average for current in situ projects). For simplicity, the following calculations assume that emissions intensity remains constant over time except where specified, although in reality we would see emissions intensity varying over the life of the project. The project is also assumed to produce at a constant rate for 35 years, ignoring project ramp-ups and ramp-downs. Finally, all figures are pre-royalty and pre-tax.

The SGER as initially implemented would assess the facility in its third year of production to set emissions-intensity baselines. From the fourth year through the ninth, the facility would be required to reduce its emissions intensity by 2 percent per year, to a cumulative 12 percent per year applied from year 9 onward. Any emissions over and above those permitted emissions would need to be compensated for by offset purchases or contributions to the CCEMF (assumed to remain constant at \$15/t). Similarly, a carbon tax or a cap-and-trade regime would charge \$15/t of emissions through the life of the facility.

The difference in net present value (NPV) costs between the two policies considered is stunning. Assuming constant production and emissions per barrel over the 35-year time horizon, the SGER liability would amount to \$6.9 million NPV at a 10 percent rate of discount, or the equivalent of an extra \$346 of upfront cost per "flowing barrel" of production capacity.[30] By contrast, the carbon tax or auctioned cap-and-trade at \$15/t adds \$115 million in NPV costs, the equivalent of \$5,765 per flowing barrel. For a typical oil sands facility with a capital cost of \$40,000/flowing bbl, the SGER adds the equivalent of a 0.9 percent increase in upfront costs, while the carbon tax or a similarly priced cap-and-trade regime would be equivalent to a 14.4 percent increase in the upfront cost in NPV terms. Clearly, the SGER will have far less impact on new investment than would a carbon tax or a similarly priced cap-and-trade regime. Compliance costs per tonne of emissions, using undiscounted dollars, average \$15/t for the carbon tax and \$1.46/t for the SGER. The latter figure is below the often-cited \$1.80/t (12% × \$15/t) because of the initial grace period up to year 4 that is allowed for new facilities under the SGER.

The policies also differ in the way in which they reward the construction of higher-performance facilities. Suppose that the possibility existed to build a facility such that emissions per barrel would be lower by a factor of 10 percent. The GHG liabilities would be reduced in each case, but by different amounts. First, for the SGER, the reduction in emissions intensity from the outset means a reduction in the facility's entitlement to emissions per unit of production from 0.095 t/bbl to 0.086 t/bbl, and reduces the NPV cost of the policy to the facility by \$691,000, to \$6.22 million, a proportional savings of 10 percent. The carbon tax and auctioned cap-and-trade regimes also induce the same percentage savings, but the relative size of the liabilities in the base case implies that the reward is greater under the carbon tax or auctioned cap-and-trade than under the SGER. For the same innovation, the

30 "Per flowing barrel" refers to a calculation per barrel of production capacity—the NPV cost divided by 20,000 in this case. By contrast, consider that the capital costs for oil sands facilities may be up to \$100,000/flowing bbl.

NPV saved would be $11.5 million under the carbon tax. The reward in undiscounted dollars per tCO_2 reduced through the construction of the new facility in this case is $1.47/t for the SGER and $15/t for the carbon tax or auctioned cap-and-trade.

The same result in terms of the implied emissions price would hold in the case of the decision to expand production in a planned facility. If it were possible to increase the scale by 10 percent while maintaining constant emissions intensity (emissions per barrel), then the facility's GHG liability would increase by $691,000 under the SGER, an average charge of $1.47/t for new carbon emissions. The equivalent expansion under a carbon tax or auctioned cap-and-trade regime would increase the project's cost by $11.5 million, an average emissions charge of $15/t.

If we consider an innovation that improves the productivity per unit of emissions, we see identical implications for the two policies in terms of the incentives provided at the project level. Rather than decreasing the emissions and holding production constant, consider a change whereby production increases by 10 percent holding emissions constant—still a decrease in emissions per barrel. In this case, the carbon tax (or auctioned cap-and-trade) liability for the facility remains constant since emissions do not change, although the liability per barrel would decrease with the increased production. The same is true for the SGER. With a 10 percent decrease in emissions intensity, the facility would also see a 10 percent decrease in its emissions intensity allocations in each period. Since the allowable emissions intensity and the actual emissions intensity each decrease by 10 percent, the compliance gap per barrel will also decrease by 10 percent. However, this is offset by the 10 percent increase in production, leaving the total cost of compliance with the SGER unchanged.[31] So, for increases in productivity holding emissions constant at the design phase, the carbon tax and the SGER provide identical incentives. This is important since many new projects may have options to build in new technologies at the design phase that would increase the facility's productivity. For example, Cenovus Narrows Lake has included in its project application the option to deploy solvent-aided extraction processes that would increase productivity per unit of emissions by approximately 10 percent. The analysis above shows that while this type of innovation would reduce the aggregate emissions intensity of oil sands supply, it would not be rewarded directly by either a carbon tax or auctioned cap-and-trade regime, or the SGER.

This result occurs because the SGER thresholds are based on historic emissions intensities. While the new projects considered above have higher performance, that superior performance is penalized with a tighter emissions-intensity requirement, offsetting the gains. The outcome would be different if the improvements in productivity considered above were delayed until after the year in which the SGER

31 In the example, the emissions per barrel would decrease from 0.108 t/bbl to 0.982 t/bbl, and so the long-run SGER compliance target would decrease from 0.095 t/bbl to 0.0864 t/bbl. The compliance gap would be reduced from 0.013 t/bbl to 0.012 t/bbl (a reduction of 10 percent), but this would be applied to 10 percent more barrels, leaving an identical total compliance cost.

benchmark was established. In such a case, the project's GHG liabilities still would not change under the carbon tax with a 10 percent increase in productivity, but would be reduced by $6.77 million under the SGER, essentially eliminating compliance costs.

Finally, the policies provide different rewards for ongoing improvements in new facilities. Suppose we allow emissions per barrel to decrease by 1 percent per year throughout the life of the facility. Under the carbon tax, an annual improvement in emissions intensity of 1 percent would yield NPV savings of $8.7 million over the 35-year life of the project. The same improvement under the SGER would yield NPV savings of $6.15 million. In undiscounted dollar terms, the carbon tax would reward the emissions reductions at $15/t, while the SGER would reward the achieved emissions reductions at an average rate of $12.54/t.[32]

The results are different again if the improvement occurs later in the project life cycle. Consider a 1 percent per year improvement that begins in the fourth year of operations (such that the baseline emissions intensity for the SGER remains at 0.108 t/bbl). In the case of a carbon tax or auctioned cap-and-trade regime, the resulting emissions reductions are still rewarded at a value of $15/t, but where the development occurs after the baseline emissions intensity is set, this is also true for the SGER, since the capitalization effect of historic emissions intensity is removed from the equation by delaying the improved performance.

To summarize, for new facilities,

- a carbon tax or cap-and-trade regime tends to discourage development with high NPV costs, more so than does the SGER at a comparable price; and
- given that development occurs, the SGER provides a weaker incentive for the implementation of technologies that reduce GHGs per barrel at the point of design, but it does reward facilities that are able to increase their productivity per unit of emissions later in the project life cycle.

CONCLUSIONS

This article has examined Alberta's SGER, describing its key attributes and comparing the inherent incentives to reduce emissions with a similarly priced carbon tax or cap-and-trade regime. The analysis has shown that, for an existing facility, the SGER provides identical incentives to reduce emissions intensity, weaker incentives to reduce emissions through reductions in output, and stronger incentives to improve productivity. For new facilities, it is shown that a carbon tax, or a cap-and-trade regime with auctioned permits, provides a significant barrier to investment with high NPV costs, but also provides stronger incentives for building a better-performing facility and at least as strong an incentive for ongoing improvement.

32 As noted earlier, Alberta is in the process of altering the treatment of new facilities such that baselines would be calculated over the third, fourth, and fifth years of operation, lengthening the grace period and thus widening this difference slightly.

The difference in incentives to reduce emissions intensity through increased productivity is important since many innovations in the oil sands sector are expected to affect emissions in this way. For example, technology such as wedge wells or solvent-aided extraction processes are expected to yield 5 to 15 percent increases in production while holding emissions roughly constant at the facility level. As shown above, for these types of improvements, the SGER would provide a stronger financial incentive for adoption of these technologies in a retrofit application than would a comparably priced carbon tax or cap-and-trade regime.

The results of the analysis presented in this article show that the SGER provides equivalent or weaker incentives to undertake emissions reductions than would a carbon tax, but that these are not as weak as is often suggested by environmental groups. Perhaps more importantly, it is shown that the SGER provides very different financial incentives for emissions reductions derived through different actions or changes, detracting from the economic efficiency of the policy. Finally, the results illustrate the importance of considering two separate measures of policy stringency, the marginal cost (or costs, in the case of the SGER) and the average cost. Since the average cost of the SGER tends to be very low, the policy will have less effect on the overall financial viability of new investments than would a comparable carbon tax.