resilient LLP

March 26, 2022

**VIA RESS**

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
Attention: Registrar

Dear Ms. Marconi,

**Re: Enbridge Gas Inc.**
**Multi-Year Demand Side Management Plan (2022-2027) Application**
**Board File No.: EB-2021-0002**

We are counsel to the Association of Power Producers of Ontario (**APPrO**) in the above-noted proceeding. Please find attached APPrO's compendium in aid of cross-examination for Panels 1 and 2 for the oral hearing scheduled to begin on March 28, 2022.

Sincerely,

Jonathan E McGillivray

Jonathan McGillivray

c. All Parties to EB-2021-0002

Encl.

Jonathan McGillivray • Bay Adelaide Centre • 333 Bay Street, Suite 625 Toronto, ON M5H 2R2 • +1.647.208.2677 • jonathan@resilientllp.com

**ONTARIO ENERGY BOARD**

**IN THE MATTER OF** the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended (the **Act**);

**AND IN THE MATTER OF** an application by Enbridge Gas Inc. pursuant to section 36(1) of the Act, for an order or orders approving its Demand Side Management Plan for 2022-2027.

**EB-2021-0002**

**ASSOCIATION OF POWER PRODUCERS OF ONTARIO**

**(APPrO)**

**CROSS-EXAMINATION COMPENDIUM**

**PANELS 1 AND 2**

**March 26, 2022**

**INDEX**

# ENBRIDGE GAS DSM PLAN – LARGE VOLUME PROGRAM

## Large Volume Program Strategy

1. Enbridge Gas's proposed Large Volume program builds on the successes and learnings of the existing Large Volume program, with modifications intended to be responsive to customer feedback. Enbridge Gas reviewed a variety of inputs in designing the Large Volume program, including the following:
   - The objectives outlined in the OEB's December 1, 2020 letter (EB-2019-0003);[1]
   - The guiding principles outlined in Enbridge Gas's Proposed Framework;[2]
   - Lessons learned by Enbridge Gas while delivering offerings to the large volume sector; and
   - Feedback from stakeholders received through the course of the 2015-2020 Multi-Year DSM Plan, subsequent 2021 DSM Plan, and over the course of the development of this application.

2. The Large Volume program is directly targeted to the following rate classes within the Union rate zones: Rate T2 (Storage and Transportation Rates for Large Volume Contract Carriage Customers – Union South) and Rate 100 (Large Volume High Load Factor Firm Service – Union North). The customers in these rate classes are generally classified as industrial (e.g., steel, pulp and paper, auto manufacturers), chemical manufacturers and refineries, and gas fired electricity generators. These sophisticated customers have extremely high natural gas consumption and while some are competitively motivated to ensure their systems are efficient, others require the input of Enbridge Gas's Technical Account Managers and financial incentives to prioritize undertaking energy efficiency measures.

[1] EB-2019-0003, OEB Letter Post-2020 Natural Gas Demand Side Management Framework (December 1, 2020), p. 2.
[2] EB-2021-0002, Application, Proposed Framework, Exhibit C, Tab 1, Schedule 1, pp. 6-8.

3. Rate T2 is a contract rate for customers in the Southern operations area who actively manage their own storage services and require a minimum aggregated Firm Daily Contract Demand of at least 140,870 $m^3$ for all redelivery points.

4. Rate 100 is comprised of large commercial and industrial customers who have signed a Northern Distribution contract for firm natural gas delivery with Enbridge Gas. These customers are typically large manufacturers requiring a very large volume of natural gas for industrial processes – such as steel, pulp and paper and mining. These customers, located in Enbridge Gas - Union North rate zone, require a minimum consumption of 100,000 $m^3$ of natural gas or more each day. These customers must maintain a 70% load factor over the course of a year.

<u>Lessons Learned</u>

5. Large volume customers utilize very large amounts of natural gas in their operations. Energy purchases are, in most cases, a significant contributor to overall production costs. However, due to their focus on production, quality, reliability, and safety, energy efficiency is sometimes viewed as a less important priority. As a result, there is an opportunity to help customers with their efforts to optimize the energy efficiency of their operations.

6. Enbridge Gas's Technical Account Managers are Professional Engineers with expertise in industrial energy efficiency and natural gas applications. Technical Account Managers engage with customers to provide industry perspective, share best practices, and support project adoption. Technical Account Managers are assigned dedicated coverage to assist customers identify, quantify, test, track, and implement energy efficiency opportunities. In this way, Enbridge Gas is able to work one on one across the varied customer group, supporting site-specific solutions and

helping these impactful customers maintain engagement on energy efficiency as a focus.

**Large Volume Program Proposal**

7. In January 2016, the OEB issued its Decision and Order on the 2015-2020 DSM plans, in which it determined that “Union’s large volume customers should be part of Union’s DSM programs”[3] and further, “that the significant benefits of continuing Union’s self-direct Large Volume program outweigh the costs of delivery and it would be inappropriate to stop a program that has been so cost-effective.”[4]

8. More recently, despite many customers who have communicated their support of the program, a select few customers have suggested that the Large Volume DSM program should be discontinued. Specific engagement with large volume stakeholders is discussed in Exhibit E, Tab 4, Schedule 6. In an effort to appeal to all interests, Enbridge Gas has made two changes to the existing Large Volume program, as follows:
   i) To decrease DSM related rate impacts in the Rate 100 and T2 large volume rates classes, Enbridge Gas has reduced the Large Volume program budget, including proposing a smaller incentive pool available to these customers. The proposed Large Volume program budget has been reduced by approximately 20%. The relative program budgets are detailed in Exhibit D, Tab 1, Schedule 1.

   ii) Enbridge Gas has removed some current limitations on measures that are eligible for incentives. In this way, the customer will have an increased opportunity to utilize the program and the incentives, based on a broadened

[3] EB-2015-0029 / EB-2015-0049, OEB Decision and Order (January 20, 2016), p. 50.
[4] Ibid, p. 51.

range of potential efficiency projects driven by the particular customer's priorities and needs.

Objectives and Guiding Principles

9. The small number of customers targeted through the Large Volume program represent a significant portion of Enbridge Gas's overall natural gas throughput. There are approximately 37 customers anticipated in the combined rate classes for 2023, who collectively consume over 5 billion cubic meters of natural gas per /u annum, or approximately one fifth of Enbridge Gas's yearly consumption. Given the considerable volume, DSM activities amongst this group has the potential to have a large impact on overall natural gas savings and net benefits.

10. Delivering DSM programming to large volume customers is consistent with both the primary and secondary objectives outlined in the OEB's December 1, 2020 letter, as follows:

> …the OEB is of the view that the primary objective of ratepayer-funded natural gas DSM is assisting customers in making their homes and business more efficient in order to help better manage their energy bills.[5]

The OEB's letter further states:

> In working towards the primary objective, Enbridge Gas's ratepayer-funded DSM plan should also consider the following secondary objectives:
>
> - Help lower overall average annual natural gas usage.
> - Play a role in meeting Ontario's greenhouse gas reductions goals.[6]

11. The Large Volume program is also in line with guiding principles outlined in the Proposed Framework including

[5] EB-2019-0003, OEB Letter Post-2020 Natural Gas Demand Side Management Framework (December 1, 2020), p.2.
[6] Ibid, p.3.

- DSM Plans should be designed to provide opportunities for a broad spectrum of consumer groups and customer needs to encourage widespread customer participation over time and "ensure all segments of the market are reached."[7]
- DSM plans should include strategies to increase the natural gas savings by targeting key segments of the market and/or customers with significant room for efficiency improvements.
- DSM plans should minimize lost opportunities for energy efficiency and should be designed to pursue long term energy savings.

**Direct Access Offering**

Background

12. Enbridge Gas has been delivering the Direct Access offering to Large Volume customers since 2013. The self-direct model has been largely well received by participants with a few exceptions. The offering continues to drive substantial cost-effective results.

13. The program provides an important opportunity for Enbridge Gas Technical Account Managers to work with these key gas customers to continue to drive natural gas savings. The direct access approach compels these customers to work with Enbridge Gas Technical Account Managers to execute on identified energy efficiency opportunities and access their portion of available incentives and services. Importantly, even with current higher free-ridership rates, given the size of these customers and the volume of consumption, the program drives substantial net gas savings that are cost-effective.

14. Further, Enbridge Gas continues to believe, given the nature of the self-direct offering, all eligible customers are provided with the opportunity to use a distributed

[7] EB-2019-0003, OEB Letter Post-2020 Natural Gas Demand Side Management Framework (December 1, 2020), p. 5.

portion of the funds for energy efficiency upgrades reducing the risk of cross-subsidization.

Objective

15. The goal of this offering is to encourage Large Volume customers to maintain a focus on energy efficiency by encouraging the development of an Energy Efficiency plan and take action on identified efficiency opportunities.

Target Market

16. This offering is delivered to customers in Rate T2 and Rate 100 in the Union rate zones. These customers are generally classified as Industrial (steel, pulp and paper, auto manufacturers), chemical manufacturers and refineries, and gas fired electricity generators.

Offering Details

17. In order to participate in the Direct Access offering, customers must:
    - Submit an Energy Efficiency Plan (“EEP”), authored with the assistance of Enbridge Gas Technical Account Managers. The EEP serves as a roadmap allowing customers and Enbridge Gas to actively work together, driving energy efficiency projects at customers’ sites and facilities. Projects identified on the EEP are earmarked for funding.
    - Work with Enbridge Gas Technical Account Managers to quantify and track annual natural gas savings achieved by each completed project.

18. To compel customers to participate in the offering and pursue cost-effective energy conservation opportunities, Enbridge Gas uses a direct access funding model. The direct access budget mechanism grants each customer access to the forecasted incentive budget they pay in rates. In this way, customers know how much funding

they have available each program year, allowing them to appropriately plan expenditures to reduce annual energy usage in their facility.

19. If a customer elects not to submit an EEP or if the direct access budget funds are not fully earmarked or used by a certain date, the unallocated funds are dispersed via an aggregated pool approach. Funds transferred to the Large Volume Aggregate Pool are available to fund additional energy efficiency projects for all other customers eligible for offering on a first-come-first-served approach. This approach is intended to focus the customer on energy efficiency through execution of the EEP and the "use it or lose it" nature of funding model.

Eligibility Criteria

20. To be eligible for the offering, participants must be an Enbridge Gas customer in Rate T2 and Rate 100 in the Union rate zones as of January 1st in a given program year.

Incentives/Enablers[8]

21. Participants can receive fixed incentives associated with the completion of eligible engineering projects as well as incentives which are commensurate with the Enbridge Gas approved natural gas savings estimates.

22. Incentives associated with eligible engineering projects contemplated at the time of submission include:
    - Engineering Feasibility Study: 50% funded up to $10,000
    - Process Improvement Study: 66% funded up to $20,000
    - Steam Trap Survey: 50% funded up to $6,000
    - Metering: 50% of meter costs funded up to $5,000

[8] Incentive details are provided as currently contemplated, Enbridge Gas routinely examines and adjusts incentive amounts in response to opportunities and market conditions, and in an effort to maximize program performance and results over the course of the Multi-Year term.

23. In addition, for new and retrofit equipment, process optimization, and operational improvements, participants can receive:
    - Direct Access Incentive Pool: \$0.10/$m^3$ saved up to the lesser of \$100,000 or 50% of project costs, and
    - Aggregate Pool: \$0.05/$m^3$ saved up to the lesser of \$40,000 or 50% of project costs.

Metrics

24. The metric for the Direct Access offering is net annual natural gas savings, measured in $m^3$.

Gross Measurement

25. Net annual natural gas savings achieved by customers in the Direct Access offering will be quantified by professional engineers using the custom engineered approach (determined relative to an Enbridge Gas approved baseline), incorporating the use of engineering calculations and process data. Due to the size, complexity and production variability of the customers participating in this offering, site meter-based analysis will not be used.

Barriers Addressed

26. In order to increase customer participation in the Large Volume offering, Enbridge Gas has removed limitations on eligible measures. This modification is responsive in particular to gas fired electricity generators, who have unique equipment which operates sporadically. In order to keep their equipment operating at peak efficiency levels, these customers need to complete expensive maintenance. The measures being reintroduced include turbine filters, wash and overhauls.

<u>Impact Evaluation & Verification</u>

27. Enbridge Gas recommends that third-party verification studies (also known as Custom Project Savings Verification studies, or “CPSV” studies) are appropriate for this offering, since most gross measurement claims are developed by Enbridge Gas. Since Enbridge Gas has been conducting gross measurement claims for several years and has been engaged in the EC’s review of the utility’s gross measurement savings claims, Enbridge Gas submits that multi-year (e.g. every other year) CPSV processes may be more appropriate in an effort to reduce participant survey fatigue and lower evaluation costs.

28. Enbridge Gas submits that Net-to-Gross (“NTG”) studies for this offering, inclusive of both free ridership and spillover elements, need to consider the unique offering design. As a direct access model, participants use their own funding to execute energy efficiency with support from Enbridge Gas. Therefore, traditional NTG approaches may not be appropriate. If NTG studies are conducted, Enbridge Gas submits they should be conducted infrequently, as the offering is not large in terms of the number of customers potentially participating.

<u>Process Evaluation</u>

29. Over the term of the plan, Enbridge Gas will explore process evaluation topics based on the evolving needs of the offering in the pursuit of continuous improvements to program design and delivery. The approach to process evaluation is discussed in Exhibit E, Tab 4, Schedule 5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Interrogatory

**Issue 10e**

Reference:

Exhibit C, Tab 1, Schedule 1, p. 5
Exhibit E, Tab 1, Schedule 1, pp.1 and 4
Exhibit E, Tab 1, Schedule 4, p. 15
Exhibit E, Tab 1, Schedule 5
Exhibit E, Tab 3, Schedule 1

Preamble:

EGI notes that one of the primary objectives of its DSM plan includes playing "a role in meeting Ontario's greenhouse gas reductions goals". EGI also notes that "all levels of government have made known the desire to reduce [GHG] emissions and have articulated target reductions for both 2030 and 2050."

EGI's Industrial Customer offering seeks to achieve sustained and progressive energy efficiency through a continuous energy improvement approach. EGI notes that one of the Industrial Custom offering's objectives is the reduction of GHG emissions to meet Ontario's reduction goals.

In EGI's 2021 DSM Plan Application proceeding, APPrO noted that GFGs are already incented to find efficiencies and reduce GHG emissions from numerous other regulatory requirements and that numerous climate change, GHG emission reduction and low-carbon fuels policies and programs at all levels of government continue to apply to GFGs. APPrP further noted "that the electricity sector, and clean, natural gas-fired electricity generators therein, appear to be subject to more, stacked, and multiple carbon-related costs than any other sector of the economy."

Question(s):

a) Please provide the rate impact of exempting GFGs from any obligation to contribute to the DSM costs allocated to the LVC rate classes.

b) Please explain and provide details regarding implementing the required changes to EGI's billing system to accommodate exempting GFGs from any obligation to contribute to DSM costs, as contemplated above and detailed in the written submissions of APPrO and the reply submissions on same of EGI in Board File No. EB-2019-0271.

Response

a) Please see Table 1 for the impacts to the Rate T2 and Rate 100 DSM unit rates for 2023 when the GFG billing units are excluded from the derivation of the unit rate.[1] For purposes of this response, 2023 DSM unit rates excluding GFG billing units do not include an allocation DSM low-income to GFG customers.

Table 1
2023 DSM Unit Rates (1)

| Line No. | Particulars | 2023 DSM Unit Rate Including GFG Billing Units (cents / m³) | 2023 DSM Unit Rate Excluding GFG Billing Units (cents / m³) | Increase/ (Decrease) (%) |
|---|---|---|---|---|
| | | (a) | (b) | (c) |
| | Rate T2 Contract Carriage Service | | | |
| 1 | Monthly Demand Charge | | | |
| 2 | First 140,870 m³ | 2.6129 | 3.3888 | 30% |
| 3 | All Over 140,870 m³ | 1.3821 | 2.6588 | 92% |
| | | | | |
| 4 | Interruptible Commodity Charge | 0.0998 | 0.0998 | 0% |
| | | | | |
| | Rate 100 Large Volume Firm Service | | | |
| 5 | Delivery Demand Charge | 2.0243 | 2.3382 | 16% |
| 6 | Delivery Commodity Charge | 0.0272 | 0.0309 | 14% |

Notes:
(1) Prepared using 2021 billing units consistent with Exhibit F, Tab 1, Schedule 3.
(2) Prepared based on the approved methodology for determining DSM unit rates for the Union rate zones as prepared in Enbridge Gas's annual rates application.

[1] Derived from allocated 2023 DSM budget costs of $4.783 million for Rate T2 and $1.184 million for Rate 100.

b) Should the OEB consider exempting GFG's from any obligation to contribute to the DSM costs allocated to the T2 and T100 large volume rate classes in the Union rate zone, the Company maintains that it would be necessary for Enbridge Gas to implement changes to its billing system and potentially downstream system and process changes. Some items that would need to be considered are:

- How to separate DSM charges from distribution rates as currently DSM charges are embedded in distribution rates (i.e. they are not specific unit rates billed independently)?
- How to uniquely identify GFG customers in the billing system, and once identified how to exclude GFG customers from DSM charges?
- How to charge DSM charges to all non-GFG customers?
- How to present DSM charges on customer bills?
- Do DSM charges need to be mapped to a separate GL account in EFS (Enterprise Financial Systems)?
- Do rates schedules need to be adjusted to include two sets of unit rates for customers in the same rate class?

ENBRIDGE GAS INC.

Undertaking Response to Association of Power Producers of Ontario (APPrO)

Undertaking

Tr: 133

To explain the derivation of the table at Exhibit F, Tab 1, Schedule 3.

Response:

Exhibit F, Tab 1, Schedule 3 provides class average DSM unit rates based on the 2021 volumetric billing unit forecast (column d). The class average DSM unit rates are applied to representative customer billing units (column g) to provide an estimate of the impact at a customer level by rate class. The DSM unit rates in Exhibit F, Tab 1, Schedule 3 do not reflect approved rate design methodologies of each individual rate class and therefore, actual unit rates and customer bill impacts will vary based on consumption and demands, depending on the applicable rate class.

Exhibit I.10e.EGI.APPrO.5, Table 1 provides the detailed unit rates for the large volume rate classes, Rate T2 and Rate 100, based on approved rate design methodologies. The rows in Table 1 provide all rate components impacted by the 2023 DSM Budget for Rate T2 and Rate 100. As an example, the approved rate design methodology for firm Rate T2 unit rates is to recover the allocation of DSM budget costs in the monthly demand charge, as provided in rows 2 and 3 of Table 1.

# GHG Emissions Performance Standards and Methodology for the Determination of the Total Annual Emissions Limit

OCTOBER 2021

# GHG Emissions Performance Standards and Methodology for the Determination of the Total Annual Emissions Limit

## Ministry of the Environment, Conservation and Parks

**Methodology Version October 2021.** This Methodology is only available in English.

Cette publication hautement spécialisée *GHG Emissions Performance Standards and Methodology for the Determination of the Total Annual Emissions Limit* n'est disponible qu'en anglais conformément au Règlement 671/92, selon lequel il n'est pas obligatoire de la traduire en vertu de la *Loi sur les services en français*. Pour obtenir des renseignements en français, veuillez communiquer avec le ministère de l'Environnement, de la Protection de la nature et des Parcs par courriel à EPShelp@ontario.ca.

**i** = a production parameter set out in column 3 of Table A for the Sub-activity in column 2 of Table A in respect of the Industrial Activity in column 1 of Table A

**y** = year of the compliance period

**$BEI_{A,i,FPE}$** = Fixed Process Baseline Emissions Intensity for the Sub-activity for production parameter 'i' expressed in tonnes of CO2e per unit of production as set out in column 4 of Table A

**$SF_{y,FPE}$** = Fixed Process Emissions Stringency Factor for the Industrial Activity in year "y" as determined in accordance with Section 4.1

$$PS_{A,i,y,nonFPE} = BEI_{A,i,nonFPE} \times SF_{y,nonFPE}$$

**Formula 3.1.1-3**

Where,

**i** = a production parameter set out in column 3 of Table A for the Sub-activity in column 2 of Table A in respect of the Industrial Activity in column 1 of Table A

**y** = year of the compliance period

**$BEI_{A,i,nonFPE}$** = Non-Fixed Process Baseline Emissions Intensity for the Sub-activity for production parameter 'i' in tonnes of CO2e per unit of production as set out in column 5 of Table A

**$SF_{y,nonFPE}$** = Non-Fixed Process Emissions Stringency Factor for the Industrial Activity in year "y" as determined in accordance with Section 4.2

### 3.1.2 Method B: Electricity Generation Sector Performance Standard

Subject to what is set out below following paragraph 4, an owner or operator of a covered facility engaging in the Industrial Activity of Generating Electricity Using Fossil Fuels may use Formula 3.1.2-1 to calculate the $AAEL_B$, unless any of the following applies:

1. The owner or operator used Formula 3.1.4-1 in respect of the electricity generation from a cogeneration system at the facility.
2. The owner or operator engaged in the Sub-activity of producing gold set out in Column 2 of Table A and the facility, or a site that forms part of the facility, is identified with one of the following GHG IDs:
   a. 1056
   b. 1193
   c. 1198
3. The owner or operator engaged in one of the following Sub-activities set out in Column 2 of Table A

a. producing grey cement from clinker

b. producing intermediate clinker

4. The covered facility, or a site that forms part of the facility, is one set out in Table E or F unless the facility, or a site that forms part of the facility, is identified with one of the following GHG IDs:

a. 1060

b. 1075

c. 1076

d. 1079

e. 1081

f. 1082

g. 1085

Despite paragraph 1, the owner or operator may use Formula 3.1.2-1 in respect of the amount of electricity generated (in GWh) at the facility that the owner or operator has not included in the electricity generation from the cogeneration system (‘$\boldsymbol{EO_{elec,y}}$’) entered in Formula 3.1.4-3 or in any other Formula.

$$AAEL_{B,y} = \sum_{i=1}^{n} PS_{B,i,y} \times Production_{B,i,y}$$

**Formula 3.1.2-1**

Where,

**n** = the number of applicable combustion devices that generate electricity at the covered facility

**i** = an applicable combustion device that generates electricity

**y** = year of the compliance period

$\mathbf{PS_{B,i,y}}$ = Electricity Generation Sector Performance Standard expressed in tonnes of CO2e per Gigawatt hour (tCO2e/GWh) of electricity generated from the combustion device “i” in year “y”, calculated in accordance with Formula 3.1.2-2

$\mathbf{Production_{B,i,y}}$ = Annual electricity generated from the combustion device “i” for the production of electricity in year “y” expressed in Gigawatt hours (GWh), reported in accordance with the Reporting Regulation and Guideline

$$PS_{B,i,y} = BEI_B \times NBF_{i,y} \times SF_{y,nonFPE}$$

**Formula 3.1.2-2**

Where,

**i** = an applicable combustion device that generates electricity

**y** = year of the compliance period

**$BEI_B$** = 370 tonnes of CO2e per Gigawatt hour (tCO2e/GWh)

**$NBF_{i,y}$ =** the non-biomass, non-coke oven gas and non-blast furnace gas, fraction of the total energy input into the combustion device "i" that generates the electricity, calculated by dividing the Gigajoules (GJ) of non-biomass fuel input into the combustion device by the total GJ of all fuels input into the combustion device

**$SF_{y,nonFPE}$** = Non-Fixed Process Emissions Stringency Factor for the Industrial Activity in year "y" as determined in accordance with Section 4.2

### 3.1.3 Method C: Thermal Energy Sector Performance Standard

Subject to what is set out below following paragraph 4, an owner or operator of a covered facility engaging in one of the following Industrial Activities:

1. Producing hydrogen gas using steam hydrocarbon reforming or partial oxidation of hydrocarbons;
2. Producing grain ethanol for use in an industrial or fuel application;
3. Generating electricity using fossil fuels;

and engaging in the generation and transfer of useful thermal energy may use Formula 3.1.3-1 to calculate the $AAEL_C$, unless any of the following applies:

1. The owner or operator used Formula 3.1.4-1 in respect of the useful thermal energy generated from a cogeneration system at the facility.
2. The owner or operator engaged in one of the following Sub-activities set out in Column 2 of Table A:
    a. producing grey cement from clinker;
    b. producing intermediate clinker;
    c. refining crude oil, including bitumen, heavy crude oil, light crude oil and synthetic crude oil;
    d. producing hydrogen using steam hydrogen carbon reforming or partial oxidation of hydrocarbon at a petroleum refinery;
    e. producing nitric acid;
    f. producing anhydrous ammonia or aqueous ammonia;
    g. producing urea liquor at a facility that produces ammonia.

CANADA

CONSOLIDATION

# Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity

SOR/2018-261

Current to March 7, 2022

Last amended on January 1, 2019

Published by the Minister of Justice at the following address:
http://laws-lois.justice.gc.ca

CODIFICATION

# Règlement limitant les émissions de dioxyde de carbone provenant de la production d’électricité thermique au gaz naturel

DORS/2018-261

À jour au 7 mars 2022

Dernière modification le 1 janvier 2019

Publié par le ministre de la Justice à l’adresse suivante :
http://lois-laws.justice.gc.ca

Registration
SOR/2018-261 November 30, 2018

CANADIAN ENVIRONMENTAL PROTECTION ACT, 1999

**Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity**

P.C. 2018-1482 November 29, 2018

Whereas, pursuant to subsection 332(1)[a] of the *Canadian Environmental Protection Act, 1999*[b], the Minister of the Environment published in the *Canada Gazette*, Part I, on February 17, 2018, a copy of the proposed *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*, substantially in the annexed form, and persons were given an opportunity to file comments with respect to the proposed Regulations or to file a notice of objection requesting that a board of review be established and stating the reasons for the objection;

Whereas, pursuant to subsection 93(3) of that Act, the National Advisory Committee has been given an opportunity to provide its advice under section 6[c] of that Act;

And whereas, in accordance with subsection 93(4) of that Act, the Governor in Council is of the opinion that the proposed Regulations do not regulate an aspect of a substance that is regulated by or under any other Act of Parliament in a manner that provides, in the opinion of the Governor in Council, sufficient protection to the environment and human health;

Therefore, Her Excellency the Governor General in Council, on the recommendation of the Minister of the Environment and the Minister of Health, pursuant to subsections 93(1) and 330(3.2)[d] of the *Canadian Environmental Protection Act, 1999*[b], makes the annexed *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*.

[a] S.C. 2004, c. 15, s. 31

[b] S.C. 1999, c. 33

[c] S.C. 2015, c. 3, par. 172(d)

[d] S.C. 2008, c. 31, s. 5

Enregistrement
DORS/2018-261 Le 30 novembre 2018

LOI CANADIENNE SUR LA PROTECTION DE L'ENVIRONNEMENT (1999)

**Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel**

C.P. 2018-1482 Le 29 novembre 2018

Attendu que, conformément au paragraphe 332(1)[a] de la *Loi canadienne sur la protection de l'environnement (1999)*[b], la ministre de l'Environnement a fait publier dans la Partie I de la *Gazette du Canada*, le 17 février 2018, le projet de règlement intitulé *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel*, conforme en substance au texte ci-après, et que les intéressés ont ainsi eu la possibilité de présenter leurs observations à cet égard ou un avis d'opposition motivé demandant la constitution d'une commission de révision;

Attendu que, conformément au paragraphe 93(3) de cette loi, le comité consultatif national s'est vu accorder la possibilité de formuler ses conseils dans le cadre de l'article 6[c] de celle-ci;

Attendu que la gouverneure en conseil est d'avis que, aux termes du paragraphe 93(4) de cette loi, le projet de règlement ne vise pas un point déjà réglementé sous le régime d'une autre loi fédérale de manière à offrir une protection suffisante pour l'environnement et la santé humaine,

À ces causes, sur recommandation de la ministre de l'Environnement et de la ministre de la Santé et en vertu des paragraphes 93(1) et 330(3.2)[d] de la *Loi canadienne sur la protection de l'environnement (1999)*[b], Son Excellence la Gouverneure générale en conseil prend le *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel*, ci-après.

[a] L.C. 2004, ch. 15, art. 31

[b] L.C. 1999, ch. 33

[c] L.C. 2015, ch. 3, al. 172d)

[d] L.C. 2008, ch. 31, art. 5

**Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity**

**Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel**

# Overview

### Purpose

**1** These Regulations establish a regime for limiting carbon dioxide ($CO_2$) emissions that result from the generation of electricity by means of thermal energy from the combustion of natural gas, whether in conjunction with other fuels, except coal, or not.

# Aperçu

### Objet

**1** Le présent règlement établit un régime visant à limiter les émissions de dioxyde de carbone ($CO_2$) provenant de la production d'électricité à partir d'énergie thermique provenant de la combustion de gaz naturel seul ou avec d'autres combustibles, sauf le charbon.

**Ministry of Energy**

Office of the Minister

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**Ministère de l'Énergie**

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Ontario

MC-994-2022-17

January 26, 2022

Ms Lesley Gallinger
President and Chief Executive Officer
Independent Electricity System Operator
Lesley.Gallinger@ieso.ca

Dear Ms Gallinger:

I would first like to thank you and your team at the Independent Electricity System Operator (IESO) for your ongoing support in responding to the challenges of COVID-19. With your help we have been able to continue to provide a reliable energy supply, keep rates stable and make life more affordable for Ontario electricity customers during this period.

As you know, approximately 94 per cent of the electricity generated in Ontario in 2020 came from non-emitting sources that include nuclear generation, waterpower, wind and solar.  Ontario families and businesses have built and paid for this system and have a lot to be proud of.  That said, our government is committed to making life more affordable and I believe ratepayers can reap further value from the electricity system that they have built.

Additionally, from my time serving as Ontario's Minister of Economic Development, Job Creation and Trade, I recognize the clean energy advantage that Ontario has when competing for jobs and investment.  As increasing numbers of corporations seek to meet their ever-growing environmental and sustainability goals by requiring clean electricity in their operations and among their suppliers, I believe Ontario is well-positioned to further leverage our clean energy advantage to attract jobs and investment.  Our government wants to ensure that Ontario is a partner in helping businesses meet their environmental goals, especially when doing so can support our own efforts to further decarbonize Ontario's electricity system and reduce Ontario's greenhouse gas emissions.

With this in mind, I am asking the IESO to work to provide further value for ratepayers by supporting the creation of a voluntary clean energy credit market by providing me with a report-back that meets the following requirements within the time set out below:

…/cont'd

1. The IESO shall assess options for the establishment and ongoing operation and management of a registry to support the creation and/or recognition, trading, and the retirement of voluntary clean energy credits (CECs) within the province.

2. I ask the IESO to provide me with its report back on or before July 4, 2022 with detailed design options and recommendations, as well as potential benefits and projected costs of building and operating the registry, based on the following design principles:

   - **Scoped to Ontario:** The registry should include clean energy credits for electricity generated and consumed in Ontario. The initial design of the registry should be scoped to enable the trading of credits within Ontario, with the potential to support cross-border trading in a future phase.

   - **Voluntary:** The purchase of credits from the registry would be entirely voluntary.

   - **Customer choice:** Evaluate market demand via stakeholder engagement and design products to satisfy that demand.

   - **Monetization of investments made:** Credit offerings should include existing non-emitting generation, including nuclear, waterpower, wind, solar and bio-energy. The IESO should enable proceeds from CEC sales to flow to ratepayers, recognizing that ratepayers have borne the significant costs of previous efforts to decarbonize Ontario's electricity system, and

   - **Future Proof:** Build the registry to offer flexibility and the potential for future expansion to other products or markets, and to consider how the registry can incentivize future investment in new clean generation, when that power is needed.

3. The Report-back should also consider the following in relation to design options provided:

   - **Timing and availability:** The IESO should examine the availability of CECs from contracted and regulated resources to enable the launch of the registry in January 2023.

   - **Maximizing market opportunity:** Work with existing generators and brokers who currently offer voluntary clean energy credits to maximize potential for the registry, and report back on potential price ranges.

   - **Avoiding double counting:** Assess the impact of the registry on other environmental goals to avoid unintended consequence of double counting efforts to meet those goals, for example with Ontario's Emissions Performance Standards (EPS) program requirements.

…/cont'd

The IESO's market sounding should include engagement activities carried out with industry and associations, major power generators and consumers, Indigenous communities and other provincial ministries.

Thank you again for your continued support of the government's work and I look forward to receiving a report back on this analysis by July 2022.

Sincerely,

Todd Smith
Minister

c: David Donovan, Chief of Staff to the Honourable Todd Smith
Carla Nell, Vice President, Corporate Relations, Stakeholder Engagement and Innovation
Stephen Rhodes, Deputy Minister of Energy

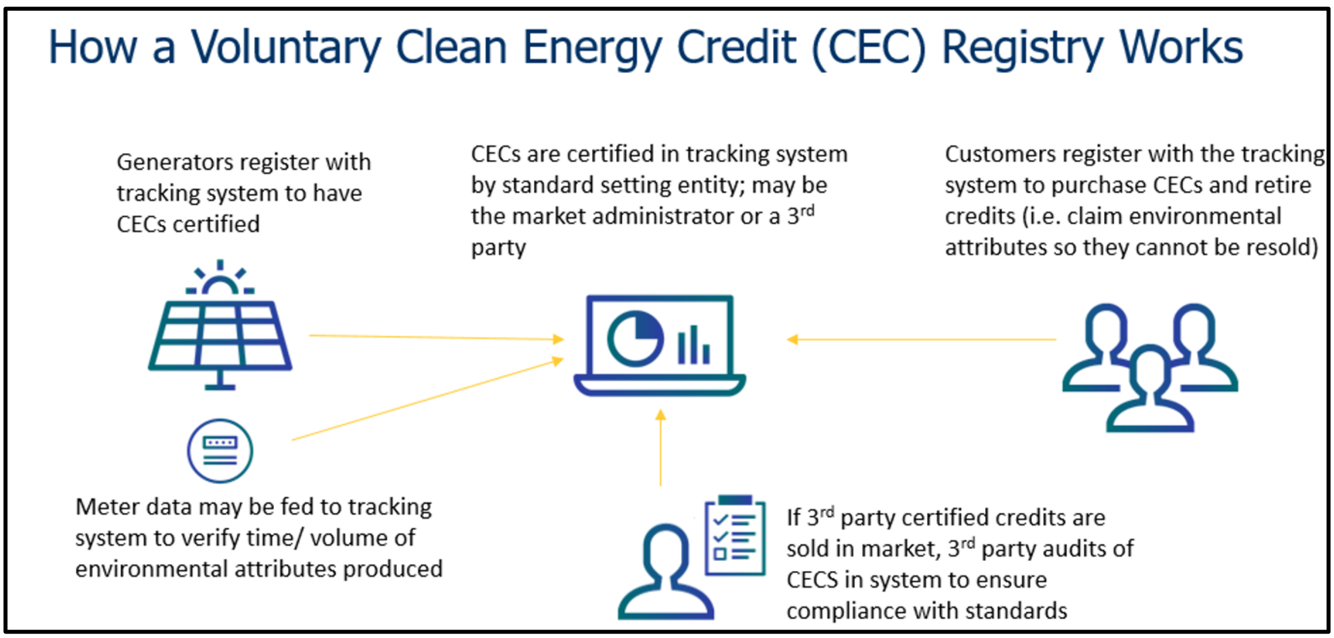
# Engagement Plan

## Clean Energy Credits

### Introduction

The Ministry of Energy has asked the IESO to assess options for the establishment and ongoing operation and management of a registry to support the creation and/or recognition, trading and valuation, and the retirement of renewable and clean energy credits (CECs) within the province. CECs may be used to demonstrate that clean/renewable energy has been procured, either to meet a compliance standard or voluntary target. The credits themselves certify that 1 MWh of clean energy has been generated and subsequently retired on behalf of a person or organization. The creation, trading, and retirement of energy credits is often certified and tracked through an energy tracking system or registry (see Figure 1 below for an explanation of how a CEC registry generally works).

Figure 1.



Voluntary CEC registries currently exist in several other jurisdictions. Prominent voluntary registries include the Midwest Renewable Energy Tracking System (M-RETS) and the North American Renewables Registry (NAR).

A voluntary CEC market can support economic development in the province by helping business and other organizations meet their clean energy goals. Voluntary investment in CECs can support efforts to decarbonize the Ontario electricity system. A voluntary Clean Energy Credits registry could also support more robust competition in the IESO's Resource Adequacy procurements by providing an additional revenue stream for clean energy resources. The IESO is to report back in July, 2022, with detailed design options and recommendations for a CEC market and registry based on the following design principles:

- **Domestic**: The registry should include renewable and clean energy credits for electricity generated and consumed in Ontario. The initial design of the registry should be scoped to enable the trading of credits within Ontario.
- **Voluntary**: The purchase of credits from the registry would be voluntary.
- **Customer choice:** Evaluate market demand and create a variety of products to satisfy that demand.
- **Monetize investments made:** Credit offerings should include existing non-emitting generation with best efforts made to enable proceeds from CEC sales to flow to ratepayers.
- **Future Proof:** Build the registry to offer flexibility and the potential for future expansion to other products or markets, and to consider how the registry might incentivize future investment in new clean or renewable generation, when that power is needed.

The IESO will engage with stakeholders on their clean energy goals, how they would like to meet those goals, and how clean energy credits could support those goals. This information will be used to ensure that customer preferences inform the IESO's report back to the Minister on options for CEC product offerings and registry. This feedback will also help inform the IESO's evaluation of a potential moratorium on the procurement of new natural gas generating stations and the development of an achievable pathway to zero emissions in the electricity sector per the Minister of Energy's October 7, 2021 letter to the IESO.

## Stakeholders and Communities

The IESO encourages all interested parties to participate in this engagement through the public engagement activities described in the Approach section below. The IESO anticipates that this initiative will be of particular interest to:

- Large industrial customers
- Industrial associations
- Commercial/institutional customers
- Indigenous communities

- LDCs
- Renewable and clean energy generators
- CEC brokers

## Engagement Objectives

- To understand customer clean energy goals, how they would like to meet those goals, and how clean energy credits could support those goals;
- Identify areas of input that may require more focused discussions to inform the initiative through possible dedicated technical sessions;
- Identify potential design options for CEC offerings and a registry for the Ontario market, incorporating stakeholder feedback and considerations;
- Understand how customers are/will report clean energy activities in order to avoid unintended consequences of a registry on efforts to meet clean energy goals (including the potential for double-counting).

## Approach

- This engagement plan will be implemented in accordance with the IESO's approved engagement principles. This is a public engagement process.
- All materials will be posted on the dedicated IESO engagement webpage, and, any information/input supplied by interested parties will also be posted (with consent). The approach for this engagement includes opportunities to provide input through various channels such as webinars, technical sessions, meetings, and written feedback.
- The project team will consider all relevant input and illustrate how feedback was considered to shape the stated objectives.
- Send out a confidential survey to large consumers in Ontario to better understand clean energy preferences.
- Utilize technical groups, as applicable, to focus on certain project deliverables and relay status updates to stakeholders for feedback

## Proposed Engagement Schedule

- The anticipated timing for this engagement is presented below. Note that timing and content associated with upcoming activities are subject to change.

| Timing | Engagement Activity |
|---|---|
| February 24, 2022 | Stakeholder Engagement Webinar<br>• Provide overview of Ministry request<br>• Introduce initiative and work plan<br>• Provide background on CEC markets and an understanding of key concepts<br>• Communicate purpose and approach to engagement<br>• Launch CEC survey<br>• Solicit stakeholder interest in joining technical sessions on how a CEC registry/market can be used to support customer goals<br>• Seek feedback on key considerations for a CEC market in Ontario |
| March 17, 2022 | Deadline for feedback on February 24, 2022 engagement session |
| March 24, 2022 | Survey closes |
| March 31, 2022 | Response to stakeholder feedback published |
| March-April, 2022 | Technical sessions with stakeholders |
| Q2 2022 | Stakeholder Engagement Webinar<br>• Share survey/technical session findings<br>• Share draft options identified through engagement for inclusion in report to Ministry<br>• Seek feedback on draft options and draft IESO recommendations |

## Additional Background and Resources

- CEC Market Recommendation Report - due July 4, 2022
- Minister's Letter – January 26, 2022

## Related Engagements

- Zero Emissions Pathway Project
- Resource Adequacy Engagement

Environnement et Changement climatique Canada
Environment and Climate Change Canada

# A Clean Electricity Standard in support of a net-zero electricity sector

## Discussion paper

Canada

Last updated: March 8, 2022



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Aussi disponible en français.

# Glossary

For the purposes of this discussion paper, it should be understood that the term:

**Low-Emitting Generation** means electricity that was produced in a manner that releases a small amount of GHGs (for example, 50 tonnes $C0_2$/GWh or less) as a result of fuel combustion, relative to unabated fossil fuel generation. One example of low-emitting generation could be natural gas-fired electricity generation where emissions are largely, but not entirely, captured through Carbon Capture Utilization and Storage (CCUS). Lifecycle emissions created in the manufacturing of generation equipment or during fossil fuel extraction and transportation to the site of combustion are not included.

**Economy-wide Net-Zero by 2050** means Canada's stated goal of having the Canadian economy achieve either no emissions of greenhouse gases (GHG) by 2050, or that all emissions are completely compensated for by removing carbon from the atmosphere (negative emissions) through other actions, for example, planting trees or CCUS deployment. In realizing this goal, it is expected that some economic sectors, facilities, institutions, and other sources of GHG emissions that are difficult to eliminate entirely would continue to emit some GHGs, but at levels much lower than current rates and thus could be balanced by negative emissions elsewhere in the economy.

**Net-Zero Electricity** means Canada's stated goal of having the electricity sector achieve, in effect, no emissions of greenhouse gases (GHG) by 2035, or emissions are offset by other actions that remove carbon from the atmosphere. This only includes direct emissions and does not include lifecycle or upstream emissions. In realizing this goal, it is expected that some low-emitting generation facilities may continue to operate past 2035. The emissions resulting from this operation would need to be balanced by removals in or attributed to the sector.

**Negative Emissions** refers to the removal of greenhouse gases (GHGs) from the atmosphere by deliberate human activities (for example, planting trees and deploying Direct Air Capture (DAC) and storage), that is, in addition to the removals that would occur via natural carbon cycle processes.

**Non-Emitting Generation** means electricity produced in a manner that does not directly release any greenhouse gases (GHGs) as a result of fuel combustion. Non-emitting generation sources include hydro, wind, photovoltaic solar, concentrated solar-thermal, geothermal, and nuclear, among others. While non-emitting sources can produce lifecycle GHG emissions from activities other than fuel combustion (for example, hydro reservoirs can release methane over time), attributing these emissions to electricity still results in a relatively low lifecycle emissions intensity.

**Offset Credits** represent GHG emission reductions or removals generated from activities that are additional to what would have occurred in the absence of the offset project (that is, generated from activities that go beyond legal requirements and a business-as-usual standard). Generally, each offset credit generated by an offset project represents 1 tonne of carbon dioxide equivalent ($CO_2e$) reduced or removed from the atmosphere.

The **Electricity System** is a complex network of power generating plants, transmission and distribution wires that produce and deliver electricity to end-users, such as households, businesses, vehicle charging stations, and other critical infrastructure in the local, regional and national economy. This complex system is often referred to as the power grid.

# 1) Purpose

The Government of Canada is taking further action to reduce greenhouse gas (GHG) emissions from the generation of electricity to achieve a net-zero electricity supply by 2035 (NZ2035). This will contribute significantly to meeting Canada's broader goal of achieving net-zero emissions economy-wide by 2050.

The transition to a net-zero electricity supply by 2035 will be transformational. The effort will involve multiple measures and jurisdictions working together to achieve a clean, reliable and affordable electricity system. A Clean Electricity Standard (CES) under the *Canadian Environmental Protection Act, 1999* (CEPA) will be a key part of this suite of measures.

The purpose of this discussion paper is to send a clear signal that the Government of Canada intends to move forward with regulations to achieve a net-zero electricity system by 2035; to outline considerations related to this objective; and to solicit comments from Canadians regarding the scope and design of the CES. While the main objective of this document is to inform and collect feedback regarding the CES, it also welcomes input on other relevant measures that would support the net-zero 2035 target. The treatment of electricity under the current *Output Based Pricing System Regulations* (OBPSR) will also be reviewed as part of this process.

# 2) Introduction

The Intergovernmental Panel on Climate Change's (IPCC) *Special Report on Global Warming of 1.5* °C concludes that achieving net-zero global GHG emissions by 2050 is necessary to avoid the worst impacts of climate change. Globally, pledges to reach net-zero by national governments, industries, companies, and others now cover almost 80% of the global economy. The United States and the European Union have committed to reducing GHG emissions by 50% from 2005 levels by 2030, while the UK has legislated a 78% emissions reduction from 1990 levels by 2035.

Canada must keep pace with, or even exceed, these targets in order to lead and compete in a net-zero emissions future. Within Canada, all provinces and territories, except for Alberta and Nunavut, have set an economy-wide GHG emissions reduction target, which range from 30% to 53% reductions over 2005 levels by 2030. Similarly, a number of Canadian companies, including many in the electricity generation sector, have made pledges to achieve net-zero emissions. In line with this ambition, both internationally and within Canada, in 2020 the Government of Canada committed to reaching net-zero emissions economy-wide by 2050[1], including achieving net-zero electricity.[2]

On December 11, 2020, the Government announced [Canada's Strengthened Climate Plan for a Healthy Environment and a Healthy Economy]() which indicated the government would: "Work with provinces, territories, utilities, industry and interested Canadians to ensure that Canada's electricity generation achieves net-zero emissions before 2035." The cornerstone of this effort will be the CES complemented by other policies, programs, and the $15 billion in investments announced under the plan in order to reduce emissions and build a clean economy. In April 2021, the Government of Canada committed to a

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[1] See **Glossary**: "Economy-wide net-zero by 2050."

[2] See **Glossary**: "Net-Zero Electricity."

national target of reducing GHG emissions by 40% to 45% below 2005 levels by 2030. At the 26th United Nations Framework Convention on Climate Change Climate Change Conference of the Parties, Prime Minister Trudeau stated Canada's goal of establishing a net-zero emissions electricity system by 2035 (NZ2035). This commitment was reflected in the mandate letters for the ministers of the Environment and of Natural Resources in December 2021.

The actions required to meet Canada's Net-Zero 2050 economy-wide goal will require transforming Canada's energy systems.[3] Electrification – the process of replacing technologies that are powered by fossil fuels with those that use electricity – will play a key role in this transformation. While the transition to a net-zero economy will not rely solely on electrification, a net-zero electricity system will be essential to achieving economy-wide Net-Zero 2050. However, there is the potential for electrification to contribute to increased GHG emissions from the electricity sector, despite reducing overall energy emissions, if the expected increased demand is met through carbon-emitting electricity generating sources. Action is required now to prevent that from happening.

Achieving net-zero electricity will require coordinated efforts. Provinces and territories hold jurisdiction over electricity planning and operation, while the federal government holds jurisdiction over emissions reduction regulations, interprovincial transmission projects, and international commitments, among others. Provinces, territories and the federal government all hold jurisdiction over environmental protection. Indigenous Peoples are important partners on critical projects and decarbonisation efforts. As such, close partnerships between multiple levels of government will be important to ensure a smooth transition.

In response to the Government of Canada's commitment to achieve a net-zero emissions electricity sector by 2035, this discussion paper will launch a collaborative process between the federal government, provinces, territories, and Indigenous groups. This process will help ensure that the design of the CES provides a clear and workable basis for provinces and territories to be able to plan and operate their electricity systems in a way that will continue to reliably deliver affordable electricity to Canadians. We recognize that establishing a net-zero-emitting electricity sector will largely be the work of provinces and territories, and a CES would provide the regulatory signal to support decision-making at the provincial and territorial level that would allow Canada to achieve this goal.

There are many important aspects to consider, and this discussion paper launches consultations to ensure that the Government of Canada considers the appropriate expertise, perspectives, and interests to develop the most effective and well-designed regulatory approach.

There are other federal policies that can support the effort to move towards a net-zero electricity system, such as support for infrastructure or tax incentives to encourage investments in or the deployment of clean generation. While views on other federal policies will be noted during CES consultations, potential new actions to support the transition will be discussed in a separate process. Natural Resources Canada will engage over the coming year on the broader strategy for achieving a NZ2035 transition.

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[3] See **Annex A** for more information on Canada's current electricity generation mix.

# 3) The need for a clear and early regulatory signal to achieve NZ2035

Canada's electricity sector has already contributed significantly to Canada's efforts to reduced GHG emissions and will play a major role in the transition to net-zero, both through additional reductions in the electricity sector and by enabling reductions in other sectors through the supply of clean electricity for the electrification of activities currently powered by GHG emitting fuels. There are economic opportunities for Canada to build on this strength as our economy makes the transition to net-zero.

Canada's electricity sector is currently 82% non-emitting and has significantly reduced its GHG emissions since 2005, even as generating capacity has increased modestly. This is a result of actions by provincial utilities and other electricity generators, as well as provincial and territorial policies that have reduced or limited GHG emissions from the electricity sector within their jurisdiction. Federal policies such as carbon pricing and regulations requiring the phase-out of coal-fired plants have also played a role.[4]

Despite these reductions, electricity generation is Canada's 4th largest source of emissions, accounting for 8.4% of Canada's total GHG emissions in 2019. Without additional policy measures, there is real potential for the current emissions reduction trend in the electricity sector to reverse. While the phase-out of conventional coal-fired electricity generation by 2030 will reduce emissions, much of this phase-out is currently planned to be accomplished by a shift from coal to natural gas. According to the Canadian Energy Regulator's Canada Energy Futures 2021 report, approximately 8,900 MW of new natural gas generating capacity is projected to be added by 2035 under current federal, provincial and territorial policies.[5]

There is also the potential for emissions to grow from the addition of emitting generation to meet the increasing demand for electricity as other parts of the economy switch from carbon-based fuels to electricity in order to decarbonize their own activities. Several potential net-zero 2050 pathways, developed by various government, academic and research organizations, have concluded that electricity generation may need to double over the next few decades. In order to ensure that the entire economy achieves net-zero 2050, however, virtually all of this additional generation would need to come from non-emitting or low GHG-emitting generating sources.[6]

Due to the long life of power generation assets, investments in emitting sources made today will directly impact our ability to meet the 2035 and 2050 goals. Building new high-emitting assets now risks transferring electricity rate increases to future generations, since these emitting assets will need to be extensively retrofitted or shut down before the end of their economic life in order to meet emissions

[4] See **Annex B** for a list of federal policy initiatives that impact the electricity sector.

[5] Consistent with Canada Energy Regulator's Canada's Energy Future 2021: Energy Supply and Demand Projections to 2050

[6] See **Glossary**: "Low-emitting Generation."

standards. Some could become stranded assets as Canada, along with the world, makes the transition to net-zero emissions.

Sending a clear regulatory signal now should discourage further investments in assets that could become stranded in the years to come by this inevitable transition. Further, it is possible that Canada's main trading partners, such as the European Union and the United States, could enact border carbon adjustments (BCAs) in the future, meaning that these countries would add a tariff to imports to avoid creating trade advantages for countries with less ambitious climate policies than their own. If this happens, then a net-zero emitting electricity sector could help protect and, in some cases, strengthen the competitiveness of Canadian-made electricity-intensive products in these markets. In addition, private sector participants with strong Environmental, Social and Governance (ESG) commitments will see Canada's clean supply of electricity as a reason to deploy capital in the country and key strategic regions.

As we approach meeting the 2035 target for a net-zero electricity system, continued reliance on natural gas will increasingly require the mitigation of its GHG emissions. Current and emerging technologies, including carbon capture, utilization and storage (CCUS) and non-emitting hydrogen blended with natural gas to generate electricity, could help make natural gas an option for low-emitting generation. Over time, however, natural gas coupled with CCUS will increasingly be in competition with other emerging options that are both non-emitting and flexible in the roles they can play in electricity systems. These include long- and medium-duration energy storage, geothermal energy, and small modular nuclear reactors (SMRs). Solutions such as these are rapidly advancing and decreasing in cost, and a CES could provide the regulatory signal to accelerate their deployment across Canada. These emerging technologies could support electricity system stability in addition to increased inter-provincial trade of hydroelectricity. Investments in non-emitting generation and the shift towards a net-zero electricity system needs to start without delay.

Although several low and non-emitting generation technologies are becoming more cost-competitive, the pace of low-carbon electricity deployment must accelerate for Canada to reach NZ2035. As such, the normal investment cycle and capital-replacement rate must also accelerate to enable new and emerging technologies to enter the marketplace rapidly. This acceleration will entail significant capital expenditures. Retrofitting existing equipment to reduce emissions, such as modifying natural gas turbines with turbines able to combust hydrogen, may provide some significant financial upside in the transition to a low-carbon environment.

A well-defined and targeted approach to achieving NZ2035 will provide assurance to investors and developers of non-emitting technologies that their investments and products will have a role in Canada's evolving electricity systems. Regulatory certainty will thus enable a smoother transition to non-emitting electricity generation, an increase in adoption rates, less risk for utilities and other electricity generators, and more limited impact on ratepayers.

# 4) The proposed CES regulations

While carbon pricing is a foundational measure in Canada's overall approach to reducing GHG emissions, it is designed to incent the lowest cost reductions across the economy and does not guarantee emission reductions in specific and targeted sectors. Given the long lifespan of electricity generation assets, decisions made over the next few years will impact Canada's GHG emissions for decades. Therefore, carbon pricing alone is not sufficient to ensure that the electricity sector achieves net-zero emissions by 2035, or likely even by 2050. A Canada-wide CES will complement carbon pricing by requiring the phase-out of all conventional fossil fuel electricity generation. In tandem, carbon pricing will incent fuel switching in other sectors to drive increased demand for clean electricity.

Regulations to limit fossil fuel generation must be decisive and swift enough to prevent locking in new fossil fuel infrastructure that will persist beyond 2035. These policies must also be flexible enough to account for regional differences, such as resource availability and interconnection (interties) with neighbouring jurisdictions. In the end, all actions taken together will ensure that electricity is clean, reliable and affordable for all Canadians.

The Government of Canada is planning new regulations under CEPA for all sources of emitting electricity generation that sell to the electricity system (grid). A CES regulation would set emissions performance standards for emitting electricity generators to ensure that the electricity sector transitions to NZ2035.

The final form of the CES' scope and design will be influenced by the full set of changes needed to transition the electricity sector to NZ2035 while providing increased supply of electricity to support electrification, and the role of available technologies in the provision of clean power to Canadians.

The electricity sector must achieve net-zero emissions while ensuring sufficient electricity is available when and where we need it. The scope and design of the CES will thus need to be stringent enough to achieve its objectives while including compliance flexibility to allow for the possibility of some natural gas. As natural gas currently plays a critical role in the electricity sector by providing fast-response power[7], exploration of the continued operation of natural gas assets in special circumstances may be needed. This includes providing flexibility to essential uses of natural gas, such as for emergency events, back-up power to complement variable renewables, and potentially supplying power during seasonal peaks of demand.

The CES will also be technologically neutral in setting the value of its standards, allowing electricity generators and decision makers the widest possible array of supply options that can contribute to the goal of achieving emission reductions.

Compliance flexibilities can thus ease the transition and ensure a reliable electricity system. Possibilities include the use of robust GHG offsets to assist with compliance with the CES as a transitional measure. Carbon dioxide removal technologies such as DAC with carbon sequestration and Bioenergy Carbon, Capture, and Storage (BECCS) have been frequently mentioned in literature as central to achieving net-zero due to their potential to achieve "negative emissions" and would enable further reductions

[7] See **Annex A** for more details.

attributable to the electricity sector. Consideration would need to be given to the scope of what emissions could be offset.

Finally, it will be necessary to ensure that the CES and the treatment of electricity generation under the federal Output-based Pricing System Regulations (OBPSR) are synchronized. The treatment of electricity under carbon pricing should maintain the incentive created by the carbon price for industrial facilities to innovate and reduce emissions, and continue to minimize carbon leakage and competitiveness risks. This may require modifications to the Output-based Standard (OBS) for electricity under the OBPSR. Similarly, where provincial or territorial carbon pricing systems cover electricity emissions, provincial/territorial governments may need to consider how to ensure their carbon pricing systems and the CES can be complementary.

# 5) Working together to achieve NZ2035

Achieving a net-zero electricity system throughout Canada represents a large economic, technical, and societal challenge. The structure of Canada's electricity sector means that the CES will need to be complemented by actions at all levels of government. A whole-of-government approach, coupled with commercial and sustainable viability is critical for the transition.

Accordingly, Environment and Climate Change Canada will engage with the public on the design of the CES as a key component of the larger objective of achieving net-zero emissions from electricity by 2035, while Natural Resources Canada will engage in a linked but parallel process on the development of other measures that will also contribute to this objective.

## 5.1 The importance of Canada-wide collaboration

Provinces and territories, as well as electricity generators and their regulators, will all play a critical role in achieving NZ2035 by supporting the transformation of the electricity system through their policies related to investments, regulating of the various aspects of electricity generation, and ensuring electricity distribution and supply. Throughout the transition to an electricity supply that is both net-zero emitting and substantially increased, provinces and territories will determine the measures needed to ensure reliable, affordable electricity within their own jurisdiction.

To mitigate rate increases, provinces and territories will have to manage several factors, including:

1) The technical challenge of integrating wind and solar into the electricity system while maintaining reliability and de-risking intermittency challenges

2) Managing the system-wide impacts of increased demand as electrification links more end-uses, such as transportation, to the electricity system

3) The cost-effective deployment of emerging non-emitting options like long and medium-duration energy storage alternatives, geothermal and SMRs

4) Providing incentives and programming for energy efficiency and demand-side management to minimize overall demand and help consumers reduce their electricity consumption, reducing their exposure to rate increases

There are significant regional differences in current electricity generation across Canada. The impacts of a CES will be largest in fossil fuel-dependent electricity generating regions including Alberta, Saskatchewan, New Brunswick, Nova Scotia, and Ontario. Nunavut, Yukon, and Northwest Territories will face unique challenges as remote, off-grid communities transition away from diesel (see Annex A). The Government of Canada will continue to work closely with provinces and territories as they address these complex challenges, and will support the development of interties to bring clean energy to where it is needed. Support for smart grids, interties, and new ways of managing power (such as distributed generation and energy storage) will be helpful in the context of these challenges.

Wind and solar will play a key role in reducing the sector's emissions. These renewable sources of energy are both cost-competitive and widely available, as is demonstrated by their ongoing rapid expansion throughout every region of Canada. Increased reliance on these intermittent resources will require careful planning so that electricity system stability and reliability are maintained. The efficient integration of wind and solar will involve market and regulatory reforms, expansion and reinforcement of transmission and distribution infrastructure, and unlocking flexibility within the broader electricity system. Utilities, other electricity generators, regulators and system operators will need to move rapidly to ensure that sufficient firm supply is in place to back a larger intermittent supply.

The "Atlantic Loop" project is an example of collaboration to bring clean power to where it's needed in Eastern Canada. The Government of Canada and the Canada Infrastructure Bank are currently collaborating with provinces and regional partners to advance this intertie project, which could greatly reduce emissions and maintain electricity affordability in the Atlantic region.

As the clean energy sector expands, the Government of Canada is committed to working with provinces and territories, Indigenous groups, industry, labour organizations, and others to ensure that workers affected by the transition to a net-zero economy can access the resources and build the skills required to work in clean energy. Creating good, well-paying jobs in the net-zero economy and ensuring that workers have the right tools and skill sets is essential to building a sustainable and prosperous future for Canada.

## 5.2 Additional federal actions and complementary policies

A successful and smooth transition to net-zero electricity generation will require a significant shift in the behaviour and operations of utilities and other electricity generators, provinces, territories, industry and other customers. The federal government will continue to provide support during this complicated transition, both through existing programs and through additional actions and complementary policies.

Considering the timeframe in which action must be taken and the amount of transformation that will need to occur, no single policy measure will suffice on its own. The Government of Canada is already investing in electricity infrastructure improvements, non-emitting electricity generation, and the development and deployment of emerging technologies. Measures specific to the electricity sector in the strengthened climate plan include:

- Investing an additional $964 million over 4 years to advance smart renewable energy and modernization projects for electricity systems, to enable the clean systems of the future
- Investing an additional $300 million over 5 years to advance the Government's commitment to ensure that rural, remote, and Indigenous communities that currently rely on diesel have the opportunity to be powered by clean, reliable energy by 2030
- Further supporting necessary intertie project pre-development work by providing $25 million in 2021-22 to help some proponents conduct engineering assessments, community engagement, and environmental and regulatory studies
- Working with provinces and territories to help build key intertie transmission projects with support from the Canada Infrastructure Bank

Through the *Investing in Canada* infrastructure plan, the Canada Infrastructure Bank (CIB) announced a $10 billion Growth Plan, which includes $2.5 billion for clean power projects (including renewable generation and storage) and electricity transmission between provinces, territories, and regions (including to northern and Indigenous communities). These investments will help to lower the costs of reducing emissions from the electricity sector for consumers and leverage the significant opportunity presented by new and emerging technologies.

The federal government will continue to explore how federal investments in infrastructure can support pathways to scale technology solutions in regulated and unregulated electricity markets with the ultimate goal of an affordable and reliable energy transition.

If ongoing engagement indicates a need for new measures, the government will consider them in close collaboration with provinces and territories, utilities and other electricity generators, Indigenous peoples, and other stakeholders to ensure that they effectively support the electricity sector as it evolves to meet the considerable technical challenge of reaching net-zero electricity by 2035.

# 6) Key questions

The Government of Canada is seeking input regarding federal regulatory actions to support net-zero electricity generation by 2035. Please consider the following questions to support your input.

**General**

1. Should interim standards be included in the period before 2035?
2. How should the CES regulation be designed to minimize stranded capital assets and associated rate impacts?
3. What would be an acceptable end-point emissions intensity standard to achieve the objective of the CES?
4. How do considerations differ for non-competitive electricity markets, vertically integrated utilities, etc.?

**Compliance Flexibilities**

5. Should the CES offer compliance flexibilities?
    a. What kinds of flexibilities?
    b. Should the flexibilities be targeted to individual generating units? To corporate fleets of units, such as fleet averaging, etc.?
    c. What constraints or limitations should be incorporated into flexibilities?
6. Under what conditions should offset credits available through federal, provincial/territorial, or other programs be permitted?
7. To what extent can negative emission technologies like BECCS and DAC contribute to meeting the obligations of a CES regulation? To what extent should they be allowed to contribute to meeting those obligations?
8. Should compliance be assessed for the electricity sector on an annual or multi-year basis?

**Alignment with carbon pricing**[8]

9. Should the way in which electricity generation is currently treated by carbon pricing be changed to facilitate achieving NZ2035?
10. How might the treatment of electricity under the OBPS have to change to align with the CES?

**Treatment of natural gas generation**

11. What is the role of natural gas in a net-zero electricity sector before 2035? Post-2035?
12. What flexibility should be allowed to use natural gas to maintain reliability in rare and extreme weather, emergencies, or other special circumstances? Which additional operating conditions/scenarios, if any, should be given special consideration?

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[8] Please see **Annex B**, "Regulations," for an overview of carbon pricing in Canada.

a. If natural gas has an electricity system-support role post-2035, what are the expected impacts on the rollout of emerging system support technologies such as energy storage?
b. If natural gas has a role in generation post-2035, what are the expected impacts on the penetration of nascent generation technologies like SMRs, geothermal electricity, etc.?

**<u>Treatment of industry, private generation and remote generation</u>**

13. How should the CES treat electricity generated by cogeneration units that is sold to the electricity system? Should the CES apply fully to cogeneration units by 2035 or should it phase-in its application to cogeneration units after 2035?
14. What are the benefits of applying a CES to industrial generation units? What are the challenges of doing so? Of not doing so?
15. How should the CES consider electricity generation in remote, northern, and Indigenous communities?
16. How should the CES consider distributed energy resources?

**<u>Treatment of biomass</u>**

17. If $CO_2$ emissions from biomass combustion are not counted towards compliance under a CES, to what degree might biomass generation increase?
18. What types of biomass are suited to electricity generation? What are their characteristics with respect to regenerative life cycle, non-$CO_2$ GHG emissions, and land use characteristics?
19. What emissions reporting and compliance requirements for biomass generation should be considered to ensure that nature is protected and land-based emissions do not increase?

**<u>Other Questions</u>**

20. What additional investments are anticipated to be necessary to achieve NZ2035 to help ensure affordability for consumers?
21. What role could existing and expanded energy efficiency programming play in helping to meet new demand as they transition towards net-zero 2035? What are the constraints for additional efficiency measures? Technological? Policy? Other?
22. What other factors should the government consider in developing the CES?

# 7) Next steps

This discussion paper seeks input to inform the development of regulatory action to support net-zero electricity generation by 2035. This input will help to ensure that the Government of Canada considers the appropriate expertise, perspectives, and interests as part of a meaningful engagement process. The goal is to develop policies that support economic growth, reduce GHG emissions from electricity generation in a way that achieves a net-zero electricity system by 2035 as other parts of the economy electrify while continuing to ensure affordable, reliable power to Canadians.

Following the publication of this discussion paper, ECCC will continue to engage with provinces, territories, Indigenous Peoples, utilities and other electricity sector stakeholders, industry, non-governmental organizations, and Canadians on regulatory design and, where relevant, complementary measures.

Parties wishing to comment on any aspect of this paper, including responding to questions posed, are invited to provide written comments to ECD-DEC@ec.gc.ca by April 15, 2022. Comments received will help to inform federal policy actions to achieve net-zero electricity generation, as part of an ongoing engagement process.

# Annex A– Cost and technological readiness of important technologies

The following table presents an indicative list of electricity generation technologies and associated costs.

**Table 1: Cost[9] and Technology Readiness Level (TRL)[10] of technologies (EIA *Annual Energy Outlook 2021* and IEA *Clean Energy Technology Guide*, 2021)**

| Technology (cont.)[11] | Fuel type | Size (MW) | Lead time (years) | Total overnight cost (2021 CAD /kw) | Variable O&M (2021 CAD /MWh) | Fixed O&M (2021 CAD /kw-yr) | Technology readiness level<br>1 (Initial idea)- 11 (Proof of stability reached) |
|---|---|---|---|---|---|---|---|
| Ultra-supercritical coal with 90% CCS | Coal | 650 | 4 | $8,413.75 | $14.59 | $79.17 | 4-5 |
| Combined cycle--single shaft | Natural Gas | 418 | 3 | $1,525.27 | $3.39 | $18.75 | 11 |
| Combined-cycle--multi shaft | Natural Gas | 1083 | 3 | $1,348.74 | $2.49 | $16.22 | 11 |
| Combined-cycle with 90% CCS | Natural Gas | 377 | 3 | $3,613.15 | $7.76 | $36.69 | 5-6 |
| Simple cycle natural gas – aeroderivative[12] | Natural Gas | 105 | 2 | $1,643.38 | $6.25 | $21.67 | 11 |
| Simple cycle natural gas—industrial frame | Natural Gas | 237 | 2 | $996.95 | $5.98 | $9.31 | 11 |

[9] Energy Information Agency. 2022. *Annual Energy Outlook 2022.* "Cost and Performance Characteristics of New Generating Technologies." (Source of lead time, total overnight cost, variable O&M, fixed O&M)
[10] International Energy Agency. 2021. *ETP Clean Energy Technology Guide.*
[11] Non- Abated fossil fuel generation included for cost comparison
[12] Compared to industrial frame CTs of the same MW output, aeroderivative CTs are lighter weight, have a smaller size footprint, and are made of advanced materials because they were adapted from aircraft engines.

| Technology (cont.) | Fuel type | Size (MW) | Lead time (years) | Total overnight cost (2021 CAD /kw) | Variable O&M (2021 CAD /MWh) | Fixed O&M (2021 CAD /kw-yr) | Technology readiness level<br>1 (Initial idea)- 11 (Proof of stability reached) |
|---|---|---|---|---|---|---|---|
| Fuel cells | Hydrogen | 10 | 3 | $9,174.48 | $0.79 | $40.93 | 7-9 |
| Nuclear—light water reactor | Uranium | 2156 | 6 | $8,928.10 | $3.15 | $161.73 | 10-11 |
| Nuclear—small modular reactor | Uranium | 600 | 6 | $9,584.69 | $3.99 | $126.31 | 6-9 |
| Battery storage (Lithium-ion utility-scale) | n/a | 50 | 1 | $1,671.32 | $0.00 | $32.97 | 9 |
| Biomass | Biomass | 50 | 4 | $5,746.75 | $6.43 | $167.16 | 4-10 |
| Geothermal | n/a | 50 | 4 | $3,906.52 | $1.54 | $181.89 | 4-11 |
| Municipal solid waste--landfill gas | n/a | 36 | 3 | $2,213.61 | $8.24 | $26.72 | 7 |
| Conventional hydropower | n/a | 100 | 4 | $3,915.41 | $1.85 | $55.60 | 11 |
| Wind, onshore | n/a | 200 | 3 | $2,181.86 | $0.00 | $35.01 | 9-10 |
| Wind, offshore seabed fixed | n/a | 400 | 4 | $7,672.07 | $0.00 | $146.25 | 9 |
| Solar thermal | n/a | 115 | 3 | $10,026.65 | $0.00 | $113.53 | 9 |
| Solar photovoltaic (PV) with tracking | n/a | 150 | 2 | $1,685.29 | $0.00 | $20.28 | 9-10 |
| Solar PV with storage | n/a | 150 | 2 | $2,219.96 | $0.00 | $42.76 | 9-10 |

**Table 2: Technological readiness level key (International Energy Agency, 2021)**

| Readiness Level | Definition | Explanation |
|---|---|---|
| 1 | Initial idea | Basic principles have been defined |
| 2 | Application formulated | Concept and application of solution have been formulated |
| 3 | Concept needs validation | Solution needs to be prototyped and applied |
| 4 | Early prototype | Prototype proven in test conditions |
| 5 | Large prototype | Components proven in conditions to be deployed |
| 6 | Full prototype at scale | Prototype proven at scale in conditions to be deployed |
| 7 | Pre-commercial demonstration | Prototype working in expected conditions |
| 8 | First of a kind commercial | Commercial demonstration, full-scale deployment in final conditions |
| 9 | Commercial operation in relevant environment | Solution is commercially available, needs evolutionary improvement to stay competitive |
| 10 | Integration needed at scale | Solution is commercial and competitive but needs further integration efforts |
| 11 | Proof of stability reached | Predictable growth |

The following table presents the direct GHG emission intensities of electricity generation technologies.

**Table 3: National Electricity Generation GHG Emission Intensities by Technology (From the internal version of ECCC's Fuel Life Cycle Analysis (LCA) Model as of March 1, 2022)**

| Technology Generation Pathway (Canada) | Direct Emissions ($tCO_2e/GWh$) |
|---|---|
| Biomass, wood, cogeneration | 15.4 |
| Biomass, wood, simple cycle | 28.5 |
| Coal, bituminous | 1036.0 |
| Coal, lignite | 721.2* |
| Coal, sub-bituminous | 660.7* |
| Heavy fuel oil | 906.9 |
| Hydro, reservoir | 0.0 |
| Hydro, run-of-river | 0.0 |
| Natural gas, cogeneration | 258.1 |
| Natural gas, combined cycle | 305.8 |
| Natural gas, converted boiler | 557.5 |
| Natural gas, simple cycle | 478.4 |
| Nuclear, CANDU | 0.0 |
| Solar, concentrated solar power | 0.0 |
| Solar, photovoltaic | 0.0 |
| Wind, onshore | 0.0 |
| Diesel, on-grid | 736.2 |

* Values under review

# Annex B – Canada's electricity sector

Electricity generation sources vary significantly across Canada's provinces and territories due to regional factors such as resource availability and industrial heat and power needs (see figure 1).

**Figure 1: Provincial GHG emissions and Electricity by Energy Source in 2019 (2021 NIR)**

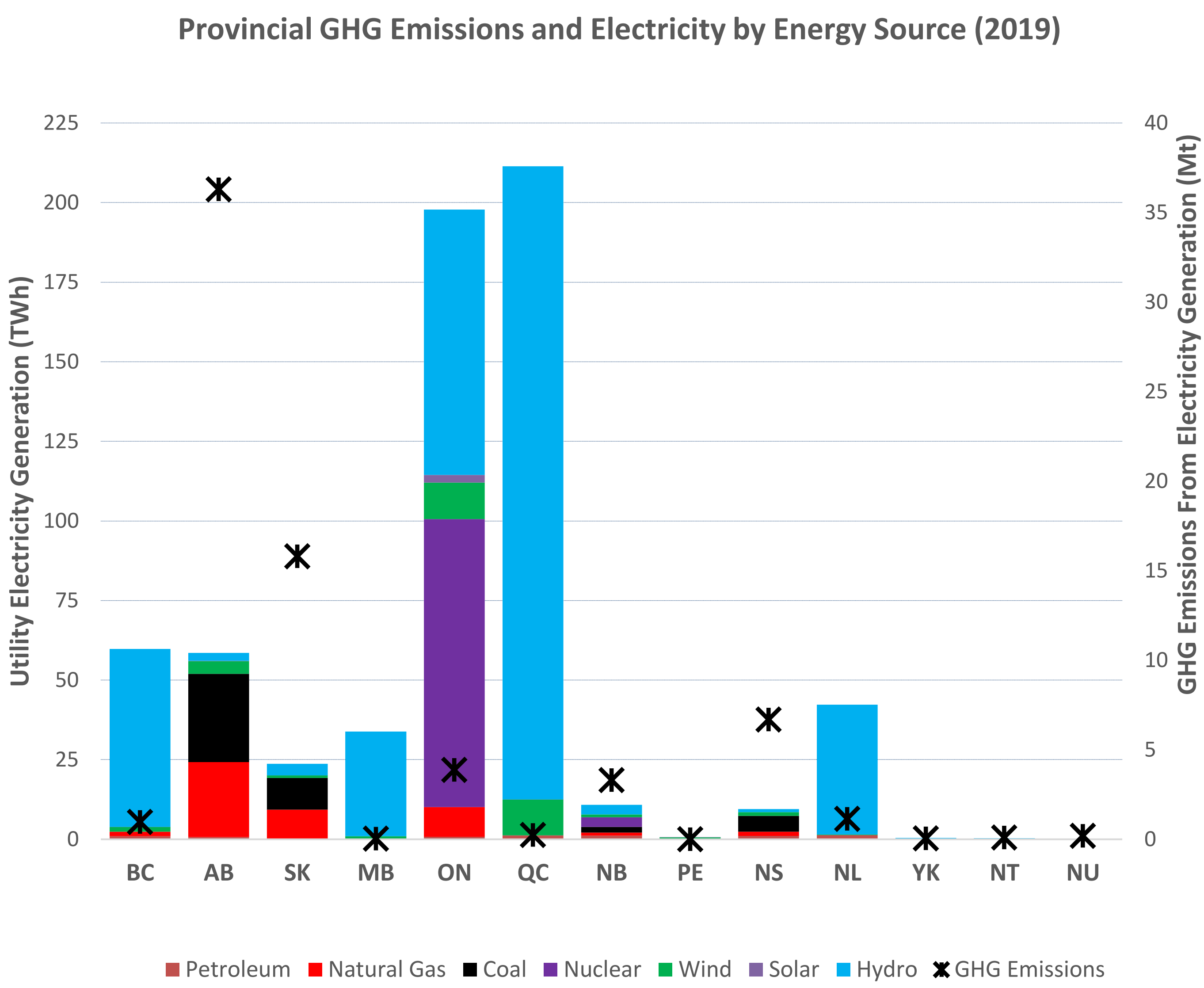

**Table 4: GHG emission data from electricity generation** (National Inventory Report, 2021) (kt $CO_2e$)**

| Source of Combustion | 1990 | 2000 | 2005 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Coal** | 80 500 | 109 000 | 98 200 | 63 800 | 60 300 | 62 300 | 57 100 | 57 200 | 44 100 | 42 500 |
| **Natural gas** | 2 720 | 13 800 | 15 400 | 18 600 | 18 600 | 19 300 | 18 300 | 16 300 | 20 900 | 21 900 |
| **Other fuels** | 11 300 | 9 380 | 11 200 | 4 860 | 4 860 | 5 400 | 5 020 | 4 800 | 4 610 | 4 200 |
| **Other emissions** | - | 27 | 52 | 63 | 73 | 87 | 80 | 80 | 78 | 80 |
| **Total** | **94 500** | **132 000** | **125 000** | **87 500** | **83 800** | **87 000** | **80 500** | **78 400** | **69 800** | **68 600** |

** NIR GHG Emissions Data for electricity generation includes utility-owned industrial generation units.

# GHG emissions by generation source

The following generating sources account for GHG emissions from the electricity sector:

**Coal**

In 2018, coal-fired generation provided approximately 9% of Canada's utility electricity generation and was responsible for approximately 63% of GHG emissions from the electricity sector. Coal continues to be a key electricity source in 4 provinces: Alberta (43%), Saskatchewan (47%), New Brunswick (21%) and Nova Scotia (58%) (2018). The Government of Canada has taken regulatory action to phase out conventional coal-fired electricity by 2030, through the ECCC-led *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*. Provincial governments, including in Alberta and Ontario, have also taken action to phase out coal. Note that under the current federal regulations, coal units employing CCUS technologies can continue to operate in Canada after 2030 if their emissions intensity does not exceed 420 tonnes per gigawatt-hour (t/GWh).

**Natural gas**

In 2018, natural gas provided 9% of Canada's electricity generation and was responsible for approximately 30% of GHG emissions from Canada's electricity sector. Historically low natural gas prices, accompanied by relatively low capital equipment costs and lower GHG emissions than coal generation, have made combined-cycle natural gas electricity generation an attractive and readily available option for many provinces. Utilities and other electricity generators are currently deploying new natural gas generation, which will likely continue without further policy action to limit electricity generation from fossil fuels. As a result, GHG emissions from natural gas electricity generation are expected to increase as coal is phased out and electricity demand increases.

**Fuel oil**

The combustion of fuel oil to generate electricity has significantly declined in Canada, largely due to fuel oil's high cost. Fuel oil now represents less than 1% of total electricity generation in Canada, and generating facilities that still burn fuel oil are used primarily as peaking or back-up units. The largest facilities that still burn some fuel oil, primarily located in Atlantic Canada, therefore generate much less electricity than their maximum capacities would allow.

**Diesel**

Diesel, a distillate fuel oil, remains an important (though costly) fuel source for small-scale electricity generation across Canada, mainly in remote and northern communities. While diesel generation accounts for a small share of Canada's GHG emissions, it is a significant source of air pollutants and black carbon (a GHG that has an increased climate impact when emitted onto glaciers, as it decreases albedo and accelerates melting) and therefore negatively affects local air quality and human health.

**Cogeneration (integration of heat and electricity)**

Reducing emissions from industrial heat and electricity generation, which relies primarily on natural gas, will be crucial to reaching economy-wide net-zero emissions by 2050. Heat is the main source of energy consumed by industrial sectors and represents approximately 80% of all industrial energy needs (with the remaining 20% being electricity). Without low or non-emitting options to supply heat, Canada will not reach its goal of economy-wide net-zero by 2050. Fortunately, emerging technologies such as small modular nuclear reactors (SMR), renewable natural gas, clean hydrogen (low-emissions production), and geothermal heat, show potential to significantly contribute to the supply of low/zero-carbon heat, when co-located or connected to heat end-users, such as industry, while simultaneously supplying low/zero-carbon electricity through cogeneration.

# Annex C – Regulations and other policy measures to reduce GHG emissions

The electricity sector is covered by various federal regulations.

**Regulations under the Canadian Environmental Protection Act**

The *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* require that coal units meet an emissions limit of 420 t $CO_2$/GWh by no later than 2030. Currently, only coal units retrofitted with CCUS can meet these standards, and the majority of coal units in Canada are expected to be retired by 2030. While this regulation indirectly encourages electricity producers to replace coal units with non-emitting generating sources, this is not a requirement.

The *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity* complements the coal regulations by setting emissions limits (420 or 550 t $CO_2$/GWh, depending on the size of the unit) for new natural gas-fired electricity generation. This regulation helps to ensure that natural gas units replacing coal-fired units are higher-performing units (top-performing natural gas units can achieve 370 t $CO_2$/GWh). The regulation also includes provisions for the economic life extension of coal units converted to natural gas (based on the initial emission performance of the converted units, ranging from 480 to 600 t $CO_2$/GWh).

**Carbon pricing**

Carbon pricing has proven to be one of the most efficient means to reduce GHG emissions in jurisdictions across the globe. Since 2019, every jurisdiction in Canada has had a price on carbon pollution. Canada's approach is flexible: any province or territory can develop its own pricing system tailored to local needs, or can choose the federal carbon pricing backstop system. The federal government sets minimum national stringency criteria (the benchmark) that all provincial and territorial systems must meet to ensure they are stringent, fair and efficient. If a province decides not to price pollution, or proposes a system that does not meet the federal benchmark, the federal carbon pricing system applies.

On July 12, 2021, the Government of Canada confirmed that the minimum price on carbon pollution will increase $15 per year until 2030, starting in 2023. Through this increase, the price of carbon pollution will rise to $170 per tonne by 2030. The Government of Canada published updated federal benchmark requirements for the 2023-2030 period in August 2021. All proceeds collected under the federal carbon pricing system are returned to the jurisdiction in which they were collected.

Under the Greenhouse Gas Pollution Pricing Act (GGPPA), the federal carbon pollution pricing system has 2 parts, the fuel charge and the Output-Based Pricing System Regulations. One or both parts may apply in a province or territory.

*Fuel charge*

Part 1 of GGPPA establishes a regulatory charge on 21 fossil fuels including gasoline and natural gas (the "fuel charge"). The fuel charge is generally paid by fuel producers and distributors. The fuel charge rates reflect a carbon pollution price of $40 per tonne of carbon dioxide equivalent ($CO_2e$) as of April 1, 2021, rising by $10 per tonne annually to $50 per tonne as of April 1, 2022. Federal fuel charge rates for the 2023-2030 period, reflecting an increase in the $15 per tonne increase each year starting in 2023 to reach $170 per tonne in 2030, were published in fall 2021. The federal fuel charge currently applies in Ontario, Manitoba, Yukon, Alberta, Saskatchewan and Nunavut.

*Output-Based Pricing System Regulations*
The federal Output-Based Pricing System Regulations (OBPSR) establishes a regulatory trading system for emission-intensive and trade-exposed industry under Part 2 of GGPPA. It is designed to ensure there is a price incentive for industrial emitters to reduce their GHG emissions while mitigating risks to competitiveness and carbon leakage (that is, the risk of industrial facilities moving from one region to another to avoid paying a price on carbon pollution). The federal OBPSR currently applies in Manitoba, Prince Edward Island, Yukon, and Nunavut.

The federal OBPSR sets output-based standards (OBSs) in the form of emissions per unit of production. Facilities must calculate an emissions limit based on their production and relevant OBSs. If a facility emits below its emissions limit, it will earn surplus credits that it can sell. Facilities that emit above their limit must provide compensation either by paying the carbon price to the federal government via an excess emissions charge or remitting eligible compliance units in an amount equivalent to their excess emissions. By allowing facilities to generate and trade surplus credits for reducing their emissions below the limit, the OBPSR ensures the incentive to reduce emissions created by the carbon pollution price applies to every tonne of emissions from industrial facilities. It also incents the lowest-cost emissions reductions across industrial sectors.

The approach to electricity under the OBPSR was designed to incent emissions reductions from electricity generation while mitigating competitiveness impacts and carbon leakage risks for industrial sectors and reducing costs for businesses and households; the OBPSR assigns different OBSs to electricity generation according to the type of fuel used.

The OBSs are:

- for existing generation using gaseous fuels like natural gas, 370 t $CO_2e$/GWh
- for new generation in 2021 or later using gaseous fuels like natural gas, starts at 370 t $CO_2e$/GWh in 2021, and then declines linearly to 0 t $CO_2e$/GWh in 2030 [13]
- for liquid fuels like diesel, 550 t $CO_2e$/GWh
- for solid fuels like coal, 800 t $CO_2e$/GWh in 2019, followed by a linear decline that starts at 650 t $CO_2e$/GWh in 2020 and ends at 370 t $CO_2e$/GWh in 2030 [14]

[13] The federal approach for new gas generation does not apply to cogeneration facilities that primarily produce steam.
[14] The solids OBS applies to coal-fired electricity generating units that co-fire with natural gas or boilers converted to run exclusively on natural gas.

# Other policy measures

Some examples of other actions the federal government announced in the December 2020 Strengthened Climate Plan and the April 2021 federal budget include:

- Working with the provinces and territories to help build key intertie projects to better integrate provincial electricity systems
- Launching a Small Modular Reactor (SMR) Action Plan in December 2020, building on the SMR Roadmap released in 2018, to lay out the next steps to develop and deploy this technology
- Releasing the Hydrogen Strategy for Canada to position Canada as a world-leading producer, user and exporter of clean hydrogen, and associated technologies
- Developing tax measures, including by updating eligibility criteria of Class 43.1/43.2 of the Accelerated Capital Cost Allowance, to ensure Canada has a competitive investment environment for the commercialization of innovative technologies necessary to meet Canada's climate goals and committing to introduce an investment tax credit for investments in carbon capture, utilization, and storage projects with the goal of reducing emissions by at least 15 MT of $CO_2$ annually
- Leveraging Canada's competitive advantage in mining to build the Canadian battery and critical mineral supply chains
- Using federal procurement to lead by example and create market demand, including by committing to net-zero federal government operations by 2030 and to power federal buildings with 100% clean electricity by 2022