Ontario Electricity Emissions Factors and Guidelines

Accurate emissions factors are the backbone of climate action strategy

June 2024 Edition | The Atmospheric Fund

TAF

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Accurate emissions factors are the backbone of climate action strategy

Electricity emissions factors are used to quantify the carbon impact of projects, programs, and policies that affect electricity consumption or generation. Best practices in carbon emissions quantification, including accurate emissions factors, are crucial to decarbonizing the electricity sector.

The Atmospheric Fund (TAF) has developed a range of electricity emissions factors for such planning purposes. This guideline summarizes the factors, outlines the methodology and data sources used, and provides recommendations for which emissions factors apply for which purpose.

This guideline will be especially helpful for Ontario's provincial and municipal policymakers, engineers, scientists, electricity industry professionals, and practitioners involved in quantifying carbon emissions.

In Ontario, 87% of electricity is produced carbon-free from hydro, nuclear, wind, and solar. But the remainder comes from natural gas plants, especially during peak hours as they are usually the generating resource responding to short-term changes in demand. Over the past few years, gas is providing more baseload power, significantly increasing emissions from electricity generation. In 2022 and 2023, electricity emissions in the Greater Toronto and Hamilton Area increased by 28% and 26%, respectively.

Increasing emissions from the electricity grid adds complexity to greenhouse gas quantification and climate change planning.

It also increases the divide between how the grid meets short- and long-term changes in demand, which is why we have updated our emissions factors and guidelines significantly since our 2021 edition.

Adding to this complexity is the uncertainty within Ontario's long-term electricity planning framework. Ontario's Independent Electricity System Operator (IESO)'s 2024 Annual Planning Outlook projects a gap between electricity supply and demand starting in 2029. Without regulatory or policy certainty, it is unclear if and to what extent natural gas will fill that gap.

If Ontario decides to expand the use of natural gas plants, electricity emissions could double by 2030, undermining carbon reduction efforts. Conversely, if that gap is met with non-emitting sources, electricity emissions would decrease in line with climate targets.

Executive Summary

Conventional methods to quantify emissions can oversimplify and distort the data.

Looking specifically at electricity systems, outdated and inaccurate emissions factors can result in poor decision-making such as underinvesting in conservation, delaying grid improvements or shifting to renewables, and underestimating the climate impacts of carbon-intensive electricity generation like natural gas.

2024 Edition Updates

Based on the most reliable information available and valuable feedback received from other practitioners, this guideline provides an update to our 2021 release.

Specific updates include:

- New electricity emissions factors for 2021 to 2023;
- Updated guidelines that differentiate between short-term and long-term changes in demand, including our recommendations for the use of a proxy in lieu of policy certainty;
- Organizational enhancements, such as categorizing historical and forecasted sections based on factors; and
- Comprehensive data tables, encompassing annual, hourly, and forecasted factors spanning from 2014 to 2023, available for download in data format.

The lack of historical and real-time data as to which resource is on the margin in any given hour, and the absence of policy certainty and adequate forecast data, have created significant challenges in estimating both short- and long-term marginal emissions factors. As a result, TAF is only able to publish limited peak/off-peak marginal emissions factors for 2024 and 2030, using data provided to us by the IESO.

This lack of data makes it challenging to evaluate changes in short-term demand, including load-shifting and the use of battery storage, and undermines the ability for responsive loads and load aggregators to mitigate their carbon impacts.

In the interim, given these challenges, we recommend using average emissions factors as a proxy for quantifying and forecasting long-term demand changes and the limited marginal emissions factors for short-term demand changes.

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Regulatory Recommendations

To address data gaps and growing emissions from the electricity grid, TAF recommends the following:

1. **The IESO should publish historical marginal resource data to enable better understanding of the carbon impacts of load shifting.**

It is currently challenging to deduce which resource is on the margin (for example, whether a fossil fuel or non-emitting resource is setting the market clearing price) using currently published data.

This in turn makes it challenging to evaluate the utility of shifting loads or using battery storage to mitigate carbon emissions.

We strongly suggest publishing disaggregate historical data on the resource that is on the margin for any given hour on the IESO's public data portal.

2. **The IESO should resume publishing long-term planning forecasts that include projections of grid-related carbon emissions, supported by clear assumptions and input data.**

Unlike previous versions, the 2024 Annual Planning Outlook (APO), did not include a data table containing annual projections on total grid-related emissions.

We recognize that there exists significant policy and procurement uncertainty which might make such forecasts unreliable. Those forecasts, however, are critical to the assessment of long-term investment decisions and need to be included in all APOs, either as a single forecast or a set of scenarios. We also strongly suggest including an additional data table in future APOs with annual projections on how often gas-fired generation is expected to be on the margin by season and time of day.

3. **The Ontario Ministry of Energy and Electrification should direct the IESO to increase the speed at which new non-emitting generation is built to fully realize emissions reductions through electrification efforts.**

Ramping up the use of gas-fired generation in Ontario will undermine carbon reductions associated with switching to electric space and water heating, vehicles, and industrial processes.

If Ontario instead commits to meeting all new demand with non-emitting generation, the marginal electricity emissions associated with electrification efforts will effectively be zero, achieving significant carbon reductions through fuel switching. Such a commitment would boost investor confidence in the province, ensuring that capital spent on projects that create new electricity demand wouldn't result in additional grid-related emissions.

Quantifying carbon emissions enables practitioners to:

1. Understand current or historical emissions (such as a carbon[1] inventory for an organization or city).

2. Evaluate the carbon impacts of an actual or potential change (such as a project, policy, or infrastructure decision).

Quantifying current or historical emissions from electricity involves determining the quantity of energy consumed and multiplying it by the average carbon intensity of the electricity supply.

Quantifying the carbon impact of a change (real or proposed) is more complex. In addition to understanding the quantity of electricity consumed, conserved, or generated because of the change, this process also requires considering the *marginal* impact on the electricity system. In other words, it requires consideration of which generating resource (hydro, nuclear, renewables, or natural gas) is expected to respond to the change in electricity demand.

Quantification is further complicated when considering whether an action leads to short-term changes in demand (for example, a gas-fired plant increases or decreases its output) or long-term change in demand (for example, the province secures new supply to support electrification efforts).

Although the resource in question is the same (electricity), different electricity emissions factors should be used for different quantification purposes.

To prepare an inventory:

When quantifying current or historical emissions resulting from electricity consumption (from within an organization or whole city, for example), an Average Emissions Factor (AEF) is recommended. While an annual AEF is sufficient for most purposes, hourly AEFs can be applied where more precision is needed and hourly consumption data is available.

To evaluate the impact of a long-term change in demand:

For use cases that result in long-term changes in demand on the grid, including fuel switching to electricity, energy efficiency projects, or new electricity demand, TAF is recommending the use of Average Emissions Factors (AEF) as a proxy for long-run marginal emissions factors.

Current best practices recommend using 'long-run' marginal emissions factors (MEFs) to estimate the emission impacts of long-term demand changes[2,3,4].

However, the development of such factors in Ontario is hindered by the current absence of policy certainty (for example, a carbon or renewables target) and publicly available granular data[5]. In this absence, TAF recommends the use of AEFs to estimate the impact of long-term demand changes.

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[1] TAF uses the term Carbon to refer to CO_2 equivalent, regardless of the specific greenhouse gases involved.
[2] Short-run marginal emission rates omit important impacts of electric-sector interventions | PNAS
3 NYSERDA's 22-18 Projected Emission Factors for New York Grid Electricity
[4] Planning for the evolution of the electric grid with a long-run marginal emission rate - PMC (nih.gov)
[5] Granular historical and forecasted marginal resource data is needed to determine which resource is on the margin (e.g. gas or non-carbon emitting).

Guidelines

To evaluate the impact of a short-term change in demand:

For changes in short-term demand, the use of hourly or peak/off-peak MEFs is recommended. Specific cases include:

- Load shifting (for example, smart appliances, smart heating systems, electric vehicle charging)
- Energy/battery storage

To assist in evaluating the carbon emissions of the above cases, TAF is providing peak/off-peak MEF values for 2024 and 2030 based on the amount of natural gas on the margin provided by the IESO.

TAF recommends using these values until more granular data is available.

To evaluate the impact of new electricity generation:

Best practices suggest using a combination of 'short-run' and 'long-run' marginal emissions factors for new, non-emitting, and grid-connected generation. *In lieu of being able to develop such factors at this time, TAF is providing a proxy method for evaluation in Example 5.*

Decision Aids

The following table can assist in determining which specific emissions factors should be used in common scenarios.

The factors presented in this guideline account only for direct (combustion) emissions, and thus can underestimate the global impact of interventions.

Type	Factor	Examples	Data Availability
Inventory/ Footprint	Annual AEF	**Historical or forecasted inventory analysis.**	✓ Historical ✓ Forecast
	Hourly AEF	**Historical inventory analysis**, specifically where more precision is needed.	✓ Historical X Forecast
Change/ Intervention	Annual AEF (Proxy for annual long-run MEF)	**Historical or forecasted analysis.** For majority of scenarios, including fuel switching, energy efficiency, and compliance with standards and/or building portfolio targets.	✓ Historical ✓ Forecast
	Hourly AEF (Proxy for hourly long-run MEF)	**Historical analysis** where more precision is needed.	✓ Historical X Forecast
	Peak/Off-Peak MEF	**Forecasted analysis.** For specific use cases like load shifting (e.g., smart appliances, smart heating systems, electric vehicle charging), and energy/ battery storage. *Note: In the absence of publicly available granular data, TAF is only able to publish limited peak/off-peak MEFs for 2024 and 2030 at this time, derived from data provided to us by the IESO.*	X Historical ✓ Forecast

Overview

Sources

All data used to generate the electricity emissions factors comes from publicly available data from the IESO or the National Inventory Report.

The forecasted emissions factors are based on the IESO's 2024 Annual Planning Outlook (APO) forecasts for electricity supply and demand.

A more detailed description of the sources of information and methodology is presented in the Appendix.

Limitations

- Lifecycle impacts, including emissions associated with the construction, maintenance, and eventual decommissioning of power plants or renewable energy facilities;
- Location of the consumption or generation of electricity and thus the effect that transmission bottlenecks might have on emissions;
- Upstream emissions from natural gas production and transmission as well as uranium mining and processing; and
- Emissions generated from imported electricity[6].

Emissions Factor		Methodology
Average	Annual	The total emissions from electricity production in Ontario divided by the total electricity produced in any given year.
	Hourly	The total emissions from electricity production in Ontario divided by the total electricity produced in a specific hour of the day, averaged over the year.
Limited Marginal	Peak/Off-Peak	The emissions generated based on the forecasted proportion of natural gas on the margin obtained from the IESO for 2024 and 2030.

[6] 93% of 2022 Ontario's imports came from Quebec and Manitoba; sources with very low or zero emissions associated.

Historical Average Emissions Factors

Annual Average Emissions Factor

The Annual Average Emissions Factor (Annual AEF) is a measure of the average amount of carbon emissions produced per kilowatt-hour (kWh) of electricity consumed in Ontario. It is estimated using a combination of IESO's electricity generation outputs[7] and Canada's National Inventory Reports (NIR)'s estimation of natural gas emissions intensity[8].

Annual AEFs are intended for calculating emissions from current or historical electricity consumption (such as an inventory), and in lieu of long-run marginal emissions factors when quantifying long-term demand changes (such as fuel switching or energy efficiency projects). *Annual AEFs are provided as a separate, downloadable data file.*

Annual AEF (gCO_2eq/kWh): The total emissions from electricity production in Ontario (gCO2eq) divided by the total electricity produced (kWh) in any given year.

2023	67
2022	51
2021	44
2020	36
2019	29
2018	29
2017	18
2016	40
2015	46

Example 1: Estimate the electricity emissions generated by a low-rise multifamily building in 2023.

Multiply the total electricity consumption of the building over the entire year (kWh) by the AEF value for the given year.

If the total consumption of electricity in the building is estimated to be 880,000 kWh/year, the total generation emissions are 59 tCO_2eq:

880,000 kWh x 67 gCO_2eq per kWh

= 58,960,000 gCO_2eq (approx. 59 tCO_2eq)

Example 2: Estimate the impact of changes in electricity consumption from fuel switching.

A building electrification feasibility study assessed the impacts of replacing the existing gas boilers with a high-efficiency electric heat pump system.

Estimated impacts are as follows:

- Decrease in natural gas consumption from the gas boilers: **30,000 m^3/year**
- Increase in electricity consumption the heat pump system: **150,000 kWh/year**

Electrifying the building heating system will save 47.9 tCO2e/year:

(150,000 kWh/year x 67 gCO_2eq/kWh x 0.000001 tCO_2eq/gCO_2eq) - (30,000 m^3/year x 0.001932 tCO_2eq/m^3)

= - 47.9 tCO_2eq/year

[7] IESO - Generator Output Fuel Type Monthly Report

[8] Starting in 2020, TAF noticed a difference in electricity generated by natural gas combustion reported by IESO and NIR. In 2022, IESO reported 40% higher electricity generation by natural gas combustion than NIR, resulting in 32% higher emissions. IESO's generation data are based on settlement purposes, whereas NIR reports data derived from StatsCan's facility owner survey data. TAF used IESO electricity generation data and will continue to monitor differences.

Hourly Average Emissions Factors

Hourly Average Emissions Factors (Hourly AEFs) are similar to the Annual AEFs but reflect the average carbon intensity of electricity consumed in Ontario during any given hour, averaged across the year.

They can be used to calculate emissions from current or historical electricity consumption as a proxy for quantifying long-term demand changes where a greater degree of precision is needed.

TAF recommends the use of hourly AEFs over annual AEFs, for cases where granular data is available. *Hourly AEFs are provided as a separate, downloadable data file.*

Hourly AEF (gCO_2eq/kWh): The total emissions from electricity production in Ontario divided by the total electricity produced in a specific hour of the day, averaged over the year.

Hour	2023	2022	2021	2020	2019
1	38	25	19	15	14
2	34	23	19	14	13
3	34	24	20	15	13
4	37	26	23	18	15
5	43	30	27	21	17
6	51	37	32	25	21
7	58	43	36	29	25
8	64	49	41	32	28
9	69	52	44	35	30
10	72	55	47	38	32
11	73	57	49	41	33
12	73	57	51	43	34
13	74	57	51	44	34
14	75	58	53	45	35
15	76	59	54	46	35
16	78	62	55	47	36
17	81	64	56	48	37
18	82	66	58	48	38
19	82	66	56	47	38
20	81	64	53	44	37
21	78	61	48	40	34
22	72	53	40	33	29
23	60	41	31	25	22
24	48	31	23	19	16

Example 3: Estimate the total emissions associated with charging several electric vehicles (EVs) in a multi-family residential building across an entire year.

Hourly electricity emissions associated with charging EVs can be estimated using hourly AEFs.

Hourly consumption data in 2023 from connected EV chargers in the building are available in the following format:

Date/Time Ending	Hour Ending	Total Consumption (kWh)
01/01/2023 01:00	1	41.3
01/01/2023 02:00	2	37.4
01/01/2023 03:00	3	36.8
01/01/2023 04:00	4	36.2
...	...	...
12/31/2023 20:00	20	28.3
12/31/2023 21:00	21	29.2
12/31/2023 22:00	22	33.7
12/31/2023 23:00	23	37.4
01/01/2024 00:00	24	38.3

This disaggregate hourly consumption data is then aggregated across the entire year and multiplied by hourly AEFs to estimate total annual emissions as follows:

Hour Ending	Total Consumption (kWh)	2023 AEF (gCO_2eq/kWh)	Total Emissions (t)
1	10,950	38	0.42
2	11,680	34	0.40
3	9,855	34	0.34
4	9,125	37	0.34
5	5,475	43	0.24
6	7,665	51	0.39
7	3,650	58	0.21
8	5,110	64	0.33
9	5,475	69	0.38
10	5,110	72	0.37
11	5,110	73	0.37
12	4,745	73	0.35
13	4,380	74	0.32
14	4,745	75	0.36
15	5,110	76	0.39
16	5,110	78	0.40
17	5,840	81	0.47
18	5,475	82	0.45
19	7,665	82	0.63
20	9,855	81	0.80
21	9,490	78	0.74
22	11,315	72	0.81
23	10,220	60	0.61
24	8,760	48	0.42
Total:	**171,915**	**-**	**10.52**

Forecasted Emissions Factors

In many cases, we want to understand the impact of changes in electricity consumption well into the future (for example, over the operational life of a heat pump). It's common practice to use the most recent year's emissions factor and simply carry it forward. However, the use of forecasted emissions factors, developed using published IESO data, are likely to be more accurate.

TAF has used the IESO's 2024 APO[9] "as is" energy adequacy forecast to estimate AEFs out to 2041. We've assumed that any forecasted gap between supply and demand will be met with non-emitting generation. The forecasted emissions factors will help to avoid underestimating the effects of interventions in the future, since any increase or decrease in consumption will have a progressively bigger impact.

The IESO's forecast changes over time with new policy decisions and technological developments, and there is considerable uncertainty around these factors. This uncertainty grows as the forecasts go further into the future.

While changes may result in material variations to the forecasts, the most up-to date and accurate information available is used to generate the projected factors in this guideline. *Forecasted emissions factors are provided in full as a separate, downloadable data file.*

Forecasted AEFs (gCO_2eq/kWh)	
2024	71
2025	138
2026	145
2027	132
2028	133
2029	126
2030	126

Example 4: Estimate the total emissions associated with two proposed retrofit options for a large residential building using forecasted emission factors.

Existing building consumption (baseline scenario) and two retrofit options (fuel switching and comprehensive building retrofit) are described below with their estimated natural gas and electricity consumption.

The emissions are estimated using forecasted AEFs until 2041 as well as natural gas emissions factors.

	Building Energy Consumption (kWh)	
Scenario	Electricity Consumption (kWh)	Natural Gas Consumption (m^3)
Baseline Performance: Natural gas boilers, hydronic baseboard heaters	1,600,000	323,810
Option 1 Fuel Switching: Improved lighting and appliances, heat pumps for space heating and hot water, double-glazed windows)	3,300,000	9,524
Option 2 Comprehensive Retrofit: Improved lighting and appliances, heat pumps for space heating and hot water, over cladding, triple-glazed windows, solar panels	2,950,000	-

Electricity consumption is multiplied by the annual AEFs for each year from 2023 to 2041. Natural gas consumption is multiplied by the natural gas emissions factor (1932.4 g/m^3). These values are then aggregated to estimate the total emissions for the building from 2023 to 2041 for each scenario:

Scenario	Total Building Emissions (t) 2023-2041
Baseline Performance	14,297
Option 1 Fuel Switching	5,317
Option 2 Comprehensive Retrofit	4,441

[9] The IESO's 2024 Annual Planning Outlook in Six Graphs

Marginal Emissions Factors (Limited)

In Ontario, natural gas power plants are frequently used to respond to changes in demand because of their ability to increase and decrease production. In other words, they are the resource primarily driving marginal emissions. Peak/off-peak marginal emissions factors (MEFs) represent the carbon impacts of changes in electricity consumption during peak and off-peak times, as defined by the IESO.

Using forecasts of the percentage of natural gas on the margin provided to us by the IESO, TAF is publishing limited MEFs for 2024 and 2030. We recommend applying these limited factors in situations like load shifting, battery storage, and local generation, where only using AEFs can misrepresent carbon impacts.

To help address some of the complexity in using these limited factors in practice, TAF is providing a proxy method for evaluating the impacts of solar generation in Example 5. *Calculation details and a user-modifiable example are provided as a separate, downloadable data file*.

Forecasted Peak/Off-Peak (gCO_2eq/kWh)

		2024	2030
Summer	On Peak	220	499
	Mid Peak	195	494
	Off Peak	95	359
Shoulder	Mid Peak	235	479
	Off Peak	107	387
Winter	On Peak	244	489
	Mid Peak	205	484
	Off Peak	100	434

Example 5: Estimate the impact of installing a residential rooftop solar photovoltaic system.

Avoided carbon emissions are calculated based on the installation of a 10 kW solar panel over the next 10 years, starting in 2024.

The adoption of residential rooftop solar, like most new, distributed generation, impacts emissions from the grid in two ways. First, it reduces the operating output of the resource on the margin (such as short-run MEF). Second, it impacts the build-out of additional generation capacity (e.g. the decision to build new supply is influenced by the adoption of incremental new solar in aggregate).

The International Financial Institution (IFI)'s approach to renewable energy projects advocates for estimating avoided grid emissions based on a weighted average of 75% operating margin (such as short-run MEF) and 25% build margin (such as long-run MEF). This example builds on this approach, with the following assumptions:

A. Interpolation and extrapolation of short-run MEFs using the provided datapoints for 2024 and 2030 to estimate operational impact.

B. Use of forecasted AEFs in lieu of long-run MEFs to estimate impact on avoided new generation capacity.

C. A weighted average of a) and b) that shifts from short-run factors initially to relying more heavily on long-run factors at the end of the 10-year estimation period. This relies on a more dynamic set of factors, rather than the static 75%/25% split used by the IFI. Practitioners may use their own assumptions here based on the specific nature of their project.

Methodology

A. Interpolation and extrapolation to estimate short-run MEFs for operational impact.

Using an estimated solar production profile mapped against the provided short-run MEFs, we estimated the blended short-run factors for 2024 and 2030. Note that the Solar Production Allocation factors are below are for demonstration purposes only and should be replaced with a practitioner's own estimates of production during each period.

	Short-Run MEF (gCO_2e/kWh)		
Type	2024	2030	Solar Production Allocation (%)
Summer On Peak	220	499	30
Summer Mid Peak	195	494	15
Summer Off Peak	95	359	5
Shoulder Mid Peak	235	479	20
Winter On Peak	244	489	10
Winter Mid Peak	205	484	15
Winter Off Peak	100	434	5
Blended Short-Run MEF	**207**	**481**	--

We then take these factors and interpolate between 2024 and 2030, with annual interpolation factors (how much weight is assigned to the 2030 value) reflecting an expected near-term ramp up of gas-fired output.

Year	Short-Run MEF (gCO_2e/kWh)	Interpolation Factor (%)
2024	**207**	--
2025	289	30%
2026	371	60%
2027	413	75%
2028	440	85%
2029	467	95%
2030	**481**	--
2031	481	100%
2032	481	100%
2033	481	100%

B. Use of forecasted annual AEFs as a proxy for long-run MEFs to estimate impact of grid supply capacity.

In lieu of published long-run MEFs, we use provided annual average emissions factors to estimate the impact on future grid supply.

Year	Forecasted Annual AEF (gCO_2e/kWh)
2024	71
2025	138
2026	145
2027	132
2028	133
2029	126
2030	126
2031	122
2032	122
2033	104

C. Use a weighted average of short-run and long-run factors to estimate overall impact for the next 10 years.

We assume that solar completely displaces operational resources on the margin in its first two years of operation, and then starts to influence long-term grid supply decisions over time. The assumed Operational Weighting Factor represents to what extent solar production in that year displaces operational output (as opposed to new grid supply).

	Assumed Emissions Factor (gCO_2e/kWh)			
Year	Short-Run (Operational) Factor	Long-Run (Grid Capacity) Factor	Operational Weighting	Weighted Factor
2024	207	71	100%	**207**
2025	289	138	100%	**289**
2026	371	145	95%	**360**
2027	413	132	90%	**385**
2028	440	133	85%	**394**
2029	467	126	80%	**399**
2030	481	126	75%	**392**
2031	481	122	70%	**373**
2032	481	122	65%	**355**
2033	481	104	60%	**330**
Average				**348.4**

Assuming that the average solar panel in Toronto outputs 1,163 kWh for each kW of capacity, we estimate the total carbon emissions avoided over a 10-year period:

1,163 kWh/kW x 10 kW x 348.4 gCO_2eq/kWh x 10 years

= 40,518,920 gCO_2eq (40.5 tCO_2eq)

Note that most solar panels have an operational lifetime of at least 25 years, and any full assessment of the carbon reduction potential of solar PV should reflect that. We have provided a simplified example here as a starting point to illustrate the complexity of evaluating these types of investments.

While there remains significant uncertainty as to which resource will be displaced by distributed solar beyond the next decade, a practitioner could apply a multiple of 1.5 or 2.0 to the above value to estimate the impact over the entire 25-year lifetime of the system.

Electricity Generation

The best available source of information to estimate average emissions factors is the Generator Output and Capability Report (IESO, Generator Output and Capability Report, 2023) which presents the energy output and capability for generating facilities in the IESO-administered energy market with a maximum output capability of 20 MW or more.

The electricity generation on an average day follows a similar pattern as demand, with a small peak between 8-9 a.m. and a more significant one between 5-7 p.m.

Using this data carries certain limitations:

- "Behind-the-meter" generation in Ontario is not captured by the IESO's generation data, which only reports distribution connected and contracted generators. This guideline is not intended to provide information or emissions factors for this type of electricity generation.
- In generating the average emissions factors, TAF relies on generators with capacities greater than 20 MW. Smaller generators (e.g, <20 MW) are not captured in our calculations. As of December 2023, there are 3,563 active contracts[10] with an output capability of 20 MW or less that account for 2,455 MW in aggregate capacity. Of those, only 24 contracted small generators run on natural gas, with a total capacity of 119 MW.

The electricity emissions factors are estimated using a combination of IESO's electricity generation outputs and NIR's natural gas emission factors intensity. We calculate the proportion of natural gas in IESO's total grid electricity generation. We then apply NIR's grid gas generation intensity (gas fuel generation in GWh divided by gas fuel emissions in ktCO_2e) and account for transmission and distribution losses. This approach allows us to estimate the hourly, annual and forecasted average emission factors.

To estimate the peak, off-peak, and mid-peak MEF, the proportion of natural gas as a marginal resource was obtained from IESO for 2024 and 2030 and applied to NIR's grid gas generation intensity. According to IESO data, natural gas electricity generators were the marginal resource 47% of the time during peak periods and 20% of the time during off-peak periods in 2024, on average. These values are forecast to increase based on IESO projections, with natural gas being the marginal resource 90% of the time during peak periods and 80% of the time during off-peak periods on average by 2030.

In lieu of more granular information, TAF is drawing on this data from the IESO to estimate the 2024 and 2030 MEF factors. These values will be updated when more information is published.

In our previous release, TAF included a lifecycle multiplier that could be applied to MEFs to estimate the full impacts of electricity generation. However, due to data and methodology issues, lifecycle impacts are not included in these guidelines.

[10] Available data from the IESO Active Contracted Generation List.


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