Ontario Electricity Emissions Factors and Guidelines

Accurate emissions factors are the backbone of climate action strategy

Oct 2025 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 and generation. Best practices in carbon emissions quantification, including accurate emissions factors, are crucial in advancing decarbonizing strategies across all sectors of the economy.

The Atmospheric Fund (TAF) has developed a range of electricity emissions factors for such planning purposes. This 2025 guideline summarizes the factors, outlines the methodology and data sources used, and provides recommendations on which emissions factors are appropriate for different purposes.

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

In Ontario, 84% 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. In 2024, electricity emissions in the Greater Toronto and Hamilton Area (GTHA) increased significantly, nearly doubling since 2020. Between January and July 2025, the use of natural gas to provide baseload power increased by 10%, further increasing emissions from electricity generation. Although data for the second half of the year is not yet available, we expect this trend to continue given the current fuel mix and operational patterns.

This year, the National Inventory Report (NIR) has adjusted its historical electricity emissions factors, which are now aligned with TAF's methodology. This correction strengthens consistency across reporting and provides a more reliable picture of historical emissions in Ontario.

Looking ahead, the IESO's 2025 Annual Planning Outlook (APO) introduces important changes compared to the 2024 outlook, particularly how Ontario expects to meet the emerging supply-demand gap. The updated forecast places greater reliance on low- and non-emitting sources—such as nuclear refurbishments, hydro, imports, and renewables—rather than defaulting to natural gas.

However, in the short term, emissions are projected to increase as natural gas continues to balance the grid, especially during peak periods. If Ontario expands the use of natural gas plants, electricity emissions could, again, double by 2030, seriously undermining electrification and carbon reduction efforts in other sectors. This highlights the critical need to invest in non-carbon-emitting generation, demand-side management, distributed energy resources (DERs), and storage solutions to reduce gas reliance and support a resilient, low-carbon electricity system.

Introduction

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.

2025 Edition Updates

Based on the most reliable information available and valuable feedback received from other practitioners, this guideline provides an update to our 2024 release.

Key updates include:

- New electricity emissions factors for 2024, including annual and hourly average factors;
- Expanded marginal emissions factors, with guidelines on use cases;
- Updates on forecasted factors, based on IESO's 2025 Annual Planning Outlook; and
- An expanded electricity generation section, including developments on electricity emissions forecasts.

The lack of historical and real-time data on which resource is on the margin in any given hour, combined with limited policy certainty and forecast information, continues to create challenges in estimating both short- and long-term marginal emissions factors.

Given these challenges, TAF continues to recommend using average emissions factors as a proxy for quantifying and forecasting long-term demand changes, reserving the use of marginal emissions factors for short-term demand changes.

This year, we are providing more granular historical marginal emissions factors, based on the amount of natural gas on the margin provided by the IESO. These factors can be applied in specific use cases, such as evaluating changes in short-term demand, including load shifting, battery storage, and demand response programs, where responsiveness to the marginal resource is critical.

TAF is also providing forecasted marginal emissions factors, also based on data provided by the IESO. These factors can be used to estimate forecasted short-term operational changes and the carbon impacts of flexible loads and load aggregators.

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Regulatory Recommendations

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

1. **That the IESO publish historical marginal resource data and future projections to enable better understanding of the carbon impacts of load shifting.**

Identifying which resource is on the margin (e.g., whether a fossil fuel or non-emitting resource is setting the market clearing price) continues to be challenging using currently published data.

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

We strongly suggest publishing disaggregated historical data of resources that are on the margin for any given hour on the IESO's public data portal. We also suggest publishing future projections of which resources will be on the margin, enabling practitioners to better predict these changes in demand.

2. **That the Ontario Ministry of Energy and Electrification direct the IESO to accelerate the procurement and development of new non-emitting generation.**

While electricity generation emissions are projected to decline in the long term, there is considerable uncertainty in this forecast. Recent IESO procurements are fuel-neutral, making it difficult to predict how much new gas capacity versus non-emitting supply will be procured.

Expanding the use of gas-fired generation in Ontario in the short term will undermine the benefits of electrification associated with switching to electric space and water heating, vehicles, and industrial processes. New gas plants also represent a long-term investment that creates a "lock-in" effect, making long-term emissions reductions much more difficult to achieve.

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, enabling 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 would not 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), including:
   - Building electrification and energy efficiency retrofits;
   - Deployment and use of electric vehicle (EV) charging infrastructure;
   - Shifts in electricity consumption patterns (e.g., time-of-use rates or load shifting strategies);
   - Adoption of distributed energy resources (DERs) such as solar, battery storage, or district energy; and
   - Transportation mode shifts and electrification of fleets.

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 (current 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 (e.g., a gas-fired plant increases or decreases its output) or long-term change in demand (e.g., the province secures new supply to support electrification efforts).

Although the resource in question-- electricity-- is the same, different types of electricity emissions factors should be used for different quantification purposes.

Four key categories are discussed on the following page (8):.

[1] TAF uses the term Carbon to refer to CO_2 equivalent, regardless of the specific greenhouse gases involved.

Guidelines

1. To prepare an inventory:

TAF recommends using Average Emissions Factors (AEFs) When quantifying current or historical emissions resulting from electricity consumption (e.g., within an organization or a city).

Annual AEFs are sufficient for most purposes. However, hourly AEFs can be applied where more precision is needed, and specifically, where hourly consumption data is available for analysis. Historic annual and hourly AEFs can also be used to assess year-to-year changes in electricity consumption and related emissions over specific periods of time.

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

TAF recommends using Average Emissions Factors (AEFs) as a proxy for long-run marginal emissions factors. 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.

AEFs can be applied to current and forecasted electricity consumption, making them suitable for estimating emissions impacts over time. This approach reflects the best available option given current and forecasted conditions in Ontario. TAF will continue to revisit this recommendation as more detailed policy signals and data become available.

Best practices continue to 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 (e.g., 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.*

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

TAF recommends using Marginal Emissions Factors (MEFs). Annual and monthly/seasonal MEFs are sufficient for most purposes. Specific use cases include:

- Load shifting (e.g., smart appliances, smart heating systems, electric vehicle charging)
- Energy or battery storage

To assist in evaluating the carbon emissions of short-term changes in demand, TAF is providing historical and forecasted annual MEFs as well as historical monthly/seasonal MEFs. These factors are based on the amount of natural gas on the margin, using data provided by the IESO

4. 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 method for evaluation in Example 5.

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[2] Short-run marginal emission rates omit important impacts of electric-sector interventions | PNAS
[3] 22-18 Projected Emission Factors for New York Grid Electricity | NYSERDA
[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).

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.

This guideline includes four types of electricity emissions factors:		
Average Emissions Factors (AEFs)	Annual	Historic + Forecasted
	Hourly	Historic
Short-run Marginal Emissions Factors (MEFs)	Annual	Historic + Forecasted
	Monthly	Historic
	Seasonal	Forecasted

Type	Applications	Recommended Emissions Factors
Preparing an inventory / Assessing a footprint	• Annual reporting of a city / organization's carbon emissions footprint (e.g., annual corporate inventory or ESG reporting) • Long-term planning or policy analysis of climate targets (e.g., forecasting municipal emissions under a new 10-year climate action plan, estimating grid emissions for a given year)	**Annual AEF** ✓ Historical *and/or* ✓ Forecast factors
	• Carbon accounting for variable-load operations (e.g., calculating a data center's electricity footprint considering fluctuating computing power) • Estimating emissions from specific time-bound activities (e.g., calculating the total emissions from charging a fleet of EVs over one year) • Analysis of the real-time carbon intensity of electricity consumption (e.g., correlating hourly grid carbon intensity with public health outcomes) • Assessing diurnal patterns of grid emissions	**Hourly AEF** ✓ Historical factors
Evaluating the impact of long-term changes in demand	• Estimating annual emissions savings from building retrofits and energy efficiency projects (e.g., energy audits, feasibility studies, decarbonization studies, assessing HVAC and lighting upgrades) • Feasibility studies for behind-the-meter generation (e.g., carbon impacts of a proposed rooftop solar PV system • Assessing the impact of policies that change the grid's generation (e.g., evaluating the emission reductions from the phase-out of gas-fired power plants) • Estimating the effect of large-scale electrification (e.g., electrification of buses, buildings across a portfolio) • Assessing the impact of long-term renewable energy contracts and compliance with standards (e.g., power purchase agreement for a new renewable energy facility) • Capacity expansion decisions (e.g., impact of permanent loads like new data centers)	**Annual AEF**[6] ✓ Historical *and/or* ✓ Forecast factors

[6] In the absence of policy certainty and publicly available granular data, TAF recommends the use of AEFs for these types of long-term changes in demand.

Guidelines

Type	Applications	Recommended Emissions Factors
Evaluating the impact of short-term changes in demand	• Estimating impacts of incremental load changes or load shifting strategies (e.g., evaluating the effectiveness of smart systems for peak-hour reduction like thermostats, smart heating systems and appliances) • Calculating the carbon value of demand response programs • Informing real-time dispatch decisions (e.g., turning on large industrial machines or load balancing)	**Annual MEF** ✓ Historical *and/or limited* forecast factors
	• Estimating avoided emissions through battery storage discharges or high-resolution load shifts (e.g., EV charging at low-carbon times)	**Hourly MEF** ✓ Historical factors
Evaluating the impact of new electricity generation	• Assessing emissions from the addition of new renewable or fossil generation	**Annual MEF + Annual AEF** ✓ Historical *and/or* ✓ Forecast factors

Methodology

Overview

Sources

All data used to generate electricity emissions factors comes from publicly available reports, including historical electricity generation data from the IESO. The data also references natural gas emission intensity of gas plants and transmission and distribution loss factors from the National Inventory Report.

The forecasted average emissions factors are based on the IESO's 2025 Annual Planning Outlook (APO) forecasts for electricity supply and demand. The historical and forecasted marginal electricity emissions factors are estimated using the percentage of gas on the margin provided by IESO.

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

Exclusions

- 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 consequently, 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[7]. TAF's analysis treats these imports (e.g., from Hydro-Québec) as having zero emissions. Other approaches (e.g., from WattTime[8]), assign imports to Ontario as having the marginal impact of natural gas, since they reduce exports to U.S. markets which then need to be backfilled by gas generation

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.
Marginal	Annual	The percentage of time natural gas is on the margin multiplied by the natural gas emissions intensity in any given year.
	Monthly/ Seasonal	The percentage of time natural gas is on the margin multiplied by the natural gas emissions intensity in each month/season.

[7] 71% of 2024 Ontario's imports came from Quebec and Manitoba; sources associated with very low or zero emissions. Imports from these provinces dropped from 93% in 2022 to 71% in 2024. Overall, the total amount of electricity Ontario imports has decreased significantly (8,708 GWh in 2021 to 1,599 GWh in 2024). | IESO

[8] WattTime Methodology

Historical Average Emissions Factors

Annual Average Emissions Factor

The Annual Average Emissions Factors (Annual AEFs) are a measure of the average amount of carbon emissions produced per kilowatt-hour (kWh) of electricity consumed in Ontario each year. They are estimated using a combination of IESO's electricity generation outputs[9] and Canada's National Inventory Reports (NIR)'s estimation of natural gas plants emissions intensity[10].

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, 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.

2024	73
2023	59
2022	49
2021	43
2020	35
2019	29
2018	29
2017	18
2016	40
2015	46

Example 1: Estimate the electricity emissions generated by a low-rise multi-family building in 2024.

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 64 tCO_2eq:

880,000 kWh x 73 gCO_2eq per kWh

= 64,240,000 gCO_2eq (approx. 64 tCO_2eq)

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

For this type of simplified analysis, we can use historical average emissions factors. For cases where it is important to understand the impact of fuel switching well into the future, over the lifetime of specific equipment, for example, forecasted factors should be used. See examples in the forecast section for more information.

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

Electrifying the building heating system will save 47.0 tCO_2e/year:

- 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 47.0 tCO_2e/year:**

(150,000 kWh/year x 73 gCO_2eq/kWh x 0.000001 tCO_2eq/gCO_2eq) - (30,000 m^3/year x 0.001931 tCO_2eq/m^3)

= - 47.0 tCO_2eq/year

[9] Generator Output Fuel Type Monthly Report |IESO

[10] 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.

Methodology

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 consumption data is available and where greater precision is required (e.g., when estimating emissions from specific time-bound activities or conducting carbon accounting for variable-load operations).

Complete 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	2024	2023	2022	2021	2020
1	49	34	24	19	15
2	44	30	23	18	14
3	44	30	23	19	15
4	46	33	25	22	17
5	52	38	30	26	21
6	60	45	35	31	25
7	67	52	42	35	28
8	72	57	47	39	31
9	75	61	51	43	34
10	77	64	53	45	37
11	78	65	55	48	40
12	79	65	55	49	41
13	80	66	55	50	43
14	80	66	56	51	44
15	80	67	57	52	45
16	82	69	60	53	46
17	86	71	62	55	47
18	88	73	64	56	47
19	88	73	64	55	46
20	87	72	62	51	43
21	86	70	59	47	39
22	80	64	51	39	32
23	69	53	40	30	25
24	58	43	30	23	18

Methodology

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. In this example, we are not considering load shifting or time-of-use strategies where the use of MEFs would be more appropriate. Instead, the focus is on estimating total emissions by applying hourly AEFs to the total electricity consumed in each hour over a given year.

Example hourly consumption data in 2024 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

Example 3 (continued):

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

Hour Ending	Total Consumption (kWh)	2023 AEF (gCO_2eq/kWh)	Total Emissions (t)
1	10,950	49	0.54
2	11,680	44	0.51
3	9,855	44	0.43
4	9,125	46	0.42
5	5,475	52	0.28
6	7,665	60	0.46
7	3,650	67	0.24
8	5,110	72	0.37
9	5,475	75	0.41
10	5,110	77	0.39
11	5,110	78	0.40
12	4,745	79	0.37
13	4,380	80	0.35
14	4,745	80	0.38
15	5,110	80	0.41
16	5,110	82	0.42
17	5,840	86	0.50
18	5,475	88	0.48
19	7,665	88	0.67
20	9,855	87	0.86
21	9,490	86	0.82
22	11,315	80	0.91
23	10,220	69	0.71
24	8,760	58	0.51
Total	**171,915**	**-**	**11.85**

Forecasted Emissions Factors

In many cases, it is important to assess the long-term impact of changes in electricity consumption (e.g., over the operational life of a heat pump). A common practice is to carry forward the most recent year's emissions factor; however, forecasted emissions factors—based on IESO data—are likely to offer greater accuracy. Those factors also help avoid underestimating the impact of future interventions, as changes in consumption will have increasing effects over time.

TAF used the IESO's 2025 Annual Planning Outlook (APO)[11] energy forecast scenario to estimate AEFs through 2050. This scenario is based on simulations from the Capacity Expansion model, which identifies the least-cost supply mix to meet Ontario's resource adequacy needs. It reflects one illustrative pathway for meeting future electricity demand, rather than a definitive procurement plan.

IESO forecasts evolve with policy and technological developments, with uncertainty increasing over longer time horizons. While such changes may affect outcomes, the most current and reliable data have been used to generate the projected factors in this report.

Complete forecasted emissions factors are available as a separate data file.

Forecasted AEFs (gCO_2eq/kWh)	
2025*	75
2026	81
2027	124
2028	113
2029	113
2030	106

** The 2025 value is calculated using the actual 2025 IESO electricity generation outputs for the first half of the year.*

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

Baseline consumption and two retrofit scenarios (fuel switching and comprehensive retrofit) are summarized below, with their estimated natural gas and electricity use.

Emissions are estimated using forecasted AEFs through 2050 and 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 2025 to 2050. Natural gas consumption is multiplied by the natural gas emissions factor (1931.3 g/m^3). These values are then aggregated to estimate the total emissions for the building from 2024 to 2050 for each scenario:

Scenario	Total Building Emissions (t) 2025-2050
Baseline Performance	18,438
Option 1 Fuel Switching	4,972
Option 2 Comprehensive Retrofit	4,017

[11] 2025 Annual Planning Outlook | IESO

Marginal Emissions Factors

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.

This guideline includes **historical** annual and monthly MEFs calculated using IESO's percentage of natural gas on the margin. Historical annual MEFs are summarized in the table below, and historical monthly MEFs are provided as a separate, downloadable data file.

Historical Annual MEF (gCO2eq/kWh):
The percentage of times natural gas is on the margin multiplied by natural gas emissions intensity in a given year.

2015	190
2016	143
2017	84
2018	181
2019	178
2020	180
2021	241
2022	288
2023	312
2024	343

Using forecasts of the percentage of natural gas on the margin provided to us by the IESO, TAF is also publishing an expanded list of MEFs. These include forecasted annual and forecasted seasonal factors. We recommend applying these factors in situations like load shifting, battery storage, and local generation, where using AEFs can misrepresent carbon impacts.

Forecasted MEFs (gCO$_2$eq/kWh):

	Winter			Shoulder		Summer		
Year	On Peak	Mid Peak	Off Peak	Mid Peak	Off Peak	On Peak	Mid Peak	Off Peak
2025	49	- -	- -	- -	- -	- -	- -	- -
2026	349	356	356	356	349	342	345	352
2027	434	434	434	434	434	434	434	434
2028	442	442	442	442	442	442	442	442
2029	382	382	382	382	382	382	382	382
2030	397	397	397	397	393	393	393	397
2031	366	366	366	366	362	362	362	366
2032	307	311	311	311	301	304	301	307
2033	294	300	300	300	297	294	300	279
2034	268	282	285	285	251	253	253	262
2035	352	371	374	374	336	340	336	336
2036	364	392	396	396	368	368	372	321
2037	382	402	402	406	361	378	378	349
2038	370	390	394	394	374	374	382	339
2039	380	392	392	392	388	380	388	361
2040	314	340	367	344	302	287	306	284

Methodology

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.

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 2026.

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. Estimating the blended short-run MEFs for operational impact

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

C. Use 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.

A. Estimating the blended 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	2026	2027	... 2035	Solar Production Allocation
Summer On Peak	345	434	336	30%
Summer Mid Peak	349	434	336	15%
Summer Off Peak	342	434	340	5%
Shoulder Mid Peak	352	434	336	20%
Shoulder off Peak	349	430	348	
Winter On Peak	356	434	374	10%
Winter Mid Peak	356	434	371	15%
Winter Off Peak	356	434	374	5%
Blended Short-Run MEF*	**350**	**434**	**347**	--

** These values differ slightly from the average annual MEF due to the specifics of the solar adoption example.*

Methodology

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)
2026	81
2027	124
2028	113
2029	113
2030	106
2031	98
2032	67
2033	54
2034	48
2035	44

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.

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
2026	350	81	100%	**350**
2027	434	124	100%	**434**
2028	442	113	95%	**426**
2029	382	113	90%	**355**
2030	395	106	85%	**351**
2031	364	98	80%	**311**
2032	305	67	75%	**246**
2033	295	54	70%	**223**
2034	264	48	65%	**188**
2035	347	44	60%	**226**
Average				**311.0**

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 311.0 gCO_2eq/kWh x 10 years

= 36,169,300 gCO_2eq (36.2 tCO_2eq)

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 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 June 2025, there are 3,436 active contracts[12] with an output capability of 20 MW or less that account for 3,369 MW in aggregate capacity. Of those, only 22 contracted small generators run on natural gas, with a total capacity of 115 MW.

Average Electricity Emissions Factors:

Historical AEFs are estimated using IESO's electricity generation output combined with natural gas plant emission intensities from the NIR, as IESO relies on NIR values in its historical reporting. Forecasted AEFs are estimated using IESO's generation forecasts and IESO's own projected natural gas plant emission intensities, since NIR does not publish forecasted values.

To estimate the average electricity emission factors, we calculate the proportion of natural gas in IESO's total grid electricity generation. We then apply grid gas generation intensity (gas fuel generation in GWh divided by gas fuel emissions in $ktCO_2e$) and account for transmission and distribution losses. Loss factors are derived from the NIR report and range from 9–10% in Ontario.

Since Toronto Hydro already includes distribution losses in its consumption and billing data, adjustments are needed to avoid double counting. **Toronto Hydro data users should first divide the reported consumption by 1.04 (for residential and small commercial customers) or by 1.01 (for large commercial customers), and then multiply by TAF's emissions factors, which already include transmission and distribution losses.**

Marginal Electricity Emissions Factors:

Specifically for historic annual and monthly MEFs, TAF is providing factors for 2015-2024 generated using IESO's monthly percentage of gas on the margin data.

To estimate the forecasted MEFs, the proportion of natural gas as the marginal resource was obtained from IESO and applied to NIR's grid gas generation intensity. According to IESO projections, natural gas is expected to serve as the marginal resource 100% of the time by 2030.

[12] Available data from the Active Contracted Generation List | IESO

Methodology

Comparisons of Electricity Emissions:

Figure A1 compares grid electricity emissions based on TAF's updated 2025 estimates, IESO's 2025 APO, and IESO's 2024 scenarios (as-is, high nuclear and the scenario in the six-graph report). Historical emissions are not fully aligned between TAF and IESO, primarily because IESO has not yet updated their historical factors, which have already been corrected by NIR. However, starting in 2025, the emissions projections are consistent between TAF and IESO estimates.

While emissions are projected to decline in the long term, there is lots of uncertainty. Future demand remains uncertain and natural gas is expected to serve as the marginal resources for the vast majority of time over the next five years. And recent IESO procurements have been fuel-neutral which may result in more new gas capacity than estimated. Long-term emissions projections appear favourable on paper, however, realizing these reductions will require substantial operational and policy changes in planning and decision-making.

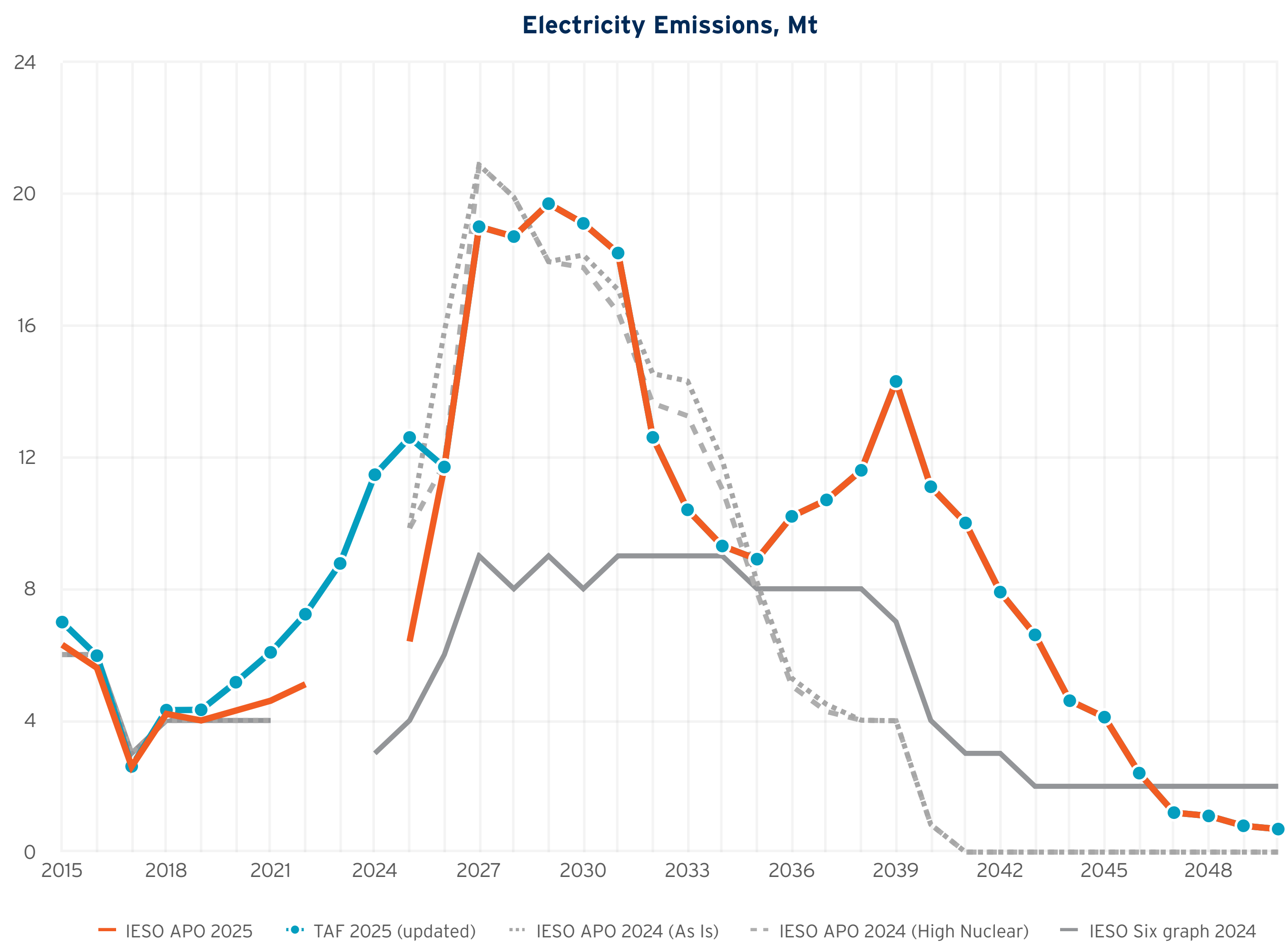

Figure A1 – Grid Electricity Emissions: Historical and Forecasts


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