EB-2024-0111

Enbridge Gas

Compendium for Examination of Energy Futures Group on LCVP/RNG

Elson
Advocacy

BY RESS AND EMAIL

June 11, 2024

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Dear Ms. Marconi:

Re: Enbridge Gas Inc. 2024 to 2028 Rates Application
EB-2024-0111

I am writing on behalf of the Green Energy Coalition and Environmental Defence to submit a request to file evidence regarding the applicant's energy transition evidence and proposals as pertinent to the phase II issues. As detailed below, the evidence would be prepared by Chris Neme and Dr. David Hill of the Energy Futures Group (EFG) and would focus on the energy transition technology fund, low-carbon gas procurement proposal, energy comparison information, and the proposed next steps for system pruning and integrated resource planning.

Experience of Energy Futures Group

Mr. Neme is a leading expert on the options for and implications of decarbonization for gas customers and best practices to address those customer risks and opportunities. Mr. Neme and his firm have prepared reports, comments to regulators and expert testimony specifically on this topic in jurisdictions across North America.[1] Mr. Neme and his firm have also critically reviewed numerous gas utility decarbonization studies across a wide range of jurisdictions.

Over the past three decades, Mr. Neme has worked for energy regulators, utilities, government agencies and other organizations in more than 30 states, 7 Canadian provinces and several European countries. He has defended expert witness testimony in approximately 70 cases before regulatory commissions in 13 different jurisdictions. He has also testified before several state legislatures.

Mr. Neme also has decades of experience specific to Ontario and its gas system. Mr. Neme served on the Enbridge and Union natural gas demand side management audit/evaluations committees since their inception approximately two decades ago and currently sits on the gas DSM Evaluation Committee, the gas Integrated Resource Planning (IRP) Technical Working Group (IRP TWG), and the Demand Side Management Stakeholder Advisory Group (SAG). He

[1] Including in Massachusetts, Vermont, Delaware, Michigan, Illinois, Washington, Oregon, and British Colombia.

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has also previously served as an external reviewer of efficiency potential and carbon pricing studies. He has earned broad respect and trust from the Ontario regulatory community and has been elected to these committee roles by other intervenors and/or appointed by the OEB. Mr. Neme has provided expert testimony in approximately 25 OEB cases. Mr. Neme's CV is attached.

Mr. Neme would be supported by Dr. David Hill, who has a Ph. D. in Energy Management and Policy Planning and over 30 years of experience in the energy and environmental sectors. Dr. Hill would assist in preparing the EFG evidence, especially with respect to the Enbridge proposal to procure low-carbon gases as this is an area where Dr. Hill has considerable knowledge and experience to contribute. Dr. Hill's CV is attached.

Evidence Description

At a high level, EFG's evidence would critique Enbridge's evidence and proposals relating to phase II energy transition issues and provide recommendations as applicable. We anticipate that EFG's evidence and potential recommendations would largely focus on the following four areas:

- The appropriateness of the ETTF and, if the ETTF is approved, recommendations regarding the spending criteria (i.e. safe bet identification), processes to ensure robust and balanced oversight and decision-making, and other design elements;

- The appropriateness of Enbridge's RNG proposals and, if they are approved, recommendations regarding program criteria and design elements to maximize consumer benefits;

- Comments on Enbridge's energy comparison information evidence, including its rationale for excluding heat pumps from its energy comparison informational materials; and

- Comments on Enbridge's proposed next steps regarding system pruning and integrated resource planning.

EFG's evidence would touch on the following issues set out in the issues list:

> 15) Are the specific proposed parameters for an Energy Transition Technology Fund and associated rate rider appropriate?
>
> 16) Is the proposal to establish a new Energy Transition Technology Fund Variance Account appropriate?
>
> 17) Are the specific proposals to amend the Voluntary RNG Program and to procure low-carbon energy as part of the gas supply commodity portfolio, appropriate?

18) Are the energy transition safe bet proposals with capital spending in the IRM term that were not addressed in Phase 1, such as the Energy Transition Technology Fund and the Low-Carbon Renewable Natural Gas Program, appropriate?

24) Has Enbridge Gas appropriately reviewed the energy comparison information in its informational and marketing materials, and taken appropriate actions based on its review?

25) Has Enbridge Gas appropriately responded to relevant OEB directions and commitments from previous proceedings, including issues related to the IRP Framework?

The energy transition raises new and important issues for gas regulation. We believe the OEB will benefit from Mr. Neme's deep knowledge in this area, especially in light of his decades of experience with Ontario's gas landscape.

Budget

We anticipate the EFG report costing $45,000 to $60,000 to produce. Although estimate that the remaining steps in the hearing may require an additional 40% in consultant costs based on past experience, we cannot provide a firm estimate of those costs as they are based on factors that are entirely outside of our control, including the number of interrogatories, whether presentations will be required, and whether Mr. Neme would be called as a witness. We anticipate incremental counsel time associated with this evidence to be less than $2,500.

Conclusion

In light of the above, we respectfully request that this evidence be approved for submission in this proceeding.

Yours truly,

Kent Elson

cc: Parties to the above proceeding

Chris Neme
Principal

ENERGY FUTURES GROUP

Professional Summary

Chris specializes in analysis of markets for energy efficiency, demand response, renewable energy and strategic electrification measures, as well as the design and evaluation of programs and policies to promote them. During his 25+ years in the industry, he has worked for energy regulators, utilities, government agencies and advocacy organizations in 30+ states, 7 Canadian provinces and several European countries. He has filed expert witness testimony in 60+ cases before regulatory commissions in 13 different jurisdictions; he has also testified before several state legislatures. Chris has authored numerous reports and papers on clean energy policies and programs, including the National Standard Practice Manual for Benefit Cost Analysis of Distributed Energy Resources (2020), the predecessor NSPM for energy efficiency (2017), and several reports on electric non-wires and gas non-pipe alternatives.

Experience

2010-present: Principal, Energy Futures Group, Hinesburg, VT

1999-2010: Director of Planning & Evaluation, Vermont Energy Investment Corp., Burlington, VT

1993-1999: Senior Analyst, Vermont Energy Investment Corp., Burlington, VT

1992-1993: Energy Consultant, Lawrence Berkeley National Laboratory, Gaborone, Botswana

1986-1991: Senior Policy Analyst, Center for Clean Air Policy, Washington, DC

Education

M.P.P., University of Michigan, 1986

B.A.., Political Science, University of Michigan, 1985

Selected Projects

- Natural Resources Defense Council (Illinois, Michigan and Ohio). Critically review efficiency, demand response, electrification, distribution system investment and integrated resource plans filed by IL, MI and OH utilities. Draft/defend regulatory testimony on critiques. Represent NRDC in regular stakeholder-utility engagement processes. Represent NRDC in collaborative development of non-wires solution pilots. Support development of Illinois clean energy legislation. (2010 to present)
- E4TheFuture. Co-authored National Standard Practice Manual Benefit Cost-Analysis of Distributed Energy Resources (2020) and NSPM for efficiency (2017). Present the NSPM to audiences across the U.S. and Canada; helping several to assess how to use it to refine current practices. (2016-present)
- Vermont Agency of Natural Resources. Supported EFG/Cadmus team in analysis of pathways for achieving the state's Global Warming Solutions Action emission reduction requirements, including marginal abatement cost curve development (2022). Supporting new assessment of emissions and cost tradeoffs between policy options for decarbonizing buildings and industry sectors (2023).

- Connecticut Energy Efficiency Board. Part of team providing on-going review and input on utility efficiency program planning and related policy issues. Lead role in providing input on New England Avoided Energy Supply Cost study and cost-effectiveness screening policy issues. (2019-present)
- Ontario Energy Board. Appointed to serve on provincial gas DSM Evaluation Advisory Committee, providing input on multi-year evaluation plans, scopes of work for evaluation studies and independent evaluator assessments of utilities' annual gas savings claims. Also serve on gas IRP committee, providing input on non-pipe alternatives, including cost-effectiveness analyses and selection of pilot projects. Previously also appointed to advisory committees on gas and electric efficiency potential studies and advisory committee on carbon price forecast studies. (2015-present)
- Green Energy Coalition (Ontario). Represent coalition of environmental groups in regulatory proceedings, utility negotiations and stakeholder meetings on DSM policies, utility proposed DSM Plans, integrated resource planning and rules governing non-pipe alternatives. (1993 to present)
- Energy Action Network (Vermont). Co-authored a white paper on the concept of a "Clean Heat Standard" – a kind of renewable portfolio standard that would impose increasing obligations on Vermont Gas and wholesale suppliers of fuel oil and propane to reduce greenhouse gas emissions from burning of fossil fuels in homes and businesses, consistent with the state's Global Warming Solutions Act requirements (e.g., 40% reduction by 2030). Co-leading related voluntary working group of interested parties providing input on the design of the policy. Testified before Vermont House Energy and Technology Committee on Clean Heat Standard legislation. (2020-present)
- Sierra Club (Massachusetts). Supported Sierra Club's participation in an year-long process in which the Massachusetts' gas utilities engaged with stakeholders to discuss and consider the future of the gas industry in the context of decarbonization policy goals. Reviewed draft inputs to technical study of options for decarbonizing the gas industry presented to the group and assisted in drafting regulatory comments on final study results as well as gas utility policy proposals. (2021-2022).
- Environmental Law and Policy Center. Filed expert witness testimony supporting AEP Ohio's initial proposal to run a portfolio of efficiency programs and in opposition to a proposed rate case settlement agreement to eliminate such programs. (2021)
- Sierra Club (Maryland). Provided strategic support on testimony on cost-effectiveness and other rules governing expansion of gas infrastructure to connect additional customers. (2021)
- New Jersey Board of Public Utilities. Served on management team responsible for statewide delivery of New Jersey Clean Energy Programs. Led strategic planning; support regulatory filings, cost-effectiveness analysis & evaluation work. (2015 to 2020). Served on management team for start-up of residential and renewables programs for predecessor project. (2006-2010)
- Regulatory Assistance Project - U.S. Provided guidance on efficiency policy and programs. Lead author on strategic reports on program options for decarbonizing Vermont buildings, achieving 30% electricity savings in 10 years, using efficiency to defer T&D system investments, & bidding efficiency into capacity markets. (2010 to 2020)
- Energy Efficiency Alberta. Assisted EEA in providing input to Alberta Utilities Commission on the role efficiency resources can play in reducing electric system costs. (2019 to 2020)

- Consumers Association of Canada (Manitoba) and Winnipeg Harvest. Critically reviewed and filed regulatory testimony on Efficiency Manitoba's first three-year plan (2020-2023), with particular emphasis on the extent to which the plan supported advanced heat pump technology as both an electric efficiency measure and a key to future building electrification. (2019-2020).
- Citizens Action Coalition of Indiana. Critically reviewed how energy efficiency resources were modeled in utility IRPs, as well as the design of energy efficiency program portfolios. (2018 to 2020)
- Efficiency Vermont. Provided technical support in review of avoided cost assumptions, as well as related policies on cost-effectiveness analyses of efficiency resources (2019).
- Earth Justice and Southern Alliance for Clean Energy. Helped critically review Florida utilities' efficiency potential studies and proposed 2020-2024 energy efficiency savings targets. (2019)
- New Hampshire Office of the Consumer Advocate. Drafted expert witness testimony on the merits of utilities adding a pilot non-wires solution project to their efficiency program plans. (2018)
- Regulatory Assistance Project - Europe. Provide on-going support on efficiency policies and programs in the United Kingdom, Germany, and other countries. Reviewed draft European Union policies on Energy Savings Obligations, EM&V protocols, and related issues. Drafted policy brief on efficiency feed-in-tariffs and roadmap for residential retrofits. (2009 to 2018)
- Green Mountain Power (Vermont). Supported development and implementation of GMP's first compliance plan for Vermont RPS Tier 3 requirement to reduce customers' direct consumption of fossil fuels, with significant emphasis on strategic electrification strategies. Also developed 10-year forecast of sales that could result from three different levels of policy/program promotion of residential electric space heating, electric water heating and electric vehicles. (2016 to 2018)
- Alberta Energy Efficiency Alliance. Drafted white paper how treatment of "efficiency as a resource" could be institutionalized in Alberta. The paper followed several presentations to government agencies and others on behalf of the Pembina Institute. (2017 to 2018)
- Southern Environmental Law Center. Assessed reasonableness of Duke Energy's historic efficiency program savings claims, as well as the design of their efficiency program portfolios for 2019. Filed expert witness testimony on findings in North Carolina dockets (2018).
- Toronto Atmospheric Fund. Helped draft an assessment of efficiency potential from retrofitting of cold climate heat pumps into electrically heated multi-family buildings (2017).
- Northeast Energy Efficiency Partnerships. Helped manage Regional EM&V forum project estimating savings for emerging technologies, including field study of cold climate heat pumps. Led assessment of best practices on use of efficiency to defer T&D investment. (2009 to 2015)
- Ontario Power Authority. Managed jurisdictional scans on leveraging building efficiency labeling/disclosure requirements and non-energy benefits in cost-effectiveness screening. Supported staff workshop on the role efficiency can play in deferring T&D investments. Presented on efficiency trends for Advisory Council on Energy Efficiency. (2012-2015)
- Vermont Public Interest Research Group. Conducted comparative analysis of the economic and environmental impacts of fuel-switching from oil/propane heating to either natural gas or efficient, cold climate electric heat pumps. Filed regulatory testimony on findings. (2014-2015)

- New Hampshire Electric Co-op. Led assessment of the co-op's environmental and social responsibility programs' promotion of whole building efficiency retrofits, cold climate heat pumps and renewable energy systems. Presented recommendations to the co-op Board. (2014)
- National Association of Regulatory Utility Commissioners (NARUC). Assessed alternatives to 1st year savings goals to eliminate disincentives to invest in longer-lived savings. (2013)
- California Investor-Owned Utility. Senior advisor on EFG project to analyze 10 leading U.S. utility portfolios to determine if there are differences in the cost of saved energy related to utility spending in specific non-incentive categories, including administration, marketing, and EM&V. (2013)
- DC Department of the Environment (Washington DC). Part of VEIC team administering the DC Sustainable Energy Utility (SEU). Helped characterize the DC efficiency market and supporting the design of efficiency programs that the SEU will be implementing. (2011 to 2012)
- Ohio Sierra Club. Filed and defended expert witness testimony on the implications of not fully bidding all efficiency resources into the PJM capacity market. (2012)
- Regulatory Assistance Project – Global. Assisted RAP in framing several global research reports. Co-authored the first report – an extensive "best practices guide" on government policies for achieving energy efficiency objectives, drawing on experience with a variety of policy mechanism employed around the world. (2011)
- Tennessee Valley Authority. Assisted CSG team providing input to TVA on the redesign of its residential efficiency program portfolio to meet aggressive new five-year savings goals. (2010)
- New York State Energy Research and Development Authority (NYSERDA). Led residential & renewables portions of several statewide efficiency potential studies. (2001 to 2010)
- Ohio Public Utilities Commission. Senior Advisor to a project to develop a web-based Technical Reference Manual (TRM). The TRM includes deemed savings assumptions, deemed calculated savings algorithms and custom savings protocols. It was designed to serve as the basis for all electric and gas efficiency program savings claims in the state. (2009 to 2010)
- Vermont Electric Power Company. Led residential portion of efficiency potential study to assess alternatives to new transmission line. Testified before Public Service Board. (2001-2003)
- Efficiency Vermont. Served on Sr. Management team. Supported initial project start-up. Oversaw residential planning, input to regulators on evaluation, input to regional EM&V forum, development of M&V plan and other aspects of bidding efficiency into New England's Forward Capacity Market (FCM), and development and updating of nation's first TRM. (2000 to 2010)
- Long Island Power Authority Clean Energy Plan. Led team that designed the four major residential programs (three efficiency, one PV) incorporated into the plan in 1999. Oversaw extensive technical support to the implementation of those programs. This involved assistance with the development of goals and budgets, development of savings algorithms, cost-effectiveness screening, and on-going program design refinements. (1998 to 2009)

Selected Publications and Reports

- *Cost Savings and CO2 Emission Reductions of Residential Electrification in Peoples Gas Territory*, prepared for the Natural Resources Defense Council, November 2022 (with David Hill & Liz Bourguet)
- *Tip of the Spear: How Efficiency Programs Supporting Cold Climate Heat Pumps in Low Income Multi-Family Buildings Could Help Lay the Foundation for Building Decarbonization in Michigan and Illinois*, 2022 ACEEE Summer Study on Energy Efficiency in Buildings (with Laura Goldberg, Valeria Rincon and Samantha Williams)
- *The Clean Heat Standard*, Vermont Energy Action Network (EAN) White Paper, December 2021 (with Richard Cowart)
- *National Standard Practice Manual for Benefit Cost Analysis of Distributed Energy Resources*, August 2020, (with Tim Woolf and others)
- *Reducing CO_2 Emissions from Vermont Buildings: Potential and Cost-Effectiveness of Select Program Options*, Regulatory Assistance Project, February 13, 2019 (with Richard Faesy)
- *Pumping Energy Savings: Recommendations for Accelerating Heat Pump Adoption in Ontario's Electrically Heated Multi-Residential Buildings*, Toronto Atmospheric Fund, July 2018 (with Devon Calder, Brian Purcell and Judy Simon)
- *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*, Edition 1, Spring 2017 (with Tim Woolf, Marty Kushler, Steven Schiller and Tom Eckman)
- *The Next Quantum Leap in Efficiency: 30% Electricity Savings in 10 Years*, Proceedings of the 2016 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 9, pp. 1-14 (with Jim Grevatt, Rich Sedano and Dave Farnsworth)
- *The Next Quantum Leap in Efficiency: 30% Electricity Savings in Ten Years*, published by the Regulatory Assistance Project, February 2016 (with Jim Grevatt)
- *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments*, published by Northeast Energy Efficiency Partnerships, January 9, 2015 (with Jim Grevatt)
- *Unleashing Energy Efficiency: The Best Way to Comply with EPA's Clean Power Plan*, Public Utilities Fortnightly, October 2014, pp. 30-38 (with Tim Woolf, Erin Malone and Robin LeBaron)
- *The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening*, published by the National Efficiency Screening Project, August 2014 (with Tim Woolf et al.)
- *U.S. Experience with Participation of Energy Efficiency in Electric Capacity Markets*, Regulatory Assistance Project, August 2014 (with Richard Cowart)
- *The Positive Effects of Energy Efficiency on the German Electricity Sector*, IEPEC 2014 Conference, September 2014 (with Friedrich Seefeldt et al.)

- *Final Report: Alternative Michigan Energy Savings Goals to Promote Longer Term Savings and Address Small Utility Challenges*, prepared for the Michigan Public Service Commission, September 13, 2013 (with Optimal Energy)
- *Energy Efficiency Feed-in-Tariffs: Key Policy and Design Considerations*, Proceedings of ECEEE 2013 Summer Study, pp 305-315 (with Richard Cowart)
- *Can Competition Accelerate Energy Savings? Options and Challenges for Efficiency Feed-in-Tariffs*, published in Energy & Environment, Volume 24, No. 1-2, February 2013 (with Richard Cowart)
- *An Energy Efficiency Feed-in-Tariff: Key Policy and Design Considerations*, published by the Regulatory Assistance Project, March/April 2012 (with Richard Cowart)
- *U.S. Experience with Efficiency as a Transmission and Distribution System Resource*, published by the Regulatory Assistance Project, February 2012 (with Rich Sedano)
- *Achieving Energy Efficiency: A Global Best Practices Guide on Government Policies*, published by the Regulatory Assistance Project, February 2012 (with Nancy Wasserman)
- *Residential Efficiency Retrofits: A Roadmap for the Future*, published by the Regulatory Assistance Project, May 2011 (with Meg Gottstein and Blair Hamilton)
- *Is it Time to Ditch the TRC?* Proceedings of ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5 (with Marty Kushler)
- *Energy Efficiency as a Resource in the ISO New England Forward Capacity Market*, in Energy Efficiency, published on line 06 June 2010 (with Cheryl Jenkins and Shawn Enterline)
- *A Comparison of Energy Efficiency Programmes for Existing Homes in Eleven Countries*, prepared for the British Department of Energy and Climate Change, 19 February, 2010 (with Blair Hamilton et al.)
- *Energy Efficiency as a Resource in the ISO New England Forward Capacity Market*, Proceedings of the 2009 European Council on an Energy Efficient Economy Summer Study, pp. 175-183 (with Cheryl Jenkins and Shawn Enterline)
- *Playing with the Big Boys: Energy Efficiency as a Resource in the ISO New England Forward Capacity Market*, Proceedings of ACEEE 2008 Summer Study Conference on Energy Efficiency in Buildings, Volume 5 (with Cheryl Jenkins and Blair Hamilton)
- *Recommendations for Community-Based Energy Program Strategies, Final Report*, developed for the Energy Trust of Oregon, June 1, 2005 (with Dave Hewitt et al.)
- *Shareholder Incentives for Gas DSM: Experience with One Canadian Utility*, Proceedings of ACEEE 2004 Summer Study on Energy Efficiency in Buildings, Volume 5 (with Kai Millyard)
- *Cost Effective Contributions to New York's Greenhouse Gas Emission Reduction Targets from Enegy Efficiency and Renewable Energy Resources*, ACEEE 2004 Summer Study Proceedings, Volume 8 (with David Hill et al.)
- *Opportunities for Accelerated Electric Energy Efficiency Potential in Quebec: 2005-2012*, prepared for Regroupement national des conseils regionaux de l'environnement du Quebec, Regroupement des organisms environnementaux energie and Regroupement pour la

responsabilite sociale des enterprises, May 16, 2004 (with Eric Belliveau, John Plunkett and Phil Dunsky)

- *Review of Connecticut's Conservation and Load Management Administrator Performance, Plans and Incentives*, for Connecticut Office of Consumer Counsel, October 31, 2003 (with John Plunkett, Phil Mosenthal, Stuart Slote, Francis Wyatt, Bill Kallock and Paul Horowitz)
- *Energy Efficiency and Renewable Energy Resource Development Potential in New York State*, for New York Energy Research and Development Authority, August 2003 (with John Plunkett, Phil Mosenthal, Stave Nadel, Neal Elliott, David Hill and Christine Donovan)
- *Assessment of Economically Deliverable Transmission Capacity from Targeted Energy Efficiency Investments in the Inner and Metro-Area and Northwest and Northwest/Central Load Zones", for Vermont Electric Power Company, Final Report: April 2003* (with John Plunkett et al.)
- *Residential HVAC Quality Installation: New Partnership Opportunities and Approaches*, Proceedings of ACEEE 2002 Summer Study Conference on Energy Efficiency in Buildings, Volume 6 (with Rebecca Foster, Mia South, George Edgar and Put Murphy)
- *A Modified Delphi Approach to Predict Market Transformation Program Effects*, Proceedings of ACEEE 2000 Summer Study Conference on Energy Efficiency in Buildings, Volume 6 (with Phil Mosenthal et al.)
- *Using Targeted Energy Efficiency Programs to Reduce Peak Electrical Demand and Address Electric System Reliability Problems*, published by the American Council for an Energy Efficient Economy, November 2000 (with Steve Nadel and Fred Gordon)
- *Energy Savings Potential from Addressing Residential Air Conditioner and Heat Pump Installation Problems*, American Council for an Energy Efficient Economy, February 1999 (with John Proctor and Steve Nadel)
- *Promoting High Efficiency Residential HVAC Equipment: Lessons Learned from Leading Utility Programs*, Proceedings of ACEEE 1998 Summer Study Conference on Energy Efficiency in Buildings, Volume 2 (with Jane Peters and Denise Rouleau)
- *PowerSaver Home Program Impact Evaluation*, report to Potomac Edison, February 1998 (with Andy Shapiro, Ken Tohinaka and Karl Goetze)
- *A Tale of Two States: Detailed Characterization of Residential New Construction Practices in Vermont and Iowa*, Proceedings of ACEEE 1996 Summery Study Conference on Energy Efficiency in Buildings, Volume 2 (with Blair Hamilton, Paul Erickson, Peter Lind and Todd Presson)
- *New Smart Protocols to Avoid Lost Opportunities and Maximize Impact of Residential Retrofit Programs*, in Proceedings of ACEEE 1994 Summer Study on Energy Efficiency in Buildings (with Blair Hamilton and Ken Tohinaka
- *Economic Analysis of Woodchip Systems* and *Finding Capital to Pay for a Woodchip Heating System*, Chapters 6 and 8 in Woodchip Heating Systems: A Guide for Institutional and Commercial Biomass Installations, published by the Council of Northeastern Governors, July 1994

- *PSE&G Lost Opportunities Study: Current Residential Programs and Relationship to Lost Opportunties*, prepared for the PSE&G DSM Collaborative, June 1994 (with Blair Hamilton, Paul Berkowitz and Wayne DeForest)
- *PSE&G Lost Opportunities Study: Preliminary Residential Market Analysis*, prepared for the PSE&G DSM Collaborative, May 1994 (with Blair Hamilton, Paul Berkowitz and Wayne DeForest)
- *Long-Range Evaluation Plan for the Vermont Weatherization Assistance Program*, prepared for the Vermont Office of Economic Opportunity, February 1994 (with Blair Hamilton and Ken Tohinaka)
- *Impact Evaluation of the 1992-1993 Vermont Weatherization Assistance Program*, prepared for the Vermont Office of Economic Opportunity, December 1993 (with Blair Hamilton and Ken Tohinaka)
- *Electric Utilities and Long-Range Transport of Mercury and Other Toxic Air Pollutants*, published by the Center for Clean Air Policy, 1991
- *Coal and Emerging Energy and Environmental Policy*, in Natural Resources and Environment, 1991 (with Don Crane)
- *Acid Rain: The Problem*, in EPA Journal, January/February 1991 (with Ned Helme)
- *An Efficient Approach to Reducing Acid Rain: The Environmental Benefits of Energy Conservation*, published by the Center for Clean Air Policy, 1989
- *The Untold Story: The Silver Lining for West Virginia in Acid Rain Control*, published by the Center for Clean Air Policy, 1988
- *Midwest Coal by Wire: Addressing Regional Energy and Acid Rain Problems*, published by the Center for Clean Air Policy, 1987
- *Acid Rain: Road to a Middle Ground Solution*, published by the Center for Clean Air Policy, 1987 (with Ned Helme)

David Hill
Managing Consultant

Professional Summary

David is known nationally for his advancement of sustainable energy program design and evaluation, and renewable energy policy. David has been the principal investigator and led analysis teams for multi-year stakeholder informed studies on solar market and decarbonization pathways and scenarios. David provides expert testimony and regulatory support; participates in national, and state boards; leads policy committees and conferences; provides comprehensive studies of the economic, technical, and achievable potentials for sustainable energy programming; and supports program budget planning and implementation. He has led or significantly contributed to the design and development of efficiency and renewable energy programs with annual budgets of $100+ million for initiatives in New Jersey, Washington DC, New York, Vermont, Arizona, and Maryland.

Experience

Energy Futures Group
- Managing Consultant 2020 – present

Vermont Energy Investment Corporation (VEIC)
- Director, Distributed Energy Resources, Policy Fellow 2014 – 2020
- Managing Consultant and Deputy Director Planning and Evaluation 2008 – 2014
- Senior Consultant and Consultant 1998 – 2008

Tellus Institute and the Boston Center of the Stockholm Environment Institute
- Research Associate 1993 - 1998

Education

Ph.D., University of Pennsylvania, Energy Management and Policy Planning, 1993.
- Fulbright Scholar: Dissertation research on energy decision-making in rural Nepal, 1991 – 1993.

Master's, University of Pennsylvania, Appropriate Technology and International Development, 1989.
B.A., Middlebury College, Geography and Political Science, 1981.

Selected Projects (from more than 100)

Vermont Agency of Natural Resources. Senior advisor to team analyzing policy and regulatory options for emissions reductions from Vermont's residential, commercial, and industrial building sectors, including analysis of benefits and costs of Clean Heat Standard. In partnership with Stockholm Environment Institute and Cadmus Group, incorporating LEAP scenario modeling and complementary models to assess program and administrative costs, customer economics, and rate impacts for electricity, gas and delivered fuels. 2023.

General Services Administration. Team leader for EFG on team primed by Cadmus Group assisting the GSA analyze and facilitate strategies for all Federal Government Agencies to procure carbon free electricity by 2030. EFG task area involves mapping results from NREL's Cambium model to Federal agencies and facilities, and assessment of trends on Carbon Free Electricity procurement options by state and electric balancing authority region. 2023-present.

Delaware Department of Natural Resources. Lead analysis for a team of EFG and NV5/Optimal Energy, providing baseline scenario modeling for an update to Delaware's Comprehensive Energy Plan using the Low Emissions Analysis Platform LEAP model. 2022.

Conservation Law Foundation. Appearance before the Rhode Island Energy Facilities Siting Board in support of Expert Witness testimony of EFG colleague Gabrielle Stebbins, relating to request for declaratory order for expansion of a propane facility in Providence RI. 2021-2022.

Vermont Agency of Natural Resources. Co-leader of team of EFG and Cadmus Group, serving as technical consultants to the Vermont Climate Council. Used Low Emissions Analysis Platform (LEAP) model to inform Pathways Analysis report on scenarios for meeting Global Warming Solutions Act requirements. 2021-2022.

Environmental Defense Fund and Citizens Utility Board. Expert testimony on two proposed pilot projects in Nicor Gas general rate case. Illinois Commerce Commission, Docket 21-0098. 2021.

Citizens Utility Board and NRDC. Expert testimony submitted to Illinois Commerce Commission on renewable natural gas pilot proposed by Nicor gas. Docket 20-0722, 2021.

Clean Energy New Hampshire. Expert testimony in support of joint utilities Triennial Energy Efficiency Plan. New Hampshire Public Utilities Commission, Docket DE 2—092, 2020.

Southern Alliance for Clean Energy. Expert testimony on energy efficiency in Dominion Energy South Carolina's 2020 Integrated Resource Plan. Public Service Commission adopted recommendations for revisions and strengthening of DSM resource in the plan. 2020.

Massachusetts Executive Office of Energy and Environmental Affairs. Under subcontract with Cadmus, Inc. Led scenario modeling team investigating the building sector decarbonization strategies for Massachusetts Decarbonization Roadmap. 2019-2020.

U.S. Department of Energy. Principal Investigator for a three-year SunShot Initiative Solar Market Pathways study, investigating the technical, regulatory, and business model implications of getting 20 percent of Vermont's total electric supply from solar by 2025. 2014-2017.

Sun Shares. Created and launched, and responsible for management and business development of, a community solar business subsidiary to provide "Easy and Affordable Solar for Employers and their Employees," 2015 – 2019.

Maryland Office of Peoples Counsel. Expert witness and senior advisor for review and design of EmPOWER Maryland portfolio. Includes strategies for coordination with grid modernization and cost recovery, amortization and utility incentives. 2011- 2020.

Washington, D.C., Department of Energy and Environment. Led design and launch of the DC Sustainable Energy Utility's Solar for All Initiative. Supports both single family and community solar installations directly benefitting income qualified households. 2017-2019.

Pennsylvania Department of Environmental Protection. Led scenario analysis and modeling for Pennsylvania's Solar Future. Stakeholder presentations at six workshops on total energy sector modeling for meeting 10% of Pennsylvania's electric needs from solar by 2030. 2016-2019.

EFG Experience with Energy Transition Issues

Decarbonization Pathways Studies

- EFG has led or played major roles in the conduct of several decarbonization studies
  - **Massachusetts 2050 Decarbonization Roadmap**. EFG was part of the Cadmus team that analyzed economy-wide decarbonization pathways for the state's Executive Office of Energy and Environmental Affairs.
  - **Vermont Pathways Analysis Report**. EFG was part of Cadmus team that analyzed economy-wide decarbonization pathways for the Vermont Agency of Natural Resources and the Vermont Climate Council. EFG led the buildings/thermal sector work.
  - **Vermont Thermal Sector Decarbonization Analysis**. EFG is currently under contract to the Vermont Agency of Natural Resources to assess the emission reduction, cost, and other trade-offs between different policy approaches to decarbonizing buildings and industry in the state.
  - **Delaware Comprehensive Energy Plan**. EFG is currently leading analysis of decarbonization pathways for the Delaware Department of Natural Resources and Environmental Control.
- EFG has helped clients critically review decarbonization studies performed by other parties, particularly those sponsored by gas utilities.
  - **Massachusetts Gas Utilities Study**: EFG helped Sierra Club participate in a year-long utility-stakeholder collaborative process for assessing and modeling options for decarbonization. This included drafting numerous comments on the utilities' consultants' proposed analysis scenarios, draft modeling assumptions, and draft reports. EFG has also supported drafting of comments to regulators critiquing the gas utilities' study and policy/planning proposals in subsequent regulatory proceeding.
  - **Assessment of Common Biases in Gas Utility Decarbonization Studies**. EFG helped the Natural Resources Defense Council review and critique numerous gas industry-funded decarbonization studies across a range of different U.S. states.

Renewable Gas Potential

- EFG recently was part of a consultant team that critiqued a Michigan RNG potential study on behalf of the Natural Resources Defense Council.

Building Decarbonization Policy and Economics

- **Vermont Clean Heat Standard**. EFG Principal Chris Neme was one of two authors of the Vermont Energy Action Network's 2021 white paper on the concept of a Clean Heat Standard, which was born out of a nearly year-long multi-stakeholder working group that Chris also co-led (and included the CEO of Vermont Gas). The concept was subsequently turned in to legislation, passed out of both the Vermont House and Vermont Senate, and came within on vote of over-riding the Governor's veto. The legislation was recently reintroduced in the current legislative session, with several modifications on which Mr. Neme provided input, as Vermont Senate Bill 5.
- **Other Vermont climate policy whitepapers**. EFG co-led the development of a "Weatherization at Scale" proposal which followed a year of work by a multi-stakeholder working group which EFG Principal Richard Faesy co-led with the CEO of Vermont Gas. We also drafted a whitepaper

for the Vermont Energy Action Network on the concept of a heating and water heating equipment “fee-bate” (sliding scale sales tax based on carbon emissions intensity).

- **Michigan Healthy Climate Plan**. EFG Principal Chris Neme represented the Natural Resources Defense Council (NRDC) in a couple of working groups organized by the state’s Department of Environment, Great Lakes and Energy to develop a state climate plan.
- **Illinois Climate Legislation**. EFG has supported NRDC in developing legislative policy proposals for advancing decarbonization in the state.
- **Customer Economics of Electrification in Chicago**. EFG published a report in November 2022 analyzing the economics and greenhouse gas emission impacts of residential electrification in the city of Chicago. The analysis was based on current and forecast future retail energy prices for gas and electricity; capital costs of heat pumps, heat pump water heaters and other electric and gas appliances; current average gas consumption by end use; performance of high efficiency gas and electric equipment; and various other factors.

Regulatory Testimony

- **White Paper on shorter-term Depreciation of new gas infrastructure investments (Rhode Island)**. EFG drafted a white paper which the Conservation Law Foundation filed with the Rhode Island Public Utilities Commission on the merits of shorter-term (e.g. 20 years) amortization of new gas utility investments to reduce risk of stranded assets in the context of evolving climate policies.
- **Nicor Gas RNG Pilots (Illinois)**. EFG filed testimony on behalf of the Environmental Defense Fund in opposition to proposed RNG pilot projects.
- **Northwest gas pipeline (FERC)**. EFG drafted a report filed with the U.S. Federal Energy Regulatory Commission, on behalf of the Washington state Attorney General, on the lack of demonstrated need for and adverse environmental consequences of a proposed expansion of an interstate gas pipeline by Gas Transition Northwest (GTN).
- **Northwest Natural Gas hydrogen blending pilot (Oregon).** EFG was recently hired to draft testimony for Sierra Club and other parties to critique a proposed hydrogen blending pilot. Testimony to be filed in December 2022.
- **Illinois and Michigan electrification programs**. EFG has supported – in testimony and then from a technical and programmatic perspective – the development of residential electrification programs. The initial programs were launched through energy efficiency program portfolios. More recently, EFG has filed testimony in electric utility rate cases in Michigan to propose electrification pilots funded through electric rates. The testimony analyzed the customer economics and electric rate impacts of such programs.
- **Fortis BC RNG purchases to offset emissions from new construction of gas heated homes**. EFG was hired by the BC Sustainable Energy Association to critique a recent Fortis proposal to meet provincial requirements for net zero emission new construction by contracting for the amount of RNG any new gas homes would consume and socializing the cost of such purchases across all gas customers. As part of its critique, EFG analyzed the relative customer economics of gas consumption under the proposal to the alternative of efficient all-electric new homes.

M1

Before the Ontario Energy Board

EB-2024-0111

Enbridge Gas 2024 Rebasing Phase 2

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The Green Energy Coalition
Greenpeace Canada
Sierra Club Ontario Chapter

Environmental Defence

August 12, 2024

Table of Contents

I. Executive Summary

We have been asked to comment and provide recommendations on Enbridge's Energy Transition Technology Fund (ETTF), its proposal to procure low-carbon energy as part of the gas supply commodity portfolio appropriate through the Low-Carbon Energy Program (LCEP), its system pruning proposals, and its residential heating fuel cost comparison. An overview of our recommendations is set out below:

Energy Transition Technology Fund

1. **Focus on high-heat industrial processes:** The OEB should either reject the fund entirely or require that it be focused on one or a few projects that support the use of non-fossil-fuel-derived gases for high-heat processes. The current proposal focuses on long shots instead of safe bets, is so unconstrained it represents a blank check, is too spread out to achieve meaningful results, is inconsistent with previous OEB orders, and is heavily biased towards solutions that rely on gas pipelines and thus support Enbridge's business model even when they are risky, far less cost-effective than alternatives, and much less likely to bring about positive benefits for customers.

RNG procurement

2. **Redirect funds to more cost-effective uses:** The OEB should require that the Company reduce the LCEP portfolio targets by a factor of 4, cap the price at $25.58/GJ, and redirect the savings to expanded energy efficiency.
3. **Maximize ratepayer benefits:** The LCEP should exclusively procure new RNG supply (not recontract for existing supply) and heavily prioritize the development of Ontario-based RNG sources to increase overall supply and maximize long-term benefits.
4. **Achieve the most cost-effective GHG reductions:** The LCEP should procure RNG based on the cost per tonne of avoided lifecycle GHG emissions to reflect the major variance in carbon intensity of different RNG sources and to minimize the cost of carbon emissions reductions.

System pruning

5. **Achieve timely progress:** The OEB should require that Enbridge develop its approach to system pruning in consultation with the IRP Working Group within 6 months and begin implementation on a small pilot within 12 months. This is possible because Enbridge can leverage its existing IRP framework. Further, a pilot may be so small and inexpensive that an application for approval would not be necessary or reasonably justified. Without these specific directions, progress will be far too slow, and the next steps will be inconsistent with the Phase 1 decision.

Heating fuel cost comparison

6. **Enhance customer choice, knowledge, and benefits:** The OEB should require Enbridge to include heat pumps in its heating fuel cost comparison charts as this would clearly benefit customers by providing them with more and better information, which will in turn enhance customer choice and bill reductions. Enbridge's reasons for excluding heat pumps from the cost comparison are baseless.

4. Low Carbon Energy Program (RNG)

1. Overview

The Phase 2 evidence includes the Company's proposal to amend its Voluntary RNG Program and to procure low-carbon energy as part of the gas supply commodity portfolio. The Company requests "*OEB approval to procure low-carbon energy, with a focus on renewable natural gas (RNG) as part of the gas supply commodity portfolio, beginning in 2026, and recover the incremental costs associated with this energy through the proposed cost recovery mechanism.*"[25] The evidence submitted by the Company includes a Low Carbon Energy Program (LCEP) proposal, an evaluation of low-carbon energy as part of the gas supply commodity portfolio, an overview of the RNG markets prepared by a third party consultant, and reporting on greenhouse gas (GHG) emissions reductions from RNG.

This section of our report discusses the risk that the proposed LCEP oversells the potential for RNG to economically reduce emissions. Specifically, the LCEP proposal risks overstating the available RNG supply, understating the costs of varying RNG supplies, and overstating potential GHG reductions. Even as proposed by the Company, putting aside the need for adjustments to assumptions, the cost for emission reductions from RNG does not compare well with the costs for other decarbonization strategies. We propose regulatory steps the Ontario Energy Board (OEB or Board) should consider in order to reduce the risks of the proposed LCEP to consumers.

As detailed below, we recommend the following:

1. **Redirect funds to more cost-effective uses:** The OEB should require that the Company reduce the LCEP portfolio targets by a factor of 4, cap the price at $25.58/GJ, and redirect the savings to expanded energy efficiency.

2. **Maximize ratepayer benefits:** The LCEP should exclusively procure new RNG supply (not recontract for existing supply) and heavily prioritize the development of Ontario-based RNG sources to increase overall supply and maximize long-term benefits.

3. **Achieve the most cost-effective GHG reductions:** The LCEP should procure RNG based on the cost per tonne of avoided lifetime GHG emissions to reflect the major variance in carbon intensity of different RNG sources and to minimize the cost of carbon emissions reductions.

2. Concerns with the LCEP/RNG Proposal

A. LCEP Likely Overstates Potential for RNG as a Decarbonization Strategy

The LCEP proposal states "*It is clear the energy transition is underway and RNG will play an important role*."[26] The proposal and application do not justify this declaration, and in several key aspects make assumptions and forecast results that likely overstate the potential value of RNG as a decarbonization pathway. These include:

- Since implementing the voluntary RNG pilot program in April 2021, the Company reports it has procured 5,600 GJ of RNG, at an average cost of $35.92/GJ.[27] As proposed, the LCEP would require the Company to procure more than **946 times more RNG in 2026 than it procured**

[25] Exhibit 4, Tab 2 Schedule 7, p. 1.
[26] Ibid. page 1.
[27] Exhibit I.1.10-PP-6, p.3.

during the 3-year pilot, increasing to **3,750 times more RNG by 2029 than it procured during the pilot**. These levels of increase are questionable, even recognizing that RNG project development is increasing in the region and throughout North America. The projected extremely rapid expansion also runs counter to the Company's reported experience of timing delays causing more than 60% lower capital expenditures for anticipated CNG and RNG projects.[28]

- It is important to recognize that the proposal to acquire 1% RNG by 2026 and 4% by 2029 **still leaves 99% to 96% of the gas commodity as fossil gas.** Moreover, because Enbridge does not plan to differentiate between different sources of RNG based on lifecycle GHG emissions, the actual emission reduction achieved through the proposed RNG purchases may be much less than the 1% to 4% volumes imply. As illustrated in some detail in Appendix A to this report, the carbon intensity of RNG varies significantly by feedstock source, conversion technologies and other project specifics. While agricultural anaerobic digestion that avoids direct methane emissions to the atmosphere (e.g., from manure) can have a negative carbon intensity (more than offsetting an equivalent combustion of fossil gas), other sources such as landfill or wastewater treatment may not even be able to off-set half of the GHG the emissions from an equivalent amount of fossil gas combustion. If approved, the Board should direct the Company's estimates of emissions reductions for RNG be differentiated to reflect the costs and varying carbon intensities by source.
- The Company's estimate of the net RNG price that is within the target bill impact and target percentages is $25.58/GJ.[29] This is 30% less than the average price for the Company's RNG procurement in the pilot program. The costs for procurement in the Company's pilot experience are more consistent with high range estimates from independent analysts. Even the low range forecast by the independent RNG analysts is 14% higher than the $25.58/GJ used in the Company's projections.[30] Thus, there is reason to be skeptical that the Company will be able to procure the levels of RNG that it has proposed within its proposed bill impact cap.
- The Company has built the LCEP based on their assessment of customer willingness to pay up to $2 per month to help decarbonize gas supply and reduce the environmental harm from the gas system. The Phase 2 application for RNG takes this threshold of consumer willingness to pay through rate impacts for enhanced environmental performance, and has assumed, without adequate comparison to alternatives and through favorable assumptions and inputs, that the increased RNG procurement proposed in the LCEP is a preferred option for maximizing the benefits from this additional spending. The Company's proposal indicates more than $630 million could be spent on RNG procurement just in calendar year 2029.[31] This annual level of spending is for a one-time reduction in emissions. The Company would need to continue to procure RNG at high costs, year over year, to just retain the level of emission reductions that it plans to achieve in 2029 (i.e. to avoid backsliding). Even if the Company was able to acquire 4% RNG by 2029 at $25.58/GJ, we estimate that increasing RNG levels to 4% by 2029 and then just maintaining that level of RNG through 2050 would likely result in more than $4.0 billion in increased gas bills for Enbridge's customers – even after accounting for reduced carbon tax

[28] Exhibit I.1.17-FRPO-43, p.3.
[29] Exhibit I.4.2-GEC-20.
[30] S&P Global estimate cited in Exhibit I.4.2-ED-50.
[31] Exhibit I.4.2-PP-46, p.2.

payments.[32] In contrast, once they are made, investments in energy efficiency, electrification and other measures typically provide emission reductions for decades. Our analysis and findings, and the Company's proposal do not support these levels of potential annual spending on RNG as a preferred option. We recommend lower targets for the LCEP, and redirecting of the resulting savings towards alternative decarbonization investments such as increased energy efficiency.

- The Company provides a range of estimates, demonstrating the costs of emissions reductions from RNG procurement are significantly higher than the realized costs for emissions reductions from their demand side management energy efficiency portfolio. The Company estimates that with an incremental cost of RNG of $25.58/GJ as assumed for the customer cost impact and reaching a 1% RNG procurement, the cost per tonne of CO2e reduction is $511.60.[33] **They also report emissions reductions from the 2023 DSM portfolio are significantly less expensive** ranging from $12.25/tCO2e for the large volume program to $94.52/tCO2e for the low-income program.[34] These DSM costs per tonne are estimated by dividing DSM spending into GHG emission reductions. They do not net out the significant energy cost savings DSM provides. Even when accounting for additional customer contributions to the cost of DSM measures and other portfolio level costs that Enbridge did not include in the DSM costs per tonne estimates, its DSM programs are very cost-effective. Thus, when all other benefits are netted out from costs, DSM actually provides GHG reductions at negative costs.
- By 2029 the LCEP's estimated annual cost for RNG supplies ranges from $337 million to $633 million.[35] In comparison, the Company's annual total DSM spending between 2019 and 2023 ranged between $119 million and $145 million.[36] **The potential scale and costs for LCEP RNG supplies and the much shorter-lived nature of their emission emissions, do not justify investments on the order of 3 to 5 times more than has historically been invested in efficiency.**
- Under the LCEP proposal, Enbridge could procure RNG supplies from anywhere across North America.[37] Rather than relying on a book and claim accounting method allowing an RNG supply injection to a pipeline that may be thousands of miles distant from Ontario and permitting an equivalent RNG supply to be credited to the LCEP, **the program, if approved, should prioritize or be restricted to support the development of regional RNG projects and infrastructure.** The availability of long-term RNG off-take contracts for regional projects can support municipalities, businesses and agriculture within the region, keeping the ratepayer supported funding for RNG procurement circulating within the regional economy. The LCEP program procurement should also restrict its procurement to newly developed RNG projects as opposed to contracting and re-purposing of pre-existing supplies. If the program does not require new sources of RNG the

[32] This is an approximate estimate of the net present value (NPV) of increased costs from 2026 through 2050, relative to a baseline of not investing in any RNG. It assumes an RNG cost of $25.58/GJ; a comparable fossil gas cost of $3.59/GJ based on 2024 Enbridge commodity prices which, for simplification, are assumed to remain unchanged; a carbon tax of $110/tonne in 2026, increasing to $170/tonne in 2030 and then increasing by inflation; and a 4% real discount rate (the same rate Enbridge is using to assess cost-effectiveness of its DSM programs).
[33] Exhibit I.4.2-ED-48 p. 3.
[34] Ibid. p.3.
[35] Exhibit I.4.2-PP-46, p.2.
[36] Exhibit I.1.10-PP-6, p.2.
[37] Exhibit 4, Tab 2, Schedule 7, p. 6.

program may simply be shifting emissions reductions from a prior user of RNG to Enbridge's portfolio, with no net gain in RNG or reductions in total atmospheric emissions.

B. Avoid Overstating RNG Supply and Growth Projections

As proposed, the LCEP risks overstating the potential of RNG supply as a long-term decarbonization strategy. The Company's application includes as an appendix the September 2022 ANEW Study and cites other studies that have primarily been conducted on behalf of the biogas and gas industries. The methods applied in these studies include top-down feedstock resource driven estimates, and bottom-up potential site inventory estimates. In both cases, the assumptions and methods need to be viewed with healthy skepticism, and with a critical eye towards how the potential estimates directly relate to the proposed value and benefits for pipeline injected RNG in the Enbridge system.

Our comments are not a new independent estimate of RNG potential for North America, Canada or Ontario. Instead, we highlight issues with the cited studies and other references that support our recommendations for the LCEP to have lower RNG procurement targets, and a regional focus. These include:

- The ANEW study references the widely cited 2019 study conducted by ICF for the American Gas Foundation[38] and the Torchlight Bioresources 2020 study. These are both cited by ANEW as examples of top-down RNG resource assessments. Both the ICF study and Torchlight indicate that prior to 2030, contributions from thermal gasification and power to gas technologies are likely to remain pre-commercial and make limited contributions. The ANEW review calculates that reaching the low and high potential estimates in the ICF study would require decade-long compound annual growth (CAGR) rates of 30% to 40% respectively.[39]
- In comparison, the International Energy Agency, in their recent annual renewable energy assessment which included for the first time a special section on biogas and biomethane, estimates biogas and RNG supplies in the United States would grow by a factor of 2.1 in the coming five years.[40] This equates to a CAGR of 16%, roughly half the level and time horizon of the calculated required growth to meet the ICF resource-based estimates. The IEA's much lower implied growth rate is still seen as very accelerated, and the IEA characterizes the financial support and incentives from various Federal and state programs as providing "a very favorable framework for accelerated growth."[41]
- The ANEW study also cites a study it conducted for the RNG coalition indicating 47,000 waste facilities in North America that could be developed for RNG production.[42] ANEW states they "believe that a bottom-up approach that focuses on project counts and includes avoided emissions is more indicative of RNG supply growth."[43] The analysis continues to estimate the RNG potential based on development of all of the potential sites (therefore appearing to be a

[38] Enbridge Gas Inc, North American Renewable Natural Gas Market Evaluation, September 2022, prepared by ANEW, p. 24.
[39] Ibid, p. 25, p. 26.
[40] International Energy Agency, Renewables 2023: Analysis and Forecasts to 2028, p. 139. (https://static1.squarespace.com/static/53a09c47e4b050b5ad5bf4f5/t/65a0575e6fd27e145d495322/1705006944797/Renewables_2023.pdf)
[41] Ibid, p. 139.
[42] ANEW, North American Gas Market Evaluation, p. 27.
[43] Ibid. p. 26.

technical rather than an achievable or economic potential), including landfills, large farm and other waste. Their resulting estimate, if 0 carbon intensity is applied, is that RNG could supply 18% by volume of the US and Canadian gas supply.[44]

- There are serious flaws with an estimate based on the assumption that all the inventoried sites will be developed. While we agree that project counts may be a more helpful method for estimating future potential, the assumed development of 47,000 sites is totally out of line with recent project counts, and with industry objectives for project development in the coming years. The 2023 Canadian Biogas and RNG market report indicates there were nearly 300 active projects operating in Canada, with estimated annual production of more than 20 PJ.[45] The RNG Coalition Sustainable Methane Abatement & Recycling Time (SMART) initiative, also cited in the ANEW study, has target of 500 operating projects by 2025, and a target of reaching 1,000 operating projects by 2030.[46] In light of these levels of existing projects and industry development targets for 2030, the ANEW studies estimate citing the potential RNG supply from 47,000 projects is misleading and contributes to the application's false sense of potential from RNG supplies.

To summarize our concerns with the LCEP's analyses of RNG supply, even if questionable approaches and assumptions on supply are put aside, and the Company's proposal for up to 4% of volume RNG be procured by 2029 is taken at face value, RNG can be expected to play a modest contributing role in decarbonizing the gas system, and should not be characterized as playing an important or major role in displacing future fossil gas commodity supplies.

Moreover, the issues with overstating potential RNG supplies should not be overlooked. Over-inflated estimates of RNG supply potential are likely to mislead and confuse consumers, regulators, and policy makers with respect to the long-term potential of RNG as decarbonization strategy.

Particularly in the near-term, during the proposed LCEP time horizon, RNG market development will not be limited by the amount of feedstock resources or by the potential number of sites that could be developed. Instead, the economics and comparative advantages of other competing renewable resources, utility and customer investment opportunities, and existing infrastructure and policy and planning factors are more likely to spur and or limit RNG growth. By citing and estimating high values for resource potential and the technical potential number of sites, the LCEP overstates the RNG role in an unhelpful manner.

C. Anticipate Higher RNG Procurement Costs

The LCEP program design proposes to procure an increasing annual percent of total commodity gas supply as RNG, starting in 2026 at 1% and increasing by 1% annually up to 4% in 2029. To contain the potential costs, the Company proposes the RNG procurement budget be limited to no more than $2/month/customer/ for each percent of RNG. Thus, in 2029 the proposed annual cost impact per customer could be up to $2*4%*12months = $96.[47]

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[44] Ibid. p. 27 and 28.

[4545] https://biogasassociation.ca/resources/page/2023_canadian_biogas_and_rng_market_report/

[46] ANEW Study, p. 24, Table 5.1.2 RNG Project Counts

[47] Exhibit 4, Tab 2, Schedule 7, p. 7.

The Company estimates the percentage targets and the cost containment cap can be met with an RNG procurement price of $25.58/GJ.[48] If this average price is exceeded, the Company would procure less RNG than the proposed percentages. The estimated price point is 30% lower than the Company's reported cost of procurement in the recent 3-year RNG pilot. It is also 14% to 30% lower than independent analyst projections cited in the application.[49] While higher volumes and market development may enable the LCEP to have lower procurement costs than the RNG pilot, it remains to be seen whether that is actually possible. To protect ratepayers, we recommend the Company not be allowed to procure RNG with a price higher than $25.58/GJ, which already represents an extremely high cost per unit of emission reduction.

It is also important to note, that while the willingness of customers to support incremental costs of up to $96 per year for decarbonization is admirable, it does not automatically lead to the conclusion that procurement of RNG is the most impactful or beneficial action that can be undertaken. The Company's should consider customers' likely responses if they were offered the choice of having this resource put towards measures that reduce emissions for multiple years (efficiency and electrification) versus RNG which has to be re-purchased every year in order to sustain a very modest level of emission reduction.

D. Prioritize Procurement Based on Carbon Intensities, Location and New Development

Lifecycle emissions accounting should be required. When burned in a furnace, GHG emissions from RNG are identical to GHG emissions from burning fossil gas. The only reason RNG can be considered emission reducing is because it provides some offsetting emission reductions elsewhere. Thus, the actual magnitude of such other emission reductions – and the net impact relative to emissions from displaced fossil gas consumption – is what really matters.

The proposal recognizes that carbon intensities of various feedstock and technology streams for RNG production vary significantly, and even vary by specific project. The application and analyses recognize that manure-based projects have the lowest, negative carbon intensities, due to their ability to capture and utilize otherwise direct atmospheric methane emissions, with attendant high global warming potentials. While manure-based projects can more than off-set an equal volume of fossil gas emissions, most of the RNG projects currently developed and a large portion of the potential RNG projects are not manure-based projects. Landfill gas, wastewater treatment, and food waste projects all typically have positive carbon intensities, which means that they only partially off-set the emissions from the avoided quantity of fossil gas (a carbon intensity of 0 means a resource exactly offsets the amount of emissions that result from burning fossil gas).[50] See Appendix A for details.

Further, to reduce emissions, RNG procurement needs to be sourced from the development of new capacity, and not merely be repurposed or re-contracted from pre-existing RNG uses. Jurisdictional resource assessments assume RNG can be acquired from large geographic "waste-sheds" via book and claim transfers. The LCEP proposes to acquire RNG from across North America. While regulatory and market conditions may support this practice, it contributes to overstating the benefits of RNG by ignoring the costs, leakage losses, and other physical constraints attendant with gas transportation and distribution. In Vermont, the Clean Heat Standard under final development specifically includes a

[48] Exhibit I.4.2-GEC-20.
[49] S&P Global estimate cited in Exhibit I.4.2-ED-50.
[50] ANEW Study p. 28-29.

requirement that Vermont Gas purchase the transmission pathway to its distribution system in Vermont before it can claim any GHG emission reduction from procured RNG. This position was supported by Vermont Gas Systems, as necessary to make RNG purchases comparable to any fossil gas purchases.

The LCEP does not propose to prioritize or require projects to have negative carbon intensities. The application states "The Company acknowledges the lifecycle emission benefits of using RNG: however, at this time, the CI (carbon intensity) score of RNG will not be the primary consideration when procuring RNG."[51]

We disagree with this position. If it is approved at the lower recommended target levels, the LCEP should be required to account for different carbon intensities in their reported emission reductions and prioritize newly developed, in region, supplies with negative or zero CI values. If out of region supplies are permitted, then transmission pathways and costs must also be included in the procurement contracts.

E. Acknowledge RNG as a Complementary and Supporting Role

Independent decarbonization pathway studies consistently show that decarbonized gas can play a *supporting* role in meeting long-term emission reduction targets.

The LCEP application's characterization of RNG as playing an important role in the energy transition, risks green-washing the impact and mis-directing resources from activities such as increased energy efficiency that the Company has demonstrated has a lower cost for avoided emissions.[52]

Even at existing and potential new RNG production sites, the on-site use of biogas for heat or power production may be a more economically attractive and valuable emission reduction resource than injection into the gas distribution system. Many landfill sites already have such alternative uses in place, based on requirements for management of methane emissions and favorable economics.

3. Recommendations for LCEP/RNG

The discussion above highlights issues and potential risks with the proposed LCEP. While there can be a constructive supporting role for RNG in the Company's plans and decarbonization efforts, we recommend the Board direct the Company to make the following adjustments to the LCEP to reduce the attendant risks to consumers.

1. **Redirect funds to more cost-effective uses:** The OEB should require that the Company to reduce the LCEP portfolio targets by a factor of 4, cap the price at $25.58/GJ, and redirect the savings to expanded energy efficiency. The 2026 target would be reduced to 0.25%, increasing by 0.25% per year to a total of 1% in 2029.
2. **Maximize ratepayer benefits:** The LCEP should exclusively procure new RNG supply (not recontract for existing supply) and heavily prioritize the development of Ontario-based RNG sources to increase overall supply and maximize long-term benefits.
3. **Achieve the most cost-effective GHG reductions:** The LCEP should procure RNG based on the cost per tonne of avoided lifetime GHG emissions to reflect the major variance in carbon intensity of different RNG sources and to minimize the cost of carbon emissions reductions.

[51] Exhibit 4, Tab 2, Schedule 7, p. 31.

[5252] Exhibit I.4.2-ED-48, p. 3.

Appendix A: Varying Carbon Intensities of Different Sources of RNG

In this Appendix we provide three references, including information from the Company's application, indicating the critical importance of considering feedstock source and project specific conditions when estimating the emission reduction impacts and carbon intensity for various RNG sources.

All three of the sources cited in this Appendix recognize manure-based RNG as having potentially negative carbon intensities, meaning it can more than offset GHG emissions from the fossil gas that it displaces. However, only a small fraction of RNG potential – on the order of 12% in the U.S. by 2040 under optimistic RNG assumptions[67] – is from manure. They also recognize that landfill gas has a positive carbon intensity and may not be able to even off-set half of the GHG emissions from the fossil gas that it displaces. This is important because landfill gas is often the least expensive and most readily available source of RNG – accounting for 23% of U.S. potential.[68]

The Company's assumption in the LCEP application that the carbon intensity of RNG can be assumed to be zero is not supported by these tables. Thus, we recommend any RNG procurement be based on more specific estimation using the GREET model or similar life-cycle basis methodology.

1. For their study on the potential for renewable natural gas conducted for the American Gas Association in 2019[69], ICF International recognized the wide range of carbon intensity variability, citing the results in Table 2 below based on modeling using the Environmental Protection Agency's GREET model for California. As the table shows, landfill gas has a lifecycle emissions intensity of 15-34 gCO2e/MJ while agricultural residues, forestry residues, energy crops and municipal solid waste had emission intensities of 25-55 gCO2e/MJ. An emissions intensity of zero means that the fuel would exactly offset emissions from fossil gas, an intensity above zero means the fuel would not fully offset emissions from fossil gas and an intensity below zero means the fuel would more than fully offset emissions from fossil gas. For context, the Canadian government's January 2023 estimate of the lifecycle emissions of fossil gas was 67.78 gCO2e/MJ. In other words, using the midpoints of the ranges provided, most sources of RNG would offset only 40-65% of GHG emissions that would have been emitted from the fossil gas that they displace.

Table 2: Lifecycle Carbon Intensity by RNG Feedstock and Region of the U.S. (g/MJ)

RNG Feedstock	New England	Mid-Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Landfill gas	18 - 26	15 - 21	28 - 34	28 - 32	22 - 26	26 - 28	26 - 31	21 - 32	13 - 29
Animal manure									
Dairy	-304 - -294	-308 - -300	-292 - -285	-292 - -286	-299 - -294	-294 - -292	-294 - -288	-300 - -286	-310 - -290
Swine	-404 - -394	-408 - -400	-392 - -385	-392 - -386	-399 - -394	-394 - -392	-394 - -388	-400 - -386	-410 - -390
Beef / Poultry	36 - 36	31 - 31	46 - 46	44 - 44	36 - 36	38 - 38	42 - 42	44 - 44	41 - 41
Water resource recovery facilities	18 - 26	15 - 21	28 - 34	28 - 32	22 - 26	26 - 28	26 - 31	21 - 32	13 - 29
Food waste	-97 - -82	-104 - -91	-79 - -68	-79 - -70	-90 - -82	-83 - -79	-83 - -73	-91 - -70	-108 - -76
Agricultural residue	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55
Forestry and forest product residue	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55
Energy crops	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55
Municipal solid waste	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55
P2G / Methanation	0	0	0	0	0	0	0	0	0

[67] Renewable Sources of Natural Gas, ICF International, for the American Gas Foundation, December 2019, pp. 66-67.

[68] Ibid.

[69] Ibid., p. 72.

2. In response to GEC-22[70], Enbridge provides the following table, similarly illustrating the wide variability of carbon intensity depending on feedstock. Enbridge's estimates are a little different from ICF's. However, it too found that landfill and waste water treatment sources of RNG would have lifecycle emissions rates that would not come close to offsetting fossil gas emissions – producing only about a 25% reduction in the case of landfill gas and about a 45% reduction in the case of waste water treatment facilities (both relative to the Canadian government's 67.78 carbon intensity factor for fossil gas).

Table 3: Enbridge Estimates of Carbon Intensities of Different Sources of RNG

Carbon Intensities and Production Costs of RNG

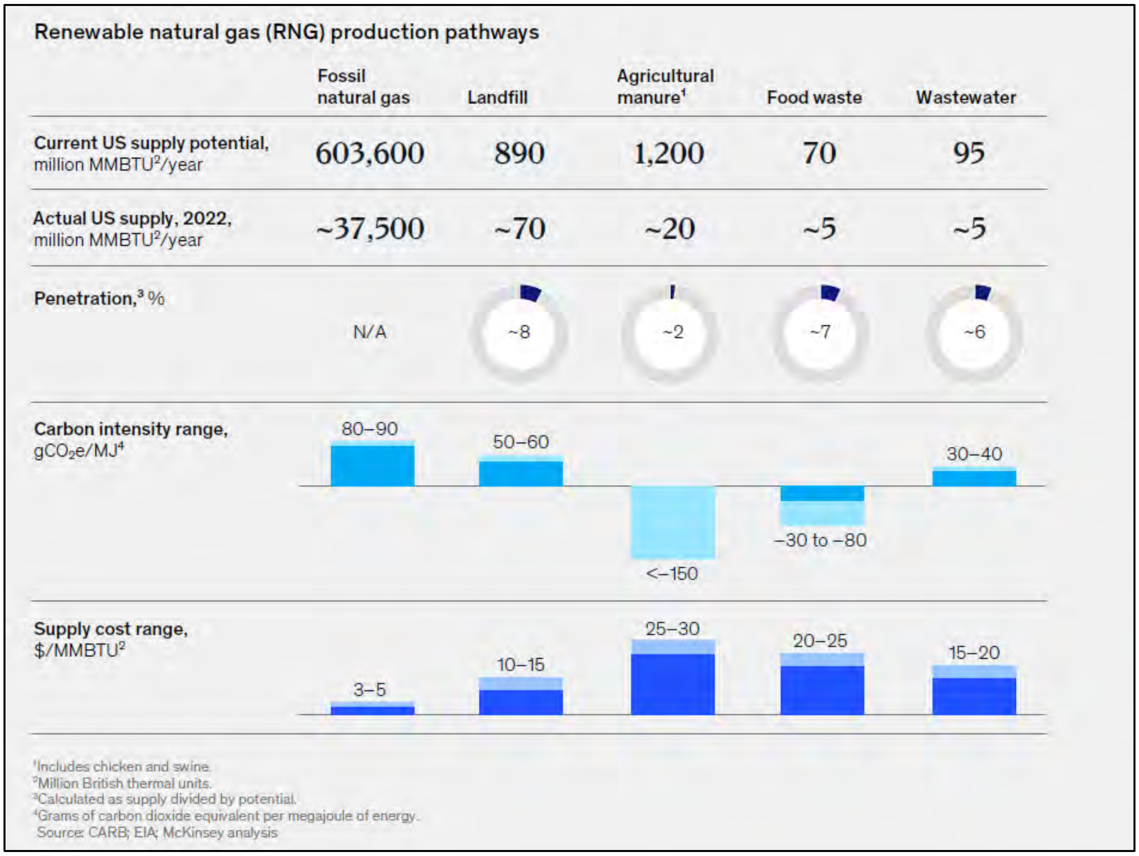
Line No.	Feedstock Type	Average Carbon Intensity (gCO_2e/MJ)	Notes	Average Carbon Intensity (gCO_2e/m^3) (6)	Production Cost ($/GJ)	Notes
		(a)		(b)	(c)	
1	Manure	(372)	(1)	(14,148)	19 to 69	(4) (5)
2	Food Waste	(36)	(1)	(1,380)	20 to 37	(4) (5)
3	Landfill Gas	51	(1)	1,927	4 to 20	(4) (5)
4	Waste Water Treatment	38	(1)	1,434	8 to 53	(4) (5)
5	Wood Waste (7)	13 to 16.8	(2) (3)	494 to 638	14 to 31	(2) (3) (4) (5)

Notes:
(1) California Air Resources Board. 2024. Certified Fuel Pathway Table. https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/current-pathways_all.xlsx
(2) Verdant Associates. August 2023. Renewable Natural Gas in California. https://www.energy.ca.gov/sites/default/files/2023-08/CEC-200-2023-010.pdf
(3) Gas Technology Institute. February 2019. Low-Carbon Renewable Natural Gas (RNG) from Wood Waste. https://www.gti.energy/wp-content/uploads/2019/02/Low-Carbon-Renewable-Natural-Gas-RNG-from-Wood-Wastes-Final-Report-Feb2019.pdf
(4) ICF. December 2019. Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf
(5) World Resources Institute. December 17, 2020. Renewable Natural Gas as a Climate Stratety:Guidance for State Policymakers. https://www.wri.org/research/renewable-natural-gas-climate-strategy-guidance-state-policymakers
(6) Converted from gCO_2e/MJ to gCO_{2e}/m^3 using the Clean Fuel Regulations specified energy density for RNG of 38 MJ/m^3.
(7) Derived via gasification.

3. A recent study by McKinsey[71] reinforces the variability of carbon intensity by source:

[70] Exhibit I.4.2-GEC-22.
[71] Renewable Natural Gas: A Swiss Army Knife for US Decarbonization, McKinsey and Company, November 2023, p. 4.

Table 4: McKinsey Estimates of Carbon Intensities of Difference Sources of RNG



Renewable natural gas (RNG) production pathways

	Fossil natural gas	Landfill	Agricultural manure[1]	Food waste	Wastewater
Current US supply potential, million MMBTU[2]/year	603,600	890	1,200	70	95
Actual US supply, 2022, million MMBTU[2]/year	~37,500	~70	~20	~5	~5
Penetration,[3] %	N/A	~8	~2	~7	~6
Carbon intensity range, gCO_2e/MJ[4]	80–90	50–60	<–150	–30 to –80	30–40
Supply cost range, \$/MMBTU[2]	3–5	10–15	25–30	20–25	15–20

[1]Includes chicken and swine.
[2]Million British thermal units.
[3]Calculated as supply divided by potential.
[4]Grams of carbon dioxide equivalent per megajoule of energy.
Source: CARB; EIA; McKinsey analysis

Ontario's Affordable Energy Future:

The Pressing Case for More Power

OCTOBER 2024

MINISTRY OF ENERGY AND ELECTRIFICATION

Ontario

Table of Contents

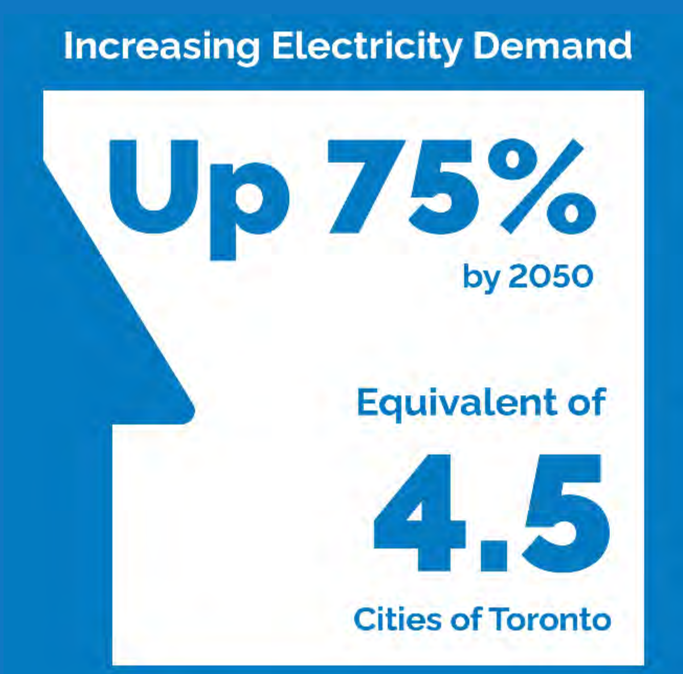
Minister's message

Ontario's energy policy will determine the success of our province, today and for the next generation.

Six years ago, the people of Ontario put their trust in us to end the previous government's failed and ideologically driven energy experiments that burdened hardworking people and businesses with billions of dollars of bad deals that led to some of the highest increases in electricity costs on the continent. High energy costs that destroyed our manufacturing sector and eliminated more than 300,000 good paying jobs for people, and the families and communities that depended on them. They hired us to fix the hydro mess and bring back good jobs by restoring Ontario's energy advantage.

We got to work.

Now, gone are the days of the previous government's sweetheart deals that paid several times the going rate for power. Instead, we're advancing a competitive all-of-the-above approach to meet growing energy demands while reducing emissions.



Gone are the days of families having to choose between putting food on the table or paying their energy bills. Instead, we're keeping energy costs down for families and workers.

Gone are the days when skyrocketing energy prices drove businesses to leave Ontario. Instead, our government has lowered the cost of doing business in the province by $8 billion every year, including by lowering the cost of power.

As a result, we already have one of the cleanest grids in the world and renewed access to affordable and clean energy has put Ontario back on the map.

Companies and foreign investment are surging into our province, with $44 billion in new investment in electric vehicle and battery plants alone, with billions more in the province's growing tech and life sciences sectors. We're revolutionizing and connecting industries like world-leading electric-powered green steel production in Hamilton and Sault Ste. Marie and sustainably-sourced critical minerals from across Ontario's north to a growing manufacturing base.

These investments are creating better jobs with better paycheques in every region of Ontario. They're also putting new and unprecedented demand on the province's clean power grid.

Ontario's Independent Electricity System Operator (IESO) now forecasts that electricity demand alone is expected to increase by 75 per cent by 2050. That means Ontario needs 111 TWh more energy by 2050, the equivalent of four and a half cities of Toronto.

We need to take steps now to address this challenge. Failing to do so puts Ontario's economic growth at risk. We must do everything we can to protect jobs by strengthening our nuclear advantage which powers our status as the economic engine of Canada.

Planning for our future first requires that we understand the challenges ahead of us.

This document is the next step forward. It provides a full accounting of the challenges facing Ontario's energy system as we work with workers, regulators, sector stakeholders, builders, businesses, Indigenous communities and union partners to confront them. In doing so, this document also affirms our government's commitment to energy policies that keep energy rates down while supporting more jobs with bigger paycheques.

This is our choice. A pro-growth agenda that takes an all-of-the-above approach to energy planning, including nuclear, hydroelectricity, energy storage, natural gas, hydrogen and renewables, and other fuels, rather than ideological dogma that offers false choices and burdens hardworking people and businesses with a costly and unnecessary carbon tax.

Our government is choosing growth and affordability. Our vision is centered on the needs of families as we remain relentlessly focused on keeping costs down and growing Ontario's economy.

This is a vision rooted in ambitious work well underway. We've got shovels in the ground to prepare for the largest expansion of nuclear energy on the continent with the first small modular reactor in the G7 as we upgrade and refurbish existing reactors at Darlington, Pickering and Bruce Power to safely extend their lifespan, all on-time and on-budget. We are launching new energy efficiency programs, helping families reduce their energy use to save money. And we've launched the largest energy procurements of its kind in Canadian history to build the energy we need in the 2030s.

But there is so much more to do. We will not set Ontario up for failure because of a lack of ambition or desire to invest in our shared prosperity. We will do what previous generations have done for us: ensure that we put in place the building blocks for future success today. We will do this in partnership and consultation with Indigenous communities to ensure that everyone benefits from our energy investments and that we respect Aboriginal and treaty rights.

When we find that right balance, the opportunities for our prosperity extend beyond Ontario's borders. The truth is there is massive demand for clean energy around the world. Not only will we meet our own domestic demand, our government sees a chance to become an exporter of clean energy and clean tech to our neighbours and allies, which will lead to lower costs for our families and businesses, reduce emissions beyond our borders and promote North American energy security.

To get this right, however, we need to move away from the current siloed approach to energy planning that left previous governments playing catch-up. That's why I'm starting the work now to put forward a new, integrated approach that brings together every part of the energy sector to fuel our growing economy. Early next year, I intend to introduce the province's first ever integrated energy resource plan so that we can support economic growth for decades to come without ever burdening families with a costly carbon tax.

Stephen Lecce

Ontario's Minister of Energy and Electrification

How We Got Here: Fixing the Hydro Mess

Introduction

Prior to 2018, high energy costs were chasing jobs and investments out of the province. Between 2008 and 2016, the previous government signed more than 33,000 contracts that paid up to ten times the going rate for power, adding billions of dollars to energy bills for families and businesses. They also planned to shut down the Pickering Nuclear Generating Station rather than refurbishing it. They cancelled planning on critical infrastructure projects, including new nuclear at the Darlington site, leaving the province with limited options to power new homes and businesses.

As a result, demand for electricity flatlined as manufacturing jobs fled the province and businesses chose not to expand their footprint. Today, our government is reversing that trend. Over the past six years we've been focused on lowering costs for consumers while we build out new energy generation. That includes putting a plan in the window – *Powering Ontario's Growth* – to provide certainty for businesses and lay out the first steps of the province's plan to expand access to reliable, affordable and clean energy.

Step One: Getting Electricity Bills Under Control

In 2018, electricity bills were out of control. Families were being forced to choose between heating and eating. Under the previous government's Fair Hydro Plans, electricity rates were expected to increase by about 5 per cent a year on average from 2025 to 2029 – representing a $28 dollar a month increase – which is unsustainable for families and businesses.

This was partially the result of 33,000 contracts signed by the previous government that paid up to ten times the going rate for power.

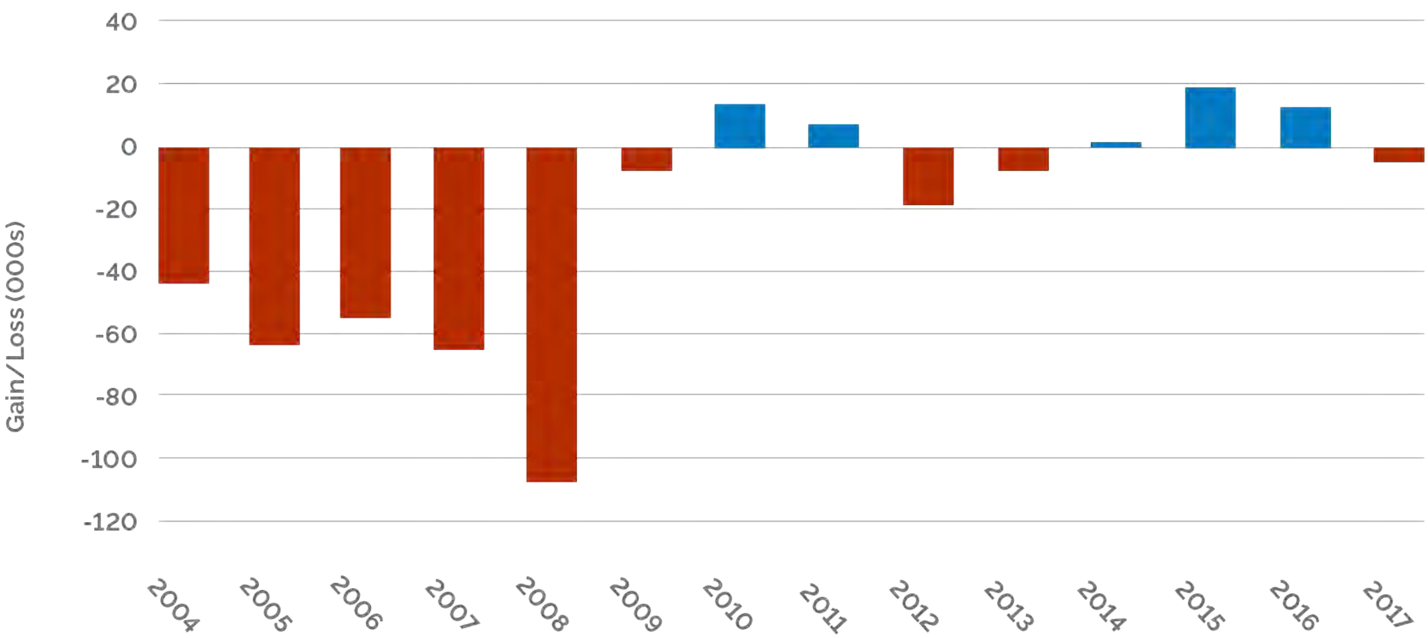
Rural and northern Ontarians were uniquely disadvantaged with fewer options to meet their energy needs.

Our government recognized it was not fair for ratepayers – whether they be businesses or families – to shoulder the burden of these overpriced and ideologically driven contracts. That's why the government moved forward with programs, including the Comprehensive Electricity Plan and the Ontario Electricity Rebate, to protect ratepayers and return stability to the province's electricity sector.

Manufacturing Jobs Lost to High Electricity Prices

Ontario lost 300,000 manufacturing jobs between 2004 and 2018 as high electricity prices drove companies to other jurisdictions, including neighbouring US states. Each of those lost jobs represents lost income for families, making life more difficult in communities like Talbotville, Chatham and Leamington that saw manufacturing plants – like Ford Talbotville - close.

Figure 1: Manufacturing Job Losses Per Year



Source: Labour force characteristics by industry, annual (x 1,000)

Comprehensive Electricity Plan (CEP)

Ontario's Comprehensive Electricity Plan (CEP) is lowering electricity costs for all consumers by funding the above-market costs of the approximately 33,000 existing renewable energy contracts, signed between 2004 and 2016. The need for this support will be reduced over time as 20-year contracts signed by the previous government come to an end.

Ontario Electricity Rebate (OER)

Introduced in 2018, the Ontario Electricity Rebate (OER) provides electricity rate relief to eligible households, farms, long-term care homes and small businesses. The OER and CEP are automatically applied to consumers' bills.

Figure 2: Sample Electricity Bills in 2023: With and Without CEP and OER

Sample Bill with OER and CEP

Account Number: 000 000 000
November 2023

Commodity	96.21
Commodity Adjustment due to CEP	-18.47
Adjusted Commodity	77.74
Delivery	49.32
Losses	3.80
Regulatory	4.07
Subtotal	134.92
OER (-19%)	-26.04
HST	17.54
Total	**126.42**
Target Bill	**126.44**
Base Delivery ($/700 kWh)	49.32
Base Commodity ($/700 kWh)	96.21

Sample Bill without OER and CEP

Account Number: 000 000 000
November 2023

Commodity	96.21
Adjusted Commodity	96.21
Delivery	49.32
Losses	4.70
Regulatory	4.07
Subtotal	154.29
HST	20.06
Total	**174.35**
Base Delivery ($/700 kWh)	49.32
Base Commodity ($/700 kWh)	96.21

Source: Ontario Energy Board and IESO data; analysis by Ministry of Energy and Electrification

Step Two: Powering Ontario's Growth

Our work to get electricity rates back under control has provided the certainty that businesses need to start investing, for the province to build new homes, and for consumers to electrify.

To provide businesses and builders with the certainty that power would be there when they needed it, we introduced *Powering Ontario's Growth* in June 2023. *Powering Ontario's Growth* laid out the first steps for new energy production including generational decisions, like starting pre-development work for a new nuclear station at Bruce, the first large scale nuclear build since 1993, and advancing four small modular reactors at Darlington, which will provide the dependable, zero-emissions electricity that businesses around the world are looking for.

Nuclear

Nuclear power accounts for more than half of Ontario's electricity supply. It was critical in Ontario's efforts to phase out coal power generation and will be just as important as our economy electrifies and demand for energy grows. In addition to a proven safety record and ability to deliver a clean, reliable supply of the baseload electricity required by homes, business and industry, nuclear power has significant economic benefits.

Nuclear Energy Creates Local Jobs

Ontario's three nuclear plants at Bruce, Darlington and Pickering directly employ close to 12,000 highly skilled workers, generate billions of dollars in economic activity and attract new jobs and investment to the province. Overall, Ontario's nuclear industry is one of the largest industrial employers in the province, supporting around 65,000 jobs. The nuclear industry in Canada also contributes around $17 billion per year to the national economy.

Refurbishments

CANDU reactors require refurbishment after 30–40 years of operation. The Darlington Nuclear Generating Station and Bruce Nuclear Generating Station have now reached that point in their operating lives and refurbishments are underway. The Pickering Nuclear Generating Station will reach that stage in the coming years and the government has announced its support for refurbishing the station's four "B" units.

Altogether the refurbishments at Darlington, Bruce and Pickering would maintain more than 12,000 MW of existing generation capacity that will be necessary if our province is going to continue to grow.

Nuclear: On-Time and On-Budget

In July 2023 Ontario Power Generation (OPG) achieved a major milestone by successfully connecting Darlington Nuclear Generating Station's Unit 3 back to Ontario's electricity grid after its three-year refurbishment, 169 days ahead of schedule. This world-class project performance demonstrates OPG and the nuclear sectors expertise and commitment to completing the station's four-unit refurbishment safely, with quality and on budget, by the end of 2026.

New Build at Bruce Power

Ontario's Bruce Nuclear Generating Station (6,550 MW) is one of the largest operating nuclear generating stations in the world.

In 2023, the province launched pre-development work to site the first large-scale nuclear build in Ontario since 1993 at the existing Bruce nuclear site. In August 2024, Bruce Power submitted its Initial Project Description to the Impact Assessment Agency of Canada, officially kicking off the regulatory approvals process with the intent of locating up to 4,800 MW of new nuclear generation on the Bruce site, enough power for 4.8 million homes.

Small Modular Reactor (SMR) Program

To meet growing demand, the province is also advancing four SMRs at the existing Darlington nuclear site which would provide a total of 1,200 MW of electricity generation, enough power for 1.2 million homes.

This "fleet approach" for SMRs in Ontario (i.e., building multiple units of the same technology) is providing significant benefits for the province's SMR program. For example, it reduces costs as common infrastructure such as the cooling water intake, transmission connection and control room that can be shared across four units instead of one. The modular nature of SMR manufacturing is also expected to reduce the cost of each additional unit.

Ontario's leadership in new nuclear technologies, particularly SMRs, is also raising the province's profile to an unprecedented level with other jurisdictions following Ontario's lead. In Canada, OPG is working with power companies in Alberta, Saskatchewan and New Brunswick as they work towards the development and deployment of SMRs in their jurisdictions leveraging Ontario's supply chains and expertise.

OPG and the province's world-leading nuclear sector are preparing to sell equipment to partner companies in the United States, Poland, Romania, the United Kingdom and other countries who are looking to deploy SMRs and watching Ontario's nuclear expansion closely, with more than $1 billion of export agreements already signed with Ontario-based nuclear supply chain companies that will see Ontario workers and companies be a workshop for the world – selling and exporting equipment we build right here in Ontario.

Nuclear Energy Saves Lives: Medical Isotopes

This year more than 247,000 Canadians will be diagnosed with cancer, and two of every five Canadians will develop cancer during their lifetime. One of the most consequential tools doctors have available to diagnose and treat this disease will come from Ontario's nuclear generating stations: life-saving medical isotopes.

Ontario's nuclear fleet is at the forefront of innovation in the production of medical isotopes, in addition to generating reliable and emissions-free electricity. Ontario's nuclear power reactors currently supply about 50% of the world's Cobalt-60, a critical treatment for head, neck and cervical cancers, as well as for the sterilization of medical tools and supplies.

Ontario is also leading the world in the production of other isotopes in nuclear power reactors including Lutetium-177, used in targeted therapy for prostate cancer and neuroendocrine tumours and Molybdenum-99 which is used in diagnostic scans for bones, heart, lung, kidney as well as cancer detection.

Hydroelectricity

Ontario built its electricity system on the power of water in the 1920s and today it continues to provide roughly a third of Ontario's total energy capacity and accounts for about 25 per cent of Ontario's electricity generation in 2022.

Some hydroelectric generating sites, like Niagara Falls' Sir Adam Beck facility, have served Ontario for more than a century and the province's commitment to the maintenance and upgrading of these facilities ensure that they will serve the province for the century ahead. In the past year the government has announced a total investment of over $1.6 billion to extend the life of these stations by an additional 30 years or more.

Competitive Procurements

The government has adopted a competitive approach for procuring non-baseload electricity resources to drive costs down. Ontario has already conducted three competitive procurements to recontract existing resources and build new resources to meet growing demand.

Families and businesses are already seeing the benefits of this competitive approach. In the government's first procurement, the province successfully procured more than 700 megawatts of existing resources at a 30 per cent savings when compared to the previous government's contracts. This will result in lower electricity system costs and lower costs for ratepayers.

The government also concluded the largest battery storage procurement in Canada's history which secured nearly 3,000 MW of battery energy storage, as well as natural gas and clean on-farm biogas generation capacity, to support the province's growing population and economy through the end of the decade.

In August 2024, the government announced the next procurement, with targets that would make it the largest competitive energy procurement in the country's history. As part of that work the Minister directed the IESO to identify options to expand and accelerate this procurement to meet growing energy demands.

Energy Efficiency

With demand increasing, the government has also expanded energy efficiency programs, an essential and cost-effective component of the province's plan. As Ontarians choose to electrify their homes and businesses there is an opportunity to install more efficient appliances and smarter controls to save money and energy while benefitting our energy system as a whole.

In September 2022, the provincial government increased funding for energy-efficiency programs by $342 million, bringing total funding to more than $1 billion over the current 2021–2024 framework. The government intends to build on this strong foundation and will unveil new energy efficiency programs aimed at helping families and businesses reduce their bills and save energy later this year.

Energy Efficiency Programs Put Money in Families' Pockets

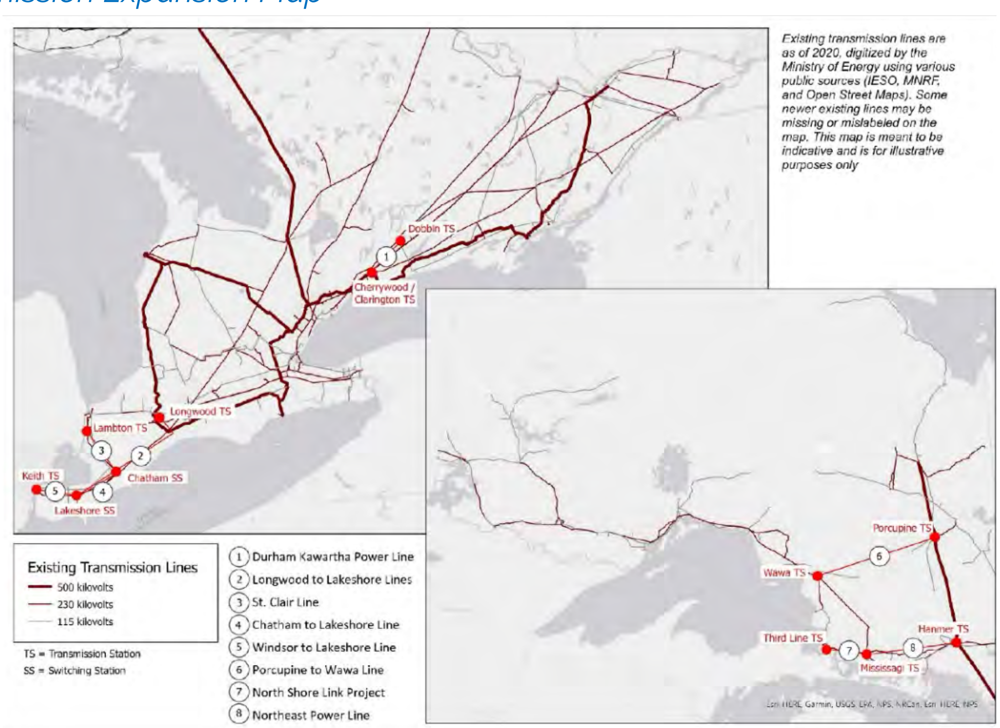
In June 2023 the government launched the new Peak Perks program to help families save money by reducing their electricity usage during peak periods. In just over a year, the program has already enrolled over 150,000 families and is providing them an upfront incentive of $75 and $20 for each additional year they stay enrolled in the program in exchange for reducing the use of their air conditioning system at peak times when the electricity system is strained. This makes it the fastest growing virtual power plant (VPP) in North America, which can reduce peak demand by up to 150 MW, the equivalent of taking the City of Barrie off grid at summer peak.

Transmission Expansion

High voltage transmission lines act as a highway that carries electricity from where it is produced to directly connected large customers and local utilities. As the province builds out new generation, we're also expanding our transmission network with new lines in all corners of the province to get that energy where it needs to go.

Over the past six years, the government has accelerated development for five new lines in southwestern Ontario to meet growing demand from auto manufacturing and agriculture, two new lines in northeastern Ontario to support Algoma steel's planned conversion to electric steelmaking as well as mining opportunities, and one new line in eastern Ontario to support demands in the Peterborough and Ottawa regions.

Figure 3: Transmission Expansion Map

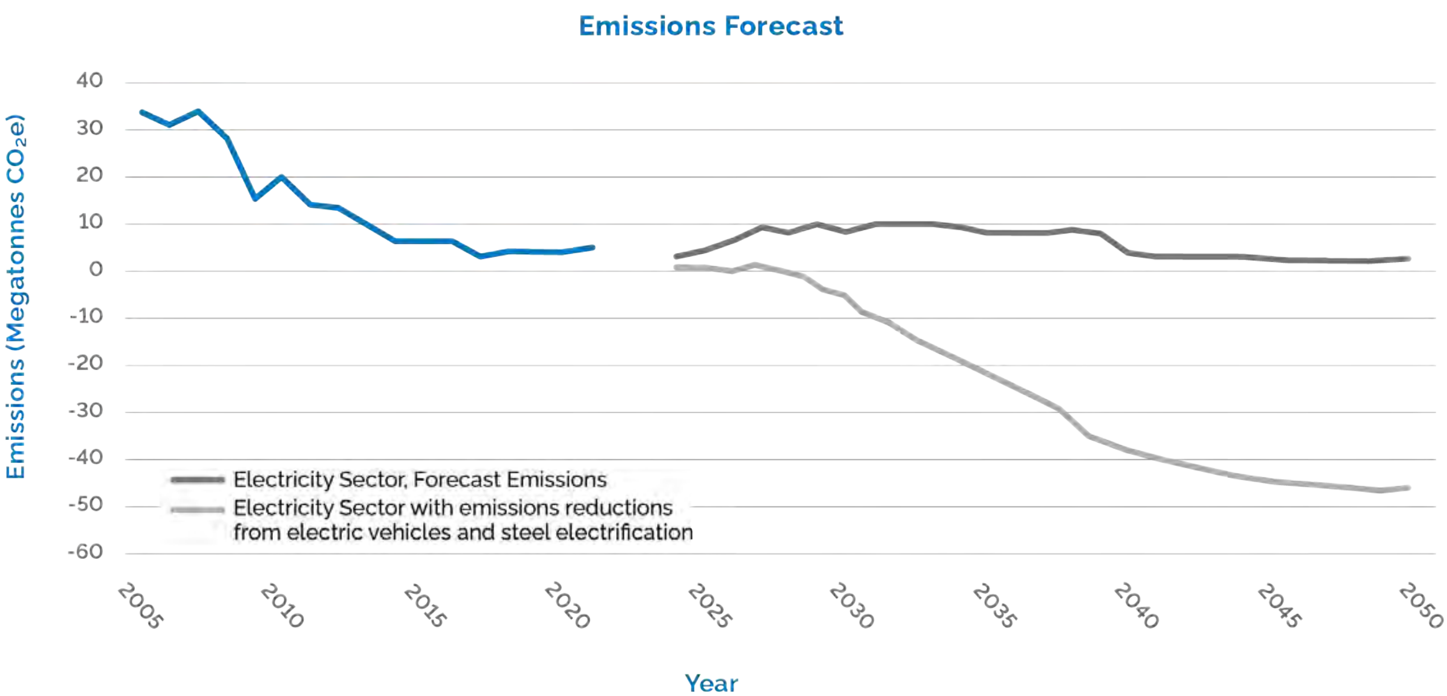


Step Three: Ontario's Clean Grid Reduces Provincewide Emissions

Ontario's expansion of clean energy generation has already put the province on the path to reduce province-wide emissions through the electrification of the economy, even with a small increase in emissions produced by using natural gas for electricity. It has also supported the province being on track to meet its 2030 emissions targets, unlike the federal government and other provinces.

According to a 2024 estimate by the IESO, by 2035, through electric vehicle adoption and electrification of steel production, province-wide emissions may reduce by a magnitude of about three times that of the electricity sector. Overall, this amount could represent the equivalent emissions reduction of taking over three million gas-powered cars off the road.

Figure 4: Province-wide Emissions Forecast



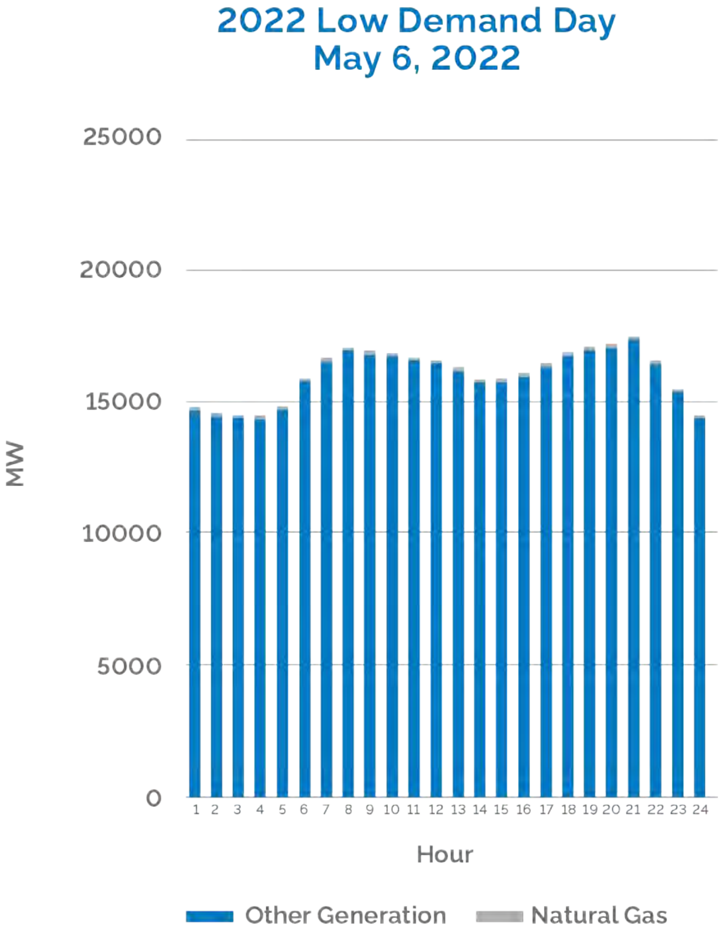
Source: Historical data sourced from Environment and Climate Change Canada's 2024 Greenhouse Gas National Inventory Report

The IESO's analysis also confirms that by 2040 electricity sector emissions will be lower than 2016 levels, once nuclear refurbishments are complete and new non-emitting sources of power like those the government is procuring and building today come online.

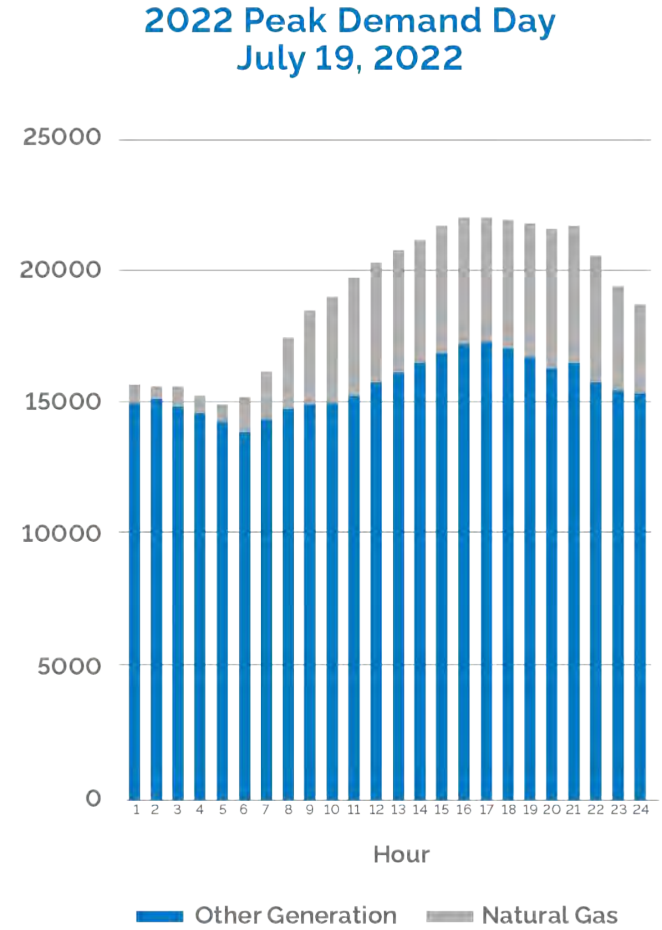
This emissions reduction opportunity is also built on consumers choosing clean electricity and switching away from fuels that have higher emissions. Whether it is a family deciding to install an electric heat pump in the home or a mining operation considering an all-electric mine, these choices require consumer confidence that our clean electricity system will remain reliable and affordable over the long term.

Why Ontario Needs Natural Gas in the Short-Term

Figure 5: Energy Supply Mix May 6, 2022 (16˚C max) and July 19, 2022 (34˚C max)



May 6 2022
Chart showing electricity generation on May 6, 2022 including natural gas generation compared to other generation sources. It was a mild day that required a minimal amount of natural gas generation.



July 19 2022
Chart showing electricity generation on July 19, 2022, including natural gas generation compared to other generation sources. It was a hot summer day when a higher amount of natural gas generation was required due to increased demand from air conditioning.

Source: IESO

In Ontario, nuclear power and hydro generally provide the continuous zero-emissions baseload power needed to ensure system reliability and meet minimum daily demand. Additional power is required to meet peak electricity demand, such as when the weather is hot and air conditioners across the province are turned on. Natural gas is the province's insurance policy, providing this reliability on the hottest and coldest days of the year when other resources like wind and solar are not available.

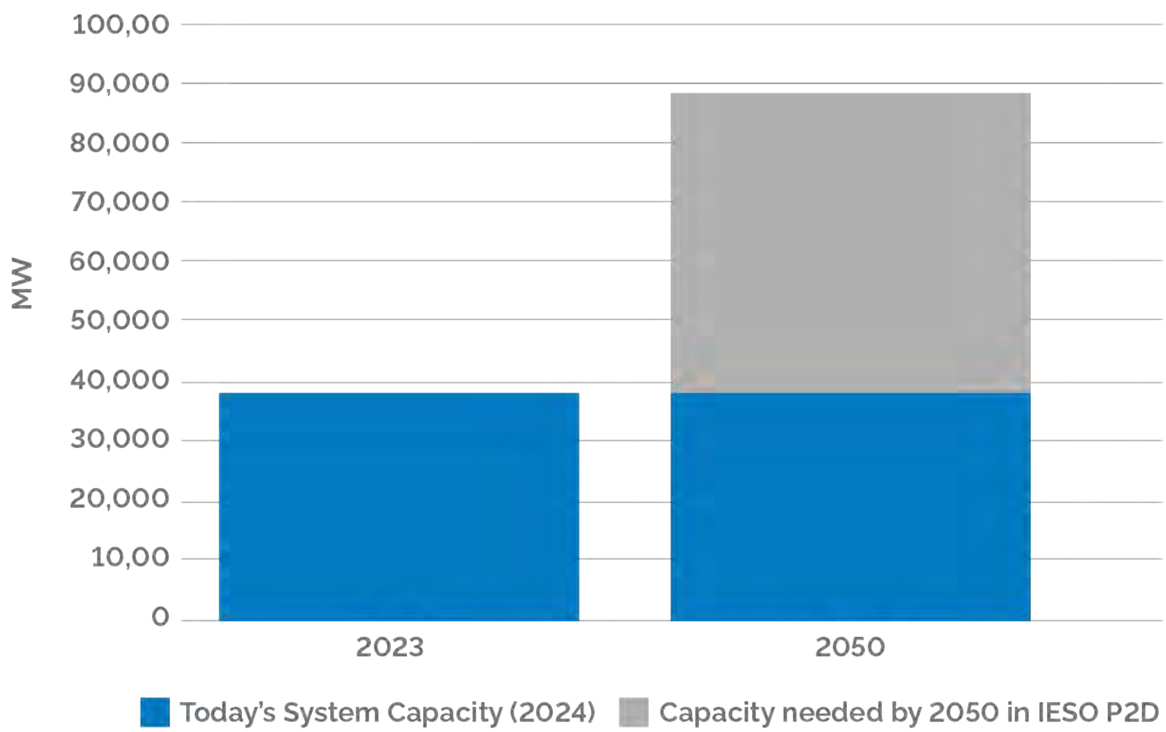
This is consistent with the expert advice of the system planners at the IESO whose Resource Eligibility Interim Report says: "Without a limited amount of new natural gas in the near term the IESO would be reliant on emergency actions such as conservation appeals and rotating blackouts to stabilize the grid."

Going Forward: Economic Growth and Electrification Driving Energy Demand

Ontario's economy and the day-to-day lives of its 15 million residents depend on a reliable electricity system that delivers power on demand. As a result of a historic run of investments and unprecedented economic growth, demand on that system is growing quickly.

According to the IESO's latest forecast, demand for clean, reliable and affordable power is expected to increase by 75 per cent by 2050, an increase of 15 percent over the previous year's forecast. A 75 per cent increase in demand would require 111 TWh of new energy – the equivalent of four and a half cities of Toronto.

Figure 6: Ontario Electricity System Capacity 2024 vs. 2050



Sources: IESO website. 2023 Year In Review. IESO. Pathways to Decarbonization report.

This growth will be driven primarily by economic growth, continued increases in Ontario's population, mining and steel industry electrification and through Ontario's success in attracting unprecedented investment in Ontario's industrial base, including the electric vehicle supply chain. In fact, five major investments alone are expected to increase industrial demand in the province by the equivalent of 36 per cent of today's industrial load, almost the entire demand of the City of Ottawa (figure 7). In Windsor, NextStar Energy, a joint venture between LG Energy Solution, Ltd (LGES) and Stellantis N.V., is investing more than $5 billion to manufacture batteries for EVs, which at the time in 2022 represented the largest automotive manufacturing investment in the province's history.

Since then, Volkswagen Group announced a $7 billion investment to build an EV battery manufacturing facility in St. Thomas. The plant, Volkswagen's largest to date, will create up to 3,000 direct and 30,000 indirect jobs. Once complete in 2027, the plant will produce batteries for as many as one million EVs a year, bolstering Canada's domestic battery manufacturing capacity to meet demand now and into the future.

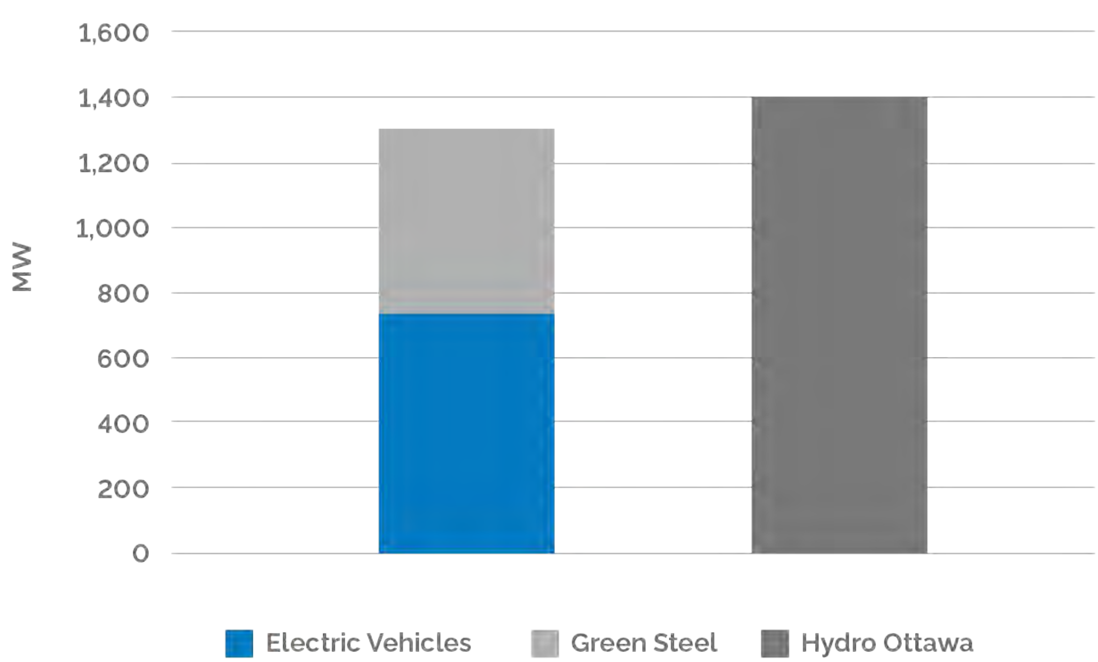
In April 2024, the government also welcomed a $15 billion investment by Honda Canada to create Canada's first comprehensive electric vehicle supply chain, located in Ontario.

This large-scale project will see four new manufacturing plants in Ontario. Honda will build an innovative and world-class electric vehicle assembly plant – the first of its kind for Honda Motor Co. Ltd. – as well as a new stand-alone battery manufacturing plant at Honda's facilities in Alliston. To complete the supply chain, Honda will also build a cathode active material and precursor (CAM/pCAM) processing plant through a joint venture partnership with POSCO Future M Co., Ltd. and a separator plant through a joint venture partnership with Asahi Kasei Corporation. Once fully operational in 2028, the new assembly plant will produce up to 240,000 vehicles per year.

Ontario has also secured major investments in clean steelmaking projects in Hamilton and Sault Ste. Marie with ArcelorMittal Dofasco and Algoma Steel. These once-in-a-generation investments will transform the province into a world-leading producer of green steel.

These investments will also boost the robust auto parts supply chain and skilled workforce in communities with deep roots in steel manufacturing and help meet the global demand for low-carbon auto production.

Figure 7: Projected Industrial Electricity Demand



Ontario's technology sector is also continuing to grow. The IESO reports that data centres will consume a total of 137 MW of demand by the end of 2026, roughly equal to adding the demand of the city of Kingston to the grid. The rise of artificial intelligence (AI) and the data centres that power advances in computing could also lead to significant increases in demand on energy grids. AI applications, particularly large language models, require substantial computational power, leading to higher energy consumption.

Several sectors are in a period of significant growth driven by longer-term trends that are driving higher demand. For example, greenhouse expansions and increased lighting requirement have resulted in the IESO projecting consumption from the agriculture sector to grow from around 5 TWh to 8 TWh by 2050, which is a 60 per cent increase, the equivalent of adding another City of London to the grid. Mining processes in northern Ontario will electrify some of their processes to improve efficiency and reduce emissions. The IESO is projecting this to contribute towards already robust industrial growth in the forecast.

At the same time, Ontario's population is expected to grow by almost 15 per cent or two million people by the end of this decade.

All of these homes will require reliable electricity, especially as households increase their consumption by electrifying heating, cooling and transportation. The IESO states that electricity demand from electric vehicles is forecast to grow from about 1.6 TWh in 2025 to 41.6 TWh in 2050, an average annual growth rate of about 13.9 per cent.

Access to other fuels and sources of energy such as natural gas also continue to be critical to attracting new jobs in manufacturing, including the automotive industry and agriculture. Natural gas currently makes up almost 40 per cent of Ontario's overall energy mix and is the dominant fuel used for heating, serving about 3.8 million customers. All of this growth highlights the need for Ontario to move forward with plans for bolder action and investment to ensure the energy system supports continued growth.

Our Vision: An Economy Powered by Affordable, Reliable and Clean Energy

1. Planning for Growth

Challenge: Ontario needs to plan for electricity, natural gas and other fuels to ensure that the province's energy needs are anticipated and met in a coordinated way.

Introduction

Ontario cannot afford to repeat the same mistakes as past governments and must move forward with energy planning that considers all sources of energy to meet our growing energy needs.

This is a complex undertaking that will require comprehensive view of how all energy sources are used across the economy. The pace of change has accelerated, and this is likely to continue as Ontario becomes home to new technologies and growing industries. Ontario must also plan for localized needs in certain communities and regions, changing the way power must flow across the province.

To meet this challenge, Ontario needs planning and regulatory frameworks that support building infrastructure and resources quickly and cost-effectively, and in a way that continues to promote Indigenous leadership and participation in energy projects. There is also a need to accelerate processes for building out the last mile to connect new homes and businesses supported by growth-oriented energy agencies to keep Ontario open for business.

Integrated Energy Resource Planning

Building the energy infrastructure necessary to power Ontario's future is a complex undertaking that requires the highest level of strategic energy planning and coordination.

The Ontario government can lead Canada in implementing an integrated energy planning process to ensure it is making the most cost-effective decisions for a clean energy future. This all-energy approach to planning would consider electricity, natural gas, hydrogen and other fuels. An integrated energy resource plan would help manage change and growing demand by providing clear signals and long-term confidence to the sector and investors.

By planning for all sources of energy and ensuring the energy system supports key goals such as building housing and attracting investment, Ontario will have a pathway to achieving its energy vision. The pace of change will be driven by the emergence of new major energy users, such as in the electric vehicle supply chain and data centres, and by individual decisions made by consumers with respect to how they power their homes, vehicles and businesses. Maintaining customer choice as a driving principle of Ontario's vision requires regular planning to ensure that energy sources are available for customers when they need them.

A key component of any integrated plan is a forecast for energy needs into the future. The IESO will continue to play a critical role in providing forecasts that drive investments in the electricity system. However, there is a need to enhance energy forecasting and coordinated planning so that there is greater alignment across energy sources.

Electrification and Energy Transition Panel

Recognizing the need for enhanced planning, the Ontario government established the independent Electrification and Energy Transition Panel to advise on high-value short, medium and long-term opportunities.

Appointed panel members included **Chair David Collie, Dr. Monica Gattinger** and **Chief Emerita Emily Whetung.**

To support the work of the panel and provide key inputs into long-term energy planning for the province, the government also commissioned an independent cost-effective energy pathways study to support the panel and understand how Ontario's energy sector can support electrification and the energy transition.

The panel's final report, *Ontario's Clean Energy Opportunity,* was released earlier this year following a comprehensive engagement with stakeholders and Indigenous communities. This work has informed Ontario's vision and affirmed the need for a first-of-a-kind integrated energy plan to coordinate the entire energy sector to help power a clean and growing economy.

Priorities for Integrated Energy Resource Planning:

- Ontario's energy sector needs to be guided by an integrated energy resource plan that ensures the province has the affordable power needed for a clean and growing economy.
- Integrated planning needs to be done on a regular cycle and incorporate all energy sources and input from Indigenous communities, the public and energy sector stakeholders.
- The IESO, as well as electricity and natural gas utilities need to coordinate their planning frameworks around shared, evidence-based forecasts for gas all types of energy use.
- The OEB will need to consider outputs from planning in its adjudication and other regulatory activities.
- There is a need for independent, external advice into the energy planning framework, including advice on the integration of energy planning with other government objectives, such as housing and economic development.
- Electricity forecasts must consider scenarios that reflect high growth, driven by population and GDP growth, accelerated electrification and evolving technological trends.
- There is a need for greater electricity and natural gas coordination in system planning that is informed by evidence-based forecasts that take the pace of electrification into account.

Electricity Generation

The province recognizes the challenge ahead and will continue to build on its successful planning for baseload resources and procurement processes to bring additional energy resources online so they support growth. That approach will ensure Ontario can take advantage of the full range of generation technologies and leverage competitive approaches wherever possible to keep electricity affordable.

To extend its clean energy advantage, Ontario needs to consider how more clean energy sources can be brought online.

Baseload Nuclear and Hydroelectricity: The Backbone of Ontario's Clean Electricity System

Ontario's plan will prioritize clean and reliable baseload electricity from nuclear and hydroelectricity. These resources have provided more than 75 per cent of the province's electricity over the last 20 years.

Ontario will continue to advance work on new nuclear and hydroelectric generation, which requires much longer lead times and long-term certainty than other resources but could serve the province well into the next century. This includes generational decisions to start pre-development and preparation for deployment of new nuclear – including work at Bruce Power and on the Darlington New Nuclear Project.

Priorities for Electricity Generation:

- Ontario's plan will prioritize clean and reliable baseload electricity from nuclear and hydroelectricity.
- Meeting the accelerating pace of growth will require:
  - A cadence of competitive long-term procurements that ensures new energy resources are built at lowest cost, thereby protecting ratepayers and taxpayers.
  - Securing energy from existing resources through competitive procurements, refurbishments and specialized programs.
  - Exploring the strategic value of other long-life assets, such as long-duration storage.
- Ontario's energy procurements must continue to advance economic reconciliation with Indigenous communities by including opportunities for Indigenous leadership and participation in generation projects, supported by community capacity funding and access to financing.

Electricity Transmission

As the province builds out new generation, the transmission network must be expanded to get that energy where it needs to go. And as the system grows and new businesses set up shop, the system must move quicker – including enhanced transmission planning and pre-development activities so lines can proceed to construction quickly with the support of sector participants, municipalities and Indigenous communities.

Priorities for Electricity Transmission:

- Ontario must continue to expedite the development of transmission infrastructure including through enhanced transmission planning and pre-development activities.
- Customers wishing to connect to the transmission system or electrify their processes need to be able to do so efficiently and at costs that are fair for everyone.
- New transmission infrastructure development needs to continue to advance reconciliation with Indigenous communities through early engagement and by creating opportunities for Indigenous leadership and partnership, economic participation and capacity building.

Last Mile Connections

Building new housing means there will be many new customers to connect to the energy system. An efficient connections framework that reduces barriers to customers will be essential to ensure the energy system supports growth.

The ability to attract investment and realize the province's housing goals will also depend on having dynamic, responsive and high-performing utilities as well as supportive and efficient regulatory processes.

Priorities for Last Mile Connections:

- There is a continued need for a regulatory framework that ensures last mile connections to homes and businesses are completed quickly to support growth.
- Ontario must look for opportunities to enhance information sharing and communication between developers, utilities, municipalities and local Indigenous communities to help address connection timeline challenges.
- Ontario's utilities need to continue to be high-performing and cost-efficient in their work to connect new homes and businesses to the province's grid.

Natural Gas

Natural gas currently makes up almost 40 per cent of Ontario's overall energy mix and is the dominant fuel used for heating, serving about 3.8 million customers. Natural gas is a vital component of Ontario's energy mix and the province's first integrated energy resource plan.

It fulfills diverse roles across the industrial, residential, commercial and agricultural sectors. It is also a critical component of the province's electricity generation mix to maintain reliability: increased electricity generation through natural gas can help reduce province-wide emissions by supporting cost-effective electrification in other sectors.

There is a need for the energy system to adapt to the pace of change so consumers continue to be empowered to make choices about their energy sources. That will require coordination among natural gas utilities, electricity utilities and the IESO to manage energy system costs and ensure reliability as significant investments in energy infrastructure are needed to support a growing and evolving economy. This coordination would ensure that electricity resources keep pace with demand as an increasing number of consumers switch energy sources over time, while reducing the risk of stranding assets before the end of their useful life.

Over the long-term, an economically viable natural gas network can also support the integration of clean fuels to reduce emissions, including renewable natural gas (RNG) and low-carbon hydrogen. Consumers in Ontario already have access to programs offered by Enbridge or non-utility suppliers (e.g., Bullfrog Power) to voluntarily add RNG to their gas supply. Pilot projects are also underway to increase low-carbon hydrogen production and use, including projects supported through the Hydrogen Innovation Fund.

Carbon capture and storage is another emerging technology that could reduce emissions generated by the continued use of natural gas by large industrial consumers. Ontario is committed to developing and implementing a framework to regulate commercial-scale geologic carbon storage projects in the province.

Going forward, Ontario will include a Natural Gas Policy Statement in its integrated energy resource plan to provide clear direction on the role of natural gas in Ontario's future energy system.

Priorities for Natural Gas:

- The build out of a cleaner and more diversified economy must be paced according to the needs of homes, businesses and economic investment, including the need to keep energy costs competitive, not ideologically driven.
- There is a need for an economically viable natural gas network to support a gradual energy transition, to attract industrial investment, to drive economic growth, to maintain customer choice and ensure overall energy system resiliency, reliability and affordability.
- Ontario must continue to seek opportunities to support energy efficiency, clean fuels and carbon capture to reduce emissions from the natural gas system while lowering energy costs for consumers.
- The OEB should continue to play its role as the natural gas system's regulator to protect consumers, to ensure utilities can invest in their systems and earn a fair return, and to enable the rational expansion and maintenance of the system.

Other Fuels

Ontario's first integrated energy resource plan will also consider other fuels including petroleum-based fuels (e.g., gasoline), propane and low-carbon fuels that make up just under 40 per cent of Ontario's energy mix.

Petroleum products are critical fuels to move goods and people and heat homes. They also have non-energy applications in the manufacturing and agricultural sector where electric options are not currently commercially available.

While the first oil well in North America was drilled in Oil Springs, near Sarnia, the province's crude oil production now accounts for less than one per cent of Ontario's total oil demand today. Ontario relies almost entirely on imported crude oil delivered from Western Canada and the United States by interprovincial and international pipelines to four refineries in Ontario. Ontario's refineries supply approximately 78 per cent of Ontario's refined product demand, with Quebec and the U.S. supplying the remainder.

Gasoline, diesel and jet fuel currently dominate the fuels sector, however, exciting and innovative advances in low-carbon fuels such as RNG, ethanol, renewable diesel, biodiesel and low-carbon hydrogen continue to provide sustainable alternatives. These may also provide a more cost-effective pathway than electrification to reduce emissions for some types of energy use.

Priorities for Other Fuels:

- Ontario needs to continue to ensure a secure supply of fuels and fuel transportation infrastructure through its work with industry stakeholders, the federal government, potentially impacted Indigenous communities, and other provincial governments.
- Further work is needed to explore opportunities to increase production of clean fuels and identify end-use applications where these clean fuels can be best deployed.
- There is a need for enhanced integration of all fuels in planning and coordination with other provincial strategies, such as for transportation, agriculture, forestry and the environment.

Indigenous Leadership and Participation

Indigenous communities are already leaders and key partners in Ontario's energy sector, with many First Nation and Métis communities owning or partnered on energy projects across the province. Those communities see immediate and lasting economic benefits that come from their participation in energy projects, including stable streams of revenue and knock-on benefits such as increased opportunities for Indigenous businesses, job creation and skills development.

Canada's Largest Indigenous-Led Infrastructure Project

The Wataynikaneyap Power Transmission Project, which is expected to reach substantial completion later this year, will be the largest Indigenous-led infrastructure project in Canada and connect over 18,000 people in northwestern Ontario to a clean, reliable and affordable supply of electricity. Wataynikaneyap Power is owned by 24 First Nation communities in partnership with FortisOntario and Algonquin Power & Utilities Corporation and provides direct benefits for those communities far beyond ending their reliance on dirty and costly diesel energy.

For example, the 100 per cent Indigenous-owned Opiikapawiin Services LP has led skills development and training to support Indigenous employment and participation throughout the project, with 51 training programs administered and over 600 Indigenous individuals completing training.

These partnerships also offer mutual benefits by creating opportunities for the province and energy proponents to learn from Indigenous leaders, elders and community members and ensure that energy developments consider potential impacts to Aboriginal and treaty rights. Indigenous participation in energy projects can ultimately help to get critical infrastructure built on time with better outcomes, such as reduced environmental impacts and employment and other economic benefits for Indigenous communities.

Priorities for Indigenous Leadership and Participation:

- Early and meaningful engagement and consultation with Indigenous communities on energy planning and major energy projects is critical to building out our energy system.
- Continued capacity funding and support for Indigenous ownership and participation in energy projects is needed, through programs like the provincial Aboriginal Loan Guarantee Program and the recently expanded IESO Indigenous Energy Support Program.
- Energy procurements need to incorporate the value of Indigenous leadership and participation by building on existing incentives and engagement requirements.
- Ontario must continue to build meaningful relationships with Indigenous communities and organizations and seek regular dialogue on regional and territorial energy interests underpinned by capacity support and relationship agreements.
- Indigenous representation is critical to ensuring there are Indigenous voices at the table on provincial energy matters.

Local, Regional and Interjurisdictional Energy Planning

Ontario has empowered municipalities as part of the energy planning process. This includes through the important role of municipal support in the energy procurement process.

Going forward, there is value in municipalities taking on a greater leadership role in energy planning in their communities because many are experiencing rapid growth. When communities are growing, municipal planning and energy planning needs to work in lockstep to support the build out of housing and business development.

There are also opportunities to work with Ontario's neighbouring jurisdictions and the federal government on energy issues that cross borders. This includes codified approaches to electric vehicle charging and to expanding electricity interties.

System planning needs to be done in a way that serves all Ontarians and ensures no one is left behind. An integrated planning approach will consider how energy choices can support healthy, diverse populations and communities.

Priorities for Local, Regional and Interjurisdictional Energy Planning:

- There is a need for strengthened local energy planning, including through municipal guidance, support and capacity building – such as through the Municipal Energy Plan program, as well as better alignment with the province's integrated energy planning process and other planning processes.
- There is a need for Ontario to work with the IESO, the OEB, Indigenous communities and stakeholders to continue to improve the Regional Planning Process so it supports coordination with natural gas planning, supports high growth regions and appropriately integrates municipal energy plans.
- There is an opportunity to work with neighbouring jurisdictions on interjurisdictional infrastructure planning (e.g., electricity interties).

Growth-Oriented Agencies

The IESO and the OEB are essential partners in achieving Ontario's vision for an affordable and clean energy system. Ontario's forecasted growth will increasingly challenge its agency partners to undertake their planning and approval functions rapidly and transparently.

In recent years, significant work has been undertaken at both the IESO and the OEB to modernize processes, support innovation and prepare for growth and electrification. This focus on continuous improvement is essential and must be accelerated to ensure planning and approvals can best serve high-growth areas and support Ontario's ability to attract future investment.

Ontario's energy sector participants, businesses and the public expect that energy planning decisions are made at the pace of growth. They also expect that planning information, such as growth forecasts and available system capacity, is informed by the best available data, which is updated regularly and made publicly available to support investment decisions. Regional planning cycles, particularly in high-growth regions, must be responsive to the pace of change.

Priorities to Support Growth-Oriented Agencies:

- There is an opportunity for the IESO to continue to build on its forecasting and planning framework to ensure there are tools to support high-growth regions.
- Ontario needs its energy agencies to continue to seek opportunities to expedite their approvals, decisions and other processes while continuing to prioritize reliability and affordability.
- Businesses need greater and more timely access to information on the state of the system to support connection decisions.
- The OEB should continue to seek opportunities to improve the efficiency of its independent adjudication and make greater use of non-adjudicative tools in regulating the sector.

2. Affordable and Reliable Energy

Challenge: Energy affordability must be prioritized as Ontario's energy system expands to meet demand and support economic growth.

Affordability is central to customers' having fair access to energy and the affordability of clean electricity is essential to driving customer choices to electrify. Customers need the right tools and data to manage their energy consumption so that they can make informed choices for their homes and transportation. This Ontario government will offer an alternative to any federal carbon tax, which maintains the pace of growth in the province while not applying new costs and makes energy available and affordable so that customers choose to switch.

Ontario's Alternative to a Carbon Tax

Affordability is a critical concern for families across Canada, but the carbon tax is only making life more expensive.

On April 1, 2024, the federal government increased the carbon tax by 23 per cent making it more expensive to build a new home, for a family to put gas in their car, put food on the table or buy everyday essentials.

Today the carbon tax adds 17.57 cents per litre to gasoline prices in Ontario. That will rise to about 30 cents by 2030. The carbon tax is adding about $350 on average to a household's annual natural gas bills.

The Government of Ontario has been clear in its opposition to the carbon tax. Ontario's first-of-a-kind integrated energy resource plan will invest in the province's prosperity and its energy systems to give residents and businesses affordable choices to use clean energy. This is Ontario's alternative to the carbon tax.

Priorities for Ontario's Alternative to a Carbon Tax:

- Ontario will never include a carbon tax in its plan.
- For Ontario's vision for a clean energy economy to be achieved, people and industry must have choice over their energy sources and no one can be left behind.
- Ontario will meet its 2030 emissions target with clean, affordable and reliable power that supports families and businesses as they make the choice to move away from higher emitting sources of energy, without a costly and unnecessary carbon tax.

Helping Ontarians Save through Energy Efficiency

As Ontarians choose to electrify their homes and businesses, there is an opportunity to install more efficient appliances and smarter controls to save energy and participate in programs and initiatives that benefit Ontario's energy system as a whole.

Ontario can build on accomplishments to date by expanding energy efficiency programs and empowering customers through energy data and tools, to lower costs for families and businesses. The government intends to unveil new energy efficiency programs aimed at helping families and businesses reduce their bills and save energy later this year.

Priorities for Helping Ontarians Save through Energy Efficiency:

- There is an opportunity to expand energy efficiency to help consumers lower their energy costs and to help offset investments in new, more expensive electricity infrastructure.
- Households, businesses and institutions would benefit from easier-to-access information about their energy use to make informed decisions about their building's energy performance, through streamlined processes that protect consumer information.
- Encouraging and supporting consumers who want to reduce their overall energy use to save money and lower emissions should be a continued priority over the long term.

Supporting Electric Vehicles (EVs)

As more families and businesses make the switch to electric vehicles, the government must ensure that electricity remains reliable and affordable, and that Ontarians can find public chargers when and where they need them.

There is a continued need to improve access to and remove roadblocks for building affordable EV charging infrastructure (e.g., public stations, home, work and fleet charging) and allow for greater choice, access and safe uptake of electric mobility options across Ontario.

Priorities for Supporting EVs:

- Ontario's regulatory framework for electricity must continue to support the efficient integration of EVs and growing EV adoption.
- Any opportunity to reduce barriers to the build out of affordable EV charging infrastructure must be explored to support greater choice, access and uptake of EVs.
- Strong collaboration across government is needed to support continued growth in private and public EV charging infrastructure.

Empowering Energy Consumers to Participate in the Grid

Industrial, commercial and residential customers are increasingly leveraging technologies like solar photovoltaic panels, batteries, electric vehicles, thermal storage, smart thermostats and electric water heaters to manage their energy use, reduce their energy costs, and provide back-up power or heat. These small-scale energy systems that generate, store or manage electricity close to where they are used, in homes and businesses, are referred to as distributed energy resources (DER). These DER systems can also be directly connected to the distribution grid and provide energy and other services to local or bulk grid.

Giving customers more ways to participate in the grid, with a focus on creating new ways for families and businesses to save money while reducing province-wide energy demand, benefits us all. As the grid evolves with the increasing adoption of DER, the policy framework too must evolve to support customer choice and reduce barriers to all types of DER investments that can support local energy needs and improve the efficient utilization of these resources within the energy system.

Priorities for Empowering Energy Consumers to Participate in the Grid:

- There is an ongoing opportunity to expand the use of DERs where it is cost-effective and beneficial to meeting local and system needs.
- Customers would benefit from increased opportunities for customer-sited generation and storage that offers bill savings or resiliency benefits for residential, small business and farm customers.
- There are opportunities to examine broader implementation of projects piloted by OEB and IESO that have demonstrated customer, local and system benefits.
- There is an opportunity to improve collection and sharing of DER data to the mutual benefit of LDCs, the OEB, the IESO, customers and DER developers.

Grid Modernization

Distribution grids throughout the province will need to modernize, utilizing and integrating innovative technologies that facilitate active monitoring of their systems, while building better resiliency to changes in weather patterns and extreme weather events.

Ontarians expect that their LDC will serve them safely, reliably, cost effectively and that over time they will steadily improve. These expectations must be met as LDCs concurrently confront the necessary modernization of the grid, improve the grid's overall resilience, and directly support Ontario's economic development and housing targets. The government continues to support voluntary consolidation in the electricity distribution sector which can help local distribution companies be better positioned to support Ontario's electrification needs and improve services for customers well into the future.

By providing further clarity on what are considered grid modernization activities, the province can help LDCs make prudent investments to support increasing energy demand.

Priorities for Grid Modernization:

- Ontario recognizes the need to work with the OEB to provide greater clarity and predictability to LDCs so that they can modernize their infrastructure to provide the energy and services that ratepayers need into the future.
- There are opportunities for the government, IESO and the OEB to accelerate implementation of grid innovation projects that provide ratepayer value.
- There is a need to strengthen the governance and accountability of LDCs to improve operational efficiencies, increase reliability, and support investments necessary for the increasing energy demand.

Grid Resiliency

As concerns about climate change and extreme weather events such as flooding, wildfires and ice storms rise, building grid resiliency across the province is essential to Ontario's economic growth and energy future.

Ontario has released the Vulnerability Assessment for Ontario's Electricity Distribution Sector which summarizes anticipated extreme weather risks to Ontario's electricity distribution networks. Further actions can be taken by working with agencies and LDCs to strengthen Ontario's grid and ensure the energy system is prepared to respond to future extreme weather events and cyber threats.

Priorities for Grid Resiliency:

- There is a need to build capacity in the sector to conduct risk assessments to drive more effective action in making Ontario's grid resilient.
- Ontario must ensure that reducing impacts on vulnerable populations is a key consideration in resiliency and adaptation planning in the sector.
- Any efforts to enhance grid resiliency must be done in an economically efficient manner that prioritizes value for customers.

Programs for Energy Affordability

Maintaining affordable electricity pricing will be critical to driving customer decisions to electrify their lives with clean energy.

Several energy support programs are in place, including broad support programs like the Ontario Electricity Rebate. The government also offers targeted supports to people who need it most. Earlier this year the government expanded access to the Ontario Electricity Support Program (OESP) by increasing the eligibility thresholds by up to 35 per cent.

To maintain the sustainability of the programs and ensure support is available to those who need it most, it will be crucial to monitor the costs and designs of these programs, and to adjust where necessary.

Priorities for Programs for Energy Affordability:

- Cost-effective, competitive and technology-agnostic procurement of energy resources is an enduring priority to manage system costs.
- There is a continued need for targeted supports to those who need it most, including low-income households.
- Ontario's suite of electricity rate mitigation programs must provide continued stability and predictability for families and businesses.

Affordable Home Heating

Not all communities have access to the same sources of energy for home heating. While more than 70 per cent of homes are heated with natural gas, many still rely on other more expensive sources including propane and home heating oil.

The government is providing families with multiple options to help make home heating more affordable.

To help families and businesses in rural Ontario transition off higher-cost and higher-emission forms of energy, the government provides support through the Natural Gas Expansion Program (NGEP). Work is underway to explore how to continue these efforts and provide financial support and affordable home heating to more communities.

This is complemented by programs like the former Clean Home Heating Initiative (CHHI), the Energy Affordability Program and the HomeEnergySaver program, which provide opportunities for households to complement their existing heating source with an electric heat pump.

Priorities for Affordable Home Heating:

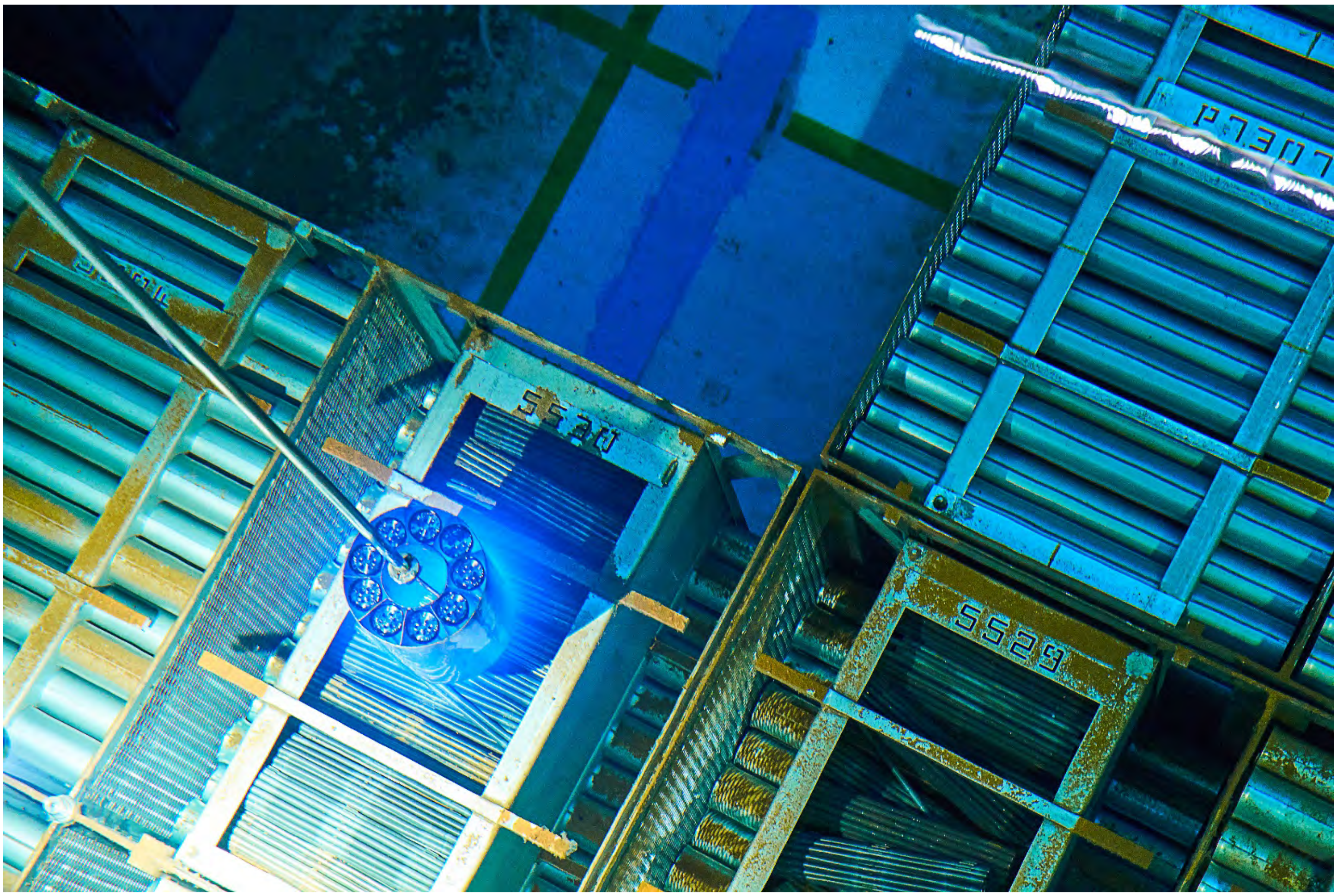
- There is a need to ensure Ontarians have affordable options for home heating from different energy sources.
- Affordable home heating options should be available that take advantage of Ontario's clean electricity system, such as through heat pumps and other new technologies as well as energy efficiency measures.

3. Becoming an Energy Superpower

Challenge: Ontario has the opportunity to use our competitive advantage to export clean energy and technology across the continent and beyond.

Energy will be a cornerstone of the province's economic strategy and success. Creating stability of supply through prudent investments and planning will foster an environment in which companies from around the world can be assured that Ontario is an ideal place to conduct business for generations to come.

That also creates an additional opportunity where other jurisdictions recognize that as they seek to meet their own clean energy goals that Ontario can be a partner in their work.



Exporting Power and Expertise

Ontario has a diverse, world-class and clean electricity system, powered by nuclear, hydroelectricity, solar, wind, natural gas, biomass, biogas and electricity storage. Ontario also has a proven ability to build complex energy projects on time and budget, benefitting from strong agencies that have led to a cost effective and highly reliable energy system.

That combination positions Ontario as a continental leader in clean energy. Across North America, many jurisdictions and businesses are establishing clean energy targets for their electricity grids that will require historic investments and lengthy lead times to accomplish. Ontario is well-placed to step in and play a critical role as a clean energy leader and help these jurisdictions reduce their GHG emissions.

History of Electricity Imports and Exports

Electricity imports and exports are a normal part of the operation of the electricity market. Ontario's electricity system currently has 26 interties connected with five neighbouring jurisdictions: three with Manitoba, eleven with Quebec, one with Minnesota, four with Michigan and seven with New York, with a total nominal transfer capacity of approximately 6,000 megawatts (MW).

Since 2006, Ontario has been a net exporter to these jurisdictions. In 2023, Ontario scheduled net exports of 12.4 terawatt-hours (TWh), an increase of 29 per cent from the 9.6 TWh net exports of 2022. For context, Ontario exported 11 per cent of its total generation in 2023.

Those exports have not always been in the province's favour. Historically, Ontario experienced periods of Surplus Baseload Generation (SBG), which occurred when output from baseload generation resources exceeded Ontario demand. These periods of SBG, which typically occurred overnight in the spring and fall, required the IESO to use market mechanisms such as exports or economic curtailment of certain resources to balance supply and demand.

SBG can result in low, or even negative, wholesale prices for participants in the electricity market. This is because hydro and nuclear generation are considered “non-dispatchable,” meaning they have limited to no flexibility to reduce energy production. Therefore, they will offer very low prices so that their production is the last to be curtailed. According to the IESO, for a sample period between 2016 and 2020, between 5 to 9 per cent of all exports were sold at $0 per megawatt-hour or less. Although the surplus power was made available to consumers, there was often limited or low demand at the time this power was available.

Future Opportunities for Electricity Exports

The IESO is forecasting that Ontario energy demand will increase by 75 per cent over the course of the next 25 years. Ontario will position itself to not just meet that domestic demand, but where it makes sense for the province, and is in the best interests of ratepayers, to exceed it.

As part of the exploration of further export opportunities, the IESO has been tasked with supporting the development of an export strategy that generates new revenue streams and creates good jobs here at home. The IESO's analysis will act as the foundation for any plan development on an export strategy. As Ontario's electricity system grows, expanding the interconnections with neighbouring jurisdictions will be important to help provide operational flexibility and mitigate risks. Many of Ontario's interconnected jurisdictions have an anticipated shortfall or a clean energy commitment to meet (i.e., New York, Maryland and Illinois) or both (i.e., Michigan and Minnesota) but are currently reliant on resources like coal which could be replaced with clean energy imports. The government believes that pursuing further export opportunities would require increasing generation.

The IESO's analysis will include:

- A scoping of the generation resources and transmission infrastructure required to serve the best opportunities to Ontario and its ratepayers while also being able to deliver the desired exports to neighbouring jurisdictions; and
- An assessment of the required commercial, market pathways and mechanisms to capture cost effective export opportunities.

The province currently has robust transmission interties with neighbouring provinces and states and trades electricity every day as a core function of the Ontario market. As the province builds out its competitive advantage in energy, there may be greater opportunities to leverage trade to benefit Ontario ratepayers and provide clean energy to other jurisdictions.

It would also improve the resilience of the Ontario energy system by expanding the option to import power when needed to meet peak demand, such as during extreme weather events.

Ontario has experience negotiating export arrangements with its neighbours. For instance, Ontario currently has an agreement in place to “swap” 600 MW of capacity on a seasonal basis with Hydro Quebec, and the IESO has a separate agreement with New York’s ISO (NYISO) to facilitate imports and exports of capacity between the two jurisdictions.

Additional opportunities might exist in these and in other neighbouring jurisdictions to which Ontario is interconnected. Both NYISO and Midcontinent ISO (MISO), which serves most of the US midwestern states, are projecting significant shortfalls in the years ahead. There may be opportunities for firm export agreements with these jurisdictions that could offset the costs of building new generation in Ontario and actually help reduce bills for Ontario families while also creating good jobs.

Ontario’s generators and electricity traders already participate extensively in the US through wholesale electricity markets. In addition, both NYISO and MISO administer capacity auctions in their jurisdictions. Ontario would not participate in long-term export commitment unless a firm revenue agreement was in place to protect and actually drive value for Ontarians.

Any export deals with other jurisdictions would need a lead counterparty in Ontario, such as a generator or the IESO, as well as firm transmission rights to ensure delivery when the power is needed. With support from the province, the province believes Ontario’s market participants are both sophisticated and capable of executing such deals.

Leadership in Nuclear Projects and Innovation

The province is a leader in nuclear projects and technology. The Canada Deuterium Uranium (CANDU) reactor technology used in our current fleet was developed in Ontario and has been exported around the world. Our multi-billion-dollar nuclear industry supports 65,000 jobs across the province and is helping our nuclear operators, OPG and Bruce Power, to deliver complex refurbishment projects at their stations on-time and on-budget. Ontario companies are also sharing their know-how beyond our borders through partnerships in the United States and Europe. The nuclear sector is advancing innovation in nuclear and non-nuclear applications, such as SMRs and medical isotopes that are used for diagnosing and treating life-threatening diseases and sterilization of medical equipment around the world.

Priorities for Exporting Power and Expertise:

- Ensure Ontario families directly benefit from any agreement to export power through lower bills, enhanced revenue streams for the province and good-paying, local jobs.
- Ontario has an opportunity to work with the IESO and other sector partners to explore cost-effective opportunities to increase trade with neighbouring jurisdictions, including through new or expanded interties.
- Ontario's nuclear leadership in SMRs, large-scale nuclear technology and other nuclear innovations, could continue to create new export opportunities, drive economic growth and create jobs across the province.
- Ontario's nuclear fleet can continue to advance key opportunities in research, development and production of medical isotopes and make Ontario a global isotope superpower.

Next Steps

Ontario intends to take early actions towards meeting the challenges laid out in this document in the weeks and months ahead. These actions would build on steps already taken since the release of *Powering Ontario's Growth*.

The priorities articulated in this document will also guide Ontario's first integrated energy resource plan. In building the plan, input from the public, stakeholders and Indigenous communities will help to inform the actions needed to achieve our energy vision.

Your feedback will be carefully reviewed as Ontario moves forward with launching its first integrated energy resource plan in 2025.

Glossary of Terms

Baseload generation
Baseload generators are typically designed to run at a constant rate and typically include nuclear and large hydroelectric facilities.

Bioenergy
Energy produced from organic material sources. Sources for bioenergy generation can include agricultural residues, food-process by-products, animal manure, waste wood and organic kitchen waste.

Distributed Energy Resources (DERs)
Resources that generate energy, store energy, or control load and are directly connected to the distribution system or located behind a customer's meter.

Electric Vehicle (EV)
Any vehicle that is partially or fully powered by electricity and plugs in to recharge. They can reduce fossil fuel consumption and emissions.

Energy Efficiency
Any conservation program or action which reduces the amount of electricity consumed or reduces the amount of power drawn from the electricity grid.

Independent Electricity System Operator (IESO)
The provincial entity that delivers key services across the electricity sector, including managing the power system in real-time, planning for the province's future energy needs, enabling conservation and designing a more efficient electricity marketplace to support sector evolution.

Local Distribution Company (LDC)
A utility that owns and/or operates a distribution system that delivers electricity to consumers.

Megawatt (MW)
A standard unit of power that is equal to 1 million watts (W) used to depict peak energy demand or generation capacity. For instance, a nuclear reactor can generate approximately 800-900 MW while a large wind turbine can generate up to 3 MW. Peak demand for the city of Ottawa is on the order of 1,500 MW.

Megawatt-hour (MWh) / Terawatt-hour (TWh)
Measure of energy demand (and generation) over time. Note: 1 million MWh is equal to 1 terawatthour (TWh).

Ontario Energy Board (OEB)
The Ontario Energy Board (OEB) is the independent agency that regulates Ontario's electricity and natural gas sectors in the public interest.

Peak Demand
Peak demand or, peak load or on peak are terms describing a period in which demand for electricity is highest. In Ontario, the annual electricity power peak demand usually occurs in the mid to late afternoon during a hot, humid, sunny weekday in July or August.

Small Modular Reactor (SMR)
Nuclear reactors that are significantly smaller and more flexible than conventional nuclear reactors and can be factory-built. Small Modular Reactors (SMRs) could operate independently or be linked to multiple units, depending on the required amount of power.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Three Fires Group Inc. (Three Fires) / Minogi Corp. (Minogi)

Interrogatory

Reference:

Exhibit 4, Tab 2, Schedule 7, pp. 3-11

Preamble:

EGI is proposing cost recovery for low-carbon energy through a Low-Carbon Voluntary Program (“LCVP”) for large volume sales service customers and through the cost of gas supply commodity purchases.

EGI proposes to increase low-carbon energy purchases by up to one percentage point each subsequent year to a maximum of up to four percent by 2029.
Enbridge Gas indicates that it intends to use the existing Gas Supply Plan review process to provide an overview of LCVP results.

EGI proposes to first offer the low-carbon energy that has been procured to large volume sales service customers on a voluntary basis and that large volume sales service customers will have the ability to voluntarily assume an elected portion of the pass-through commodity costs associated with low-carbon energy as part of the proposed LCVP, up to 100 percent of their actual consumption.

Participating LCVP customers will receive a specified portion of their supply as low-carbon energy and pay the associated premium cost of low-carbon energy above the gas commodity cost through Rider L. The premium will vary based on the portfolio of low-carbon energy EGI procures.

Question(s):

a) How did EGI arrive at the incremental 1% target? In your response please also explain how the 1% target compares to other comparable programs and include in your response why EGI believes these programs are comparable.

b) Has EGI estimated the demand for the LCVP? If yes, please provide a breakdown of EGI’s estimates for demand over each year of the rebasing period, including number of participants, total RNG procured, total costs, etc.

c) What considerations does EGI anticipate that large volume customers will entertain as part of a decision to enter into the program? In your response, please indicate where in the record in this proceeding the full implications of opting into the LCVP are set out and explained.

d) Based on EGI's estimates of participation and/or interest in the LCVP, is there an adequate supply of cost-effective RNG available to satisfy the demand? If no, please discuss how EGI will manage the program and customers if there is an inadequate supply of RNG and/or how EGI will ensure that there is an adequate supply of RNG to support the LCVP and any other RNG program.

e) How have EGI's forecasts of the supply of RNG in Canada, the U.S., and Ontario changed since EGI's last rebasing application and the applicable Annual Gas Supply Plan updates throughout the current gas supply plan period?

f) Does EGI have any estimates of the anticipated emissions abated through the procurement of RNG throughout the rebasing period? If yes, please provide EGI's estimates.

g) Please provide full details of all metrics EGI intends to use to track its progress and performance related to the LCVP. In your response, and in addition to any other metrics, please indicate whether EGI will track specific metrics such as (i) Indigenous participation, (ii) amount of RNG procured from Indigenous-owned sources and suppliers, and (iii) any other metric related to supporting Ontario First Nations and the supply of Ontario RNG to meet demand of the LCVP.

h) Please provide all factors that EGI believes will go into the variance in price for RNG procured by EGI as part of its portfolio of low-carbon energy.

<u>Response:</u>

a) Please see response at Exhibit I.4.2-STAFF-32, part d).

The existing Canadian RNG programs of FortisBC and Energir are comparable to the Enbridge Gas proposal in that they include a voluntary and a blend component, however, the programs are underpinned by provincial lower-carbon fuel requirements. These utilities have been actively procuring in the RNG market for several years. In British Columbia (BC), the CleanBC Roadmap[1] targets renewable energy, including RNG, at 15% of BC's natural gas by 2030. FortisBC has a hybrid

[1] Government of British Columbia. (2021 October 25). CleanBC Roadmap to 2030. https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_roadmap_2030.pdf

RNG procurement program offering both a voluntary program and a target blend percentage for all sales gas customers. The British Columbia Utilities Commission (BCUC) approved all FortisBC gas customers receiving a one percent blend as of July 1, 2024, with the percentage blend increasing over time. The blend percentage is intended to act as a mechanism to balance the RNG supply and demand as the voluntary program does not have sufficient demand to meet the Green House Gas Reduction (Clean Energy) Regulation[2]. In Quebec, Energir was required to blend RNG into system gas at one percent by 2020 and gradually increase the blend to 10 percent by 2030[3].

b) Please see response at Exhibit I.4.2-SEC-32.

c) Responses from the LCVP Expression of Interest (EOI) indicated that customers are seeking further information and understanding of RNG and how it can be leveraged to meet sustainability targets. Enbridge Gas anticipates that large volume customers will further consider program simplicity including ease of enrolment, election, reporting, billing as well as the incremental financial implications when comparing RNG to alternative lower emission energies and the equipment/infrastructure required to utilize them.

   Please see response at Exhibit I.4.2-SEC-30 for details on the LCVP.

d-e) Yes, Enbridge Gas expects there to be sufficient supplies of RNG to meet LCVP demand. Please see response at Exhibit I.4.2-TFG/M-10, part e) for in-service RNG capacity for Canada and the U.S. as of 2022.

f) Please see response at Exhibit.I.4.2-PP-46.

g) Please see response at Exhibit 1.4.2-STAFF-35, part c). Metrics specific to Indigenous participation or Indigenous-owned sources and suppliers have also not been identified.

h) Please see response at Exhibit I.4.2-ED-40.

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[2] British Columbia Utilities Commission. (20 Mar 2024). Biomethane Energy Recovery Charge Rate Methodology and Comprehensive Review of a Revised Renewable Gas Program. https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/g-77-24-fei-stage2-comp-review-revised-rng-program-decision.pdf?sfvrsn=8319fc0f_1

[3] Government of Quebec. (23 Nov 2023). Renewable Natural Gas. https://www.quebec.ca/en/agriculture-environment-and-natural-resources/energy/energy-production-supply-distribution/bioenergy/renewable-natural-gas

M1-TFG/MC-3

Reference: Exhibit M1, pp. 14-20

Preamble: EFG notes that under the Low-Carbon Energy Program ("**LCEP**") proposal, EGI could procure renewable natural gas ("**RNG**") supplies from anywhere across North America and recommends that the LCEP should prioritize or be restricted to support the development of regional (i.e., Ontario-based) RNG projects and infrastructure.

EFG recommends that the Board cap the price at which EGI can procure RNG at $25.58/GJ.

Questions:

(a) How should EGI and/or Ontario policy work to encourage the development of RNG projects and infrastructure to ensure the supply of Ontario RNG satisfies the demand anticipated in your proposals?
(b) What does the recommendation to prioritize the procurement of Ontario-sourced RNG mean for Ontario First Nations and Indigenous groups that may be interested in developing RNG projects?
(c) Please comment on whether the price cap will limit the ability of First Nations and Indigenous groups to develop RNG projects? In your response, please consider the unique challenges of many First Nations including (i) access to capital, (ii) location (remote and near-remote), and (iii) the economic realities of many of Ontario's First Nations that may impact the price at which RNG is financially viable.
(d) Please comment on how the recommendation to prioritize and/or restrict the development of RNG projects benefits or disadvantages Ontario First Nations and Indigenous groups interested in producing and supplying RNG. In your response, please discuss any unique benefits and/or disadvantages for Ontario First Nations and Indigenous groups as compared to non-Indigenous suppliers and producers, if any.
(e) Please comment on setting targets under the LCEP for procuring RNG from First Nations and Indigenous-owned suppliers in Ontario.

Responses:

a) The proposed LCEP program should encourage development of RNG projects and resources. Our recommendation to reduce the total level of procurement from 4% to 1% of supply with a focus on Ontario supply, as opposed to out-of-region sourcing, will help match Ontario supply with the program's target.

b) Our recommendations that procurement prioritize new in region projects can benefit First Nation or Indigenous groups interested in RNG development. That said, the relative economics for individual RNG production sites in Ontario, whether First Nation/Indigenous or not, will vary according to levels of existing infrastructure and feedstock resources.

c) The recommended price cap equates to offering a high price for new RNG development while remaining consistent with EGI's proposed structure for limiting per customer rate impacts for the LCEP procurement. EFG has not considered, and does not take a position on, whether a higher price cap for the development of new RNG by First Nation or Indigenous groups is appropriate. However, to the degree such projects have higher development costs (for example an RNG site that does not have current gas connection), and their development is aligned with policy objectives, a differentiated price cap, or other mechanism, such preferential scoring in procurement or a percent set-aside could be considered.

d) Remote sites, or sites without more limited existing infrastructure (such as an anaerobic digester, or a landfill site with existing gas capture) will face higher costs for RNG development than those that are closer to the existing gas system, or those with some existing infrastructure. This applies to sites whether or not they are affiliated with First Nation or Indigenous groups.

e) See response to c).

M1.EGI-9

Reference: Exhibit M1, page 30

Preamble: EFG states: "The Company's assumption in the LCEP application that the carbon intensity of RNG can be assumed to be zero is not supported by these tables."

Questions:

(a) Please provide the specific text and reference from Phase 2 Exhibit 4, Tab 2, Schedule 7, where Enbridge Gas has indicated that the carbon intensity of RNG is zero.
(b) Please confirm that carbon intensities (i.e., lifecycle GHG emissions) are different from emission factors used to calculate facility emissions (i.e., direct end-use emissions) and are not interchangeable terms.
(c) Please confirm that carbon intensity is not used to calculate facility emissions in Version 7.0 of Canada's Greenhouse Gas Quantification Requirements for Canada's Greenhouse Gas Reporting Program.
(d) Please confirm that carbon intensity is not used to calculate facility emissions in Ontario Regulation 390/18: Greenhouse Gas Emissions: Quantification, Reporting, and Verification, or the March 2024 Version of the Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions under Ontario's Emissions Reporting Program.

Responses:

a) In item 71 on page 28 of 32 EGI states the Greenhouse Gas Pollution Pricing Act (GGPPA) has inherently recognized RNG as being free of CO2 emissions. In item 76, the EGI further acknowledges: "the lifecycle emission benefits of using RNG; however, at this time, the CI score of RNG will not be the primary consideration when procuring RNG."

   EFG acknowledges that EGI does not directly state the carbon intensity of RNG is zero. However, our understanding of the proposed accounting is that RNG impacts will be counted in that fashion. This potentially overstates the level of emissions reductions from landfill gas and wastewater treatment sourced projects, while understating the benefits from manure anaerobic digester sourced RNG.

   While EGI may recognize that there are important levels of variation in the lifecycle carbon intensity for various RNG feedstock supplies, the proposed procurement will not treat carbon intensity (CI) as a primary consideration. If differences in carbon intensity do not affect decisions about what sources of RNG to procure, that is effectively treating them as if they all have the same carbon intensity. This is a problematic simplification, and we recommend CI be considered and accounted when emission reductions are calculated and that CI also inform procurement decisions.

b) Confirmed. If one focuses only on emissions at the point of combustion (direct end-use emissions), there is no difference between RNG and fossil gas.

c, d) In both cases, the methods and required reporting focus on the onsite facility combustion emissions and would treat all RNG as zero-emitting. While certain government reporting requirements do not account for lifecycle carbon intensities, EGI's proposal for LCEP program and RNG procurement can, and should account for differences in lifecycle emissions based on available information on the lifecycle CI's for various RNG feedstock streams for all of the reasons set out in the EFG report. See the EFG report for details.

B.C. Reg. 102/2012 Deposited May 15, 2012
O.C. 295/2012

This consolidation is current to December 10, 2024.

Link to consolidated regulation (PDF)

Link to Point in Time

Clean Energy Act

GREENHOUSE GAS REDUCTION (CLEAN ENERGY) REGULATION

[Last amended July 1, 2024 by B.C. Reg. 125/2024]

Contents

Definitions

1 In this regulation:

"Act" means the *Clean Energy Act*;

"annual percentage change" means the annual percentage change in the annual average All-items Consumer Price Index for British Columbia, as published by

Statistics Canada under the authority of the *Statistics Act* (Canada);

"environmental attribute" means any credit, benefit, greenhouse gas emissions reduction, offset or allowance attributable to

(a) the production and use of renewable natural gas, hydrogen, synthesis gas or lignin, and

(b) the displacement, by the production and use described in paragraph (a), of the production and use of natural gas derived from fossil fuels;

"farm tractor" has the same meaning as in section 1 of the *Motor Vehicle Act*;

"fiscal year" means the period from April 1 in one year to March 31 in the next year;

"former regulation" means the Greenhouse Gas Reduction (Clean Energy) Regulation as it read immediately before May 22, 2023;

"implement of husbandry" has the same meaning as in section 1 of the *Motor Vehicle Act*;

"industrial utility vehicle" has the same meaning as in section 1 of the *Motor Vehicle Act*;

"light-duty vehicle" means a vehicle with a manufacturer's gross vehicle weight rating of 3 856 kg or less;

"logging truck" has the same meaning as in section 1 of the Motor Vehicle Act Regulations;

"non-bypass customer" means a customer of a public utility that receives service under a rate that is not specific to the customer;

"operating costs", in relation to a fuelling station or to distribution or storage infrastructure, means

(a) operating and maintenance expenses,

(b) electricity expenses,

(c) interest expenses,

(d) taxes, including property taxes,

(e) return on equity,

(f) extraordinary retirement costs, and

(g) amounts with respect to the depreciation of the

(i) capital costs,

(ii) construction carrying costs,

(iii) feasibility and development costs,

(iv) sustaining capital costs, and

(v) decommissioning and salvaging costs

determined with reference to the remaining service life of the fuelling station or distribution or storage infrastructure, as approved by the commission in setting rates;

"safety guidelines" means safety guidelines adopted by the British Columbia Safety Authority;

"shore-side asset" means any of the following:

(a) boil-off gas recovery equipment;

(b) an LNG cryogenic loading manifold;

(c) an LNG cryogenic pipeline and vessel loading berth;

(d) an LNG cryogenic storage tank;

(e) an LNG measurement apparatus;

"tanker truck load-out" means equipment for transferring liquefied natural gas from a storage tank to a liquefied natural gas tank trailer.

[am. B.C. Regs. 235/2013, s. 1; 98/2015, s. 1; 214/2016, s. 1; 114/2017, s. 1; 84/2018, s. 1; 134/2021, s. 1; 126/2023, s. 1; 125/2023, s. 1; 125/2024, Sch. 2, s. 1.]

Prescribed undertaking — marine vehicles using liquefied natural gas

2 (1) In this section:

"natural gas marine vehicle" means a marine vehicle that uses, as a fuel source, liquefied natural gas;

"undertaking period" means the period ending on March 31, 2026.

(2) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility provides, on or before March 31, 2026, through an open and competitive application process,

(i) grants or zero-interest loans to persons in British Columbia for the purchase of a natural gas marine vehicle to be operated in British Columbia, or

(ii) grants to persons in British Columbia

(A) to implement safety practices, or

(B) to improve maintenance facilities

to meet safety guidelines for operating and maintaining a natural gas marine vehicle;

(b) an expenditure on a grant or loan for a natural gas marine vehicle does not exceed 50% of the difference between the cost of the natural gas marine vehicle and the cost of a comparable vehicle that uses gasoline or diesel;

(c) during the undertaking period,

(i) total expenditures on the undertaking in this section, including expenditures on administration, marketing, training and education, do not exceed $60 million in total,

(ii) expenditures on administration, marketing, training and education related to the prescribed undertaking in this section do not exceed $9 million in total, including any expenditures on administration, marketing, training and education related to the prescribed undertakings described in section 2 (1) and (3.2) of the former regulation, and

(iii) expenditures on the undertaking on grants referred to in subsection (2) (a) (ii) do not exceed $6 million.

[en. B.C. Reg. 125/2023, s. 2; am. B.C. Regs. 124/2024, s. 1; 125/2024, Sch. 2, s. 2.]

Prescribed undertaking — liquefied natural gas distribution and storage

2.1 (1) In this section:

"expenditures" includes, except with respect to expenditures on administration and marketing, binding commitments to incur expenditures in the future;

"undertaking period" means the period ending on March 31, 2026.

(2) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility, before March 31, 2026, enters into a binding commitment to

(i) construct and operate, or

(ii) purchase and operate

liquefied natural gas distribution and storage infrastructure, other than liquefied natural gas fuelling stations, in British Columbia, including liquefied natural gas rail tank cars, ISO containers and shore-side assets, for the purpose of reducing greenhouse gas emissions;

(b) total expenditures on the undertaking during the undertaking period do not exceed $40 million, including

(i) any expenditures related to the prescribed undertaking described in section 2 (3.4) of the former regulation, and

(ii) expenditures on administration, marketing, training and education;

(c) at least

(i) 80% of the forecast total operating costs of the distribution and storage infrastructure for the first 5 years of the operation are recovered from one or more persons under a take-or-pay agreement with a minimum term of 5 years, or

(ii) 60% of the forecast total operating costs of the distribution and storage infrastructure for the first 7 years of the operation are recovered from one or more persons under a take-or-pay agreement with a minimum term of 7 years.

[en. B.C. Reg. 125/2023, s. 2; am. B.C. Reg. 125/2024, Sch. 2, s. 2.]

Prescribed undertaking — acquiring renewable natural gas

2.2 (1) A public utility's undertaking that is in the class defined in subsection (3) is a prescribed undertaking for the purposes of section 18 of the Act.

(2) For the purposes of subsection (3), **"acquires renewable natural gas"** includes producing renewable natural gas by producing or purchasing biogas and upgrading it to renewable natural gas.

(3) The public utility

(a) acquires renewable natural gas that meets the criteria described in section 8.2 (3) at costs that meet the following criteria, as applicable:

(i) if the public utility enters into a contract, before December 31, 2023, to acquire renewable natural gas by purchasing it, the purchase price of the renewable natural gas does not exceed the maximum amount, determined in accordance with section 9 (1), in effect in the fiscal year in which the contract for purchase is signed;

(ii) if the public utility enters into a contract, on or after December 31, 2023, to acquire renewable natural gas by purchasing it, the purchase price of the renewable natural gas for each fiscal year of the contract for purchase does not exceed the maximum amount, determined in accordance with section 9 (2), in effect in that fiscal year;

(iii) if the public utility acquires renewable natural gas by producing it, the levelized cost of production reasonably expected by the public utility does not exceed the maximum amount, determined in accordance with section 9 (1), in effect in the fiscal year in which the public utility decides to construct or purchase the production facility,

(b) subject to subsection (4) of this section and section 10, acquires renewable natural gas that, in a calendar year, does not exceed 15% of the total amount, in GJ, of natural gas provided by the public utility to its non-bypass customers in 2019,

(c) acquires and sells or transfers to its customers the environmental attributes of the renewable natural gas it purchases or produces, and

(d) the environmental attributes described in paragraph (c) are retired at the time of sale or transfer to the customers of the public utility.

(4) The amount referred to in subsection (3) (b) does not include renewable natural gas acquired by the public utility that the public utility provides to a customer in accordance with a rate under which the full cost of the following is recovered from the customer:

(a) the acquisition of the renewable natural gas;

(b) the service related to the provision of the renewable natural gas.

[en. B.C. Reg. 125/2023, s. 2; am. B.C. Reg. 125/2024, Sch. 2, s. 3.]

Repealed

3 Repealed. [B.C. Reg. 235/2013, s. 3.]

Prescribed undertaking — electricity purchases for non-integrated areas

3.1 (1) In this section:

"microgrid" means an electricity generation, storage and distribution system owned and operated by the authority for a non-integrated area;

"non-integrated area" means any of the following:

(a) Ah-Sin-Heek (Bella Coola);

(b) Anahim Lake;

(c) Atlin;

(d) Bella Bella;

(e) Dease Lake;

(f) Ehthlateese;

(g) Good Hope Lake;

(h) Hartley Bay;

(i) Kwadacha;

(j) Masset;

(k) Sandspit;

(l) Telegraph Creek;

(m) Toad River;

(n) Tsay Keh Dene.

(2) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility, on or before December 31, 2029, enters into a contract to purchase electricity;

(b) the electricity referred to in paragraph (a) is

(i) produced, at a facility that begins operating on or after January 1, 2024, using a clean or renewable resource as defined in the Act, and

(ii) used to provide service to a non-integrated area;

(c) if the public utility reasonably expects that upgrades are necessary to enable distribution of the electricity referred to in paragraph (a) in a microgrid, the public utility constructs and operates those upgrades.

[en. B.C. Reg. 124/2024, s. 2.]

Prescribed undertaking — electrification

4 (1) In this section:

"benefit", in relation to an undertaking in a class defined in subsection (3) (a) or (b), means all revenues the public utility reasonably expects to earn as a result of implementing the undertaking, less revenues that would have been earned from the supply of undertaking electricity to export markets;

"cost", in relation to an undertaking in a class defined in subsection (3) (a) or (b), means costs the public utility reasonably expects to incur to implement the undertaking, including, without limitation, development and administration costs;

"cost-effective" means that the present value of the benefits of all of the public utility's undertakings within the classes defined in subsection (3) (a) or (b) exceeds the present value of the costs of all of those undertakings when both are calculated using a discount rate equal to the public utility's weighted average cost of capital over a period that ends no later than a specified year;

"natural gas processing plant" means a facility for processing natural gas by removing from it natural gas liquids, sulphur or other substances;

"specified year", in relation to an undertaking within a class defined in subsection (3), means

(a) a year determined by the minister with respect to an identified public utility, or

(b) if the minister does not make a determination for the purposes of paragraph (a), 2030;

"undertaking electricity" means electricity that is provided to customers in British Columbia as a result of an undertaking and is in addition to electricity that would have been provided had the undertaking not been carried out.

(2) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) for the purpose of reducing greenhouse gas emissions in British Columbia, the public utility constructs or operates an electricity transmission or distribution facility, or provides for temporary generation until the completion of the construction of the facility, in northeast British Columbia primarily to provide electricity from the authority to

(i) a producer, as defined in section 1 (1) of the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation, B.C. Reg. 495/92, or

(ii) an owner or operator of a natural gas processing plant;

(b) the public utility reasonably expects, on the date the public utility decides to carry out the undertaking, that the facility will have an in-service date no later than December 31, 2022.

(3) Subject to subsection (4), a public utility's undertaking that is in a class defined in one of the following paragraphs is a prescribed undertaking for the purposes of section 18 of the Act:

(a) a program to encourage the public utility's customers, or persons who may become customers of the public utility, to use electricity, instead of other sources of energy that produce more greenhouse gas emissions, by

(i) educating or training those customers respecting energy use and greenhouse gas emissions, carrying out public awareness campaigns respecting those matters, or providing energy management and audit services, or

(ii) providing funds to those persons to assist in the acquisition, installation or use of equipment that uses or affects the use of electricity;

(b) a program to encourage the public utility's customers, or persons who may become customers of the public utility, to use electricity instead of other sources of energy that produce more greenhouse gas emissions, by

(i) educating, training, providing energy management and audit services to, or carrying out awareness campaigns respecting energy use and greenhouse gas emissions for, or

(ii) providing funds to

persons who

(iii) design, manufacture, sell, install or, in the course of operating a business, provide advice respecting equipment that uses or affects the use of electricity,

(iv) design, construct, manage or, in the course of operating a business, provide advice respecting energy systems in buildings or facilities, or

(v) design, construct or manage district energy systems;

(c) a project, program, contract or expenditure for research and development of technology, or for conducting a pilot project respecting technology, that may enable the public utility's customers to use electricity instead of other sources of energy that produce more greenhouse gas emissions;

(d) a project, program, contract or expenditure supporting a standards-making body in its development of standards respecting

(i) technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions, or

(ii) technologies that affect the use of electricity by other technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions;

(e) a project for the construction, acquisition or extension of a plant or system, that the public utility reasonably expects is necessary to meet the public utility's incremental load-serving obligations arising as a result of an undertaking defined in paragraph (a), (b), (c) or (d), if the public utility reasonably expects any one such project to cost no more than $20 million.

(4) An undertaking is within a class of undertakings defined in paragraph (a) or (b) of subsection (3) only if, at the time the public utility decides to carry out the undertaking, the public utility reasonably expects the undertaking to be cost-effective.

[en. B.C. Reg. 76/2017; am. B.C. Reg. 124/2024, s. 3.]

Prescribed undertaking — electric vehicle charging stations

5 (1) In this section:

"eligible charging site" means a site where one or more eligible charging stations are located;

"eligible fast charging station" means a fast charging station that

(a) is available for use by any member of the public during the site's hours of operation,

(b) does not require users to be members of a charging network, and

(c) is capable of charging electric vehicles of more than one make;

"eligible level 2 charging station" means a charging station that

(a) is a fixed device capable of charging an electric vehicle using 240V,

(b) shares a site with an eligible fast charging station or is on a site owned by any of the follow entities:

(i) a public utility;

(ii) the government;

(iii) the government of Canada;

(iv) an agency of the government or government of Canada;

(v) a government body, as defined in section 1 of the *Financial Administration Act*;

(vi) a local authority, as defined in section 1 of the Schedule to the *Community Charter*;

(c) is available for use by any member of the public during the site's hours of operation,

(d) does not require users to be members of a charging network, and

(e) is capable of charging electric vehicles of more than one make;

"fast charging station" means a fixed device capable of charging an electric vehicle using a direct current;

"limited municipality" means a municipality with a population of 9 000 or more;

"site limit", in relation to a limited municipality, means the number calculated by

(a) dividing the population of the municipality by 9 000, and

(b) if applicable, rounding the quotient up to the nearest whole number.

(2) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility constructs and operates, or purchases and operates, an eligible fast charging station;

(b) the public utility reasonably expects, on the date the public utility decides to construct or purchase an eligible fast charging station, that

(i) the station will come into operation by December 31, 2030, and

(ii) if the station will be located in a limited municipality, the number of eligible charging sites in the municipality on the date the station will come into operation will not exceed the site limit for the municipality on that date;

(c) if an eligible fast charging station comes into operation on or after January 1, 2022, the station uses or is configured to use the Open Charge Point Protocol.

(3) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility constructs and operates, or purchases and operates, an eligible level 2 charging station;

(b) the eligible level 2 charging station conforms or will conform to the Open Charge Point protocol;

(c) the public utility reasonably expects, on the date the public utility decides to construct or purchase the eligible level 2 charging station, that the station will come into operation by December 31, 2030.

[en. B.C. Reg. 139/2020; am. B.C. Regs. 125/2023, s. 3; 175/2023, s. (a); 124/2024, s. 3.]

Prescribed undertaking — zero-emission vehicles, machines and charging infrastructure

5.1 (1) In this section:

"commercial zero-emission charging infrastructure" means

(a) a device or battery capable of charging a zero-emission vehicle or machine using 240V or direct current, or

(b) battery-based storage installed for the purposes of charging a zero-emission vehicle or machine;

"eligible zero-emission vehicle or machine" means

(a) a vehicle or machine that is propelled by electricity or hydrogen from an external source and emits no greenhouse gases at least some of the time while the vehicle or device is being operated, and

(b) the vehicle or machine is one of the following:

(i) a vehicle with a manufacturer's gross vehicle weight rating of more than 4 536 kg;

(ii) a school bus;

(iii) a transit bus;

(iv) a marine vehicle;

(v) a mine haul truck;

(vi) a locomotive;

(vii) an implement of husbandry;

(viii) a farm tractor;

(ix) a logging truck;

(x) an industrial utility vehicle;

"expenditures" includes, except with respect to expenditures on administration and marketing, binding commitments to incur expenditures in the future.

(2) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility provides, on or before March 31, 2030, through an open and competitive application process,

(i) grants or zero-interest loans to persons in British Columbia for the purchase of an eligible zero-emission vehicle or machine to be operated in British Columbia, or

(ii) grants to persons in British Columbia

(A) to implement safety practices, or

(B) to improve maintenance facilities

to meet safety guidelines for operating and maintaining an eligible zero-emission vehicle or machine;

(b) subject to paragraph (c) and subsection (4), total expenditures on the undertaking during the period ending on March 31, 2030 do not exceed $100 million;

(c) total expenditures on grants to persons in British Columbia during the period ending on March 31, 2030 in relation to subsection (2) (a) (ii) do not exceed $6 million;

(d) an expenditure on a grant or zero-interest loan for an eligible zero-emission vehicle or machine does not, in any year of the undertaking, exceed 50% of the difference between the cost of an eligible zero-emission vehicle or machine and the cost of comparable vehicle or machine that uses gasoline or diesel.

(3) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility, before March 31, 2030, enters into a binding commitment to construct or purchase, for the purposes of charging and fuelling eligible zero-emission vehicles or machines, commercial zero-emission charging infrastructure or hydrogen fuelling infrastructure and operate the infrastructure;

(b) subject to subsection (4), total expenditures on the undertaking during the period ending on March 31, 2030 do not exceed $100 million.

(4) The undertakings referred to in subsections (2) and (3) are prescribed undertakings for the purposes of section 18 of the Act only if

(a) the total combined expenditures of the undertakings in this section on administration and marketing during the period ending on March 31, 2030 do not exceed $6 million, and

(b) the total combined expenditures of the undertakings in this section on training, education, studies, pilot projects and standards development during the period ending on March 31, 2030 do not exceed $8 million.

[en. B.C. Reg. 125/2023, s. 4; am. B.C. Reg. 124/2024, s. 3.]

Prescribed undertaking — zero-emission vehicle grants

5.2 (1) In this section:

"adjusted average price", in relation to a fiscal year, means the product of

(a) 0.75, and

(b) the average price of a credit transferred in the calendar year that ends on a date in the fiscal year;

"credit" means a credit under the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* or the *Low Carbon Fuels Act*;

"government corporation" has the same meaning as in section 1 of the *Financial Administration Act*;

"motor vehicle liability policy" has the same meaning as in section 1 of the *Motor Vehicle Act*;

"specified credit" means a credit for the supply of electricity

(a) before January 1, 2022 to charge a vehicle at a residential building, or

(b) on or after January 1, 2022 to charge a vehicle at a residential building that includes fewer than 5 dwelling units;

"zero-emission vehicle" has the same meaning as in section 1 of the *Zero-Emission Vehicles Act*.

(2) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility provides grants for the following who purchase or lease in British Columbia a new zero-emission vehicle that is a light-duty vehicle:

(i) an individual who is resident in British Columbia;

(ii) a person, other than a person excluded under subsection (3), who operates in British Columbia, if the person

(A) registers and licenses the vehicle in accordance with section 3 (1) (a) and (b) of the *Motor Vehicle Act*, and

(B) insures the vehicle under a motor vehicle liability policy that is valid for a period of 12 months beginning on the date the vehicle is delivered to the person and maintains that policy in force for that period;

(b) expenditures on administration and marketing in relation to the undertaking, in each fiscal year of the public utility, do not exceed $2.5 million;

(c) total expenditures on the undertaking, other than expenditures on administration and marketing, do not exceed the amount specified by subsection (4).

(3) For the purposes of subsection (2) (a) (ii), the following are excluded:

(a) the government;

(b) the government of Canada;

(c) the government of a province or territory within Canada;

(d) the government of a jurisdiction outside of Canada;

(e) an agency of a government described in paragraphs (a) to (d);

(f) a government corporation or a corporation that stands in relation to a government described in paragraphs (b) to (d) as a government corporation stands in relation to the government of British Columbia.

(4) For the purposes of subsection (2) (c), the specified amount is the sum of the products, for the fiscal year of the public utility that begins in 2022 and each subsequent fiscal year, of

(a) the number of specified credits transferred away by the public utility in the fiscal year, and

(b) the adjusted average price for the fiscal year.

[en. B.C. Reg. 126/2023, s. 2; am. B.C. Regs. 80/2024; 124/2024, s. 3.]

Prescribed undertaking — hydrogen

6 A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility

(i) produces or purchases hydrogen that is distributed through the natural gas distribution system in British Columbia to the customers of that public utility or of another public utility, or

(ii) purchases hydrogen that is provided to a customer of the public utility other than through the natural gas distribution system in British Columbia and that is to be used by that customer to replace, at least in part, natural gas derived from fossil fuels;

(b) the hydrogen referred to in paragraph (a) meets the criteria described in section 8.2 (3);

(c) the costs incurred by the public utility in producing or purchasing the hydrogen referred to in paragraph (a) meet the following criteria, as applicable:

(i) if the public utility produces hydrogen, the levelized cost of production reasonably expected by the public utility does not exceed the maximum amount, determined in accordance with section 9 (1), in effect in the fiscal year in which the public utility decides to construct or purchase the production facility;

(ii) if the public utility purchases the hydrogen for distribution through the natural gas distribution system in British Columbia, the purchase price of the hydrogen for each fiscal year of the contract for purchase does not exceed the maximum amount, determined in accordance with section 9 (2), in effect in that fiscal year;

(iii) if the public utility purchases the hydrogen to provide it to a customer by a means other than the natural gas distribution system in British Columbia, the sum of the purchase price of the hydrogen and the costs of distribution reasonably expected by the public utility does not exceed, for each fiscal year of the contract for purchase, the maximum amount, determined in accordance with section 9 (2), in effect in that fiscal year;

(d) subject to section 10, the public utility purchases hydrogen in an amount that, in a calendar year, does not exceed 5 PJ;

(e) the public utility acquires and sells or transfers to its customers the environmental attributes of the hydrogen it purchases or produces;

(f) the environmental attributes described in paragraph (e) are retired at the time of sale or transfer to the customers of the public utility.

[en. B.C. Reg. 134/2021, s. 3; am. B.C. Regs. 124/2024, s. 3; 125/2024, Sch. 2, s. 4.]

Prescribed undertaking — synthesis gas

7 (1) In this section, **"biomass"** means non-fossilized plants or parts of plants, animal waste or any product made of either of these, other than a fuel product, and includes wood and wood products, agricultural residues and wastes, biologically derived organic matter found in municipal and industrial wastes, black liquor and kraft pulp fibres.

(2) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility purchases and distributes synthesis gas that meets the criteria described in section 8.2 (3) and that is

(i) derived from biomass,

(ii) to be used by a customer to replace, at least in part, natural gas derived primarily from fossil fuels, and

(iii) to be used at the site at which it is produced;

(b) the sum of the purchase price of the synthesis gas referred to in paragraph (a) and the costs of distribution reasonably expected by the public utility does not exceed, for each fiscal year of the contract for purchase, the maximum amount, determined in accordance with section 9 (2), in effect in that fiscal year;

(c) subject to section 10, the public utility purchases the synthesis gas in an amount that, in a calendar year, does not exceed 15% of the total amount of natural gas, in GJ, provided by the public utility to its non-bypass customers in 2019;

(d) the public utility acquires and sells or transfers to its customers the environmental attributes of the synthesis gas it purchases;

(e) the environmental attributes described in paragraph (d) are retired at the time of sale or transfer to the customers of the public utility.

(3) The costs of distribution described in subsection (2) (b) are limited to the costs of the construction and operation, at the site at which the synthesis gas is produced, of meters and pipelines associated with the undertaking.

[en. B.C. Reg. 134/2021, s. 3; am. B.C. Regs. 124/2024, s. 3; 125/2024, Sch. 2, s. 5.]

Prescribed undertaking — lignin

8 (1) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility purchases and distributes lignin that meets the criteria described in section 8.2 (3) and that is

(i) derived from black liquor,

(ii) to be used by a customer to replace, at least in part, natural gas derived from fossil fuels, and

(iii) to be used at the site at which it is produced;

(b) the sum of the purchase price of the lignin referred to in paragraph (a) and the costs of distribution reasonably expected by the public utility does not exceed, for each fiscal year of the contract for purchase, the maximum amount, determined in accordance with section 9 (2), in effect in that fiscal year;

(c) subject to section 10, the public utility purchases the lignin in an amount that, in a calendar year, does not exceed 15% of the total amount of natural gas, in GJ, provided by the public utility to its non-bypass customers in 2019;

(d) the public utility acquires and sells or transfers to its customers the environmental attributes of the lignin it purchases;

(e) the environmental attributes described in paragraph (d) are retired at the time of sale or transfer to the customers of the public utility.

(2) The costs of distribution described in subsection (1) (b) are limited to the costs of the construction and operation, at the site at which the lignin is produced, of meters and pipelines associated with the undertaking.

[en. B.C. Reg. 134/2021, s. 3; am. B.C. Regs. 124/2024, s. 3; 125/2024, Sch. 2, s. 6.]

Prescribed undertaking — grants and loans for synthesis gas or lignin

8.1 (1) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility purchases and distributes synthesis gas or lignin that meets the criteria described in section 7 (2) (a) or 8 (1) (a), as applicable;

(b) the purchase described in paragraph (a) is from a customer of the public utility to whom the public utility provides a grant or zero-interest loan to cover the costs that the customer will incur to convert facilities, or to purchase equipment for the purpose of producing the synthesis gas or lignin to be sold to the public utility;

(c) the sum of the following costs incurred by the public utility does not exceed, for each fiscal year of the contract for purchase of the synthesis gas or lignin, the maximum amount, determined in accordance with section 9 (2), in effect in that fiscal year:

(i) the costs incurred by the public utility to provide the grant or zero-interest loan;

(ii) the purchase price of the synthesis gas or lignin;

(iii) the costs of distribution reasonably expected by the public utility;

(d) subject to section 10, the total amount of synthesis gas or lignin the public utility purchases, in a calendar year, from all customers described in paragraph (b) does not exceed 5 PJ;

(e) the public utility acquires and sells or transfers to its customers the environmental attributes of the synthesis gas or lignin it purchases;

(f) the environmental attributes described in paragraph (e) are retired at the time of sale or transfer to the customers of the public utility.

(2) The costs of distribution described in subsection (1) (c) (iii) are limited to the costs of the construction and operation, at the site at which the synthesis gas or lignin is produced, of meters and pipelines associated with the undertaking.

[en. B.C. Reg. 125/2024, Sch. 2, s. 7.]

Carbon intensity

8.2 (1) In this section:

"carbon dioxide equivalent" means the mass of carbon dioxide that would produce the same global warming impact as a given mass of another greenhouse gas, as determined in accordance with section 2 of the Low Carbon Fuels (Technical) Regulation;

"carbon intensity" has the same meaning as in section 1 of the *Low Carbon Fuels Act*;

"gCO2e/MJ" means grams of carbon dioxide equivalent per megajoule of energy;

"GHGenius" means the spreadsheet model of that name designed for analyzing the components attributable to the stages of the life cycles of fuels for the purpose of determining all greenhouse gases resulting from the production and use of those fuels;

"greenhouse gas" has the same meaning as in section 1 of the *Climate Change Accountability Act*;

"higher heating value" means a measure of heat content based on the gross energy content of a combustible fuel;

"ISO" means the International Organization for Standardization;

"ISO 14044:2006" means ISO standard entitled *Environmental management — Life cycle assessment — Requirements and guidelines*, published in July 2006;

"reference date" means the date

(a) a public utility decides to construct or purchase a production facility for the purposes of section 2.2 (3) (a) (iii), or

(b) a contract for purchase is signed for the purposes of section 2.2 (3) (a) (ii), 6, 7, 8 or 8.1;

"verification body" means a person that is accredited as a verification body by, and is in good standing with, a member of the International Accreditation Forum.

(2) For the purposes of the definition of "carbon intensity" in subsection (1),

(a) greenhouse gas emissions attributable to fuel are the total greenhouse gas emissions from all stages in the life cycle of the fuel, as calculated using the most recent version of GHGenius available on the reference date, and

(b) the expected use of the fuel is for transportation, unless the public utility reasonably expects that the fuel will be used for another purpose.

(3) For the purposes of sections 2.2 (3) (a), 6 (b), 7 (2) (a), 8 (1) (a) and 8.1 (1) (a), an undertaking is a prescribed undertaking only if the renewable natural gas, hydrogen, synthesis gas or lignin, as the case may be, that is acquired by the public utility has a carbon intensity that does not exceed 30.8 gCO2e/MJ

(a) as forecast in accordance with subsection (4),

(b) as determined in accordance with subsection (5), and

(c) as verified in accordance with subsection (6).

(4) The carbon intensity described in subsection (3) must be forecast

(a) within a reasonable time before the reference date,

(b) for the entire duration of the undertaking, and

(c) based on higher heating value.

(5) The carbon intensity described in subsection (3) must,

(a) during the undertaking, be determined every 3 years, or at any other interval specified by the commission, and

(b) at the conclusion of the undertaking, be determined for the entire duration of the undertaking.

(6) The carbon intensity forecast or determined for the purposes of subsection (3) is verified if the public utility provides to the commission a statement by a verification body that

(a) attests to the fair and accurate representation of the data used to forecast or determine the carbon intensity, and

(b) is prepared in accordance with ISO 14044:2006.

(7) If, in a single undertaking, a public utility purchases renewable natural gas, hydrogen, synthesis gas or lignin that is produced at multiple production facilities, each delivery of the renewable natural gas, hydrogen, synthesis gas or lignin produced at each facility must meet the criteria described in subsection (3).

[en. B.C. Reg. 125/2024, Sch. 2, s. 7.]

Maximum amount for costs

9 (1) For the purposes of sections 2.2 (3) (a) (i) and (iii) and 6 (c) (i),

(a) the maximum amount in effect in the 2021/2022 fiscal year is $31 per GJ, and

(b) for fiscal years subsequent to the 2021/2022 fiscal year, the maximum amount is calculated on April 1 of each year by multiplying

(i) the maximum amount in effect in the immediately preceding fiscal year, and

(ii) the sum of

(A) 1, and

(B) the annual percentage change for the previous calendar year.

(2) For the purposes of sections 2.2 (3) (a) (ii), 6 (c) (ii) and (iii), 7 (2) (b), 8 (1) (b) and 8.1 (1) (c),

(a) the maximum amount for the first year of the contract for purchase is calculated on April 1 of that year in accordance with subsection (1), and

(b) the maximum amount for subsequent years of the contract for purchase is calculated on April 1 of each year by multiplying

(i) the maximum amount for the contract in effect in the immediately preceding fiscal year, and

(ii) the sum of

(A) 1, and

(B) half of the annual percentage change for the previous calendar year.

[en. B.C. Reg. 125/2024, Sch. 2, s. 8.]

Aggregate amount if multiple undertakings

10 If a public utility does 2 or more of the following:

(a) acquires renewable natural gas in accordance with section 2.2 (3);

(b) produces or purchases hydrogen in accordance with section 6;

(c) purchases synthesis gas in accordance with section 7;

(d) purchases lignin in accordance with subsection 8;

(e) purchases synthesis gas or lignin from customers to which it has provided grants or zero-interest loans in accordance with section 8.1, the aggregate amount of all products must not exceed 15% of the total amount of natural gas, in GJ, provided by the public utility to its non-bypass customers in 2019.

[en. B.C. Reg. 134/2021, s. 3; am. B.C. Regs. 125/2023, s. 6; 175/2023, s. (c); 125/2024, Sch. 2, s. 9.]

[Provisions relevant to the enactment of this regulation: *Clean Energy Act*, S.B.C. 2010, c. 22, s. 35.]
