THE CORPORATION OF THE TOWNSHIP OF PUSLINCH
SEPTEMBER 16, 2026 COUNCIL MEETING
VIRTUAL MEETING BY ELECTRONIC PARTICIPATION &
IN-PERSON AT THE MUNICIPAL OFFICE –
7404 WELLINGTON RD 34, PUSLINCH

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A G E N D A ADDENDUM #2

DATE: September 16, 2026
REGULAR MEETING: 9:00 A.M.
CLOSED MEETING: Directly following Section 13 Announcements

Addendum #2

7.1.1 9:05 A.M. Delegation by Ilham Abdulkadir regarding item 10.5 Notice of Permit to Take Water 101 Brock Rd S

9.4.1 Presentation Added - Puslinch Development Design Guidelines - A Framework for Renewal, Reinvestment and Community Building

≠ Denotes resolution prepared

1. Call the Meeting to Order

2. Roll Call

3. Moment of Reflection

4. Confirmation of the Agenda ≠

5. Disclosure of Pecuniary Interest & the General Nature Thereof

6. Consent Agenda ≠

Consent Agenda items are considered routine in nature and are voted on collectively. Any member of Council may request one or more items be removed from the Consent Agenda for separate action.

6.1 Adoption and Receipt of the Minutes of the Previous Council and Committee Meetings
- 6.1.1 August 26, 2026 Council Meeting Minutes
- 6.1.2 January 15, 2026 Joint Recreation and Community Wellness and Youth Advisory Committee Meeting Minutes

6.2 AMO Policy Update - Property Tax Reassessment, National Housing Strategy, Provincial Data Centre
6.3 AMO Policy Update - Key takeaways from the 2026 AMO Conference
6.4 Office of the Solicitor General regarding Update on OPP Municipal Policing Costs for 2027
6.5 Proposal for Regulations to Establish a Standardized Municipal Code of Conduct Summary
6.6 Enbridge Gas 2025 Utility Earnings and Disposition of Deferral and Variance Accounts
6.7 July 2026 Grand River Conservation Authority Summary of General Meeting
6.8 August 2026 Grand River Conservation Authority Summary of General Meeting
6.9 Village of Sunridge resolution regarding Public Sector Salary Disclosure
6.10 City of Hamilton Notice of Adoption of City Improvement Plan
6.11 September 2026 Puslinch Profile
6.12 August 2026 Monthly Monitoring Report – Licence #5738
6.13 Ontario Provincial Conservation Agency CA board governance and 2026 municipal election

Recommendation:
That the Consent Agenda items listed for the September 16, 2026, Council meeting be received for information.

7. Delegations ≠

7.1 Specific Interest (Items Listed on the Meeting Agenda)
- 7.1.1 <u>9:05 A.M. Delegation by Ilham Abdulkadir regarding item 10.5 Notice of Permit to Take Water 101 Brock Rd S</u>

Recommendation:
That the delegation by Ilham Abdulkadir regarding item 10.5 Notice of Permit to Take Water 101 Brock Rd S be received for information.

7.2 General Interest (Items Not Listed on the Meeting Agenda)

7.2.1 None

8. Public Meeting

8.1 September 16, 2026 at 6:30 P.M. Public Information Meeting held in-person at the Municipal Office (7404 Wellington Road 34) and by electronic participation through Zoom regarding 2027 User Fees and Charges By-law

8.2 September 16, 2026 at 7:30 P.M. Public Open House held in-person at the Puslinch Community Centre (23 Brock Road South) regarding Recreation and Parks Master Plan

8.3 October 7, 2026 at 6:00 P.M. Public Information Meeting held in-person at the in-person at the Municipal Office (7404 Wellington Road 34) and by electronic participation through Zoom regarding Zoning By-law Amendment Application D14-SNY – 339 Downey Road

8.4 October 7, 2026 at 6:00 P.M. Public Information Meeting held in-person at in-person at the Municipal Office (7404 Wellington Road 34) and by electronic participation through Zoom regarding Zoning By-law Amendment Application D14-KUK – Arkell Subdivision

8.5 October 7, 2026 at 6:00 P.M. Public Information Meeting held in-person at the in-person at the Municipal Office (7404 Wellington Road 34) and by electronic participation through Zoom regarding Zoning By-law Amendment Application D14-HAS – 7248 Gore Road (Emerald Lake)

9. Reports ≠

9.1 Puslinch Fire and Rescue Services

9.1.1 Report FIR-2026-004 Puslinch Fire and Rescue Services 2nd Quarter Report (Circulated under separate cover)

Recommendation:
That Report FIR-2026-004 Puslinch Fire and Rescue Services 2nd Quarter Report be received for information.

9.2 Finance Department

9.2.1 Report FIN-2026-021 2027 Proposed User Fees and Charges (Circulated under separate cover)

Recommendation:
That Report FIN-2026-021 entitled 2027 Proposed User Fees and Charges be received; and

That the Alcohol Risk Management Policy be brought forward to Council for consideration based on the recommendations outlined in this Report regarding security requirements and facility capacity limits; and

That Council direct staff to proceed with holding a Public Information Meeting on September 16, 2026 at 6:30 p.m. to obtain public input on the proposed User Fees and Charges By-law as outlined in Schedule A to Report FIN-2026-021; and

That staff report back to Council with the results of the public engagement process and Council's feedback into the final proposed 2027 User Fees and Charges By-law for consideration.

9.2.2 Report FIN-2026-022 2025 Commodity Price Hedging Agreements

Recommendation:
That Report FIN-2026-022 entitled 2025 Commodity Price Hedging Agreements be received; and

That Council accepts the Treasurer's statement that based on the information supplied by Local Authority Services (LAS), all commodity price hedging agreements are consistent with the Township's statement of policies and goals related to the use of financial agreements to address commodity pricing and costs as outlined in Schedule A to Report FIN-2026-022.

9.2.3 Report FIN-2026-024 Municipal Performance Measurement Program Report for 2025

Recommendation:
That Report FIN-2026-024 entitled Municipal Performance Measurement Program Report for 2025 be received.

9.3 Office of the CAO

9.3.1 Report CAO-2026-009 Temporary Use Conformity Request (Circulated under separate cover)

Recommendation:
That Report CAO-2026-012 entitled Temporary Use Conformity Request be received for information; and

That Council request that the County of Wellington amend Section 13.4 of the Wellington County Official Plan to ensure that the temporary use provisions accurately reflect the authority provided under Section 39 of the Planning Act, through whatever administrative or other process the County considers appropriate, having regard for the timeliness of the correction; and

That should the County determine that the correction cannot be made through an administrative process, the County advise the Township accordingly, at which time the Township will commence the appropriate Official Plan Amendment process.

9.4 Corporate Services Department

9.4.1 9:45 A.M. Presentation Added - Puslinch Development Design Guidelines - A Framework for Renewal, Reinvestment and Community Building

Recommendation:
That the Puslinch Development Design Guidelines - A Framework for Renewal, Reinvestment and Community Building be received for information; and,

That Council approves the Puslinch Development Design Guidelines as [presented/amended].

9.5 Building Department

9.5.1 None

9.6 Public Works Department

9.6.1 None

9.7 Community Services and Human Resources Department

9.7.1 10:45 A.M. Draft Puslinch Recreation and Parks Master Plan

Recommendation:
That the Draft Puslinch Recreation and Parks Master Plan be received for information.

10. Correspondence ≠

10.1 9:25 A.M. Presentation by Sonny Karunakaran regarding Wellington Waterloo Power Line Project Hydro One ≠

Recommendation:
That Correspondence Item 10.1 entitled Presentation by Sonny Karunakaran regarding Wellington Waterloo Power Line Project Hydro One be received for information.

10.2 10:15 A.M. Response to MECP Comments regarding Glen Christie Quarry Permit to Take Water ≠
(Circulated under separate cover)

Recommendation:
That Correspondence Item 10.2 entitled Response to MECP Comments regarding Glen Christie Quarry Permit to Take Water be received for information; and,

That Council direct staff to submit the comments from the Township's Hydrogeologist and ecologist as [presented/amended].

10.3 1:00 P.M. Presentation by Karen Medeiro regarding Wellington County O.P.P. Detachment Board Report ≠

Recommendation:
That Correspondence Item 10.3 entitled Presentation by Karen Medeiros regarding Wellington County OPP Detachment Board Report be received for information.

10.4 IESO South and Central Final Bulk Plan ≠

Recommendation:
That Correspondence Item 10.4 entitled IESO South and Central Final Bulk Plan be received for information.

10.5 9:15 A.M. Notice Permit to Take Water 101 Brock Rd S - White Wolf Property Management Inc. ≠

Recommendation:
That Correspondence Item 10.5 entitled Notice Permit to Take Water 101 Brock Rd S - White Wolf Property Management Inc be received for information.

10.6 Hamilton Conservation Authority 2027 Draft Budget ≠

Recommendation:
That Correspondence Item 10.6 entitled Hamilton Conservation Authority 2027 Draft Budget be received for information.

11. Council reports
    11.1 Mayor's Updates
    11.2 Council Member Reports (verbal or written updates from members who sit on boards/committees)

12. By-laws ≠
    12.1 First, Second and Third Reading
        12.1.1 BL2026-057 Joint Audit Compliance Committee Appointment Update
        12.1.2 BL2026-058 Remuneration By-law for Staff
        (Circulated under separate cover)

Recommendation:
That the following by-laws be taken as read three times and finally passed in Open Council:

By-law 2026-057 Being a By-law being a by-law to appoint Members to the Wellington County Joint Municipal Election Compliance Audit Committee.

By-law 2026-058 Being a By-law being a by-law to establish the rates of remuneration to Staff of the Corporation of the Township of Puslinch.

13. Announcements

14. Closed Session - Pursuant to Section 239 Subsection (2) of the Municipal Act, 2001
    14.1 None

15. Business Arising from Closed Session

16. Notice of Motion

17. New Business

18. Confirmatory By-law ≠
    18.1 BL2026-059 Confirm By-law – September 16, 2026

Recommendation:
That the following by-law be taken as read three times and finally passed in open Council:
By-law 2026-059 being a by-law to confirm the proceeding of Council for the Corporation of the Township of Puslinch at its meeting held on the 16th day of September 2026.

19. Adjournment ≠

THE CORPORATION OF THE TOWNSHIP OF PUSLINCH
AUGUST 26, 2026 COUNCIL MEETING
VIRTUAL MEETING BY ELECTRONIC PARTICIPATION
& IN-PERSON AT 7404 WELLINGTON RD 34, PUSLINCH

MINUTES

DATE: August 26, 2026
CLOSED MEETING: Directly following Item 13. Announcements
COUNCIL MEETING: 9:00 A.M.

The August 26, 2026 Council Meeting was held on the above date and called to order at 9:00 a.m. via electronic participation and in-person at 7404 Wellington Rd, Puslinch.

1. CALL THE MEETING TO ORDER

2. ROLL CALL

ATTENDANCE:

Councillor Sara Bailey
Councillor Russel Hurst
Councillor Jessica Goyda
Councillor John Sepulis
Mayor James Seeley

STAFF IN ATTENDANCE:

1. Courtenay Hoytfox, CAO
2. Justine Brotherston, Director of Corporate Services / Municipal Clerk
3. Laura Emery, Manager of Corporate Services / Deputy Clerk
4. Michael Chant, Fire Chief
5. Mary Hasan, Director of Finance/Treasurer
6. Andrew Hartholt, CBO
7. Sarah Huether, Director of Community Services & Human Resources

3. MOMENT OF REFLECTION

4. CONFIRMATION OF THE AGENDA

Resolution No. 2026-252: Moved by Councillor Bailey and Seconded by Councillor Hurst

That Council approves the August 26, 2026 Agenda and Addendum as circulated; and

That Council defer the presentation by Karen Medeiros regarding Wellington County OPP Detachment Board 2025 Annual Report to a future Council meeting; and

That Council approves the addition to the agenda as follows:

Consent Item 6.1.6 Questions received from Council seeking additional information and the corresponding responses provided by staff regarding the August 26, 2026 Council agenda

CARRIED

5. DISCLOSURE OF PECUNIARY INTEREST & THE GENERAL NATURE THEREOF:

Mayor Seeley declared a potential pecuniary interest related to item 14.4.2.

6. CONSENT AGENDA

6.1. Adoption and Receipt of the Minutes of the Previous Council and Committee Meetings
- 6.1.1. July 15, 2026 Council Meeting Minutes
- 6.1.2. July 14, 2026 Planning and Development Advisory Committee Minutes
- 6.1.3. June 17, 2026 Public Information Meeting Minutes
- 6.1.4. June 9, 2026 Committee of Adjustment Minutes
- 6.1.5. June 9, 2026 Planning and Development Advisory Committee Minutes
- 6.1.6. Questions received from Council seeking additional information and the corresponding responses provided by staff regarding the August 26, 2026 Council agenda

6.2. AMO Policy Update Property Tax Reassessment, National Housing Strategy Renewal, Provincial Data Centre Playbook

6.3. Ontario Provincial Conservation Agency regarding Conservation Authority Transition Committee Members

6.4. Hamilton Conservation Authority acquires more than 200 acres of provincially significant natural lands

6.5. South Huron Support Resolution regarding Heads and Beds Payment in-lieu of Taxes Program

6.6. Township of Alnwick Haldimand Council Resolution regarding Beacons of Light British Home Children & Child Migrants

6.7. Municipality of Central Manitoulin Support Resolution regarding Support for Ontario Health Care System

6.8. Municipality of Wawa Support Resolution regarding Support for Ontario Health Care System

6.9. Township of South-West Oxford Resolution regarding Request for Changes to the Pesticides Act

6.10. Huron OPP Detachment Board requesting Letter of Support for Traffic Calming and Speeding Mitigation Techniques

6.11. Municipality of Wawa Support Resolution regarding Traffic Calming and Speed Mitigation Initiatives

6.12. Township of Clearview Council Resolution regarding Traffic Calming & Speeding Mitigation Initiatives

6.13. ERO 026-0312 Decision Proposed Changes to Support Standardizing of Parkland Requirements Under the Planning Act

6.14. July 2026 Monthly Monitoring Report - #5738

6.15. June 2026 Monthly Monitoring Report - #5738

6.16. May 7, 2026 County of Wellington Accessibility Advisory Committee Minutes

6.17. TAPMO Newsletter July 2026

Resolution No. 2026-253: Moved by Councillor Hurst and
Seconded by Councillor Sepulis

That the Consent Agenda items listed for August 26, 2026 Council meeting be received for information with the exception of 6.10, 6.11 ,6.12, and 6.17.

CARRIED

Resolution No. 2026-254: Moved by Councillor Bailey and
Seconded by Councillor Hurst

That the Consent Agenda items 6.10, 6.11, and 6.12 be received for information; and,

Whereas Council Supports the resolutions from the Huron OPP Detachment Board, Municipality of Wawa and Township of Clearview regarding Traffic Calming and Speeding Mitigation initiatives;

That Council direct staff to send a support resolution accordingly.

CARRIED

Resolution No. 2026-255: Moved by Councillor Sepulis and
Seconded by Councillor Bailey

That the Consent Agenda item 6.17 be received for information; and

Whereas the Aggregate Resources Act, R.S.O. (ARA) governs the licensing and regulation of aggregate pits and quarries in Ontario;

And Whereas the Planning Act and the Provincial Planning Statement establish the policy framework for land use planning in Ontario and recognize aggregate extraction as an interim land use, with defined expectations for progressive rehabilitation and ultimate transition to an appropriate end use;

And Whereas the Ministry of Natural Resources (MNR) has provided written clarification confirming that where a licensed site's site plan expressly permits the importation of aggregate material from other licensed sites in Ontario:

- **such imported material may be brought to the site;**
- **such imported material does not count toward the site's annual licensed tonnage limit; and**
- **where processing and blending are permitted in the site plan, imported material may be processed or blended for the duration of the licence;**

And Whereas under the Ministry's current interpretation, imported aggregate material that is processed or blended is not currently subject to annual licensed tonnage limits or associated TOARC levy payments;

And Whereas this interpretation may enable a licensed site to function as an ongoing industrial processing and blending facility, including in circumstances where on-site extraction has ceased or is winding down;

And Whereas municipalities may experience increased truck traffic, road deterioration, noise, and dust impacts where processing and blending continue independent of extraction;

And Whereas such an outcome may not align with the planning principle that aggregate operations are intended to be interim land uses and may have implications for municipal land use planning, infrastructure management, environmental oversight, and long-term rehabilitation objectives;

And Whereas clarity and consistency between the implementation of the ARA and the provincial land use planning framework are essential to maintaining policy coherence and municipal planning certainty;

Now Therefore Be It Resolved That the Council of Township of Puslinch respectfully requests that the MNR reconsider its current interpretation respecting the importation, processing, and lending of aggregate material under the ARA, particularly where such interpretation:

- **permits unlimited importation of aggregate material from other licensed sites;**
- **excludes imported and processed materials from annual licensed tonnage limits; and**
- **allows processing and blending activities to continue for the duration of the licence without regard to the interim nature of aggregate extraction contemplated under provincial planning policy; and,**

That the Province clarify how the interpretation and administration of the ARA will be aligned with the *Planning Act* and Provincial Planning Statement, including the recognition of aggregate extraction as an interim land use with defined rehabilitation and transition objectives;

That the Province provide guidance on how imported and processed aggregate materials are to be considered in relation to licensed tonnage limits, rehabilitation timelines, and the interim land use intent of aggregate operations;

That the Province consult with municipalities prior to finalizing any policy, regulatory, or interpretive direction related to importation, processing, blending, and tonnage calculations under the ARA and importantly any TOARC regulatory reform;

Further be it resolved that the Council of the Township of Puslinch supports TAPMO's call for policy clarification regarding importation, processing and blending under the Aggregate Resources Act; and

Be It Further Resolved That a copy of this resolution be forwarded to the Minister of Natural Resources, the Minister of Municipal Affairs and Housing, the Association of Municipalities of Ontario (AMO), the Top Aggregate Producing Municipalities of Ontario (TAPMO), MPP Joseph Racinsky and all Ontario Municipalities.

CARRIED

7. DELEGATIONS

7.1. Specific Interest (Items Listed on the Meeting Agenda)

7.1.1. Delegation by Neal DeRuyter and Andreanne Simard regarding 9.4.1 Zoning By-law Amendment Application Request for Council to Deem Complete 4454 Victoria Road South

Resolution No. 2026-256: Moved by Councillor Sepulis and Seconded by Councillor Hurst

That the delegation by Neal DeRuyter regarding Zoning By-law Amendment Application Request for Council to Deem Complete 4454 Victoria Road South be received for information.

CARRIED

7.1.2. Delegation by John McNie regarding 10.4 Wellington Waterloo Power Line Project Notice of Commencement

Resolution No. 2026-257: Moved by Councillor Hurst and Seconded by Councillor Goyda

That the delegation by John McNie regarding the Wellington Waterloo Power Line Project Notice of Commencement be received for information.

CARRIED

7.2. General Interest (Items Not Listed on the Meeting Agenda)

7.2.1. Delegation by Manu Kaushik regarding request for a Letter of Support for Diagnostic Ultrasound Services in Puslinch

Resolution No. 2026-258: Moved by Councillor Bailey and Seconded by Councillor Goyda

That the delegation by Manu Kaushik regarding request for a Letter of Support for Diagnostic Ultrasound Services in Puslinch be received for information; and

That Council provide a letter of support for Manu Kaushik for Morriston Medical Centre to support Diagnostic Ultrasound Services in Puslinch.

CARRIED

7.2.2.Delegation by Karen Slade and Bill Knetsch regarding safety of Calfass Road

Resolution No. 2026-259: Moved by Councillor Hurst and
Seconded by Councillor Bailey

That the delegation by Karen Slade and Bill Knetsch regarding safety of Calfass Road be received for information; and

That Council direct staff to report back on traffic calming, emergency detour, signage, speed mitigation measures, and other requests outlined in the presentation materials, for Calfass Road as part of the 2027 budget process; and

That Council direct staff to continue to advocate for traffic mitigation measures at Highway 6 and Concession Rd 1 intersection with the MTO; and

That Council direct staff to investigate further signage near Concession Rd 2 and Concession Rd 7 better directing traffic to the established detour route on Wellington Rd 34; and

That Council direct staff to pass the Cultural Heritage Designation request to the Heritage Advisory Committee for review and recommendation to Council.

CARRIED

8. PUBLIC MEETINGS

8.1. September 16, 2026 at 6:30 P.M. Public Information Meeting held in-person at the Municipal Office (7404 Wellington Road 34) and by electronic participation through Zoom regarding 2027 User Fees and Charges By-law

8.2. September 16, 2026 at 7:30 P.M. Public Open House held in-person at the Puslinch Community Centre (23 Brock Road South) regarding Recreation and Parks Master Plan

9. REPORTS

9.1. **Puslinch Fire and Rescue Services**

9.1.1.None

9.2. **Finance Department**

9.2.1.Report FIN-2026-020 2027 Proposed Cost of Living Adjustment

Resolution No. 2026-260: Moved by Councillor Sepulis and
Seconded by Councillor Hurst

That report FIN-2026-020 entitled 2027 Proposed Cost of Living Adjustment be received; and,

That Council approve a Cost-of-Living Adjustment of 2.60% effective January 1, 2027; and,

That Council consider, through the 2027 budget process, allocating funding equivalent to an additional 1% Cost-of-Living Adjustment to a discretionary reserve for the 2028 compensation and benefits review.

CARRIED

9.2.2.Report FIN-2026-023 - Second Quarter Financial Report – 2026

Resolution No. 2026-261: Moved by Councillor Sepulis and
Seconded by Councillor Goyda

That Report FIN-2026-023 entitled Second Quarter Financial Report – 2026 be received for information; and,

That the Budget Development and Control Policy be amended to discontinue the standalone third-quarter financial report and require financial reporting following the first, second and fourth quarters of each year, recognizing that updated year-to-date financial information is provided to Council through the annual operating budget process, as outlined in this Report.

CARRIED

Council Recess 11:18am to 11:21am

Councillor Sara Bailey
Councillor Russel Hurst
Councillor Jessica Goyda
Councillor John Sepulis
Mayor James Seeley

9.3. **Office of the CAO**

9.3.1.**Report CAO-2026-008 Site Alteration By-law Proposed Amendments**

Resolution No. 2026-262: Moved by Councillor Bailey and
Seconded by Councillor Hurst

That Report CAO-2026-008 entitled Site Alteration By-law Proposed Amendments be received; and

That Council direct staff to incorporate Council's feedback in addition to the legal review and technical feedback, into the next draft of the by-law.

CARRIED

9.4. **Corporate Services Department**

9.4.1. Report COR-2026-039 Zoning By-law Amendment Application Request for Council to Deem Complete 4454 Victoria Road South (D14-CBM)

Resolution No. 2026-263: Moved by Councillor Sepulis and
Seconded by Councillor Goyda

That report COR-2026-039 entitled Request for Council to Deem Zoning By-law Amendment Application Complete – D14/CBM (4454 Victoria Rd S) be received for information; and,

Whereas the Township's subconsultants have reviewed the application and have raised no concerns regarding deeming the application complete, confirming that all required studies have been provided; and

Whereas the Township acknowledges that deeming the application complete does not imply any judgment or position on the merits of the application; and

Whereas the application is still undergoing ongoing review, including public consultation and further detailed analysis, with a formal position on the matter to be presented following the completion of these processes; and

Whereas the Township expects that all concerns raised by its professional consultants during the review process will be adequately addressed to the satisfaction of the Township;

Therefore Be It Resolved that Council deems the application D14/CBM to be complete in accordance with the Planning Act; and

That Council acknowledges that the deeming of the application as complete is procedural and does not constitute a decision on the merits of the application, which will be determined following the full review process, including public consultation and the final analysis of all relevant information; and

That Council expects the applicant to adequately address concerns raised by the Township's professional consultants in accordance with the Planning Act and Township's policies and standards; and,

That staff be directed to proceed with notice in accordance with Section 3 and Section 5 of O. Reg. 545/06 of the Planning Act, 1990; and

That Council's feedback be forwarded to the Township's review team for consideration as part of the technical review of the application.

CARRIED

9.4.2. Report COR-2026-046 Zoning By-law Amendment Application Request for Council to Deem Complete 4078 Highway 6 (D14-WAL)

Resolution No. 2026-264: Moved by Councillor Sepulis and
Seconded by Councillor Goyda

That report COR-2026-046 entitled Request for Council to Deem Zoning By-law Amendment Application Complete – D14/WAL (4078 Highway 6) be received for information; and,

Whereas the Township's subconsultants have reviewed the application and have raised no concerns regarding deeming the application complete, confirming that all required studies have been provided; and

Whereas the Township acknowledges that deeming the application complete does not imply any judgment or position on the merits of the application; and

Whereas the application is still undergoing ongoing review, including public consultation and further detailed analysis, with a formal position on the matter to be presented following the completion of these processes; and

Whereas the Township expects that all concerns raised by its professional consultants during the review process will be adequately addressed to the satisfaction of the Township;

Therefore Be It Resolved that Council deems the application D14/WAL to be complete in accordance with the Planning Act; and

That Council acknowledges that the deeming of the application as complete is procedural and does not constitute a decision on the merits of the application, which will be determined following the full review process, including public consultation and the final analysis of all relevant information; and

That Council expects the applicant to adequately address concerns raised by the Township's professional consultants in accordance with the Planning Act and Township's policies and standards; and,

That staff be directed to proceed with notice in accordance with Section 3 and Section 5 of O. Reg. 545/06 of the Planning Act, 1990.

CARRIED

9.4.3. Report COR-2026-047 Zoning By-law Amendment Application Request for Council to Deem Complete 7248 Gore Road (D14-HAS)

Resolution No. 2026-265: Moved by Councillor Bailey and
Seconded by Councillor Hurst

That report COR-2026-047 entitled Request for Council to Deem Zoning By-law Amendment Application Complete – D14/HAS (7248 Gore Rd) be received for information; and,

Whereas the Township's subconsultants have reviewed the application and have raised no concerns regarding deeming the application complete, confirming that all required studies have been provided; and

Whereas the Township acknowledges that deeming the application complete does not imply any judgment or position on the merits of the application; and

Whereas the application is still undergoing ongoing review, including public consultation and further detailed analysis, with a formal position on the matter to be presented following the completion of these processes; and

Whereas the Township expects that all concerns raised by its professional consultants during the review process will be adequately addressed to the satisfaction of the Township;

Therefore Be It Resolved that Council deems the application D14/HAS to be complete in accordance with the Planning Act; and

That Council acknowledges that the deeming of the application as complete is procedural and does not constitute a decision on the merits of the application, which will be determined following the full review process, including public consultation and the final analysis of all relevant information; and

That Council expects the applicant to adequately address concerns raised by the Township's professional consultants in accordance with the Planning Act and Township's policies and standards; and,

That staff be directed to proceed with notice in accordance with Section 3 and Section 5 of O. Reg. 545/06 of the Planning Act, 1990.

CARRIED

9.4.4.Report COR-2026-049 Proposed Amendment to Entrance By-law

Resolution No. 2026-266: Moved by Councillor Goyda and
Seconded by Councillor Sepulis

That Report COR-2026-049 entitled Amendment to Entrance By-law be received for information; and

That Council give three readings to By-law 2026-054 being a by-law to amend the Township's Entrance Permit By-law.

CARRIED

9.4.5.Report COR-2026-050 Proposed 2027 Council, Committee and Budget Meeting Schedule

Resolution No. 2026-267: Moved by Councillor Bailey and
Seconded by Councillor Hurst

That Report COR-2026-050 entitled proposed 2027 Council, Committee & Budget Meeting Schedule be received; and,

That Council adopts the 2027 Council, Committee & Budget Meeting Schedule, attached as Schedule "A" as presented; and

That Council direct staff to amend its process to appoint a representative to the Safe Communities Committee to allow for a citizen appointment to this committee as it is statutory and meeting dates conflict with Council meeting dates; and

That Council direct staff to include a per diem for meeting attendance should we be permitted to appoint a citizen member and that Council request that virtual attendance.

CARRIED

9.4.6.Report COR-2026-051 2026 Township of Puslinch Emergency Management Programme Annual Report

Resolution No. 2026-268: Moved by Councillor Sepulis and
Seconded by Councillor Goyda

That Report COR-2026-051 entitled 2026 Township of Puslinch Emergency Management Programme Annual Report be received for information; and,

That the Council of the Township of Puslinch accepts the annual report of the Township's Emergency Management Programme for 2026.

CARRIED

9.4.7. Report COR-2026-048 Zoning By-law Amendment Application Recommendation Report - To lift the holding provision McLean Rd W & 401 (D14/PPL)

Resolution No. 2026-269: Moved by Councillor Hurst and
Seconded by Councillor Bailey

That Report COR-2026-048 entitled Zoning By-law Amendment Application Recommendation Report to lift the holding provision – McLean Rd W & 401 – D14/PPL be received for information; and

Whereas the Township and its expert consultants are satisfied with the application to lift the holding provision of the Part Lots 26 & 27 Concession 7 through their comprehensive review of the submission materials;

Therefore be it resolved,

That Council approves the Zoning By-law Amendment to lift the holding provision for the property municipally known as Part Lots 26 & 27 Concession 7; and

That Council give three readings to By-law 2026-055 as presented, being a by-law to amend By-law no. 2018-023, as amended, being the Zoning By-law of the Township of Puslinch.

CARRIED

9.4.8. Report COR-2026-052 Noise By-law Exemption Request 4591 Wellington Road 32

Resolution No. 2026-270: Moved by Councillor Sepulis and
Seconded by Councillor Bailey

That Report COR-2026-052 entitled Noise By-law Exemption Request – 4591 Wellington Road 32 be received for information; and,

That Council approve the request for relief from Noise By-law 6001-24 for 4591 Wellington Road 32, to permit Instruments/Human noise from 2300 hours on Sunday September 6, 2026 to 0000 hours on Monday September 7, 2026.

CARRIED

9.5. **Building Department**

9.5.1.Report BLD-2026-003 Building Department Second Quarter Update – April to June 2026

Resolution No. 2026-271: Moved by Councillor Hurst and
Seconded by Councillor Sepulis

That Report BLD-2026-003 entitled Building Department Second Quarter Update be received for information.

CARRIED

9.6. **Public Works Department**

9.6.1.None

9.7. **Community Services and Human Resources Department**

9.7.1.None

10. CORRESPONDENCE

10.1. Deferred to future Council Meeting - Wellington County 2025 Detachment Board Annual Report

10.2. Consultation on Proposed Governance Regulations for Regional Conservation Authorities and the Ontario Provincial Conservation Agency

Resolution No. 2026-272: Moved by Councillor Sepulis and
Seconded by Councillor Hurst

Whereas, the Province of Ontario has proposed the consolidation of Ontario's existing conservation authorities into nine Regional Conservation Authorities (RCA), with a proposed transition date of February 1, 2027, or such later date as may be prescribed; and

Whereas, Environmental Registry of Ontario Posting No. 026-0740 proposes regulations respecting the method for determining the number of members appointed by participating municipalities to RCAs and additional eligibility criteria for appointments to the Board of Directors of the Ontario Provincial Conservation Agency (OPCA); and

Whereas, under the proposed governance framework, upper-tier and single-tier municipalities will be responsible for appointing members to RCAs, resulting in lower-tier municipalities no longer having the ability to directly appoint representatives to the governing board; and

Whereas, lower-tier municipalities continue to have a direct and significant interest in the programs, services, land use planning matters, natural hazard management, environmental

protection and other responsibilities undertaken by conservation authorities within their communities; and

Whereas, meaningful local and watershed-based representation will be essential to ensuring that local municipal priorities, knowledge and watershed-specific considerations continue to inform decision-making within the new RCA structure; and

Whereas, the geographic size of the proposed RCAs further emphasizes the importance of ensuring that appointed Board members have a meaningful connection to the watershed they are responsible for governing; and

Whereas, there remains a need for additional information and guidance respecting several significant aspects of the proposed transition and future operation of the RCAs, including the governance framework, member recruitment and eligibility, travel and time commitments, budgeting, financial responsibility and the future apportionment and payment of conservation authority levies;

Therefore be it resolved, that the Council of the Township of Puslinch supports continued consultation with municipalities and existing local Conservations Authorities on the development and implementation of the new RCA governance framework; and

That the Province of Ontario be requested to ensure that any individual appointed to a RCA Board of Directors reside within the applicable watershed of the RCA to which they are appointed, in order to ensure that Board members have a direct and meaningful connection to the communities, municipalities and watershed they are responsible for governing; and

That the future regulations establishing the composition, role and operation of Watershed Advisory Committees provide meaningful opportunities for lower-tier municipal representation and participation, recognizing that lower-tier municipalities will no longer directly appoint members to RCA Boards; and

That the Province be requested to reconsider the proposed eligibility restrictions for the OPCA Board in order to establish a meaningful connection between the RCAs and the Ontario Provincial Conservation Agency, including consideration of providing for at least one representative from each RCA on the OPCA Board, or another formal mechanism to ensure direct communication and coordination between the two levels of governance; and

That the Province be requested to provide clear guidance to upper-tier and lower-tier municipalities respecting the recruitment and appointment of RCA Board members, including eligibility criteria, desired qualifications and expertise, expected roles and responsibilities, anticipated meeting frequency, travel requirements and the time commitment associated with serving on the larger regional authorities; and

That the Province be requested to provide municipalities with additional information regarding the financial and operational implications of the consolidation, including how RCA budgets will be developed and approved, how municipal levies and apportionment will be determined and collected, whether upper-tier and single-tier municipalities will assume responsibility for levy payments on behalf of lower-tier municipalities, and how costs and financial obligations will be allocated throughout the transition and ongoing operation of the new RCAs; and

That the Province be encouraged to provide this information as soon as possible to allow municipalities sufficient time to understand the governance, operational and financial implications of the new model and to prepare for implementation; and

Whereas the County of Wellington is currently represented by 3 members serving on the GRCA board and representing 7 lower-tier municipalities with diverse needs; and

Whereas it's population count for the new Eastern Lake Erie RCA area is 70,348 (4.8%); and

Whereas it's representation on the new Eastern Lake Erie RCA Board will be one member; and

Whereas a municipality of 1,009 (0.1 %) will also have a representation of one member on the new Eastern Lake Erie RCA Board;

Be it further resolved that that the Province be requested to review its eligibility criteria to make it more equitable for Wellington County representation on the new Eastern Lake Erie RCA Board and other municipalities in similar circumstances; and

That this resolution be forwarded to the Honourable Todd McCarthy, Minister of the Environment, Conservation and Parks; the Environmental Registry of Ontario as the Township's comments on ERO Posting No. 026-0740; the Association of Municipalities of Ontario; the Rural Ontario Municipal Association; Conservation Ontario; MPP Racinsky; the County of Wellington; and all Ontario municipalities.

CARRIED

10.3 Cambridge East Municipal Class Environmental Assessment

Resolution No. 2026-273: Moved by Councillor Hurst and
Seconded by Councillor Sepulis

That Correspondence Item 10.3 entitled Cambridge East Municipal Class Environmental Assessment be received for information; and,

That Council direct staff to have the environmental assessment reviewed by the Township's Hydrogeologist for comment.

CARRIED

10.4 Wellington Waterloo Power Line Project Notice of Commencement

Resolution No. 2026-274: Moved by Councillor Sepulis and
Seconded by Councillor Bailey

That Correspondence Item 10.4 entitled Wellington Waterloo Power Line Project Notice of Commencement be received for information; and,

Whereas Hydro One has proposed several alignments for its Wellington Waterloo Power Line Project through the Township of Puslinch;

And Whereas it is essential the impacts to residents be minimized;

And Whereas not all potentially affected residents have been made aware of the alignment Proposals;

Therefore Be it resolved that Hydro One Be requested to:

- **Make a presentation to Council at the September 16th Council meeting; and**
- **review their notification to residents and ensure all residents within 500m be notified in accordance with the Hydro One protocol; and**
- **Whereas the Township is unaware of a TAC and specifically requested that it participate on the TAC, that Hydro One consider having a Township representative on their Technical Advisory Committee for this study; and**
- **Whereby Puslinch Council fully supports the preferred route along the 401 corridor as presented through John McNie's Delegation; and,**

That Hydro One be requested to include a presentation to the residents at their Open House of September 17, 2026 including the preferred route along the 401 as an option and include a moderated Q&A session to ensure adequate public consultation.

CARRIED

11. COUNCIL REPORT

11.1. Mayor Updates – The mayor provided an update on the AMO conference and the delegations on current issues for the Township as well as the TAPMO AGM.

Resolution No. 2026-275: Moved by Councillor Hurst and
Seconded by Councillor Bailey

That Council receive Mayor's updates for information.

CARRIED

11.2. Councillor Updates

None

12. BY-LAWS

12.1. First, Second and Third Reading

12.1.1. BL2026-054 Amend Entrance Permit By-law

12.1.2. BL2026-055 Zoning By-law Amendment Lifting Holding Provision 7 (D14-PPL)

Resolution No. 2026-276: Moved by Councillor Hurst and
Seconded by Councillor Sepulis

That the following by-laws be taken as read three times and finally passed in Open Council:

By-law 2026-054 Being a By-law to amend By-law 032/2020 being a by-law to regulate the installation, construction, alteration or change in the use of any private entranceway that permits access to a Township Road allowance; and

By-law 2026-055 being a By-law to amend By-law 023-18, as amended, being the zoning by-law of the Township of Puslinch.

CARRIED

13. ANNOUNCEMENTS

Mayor Seeley congratulated Deputy Fire Chief Aaron Ferroccioli on his promotion to Deputy Fire Chief of the Township of Puslinch.

Mayor Seeley announced that the Aberfoyle Agricultural Society is hosting the 2026 Fall Fair September 11th and 12th.

Mayor Seeley announced that the Fastball tournament is taking place in Puslinch on the same weekend as the Fall Fair.

Council Recess 11:58 a.m. to 12:37p.m.

Councillor Sara Bailey
Councillor Russel Hurst
Councillor Jessica Goyda
Councillor John Sepulis
Mayor James Seeley

14. CLOSED SESSION

Council was in closed session from 12:39 p.m. to 2:07 p.m.

The Clerk stopped the recording and removed all public attendees from the webinar. The webinar was then 'locked' so no new participants are able to join.

Mayor Seeley declared a potential conflict of interest related to Confidential Item 14.4.2. and left the Council Chambers during discussions on this item and did not participate in any associated vote.

Resolution No. 2026-277: Moved by Councillor Goyda and
Seconded by Councillor Sepulis

That Council shall go into closed session under Section 239 of the Municipal Act for the purpose of:

14.1 **Confidential report regarding personal matters about an identifiable individual, including municipal or local board employees – Human Resources Matter**

14.2 **Confidential report regarding personal matters about an identifiable individual, including municipal or local board employees – Human Resources Matter**

14.3 **Confidential report regarding litigation or potential litigation, including matters before administrative tribunals, affecting the municipality or local board – In accordance with Section 3.14(c) of the Township's By-law Complaint Policy**

14.4 **Confidential minutes from previous closed meetings:**

- 14.4.1 **June 17, 2026 First Closed Council Meeting Minutes**
- 14.4.2 **June 17, 2026 Second Closed Council Meeting Minutes**
- 14.4.3 **July 15, 2026 Closed Council Meeting Minutes**

14.5 **Confidential report regarding litigation or potential litigation, including matters before administrative tribunals, affecting the municipality or local board – Potential OLT Matter.**

CARRIED

Resolution No. 2026-278: Moved by Councillor Bailey and
Seconded by Councillor Sepulis

That Council moves into open session at 2:07 p.m.

CARRIED

Council resumed into open session at 2:07 p.m.

Resolution No. 2026-279: Moved by Councillor Hurst and
Seconded by Councillor Sepulis

That Council receives the following report for information:

14.1 **Confidential report regarding personal matters about an identifiable individual, including municipal or local board employees – Human Resources Matter**

14.2 **Confidential report regarding personal matters about an identifiable individual, including municipal or local board employees – Human Resources Matter**

14.3 **Confidential report regarding litigation or potential litigation, including matters before administrative tribunals, affecting the municipality or local board – In accordance with Section 3.14(c) of the Township's By-law Complaint Policy**

14.4 **Confidential minutes from previous closed meetings:**

14.4.1 **June 17, 2026 First Closed Council Meeting Minutes**
14.4.2 **June 17, 2206 Second Closed Council Meeting Minutes**
14.4.3 **July 15, 2026 Closed Council Meeting Minutes**

14.5 **Confidential report regarding litigation or potential litigation, including matters before administrative tribunals, affecting the municipality or local board – Potential OLT Matter; and,**

That staff proceed as directed.

CARRIED

15. BUSINESS ARISING FROM CLOSED SESSION
None

16. NOTICE OF MOTION
None

17. NEW BUSINESS
None

18. CONFIRMATORY BY-LAW

18.1. By-law to confirm the proceedings of Council for the Corporation of the Township of Puslinch

Resolution No. 2026-280: Moved by Councillor Bailey and
Seconded by Councillor Hurst

That the following By-law be taken as read three times and finally passed in open Council:

By-law 2026-056 being a by-law to confirm the proceedings of Council for the Corporation of the Township of Puslinch at its meeting held on the 26 day of August 2026.

CARRIED

19. ADJOURNMENT

Resolution No. 2026-281: Moved by Councillor Sepulis and
Seconded by Councillor Hurst

That Council hereby adjourns at 2:09 p.m.

CARRIED

_____
James Seeley, Mayor

_____
Justine Brotherston, Municipal Clerk

THE CORPORATION OF THE TOWNSHIP OF PUSLINCH
JANUARY 13, 2025 JOINT RECREATION AND COMMUNITY WELLNESS ADVISORY COMMITTEE AND YOUTH ADVISORY COMMITTEE
IN-PERSON MEETING AT 23 BROCK RD S, PUSLINCH ON

M I N U T E S

DATE: January 13, 2025
MEETING: 6:00 P.M.

The January 13, 2025 Joint Recreation and Youth Advisory Committee was held on the above date and called to order at 6:07 p.m. via in person participation at the Puslinch Community Centre at 23 Brock Rd S, Puslinch.

1. CALL THE MEETING TO ORDER

2. ROLL CALL

Attendance:
Councillor Sara Bailey
Councillor Jessica Goyda
Aaron Dochstader
Oliver Van Gerwen
Katey Whaling
Kenzo Szatori
Carter Devries
Kaiden Wineberg
Talia Wineberg
Jasmine Coburn
Mary Christidis
Stephanie McCrone

Absent:
Joanna Jefferson
Tracey McQueen
Xander Wineberg

Staff in Attendance:
Laura Emery, Communications and Committee Coordinator
Sarah Huether, Interim Deputy Clerk

3. MOMENT OF REFLECTION

4. CONFIRMATION OF THE AGENDA

Resolution No. 2025-001: Moved by Carter Devries and Seconded by Oliver Van Gerwen

That the Joint Recreation and Community Wellness Advisory Committee and Youth Advisory Committee approves the January 13, 2025 Agenda as circulated.

CARRIED

5. DISCLOSURE OF CONFLICT OF INTEREST

None

6. DELEGATIONS

None

7. CONSENT AGENDA

Resolution No. 2025-002: Moved by Kenzo Szatori and Seconded by Talia Wineberg

That Consent Agenda item listed for the January 13, 2025 Joint Recreation and Community Wellness Advisory Committee and Youth Advisory Committee meeting be received for information.

CARRIED

8. COMMITTEE AND STAFF REPORTS

8.1 Report – JRY-2025-001 – Boreham Park Tree Planting Initiative Update

Resolution No. 2025-003: Moved by Katey Whaling and Seconded by Kaiden Wineberg

That Report JRY-2025-001 entitled Boreham Park Tree Planting Update be received for information.

CARRIED

8.2. Report JRY-2025-002 – Proposed Donation Policy

Resolution No. 2025-004: Moved by Aaron Dochstader and Seconded by Jasmine Coburn

That report JRY-2025-002 entitled Proposed Donation Policy be received for information; and,

That the following comments from the Joint Recreation and Community Wellness Advisory Committee and Youth Advisory Committee be provided to Council for its consideration regarding the Proposed Donation Policy:

- **The Committee recommends clarified wording regarding how an Official Donation Receipt is not -issued to a business should they choose to advertise their business as part of the donation**
- **That staff review Section 8. D.) ii. to ensure sponsorship and/or naming rights be considered**

CARRIED

9. CORRESPONDENCE

None

10. ANNOUCEMENTS

Committee member Carter Devries notified the Committee's that the Optimist Recreation Centre Rink is open for the 2025 season.

11. NOTICE OF MOTION

None

12. NEW BUSINESS

None

13. ADJOURNMENT

Resolution No. 2025-005: Moved by Mary Christidis and Seconded by Oliver Van Gerwen

That the Joint Recreation and Community Wellness Advisory Committee and Youth Advisory Committee hereby adjourns at 6:56 p.m.

CARRIED

Maureen Barlow

From: AMO Policy <policy@amo.on.ca>
Sent: August 13, 2026 5:43 PM
To: Admin
Subject: AMO Policy Update - Property Tax Reassessment, National Housing Strategy Renewal, Provincial Data Centre Playbook

Categories: Consent

This sender is trusted.

AMO Policy Update – Property Tax Reassessment, National Housing Strategy Renewal, Provincial Data Centre Playbook

Top Insights

- AMO calls on the province to restart property tax reassessment
- AMO set out municipal sector priorities for the province to inform its renewal and renegotiation of the Canada-Ontario National Housing Strategy agreement beyond 2028
- The province is consulting on a new framework to guide decision-making on data centres, and prioritize projects that deliver meaningful local benefits
- AMO Conference key messages and priorities

Property Tax Reassessment

AMO sent a letter to Premier Ford to reinforce our long-standing call for the province to establish a clear and timely path back to regular property assessment cycles. A well-functioning and up-to-date assessment system makes Ontario an attractive place to invest, provides municipalities with a stable and predictable source of revenue, and stability and predictability for property taxpayers.

Public support and understanding of the benefits of re-assessment will also be key to resuming a regular reassessment cycle. AMO has offered to partner with the Municipal Property Assessment Corporation and the Province to ensure effective communication and implementation of the transition back to regular assessments.

Ontario is the only province in Canada that has not resumed property reassessments post COVID-19 pandemic, with the last assessment taking place in 2016.

National Housing Strategy Renewal – Municipal Priorities

The National Housing Strategy (NHS) is set to expire in 2028. AMO is pleased that both the provincial and federal governments have committed to working together on a renewed agreement. The homelessness crisis continues to worsen in communities across Ontario. The continuation of NHS funding is crucial. To ensure that municipal perspectives are considered as part of the renegotiation, AMO issued a letter to the Ministry of Municipal Affairs and Housing identifying and providing input about Ontario's municipal core priorities for the renegotiation of the strategy and a new Canada-Ontario bilateral agreement. These include:

- Provide long-term predictable funding through a renewed bilateral agreement.
- Focus investments on households experiencing the greatest housing need.
- Renew and expand the Canada-Ontario Housing Benefit.
- Increase investment in non-market housing and preservation of existing affordable housing stock.
- Expand supportive and transitional housing.
- Make Reaching Home a permanent and expanded program.
- Advance Indigenous-led housing and homelessness solutions.
- Strengthen housing system capacity and delivery.

AMO is hopeful that this initial input will serve as a launch pad for more conversation and collaboration with both the provincial and federal governments.

Provincial Consultation on Data Centre Playbook

The provincial government has announced a framework for data centres to guide decisions on new data centres. Under the proposed Data Centre Playbook, data centres would be required to pay for the full cost of electricity, and be assessed based on three priorities:

- **Economic Development:** Creating high-quality jobs, attracting investments, creating new tax revenue, and supporting domestic supply chains
- **Digital Sovereignty:** Protecting Canadian data and security, and prioritizing Canadian companies
- **Community Investment:** Delivering significant benefits to host communities and earning public trust, and minimizing impacts on host communities

This Playbook responds to AMO's data centre advocacy. AMO has called for the development of a provincial framework that ensures data centres do not limit municipal ability to meet other priorities like housing and job creation. We have also called for priority to be given to projects that provide clear benefits to host communities.

The proposed Data Centre Playbook is open for public consultation until September 12. AMO will continue providing advice to the province on how data centre development can balance local needs and infrastructure demands while supporting Ontario's economy.

AMO Conference Key Messages and Priorities

The AMO Conference, the biggest event in the municipal calendar, kicks off in Ottawa on August 17, and key messages of our policy priorities can be found on the AMO Website. See you in Ottawa!

An online version of this Policy Update is also available on the AMO Website.

Maureen Barlow

From: AMO Policy <policy@amo.on.ca>
Sent: August 20, 2026 4:18 PM
To: Admin
Subject: Policy Update: Key takeaways from the 2026 AMO Conference

Categories: Consent

This sender is trusted.

AMO Policy

The 2026 AMO Conference brought together more than 3,600 municipal leaders, provincial and federal representatives, sector partners and stakeholders representing 444 municipalities across Ontario.

Over four days, municipal leaders advanced local priorities through over 750 delegation meetings, policy discussions and conversations with government and sector partners. Several significant announcements and developments also emerged from the conference.

Infrastructure funding for growth and renewal
The conference opened with a joint federal-provincial announcement of $1 billion in combined funding through a new Canada–Ontario Partnership to Build funding stream.

The program is intended to support municipalities that do not levy development charges, often rural, small and northern communities, with funding available for both growth-related housing infrastructure and asset renewal. AMO and the Ministry of

Infrastructure will be co-hosting webinars to answer your questions, and additional details will be provided in next week's policy update.

Municipalities that applied for the Development Charge Reduction Program (DCRP) have started to hear back from the provincial government. Some municipalities are receiving responses to their applications and will need to assess next steps. AMO's position continues to be that if a municipality receives less funding than it requested, it should have the flexibility to reduce the size of its development charge reduction.

Questions about the interaction between the DCRP and the Non-Development Charge Municipalities Stream funding, including if a municipality can be eligible under both, should be directed to the province.

Community Sport and Recreation Infrastructure Fund
The province announced that applications are now open for the next round of the $500-million Community Sport and Recreation Infrastructure Fund (CSRIF). The fund is intended to support the development and renewal of local sport and recreation infrastructure across Ontario. The Ministry is hosting a webinar on August 26 at 11 a.m. to learn about the fund and application process.

Municipal Accountability Act consultations
The province also launched consultations on proposed regulations to implement the new municipal code of conduct legislation passed earlier this year. The proposed regulatory framework includes:

- potential elements of a standard municipal code of conduct
- processes for municipal Integrity Commissioners
- and education and training requirements for municipal officials and Integrity Commissioners.

AMO will provide formal comments and create additional channels for you to have your say. Stay tuned for more to come.

Housing, homelessness and local democracy
Housing affordability, homelessness and supportive housing remained key issues throughout the conference. Discussions focused on the need for stronger coordination among governments, health and housing providers, and the non-profit, co-operative and private sectors to address growing pressures in communities. All three levels of government acting now to address the waitlist for voluntary treatment, wraparound supports, and supportive housing would make real progress on this important issue.

Delegates also examined local democracy and governance, including how municipalities can navigate changes while maintaining transparent, accountable decision-making and strong local voices.

New AMO leadership
AMO members elected Riley Brockington as President for the 2026–2028 term, alongside a new Board of Directors. The incoming Board will continue AMO's advocacy

on the issues affecting municipalities and the sustainability of local government.

Advancing reconciliation
AMO and the Anishinabek Nation signed a Memorandum of Understanding establishing a framework to identify shared priorities, exchange perspectives and work together to advance common goals through advocacy and sector leadership. The MOU is one of the commitments identified in AMO's Indigenous Reconciliation Action Plan.

The conference reinforced the scale and complexity of the pressures facing municipalities. AMO will continue working with members and government partners to advance solutions that support strong, sustainable and resilient communities.

To follow for more policy updates, visit us at amo.on.ca/policy.

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*Disclaimer: The Association of Municipalities of Ontario (AMO) is unable to provide any warranty regarding the accuracy or completeness of third-party submissions. Distribution of these items does not imply an endorsement of the views, information or services mentioned.

Association of Municipalities of Ontario

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155 University Ave Suite 800 | Toronto, ON M5H 3B7 CA

Solicitor General

Office of the Solicitor General

25 Grosvenor Street, 18th Floor
Toronto ON M7A 1Y6
Tel: 416 326-5000
Toll Free: 1 866 517-0571
Minister.SOLGEN@ontario.ca

Solliciteur général

Bureau du solliciteur général

25, rue Grosvenor, 18e étage
Toronto ON M7A 1Y6
Tél. : 416 326-5000
Sans frais : 1 866 517-0571
Minister.SOLGEN@ontario.ca

Ontario

132-2026-3665
By email

August 14, 2026

Dear Heads of Council, Chief Administrative Officers and Clerks of OPP-Policed Municipalities:

I am writing to provide you with an update on OPP municipal policing costs for 2027.

Our government recognizes the importance of providing municipalities with predictability as you plan your budgets, while ensuring the OPP has the resources it requires to continue delivering high-quality policing services and keeping communities safe.

With that in mind, we are taking action to limit increases in OPP policing costs for municipalities in 2027.

For the 2027 calendar year, no OPP-policed municipality will see its total amount owed for OPP policing increase by more than 11 per cent compared to 2026, excluding costs associated with any additional policing services a municipality has chosen to receive through a separate agreement with the OPP.

This is a time-limited measure for the 2027 OPP billing cycle, intended to provide municipalities with cost certainty to support local budget planning.

To implement this change, an amendment has been made to Ontario Regulation 413/23: Amount Payable by Municipalities for Policing from Ontario Provincial Police, made under the *Community Safety and Policing Act, 2019* (CSPA). The amendment is being filed with the Registrar of Regulations and will be publicly available through the e-Laws page in the coming days.

The OPP is currently preparing 2027 annual billing statements, which are expected to be provided to municipalities this fall.

We value the important partnership between the province, municipalities and the OPP in keeping Ontario communities safe. We also recognize the importance of ensuring policing costs are sustainable and predictable for municipalities, and we will continue working with our municipal partners on these shared priorities.

…/2

Should you have any questions about the regulatory updates, please reach out to solgeninput@ontario.ca. Questions regarding your municipality's annual OPP billing statement can be directed to OPP Municipal Policing at opp.municipalpolicing@opp.ca.

Sincerely,

The Honourable Michael S. Kerzner
Solicitor General

c: Mario Di Tommaso, O.O.M.
Deputy Solicitor General, Community Safety

Thomas Carrique, C.O.M.
Commissioner, Ontario Provincial Police

Posted Date: Aug 18, 2026

Last Updated: Aug 20, 2026

Regulation Number:

N/A

Instrument Type:

Regulation - LGIC

Act/Bill: Municipal Act, 2001, City of Toronto Act, 2006

Proposal Number: 26-MMAH054

Summary of the proposal

Relevant dates

Analysis of the regulatory impact

Supporting documents

Contact

Comment on this proposal

37 DAY(S) LEFT TO COMMENT

Proposal for Regulations to Establish a Standardized Municipal Code of Conduct; Municipal Integrity Commissioner Processes and Education and Training Requirements

Summary of the proposal

The Municipal Accountability Act, 2026 received Royal Assent on June 2, 2026. If brought into effect, the Act would strengthen the municipal code of conduct framework and enable Minister's and Lieutenant Governor in Council (LGIC) regulations to:
I. Establish a single, standardized municipal code of conduct that would apply to all members of council and of certain local boards.
II. Create standardized inquiry processes to be followed by municipal integrity commissioners.
III. Establish roles and requirements related to education and training for the Integrity Commissioner of Ontario (ICO), municipal integrity commissioners, and members of councils and certain local boards.

It is proposed that regulations would be in effect on November 15, 2026 - the start of the new municipal council term.

The government is seeking public input on the contents to include in these regulations. The proposed contents of the regulations are presented in the document linked below: "Consultation on proposed content of regulations under the Municipal Accountability Act, 2026."

Relevant dates

Posted Date: **Aug 18, 2026**

Comment Due Date: **Oct 2, 2026**

Last Updated: **Aug 20, 2026**

Analysis of the regulatory impact

As part of this consultation, MMAH is seeking comments and feedback pertaining to the anticipated costs and benefits of implementing this proposal.

Regulated entities, including municipalities and municipal integrity commissioners, may experience administrative and compliance impacts associated with implementing the proposed regulations. These potential costs are primarily related to the time required for integrity commissioners, council and local board members, and municipal staff to become familiar with the new standardized code of conduct and inquiry processes. Additional impacts may include time allocated by integrity commissioners to develop and deliver training materials, time required for individuals to complete mandatory training, and municipal staff time needed to update local administrative and reporting procedures to align with new requirements and support transparency.

Establishing a single, standardized municipal code of conduct and inquiry process across all 444 Ontario municipalities is anticipated to support operational efficiency for municipal integrity commissioners by providing a uniform framework and standard inquiry process. Mandatory training requirements for council and board members, as well as integrity commissioners, are anticipated to improve understanding of obligations and foster greater compliance. The proposal is also expected to reduce administrative duplication associated with developing and maintaining local codes of conduct, foster greater consistency in code of conduct administration, clarify expectations for elected officials and municipal staff, and support overall public transparency.

Supporting documents

Type	File name	Action
PDF	Consultation on Proposed Contents of Regulations under the Municipal Accountability Act, 2026	Download

Download all

Contact

localgov@ontario.ca

From the same ministry

View all

Consultation on Reducing Regulatory Burden in Ontario's Building Code

(source: Environmental Registry)

Invitation to Municipalities to register potential interest in implementing a Water and Wastewater Public

Exploring Commercial Property Assessed Clean Energy (C-PACE) Financing in Ontario

(source:

We want your feedback on Ontario's Building Code review so we can identify ways to reduce unnecessary costs, delays, complexity, and administrative burden, while maintaining health, safety, accessibility, and performance outcomes.

Corporation model

(source: Environmental Registry)

MMAH is inviting municipalities with a potential interest in locally implementing the water and wastewater public corporation service delivery model to make a submission expressing their interest. This input will help the Ministry understand levels of interest, needs, readiness and potential next steps to support future expansion of the model.

Environmental Registry)

The government is exploring a C-PACE framework that would let municipalities opt in to support private financing for clean energy upgrades through property based repayment. The proposal outlines eligible properties, lender consent rules, municipal roles, and safeguards. Feedback is requested on design, regulation, and enforcement.

Subscribe to our email alerts for timely updates on proposals, policies, and regulatory changes.

Justine Brotherston

From: Justine Brotherston
Sent: August 31, 2026 1:52 PM
To: Justine Brotherston
Subject: FW: EB-2026-0108 Enbridge Gas Inc. - 2025 Utility Earnings and Disposition of Deferral & Variance Accounts - OEB Notice of Application
Attachments: EGI_APPL_updated 20260824.pdf; Notice_EGI_2025 DVA_20260824.pdf; Notice_EGI_2025 DVA_fr_20260824.pdf

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Subject: EB-2026-0108 Enbridge Gas Inc. - 2025 Utility Earnings and Disposition of Deferral & Variance Accounts - OEB Notice of Application

Caution! This message was sent from outside your organization. Allow sender | Block sender | Report

To: Clerks of All Municipalities in which Enbridge Gas Supplies Gas

On July 30, 2026, Enbridge Gas Inc. (Enbridge Gas) filed an application with the Ontario Energy Board (OEB) for an Order or Orders approving the clearance or disposition of amounts recorded in certain deferral or variance accounts. On August 24, 2026, Enbridge Gas filed an update to the application and evidence to include the Estimated Billing and Meter Reading Performance Report.

On August 24, 2026, the OEB issued the Notice of Application along with the Letter of Direction for the proceeding.

Attached please find the OEB's Notice of Application (English and French) along with Enbridge Gas' application and evidence as filed with the OEB. The OEB's Notice of Application provides information on how to become informed and involved in the proceeding.

Interested parties can apply to the OEB for Intervenor Status in this proceeding by September 8, 2026.

A paper copy of the evidence filed in this proceeding is available upon request and can also be viewed on the Enbridge Gas website under Other Regulatory Proceedings: Regulatory Information | Enbridge Gas

Please contact me if you have any questions.

Sincerely,

Bonnie Jean Adams
Regulatory Coordinator

Enbridge Gas Inc.
T: 416-495-5751
500 Consumers Road I North York Ontario I M2J 1P8

enbridgegas.com
Safety. Integrity. Respect. Inclusion. High Performance.

My working day may differ from your working day. Please do not feel obliged to reply to this email outside of your normal working hours.

Richard Wathy
Technical Manager
Regulatory Applications
Regulatory Affairs

tel 519-365-5376
Richard.Wathy@enbridge.com
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
P. O. Box 2001
50 Keil Drive North
Chatham, ON N7M 5M1

August 24, 2026

VIA RESS AND EMAIL

Ritchie Murray
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ritchie Murray

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2026-0108
2025 Utility Earnings and Disposition of Deferral & Variance Account Balances Application and Evidence - Update

Further to the submission filed on July 30, 2026, enclosed please find the following updated exhibit:

Exhibit	Update
G-1-3	Enbridge Gas is filing the Estimated Billing and Meter Reading Performance Report

In the event that you have any questions on the above or would like to discuss in more detail, please do not hesitate to contact me.

Sincerely,

[redacted]

Richard Wathy
Technical Manager, Regulatory Applications

cc.: D. Stevens (Aird & Berlis)

EXHIBIT LIST

A – Overview and Introduction

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	3	1	Overview and Approvals Required

B - Utility Results and Earning Sharing

Exhibit	Tab	Schedule	Contents
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		3	Utility Income
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		5	Utility Rate Base and Continuity Schedules
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B - Utility Results and Earning Sharing

Exhibit	Tab	Schedule	Contents
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C - Enbridge Gas Inc Deferral and Variance Accounts

Exhibit	Tab	Schedule	Contents
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C - Enbridge Gas Inc Deferral and Variance Accounts

Exhibit	Tab	Schedule	Contents
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		15	Account No. 179-328 Post Retirement True-up V/A
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D - EGD Rate Zone Deferral and Variance Accounts

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D - EGD Rate Zone Deferral and Variance Accounts

Exhibit	Tab	Schedule	Contents
D	2	1	Storage RFP Letter
		2	Storage RFP Summary (Redacted)

E – Union Rate Zones Deferral and Variance Accounts

Exhibit	Tab	Schedule	Contents
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F – Rate Allocation

Exhibit	Tab	Schedule	Contents
F	3	2	Union – Classification and Allocation of Deferral and Variance Account Balances
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G – Additional Items Not Requiring OEB Approval

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	6	1	Brand Clarity Study

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an order or orders clearing certain commodity and non-commodity related deferral or variance accounts.

APPLICATION

1. The Applicant, Enbridge Gas Inc. (Enbridge Gas) is an Ontario corporation with its head office in the City of Toronto. It carries on the business of selling, distributing, transmitting, and storing natural gas within Ontario. Enbridge Gas was formed effective January 1, 2019, upon the amalgamation of Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union).

2. On October 31, 2022, Enbridge Gas filed a Cost of Service and Rebasing Application for 2024 rates and for approval of an incentive rate-setting mechanism (IRM) for the following four years under EB-2022-0200. The Ontario Energy Board (OEB) split the Rebasing Application into 3 phases, with Phase 1[1] focused on cost of service rates for 2024, while Phase 2[2] was focused on setting the IRM for 2025 to 2028. Through Decisions and OEB-approved Settlement Agreements for Phase 1 and Phase 2, the OEB approved deferral and variance accounts for Enbridge Gas to be in effect for the 2024 to 2028 IRM term. Some of the deferral and variance accounts relate to Enbridge Gas as a whole, while some apply to either the EGD or Union Rate Zones.[3]

[1] EB-2022-0200.

[2] EB-2024-0111.

[3] "Union rate zones" collectively refers to Union North West, Union North East and Union South.

3. Enbridge Gas hereby applies to the OEB, pursuant to Section 36 of the *Ontario Energy Board Act*, 1998, for an Order or Orders approving the clearance or disposition of amounts recorded in certain deferral or variance accounts.

1. Earnings Sharing

4. The OEB has approved, among other things, an asymmetrical earnings sharing mechanism (ESM) during the IRM term period, where each year any earnings in excess of 100 basis points over the OEB-approved return on equity (ROE) would be shared 50/50 between the Company and ratepayers. Further, earnings over 300 basis points above the allowed ROE will be credited to ratepayers on a 90/10 basis.

5. In 2025, Enbridge Gas's actual utility earnings exceeded the OEB-approved ROE by more than 100 basis points. Accordingly, the ESM amount proposed to be shared with ratepayers is outlined at Exhibit C, Tab 2, Schedule 11.

2. Enbridge Gas Inc.

6. The OEB has approved several deferral and variance accounts that relate to Enbridge Gas as a whole (and not to specific Rate Zone(s)). Enbridge Gas requests approval to clear the final balances of certain Enbridge Gas deferral and variance accounts for 2025 as set out at Exhibit C, Tab 1, Schedule 1.

3. EGD Rate Zone

7. Enbridge Gas requests approval to clear the final balances of certain EGD rate zone deferral and variance accounts for 2025 as set out at Exhibit C, Tab 1, Schedule 1.

8. The final balance in account 179-325 Open Bill Extension Deferral Account was brought forward for disposition in 2024. The program was discontinued as of October 31, 2024, and no balance will be recorded in the account going forward. As such, Enbridge Gas requests that this account be approved for closure.

4. Union Rate Zones

9. Enbridge Gas requests approval to clear the final balances of certain Union rate zones deferral and variance accounts for 2025 as set out at Exhibit C, Tab 1, Schedule 1.

5. Relief Requested

10. Enbridge Gas therefore applies to the OEB for such final, interim or other orders as may be necessary or appropriate for the clearance or disposition of the 2025 deferral and variance accounts requested in Exhibit C, Tab 1, Schedule 1. This includes final disposition of certain accounts previously cleared on an interim basis. The proposed manner of disposition is described at Exhibit F. Enbridge Gas proposes to clear the balances in these accounts with the first available QRAM application following the OEB's approval.

11. Enbridge Gas requests that certain information included at Exhibit D, Tab 2, Schedule 2 be treated as confidential under the OEB's Practice Direction on Confidential Filings. Equivalent information has been treated as confidential in prior deferral and variance account clearance proceedings.

12. Enbridge Gas requests approval to close account 179-325 Open Bill Extension D/A.

13. Enbridge Gas requests that this proceeding be heard in writing.

14. Enbridge Gas further applies to the OEB pursuant to the provisions in the Act and the OEB's *Rules of Practice and Procedure* for such final, interim or other Orders and directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.

15. This Application is supported by written evidence. This evidence may be amended from time to time as required by the OEB, or as circumstances may require.

16. The persons affected by this Application are the customers resident or located in the municipalities, police villages and First Nations reserves served by Enbridge Gas, together with those to whom Enbridge Gas sells gas, or on whose behalf Enbridge Gas distributes, transmits or stores gas. It is impractical to set out in this Application the names and addresses of such persons because they are too numerous.

17. Enbridge Gas requests that a copy of every document filed with the OEB in this proceeding be served on the Applicant and Applicant's counsel, as follows:

The Applicant:

Mr. Richard Wathy
Technical Manager, Regulatory Applications
Enbridge Gas Inc.

Address for personal service	Enbridge Gas Inc. P. O. Box 2001 50 Keil Drive North Chatham, ON N7M 5M1
Telephone:	519-365-5376
Email:	Richard.Wathy@enbridge.com EGIRegulatoryproceedings@enbridge.com

- and –

The Applicant's counsel:

Mr. David Stevens
Aird & Berlis LLP

Address for personal service and mailing address:	Brookfield Place, P.O. Box 754 Suite 1800, 181 Bay Street Toronto, Ontario M5J 2T9
Telephone:	416-863-1500
Email:	dstevens@airdberlis.com

DATED: July 30, 2026, at Chatham, Ontario

ENBRIDGE GAS INC.

[redacted]

Richard Wathy
Technical Manager, Regulatory Applications

2025 DEFERRAL ACCOUNT DISPOSITION AND EARNINGS SHARING OVERVIEW AND APPROVALS REQUESTED

1. Enbridge Gas Inc. (Enbridge Gas) is applying to the Ontario Energy Board (OEB) pursuant to Section 36 of the *OEB Act* for approval to dispose and recover certain 2025 deferral and variance account final balances for Enbridge Gas, and the Enbridge Gas Distribution (EGD) and Union Gas (Union)[1] rate zones. Enbridge Gas is also presenting the earnings sharing mechanism (ESM) calculations for the amalgamated utility.

2. The evidence in this Application is organized as follows:
   Exhibit A: Overview and Introduction
   Exhibit B: 2025 Utility Results and Earnings Sharing Amount
   Exhibit C: Enbridge Gas Inc. Deferral and Variance Accounts
   Exhibit D: EGD Rate Zone Deferral and Variance Accounts
   Exhibit E: Union Rate Zones Deferral and Variance Accounts
   Exhibit F: Rate Allocation
   Exhibit G: Additional Items Not Requiring OEB Approval

3. Enbridge Gas proposes that the impacts which result from the disposition of 2025 deferral and variance account balances be implemented with the first available Quarterly Rate Adjustment Mechanism (QRAM) application following the OEB's approval, to align with other rate changes implemented through the QRAM.

1. Relief requested

4. Enbridge Gas requests approval to clear the final balances of certain Enbridge Gas, EGD rate zone, and Union rate zones 2025 deferral and variance accounts. The

[1] "Union rate zones" collectively refers to Union North West, Union North East and Union South.

balances of the 2025 deferral and variance accounts are set out at Exhibit C, Tab 1, Schedule 1. For ease of reference, a copy of Exhibit C, Tab 1, Schedule 1 is attached at Appendix A to this exhibit.

5. Explanations for the balances in each account are set out at Exhibit C (Enbridge Gas), Exhibit D (EGD rate zone) and Exhibit E (Union rate zones). The evidence also indicates which accounts Enbridge Gas does not seek to clear in this proceeding. The proposed clearance methodology for the accounts being cleared is set out at Exhibit F.

2. Disposition of deferral and variance accounts

6. Integration of the legacy billing systems for EGD and Union Gas enables Enbridge Gas to dispose of balances in the 2025 deferral and variance accounts as a one-time adjustment for all customers. Enbridge Gas proposes to dispose of the 2025 deferral and variance accounts as a one-time adjustment for all general service, in-franchise contract and ex-franchise rate classes.

7. The proposed approach to the one-time adjustment is consistent between the EGD and Union rate zones and, subject to OEB approval as to timing, will be disposed of with the first available QRAM application.

3. 2024 Upstream Transportation Optimization Variance Account and Union Rate Zones Unabsorbed Demand Costs Variance Account final disposition

8. In the 2024 Utility Earnings and Disposition of Deferral and Variance, Decision and Order, the OEB approved the disposition of the Upstream Transportation Optimization V/A and Unabsorbed Demand Costs V/A on an interim basis, to provide parties the opportunity to ask follow-up clarification questions.[2] Upon addressing the

[2] EB-2025-0155, Decision and Order, p.7.

follow-up clarification questions, Enbridge Gas requests that the prior interim disposition of these accounts be declared final.

4. Open Bill Extension Deferral Account closure request

9. The final balance in the account was brought forward for disposition in the 2024 Utility Earnings and Disposition of Deferral and Variance Account proceeding.[3] The program was discontinued as of October 31, 2024, and no balance will be recorded in the account going forward. As such, Enbridge Gas requests that this account be approved for closure.

[3] EB-2025-0155, Exhibit D, Tab 1, Schedule 2.

Enbridge Gas
Deferral & Variance Account
Actual & Forecast Balances

Line No.	Account Description	OEB Account Number	Col. 1 Principal ($000's)	Col. 2 Interest ($000's)	Col. 3 Total ($000's)	Col.4 Reference to Evidence
			Forecast for clearance at July 1, 2027			
	EGI Commodity Related Accounts					
1.	Upstream Transportation Optimization V/A	179-201	(34,774.9)	(1,882.5)	(36,657.4)	Exhibit C-2-1
2.	UFG Volume V/A	179-203	10,558.8	408.1	10,966.9	Exhibit C-2-3
3.	UFG Price V/A	179-204	(3,557.1)	(138.2)	(3,695.4)	Exhibit C-2-4
4.	Total Commodity Related Accounts		(27,773.2)	(1,612.6)	(29,385.8)	
	EGI Non Commodity Related Accounts					
5.	Transportation from Dawn Service D/A	179-202	70.4	3.7	74.0	Exhibit C-2-2
6.	Deferral Clearing V/A	179-302	3,529.2	174.3	3,703.5	Exhibit C-2-5
7.	Parkway Delivery Obligation V/A	179-303	2,558.2	129.5	2,687.7	Exhibit C-2-6
8.	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-	
9.	Pension & OPEB V/A	179-305	-	(4,909.1)	(4,909.1)	Exhibit C-2-7
10.	Facility Carbon Charge V/A	179-307	(742.7)	(99.8)	(842.4)	Exhibit C-2-8
11.	Customer Carbon Charge V/A	179-308	(2.1)	(0.2)	(2.2)	Exhibit C-2-9
12.	Carbon Charges Bad Debt D/A	179-309	6,948.4	417.7	7,366.1	Exhibit C-2-10
13.	Earnings Sharing Mechanism D/A	179-311	(24,300.0)	(932.7)	(25,232.7)	Exhibit C-2-11
14.	Tax V/A	179-312	(13,621.5)	(347.3)	(13,968.8)	Exhibit C-2-12
15.	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-	
16.	Green Button Initiative D/A	179-320	-	-	-	
17.	Dawn Parkway Surplus Capacity D/A	179-323	(2,260.3)	(105.1)	(2,365.4)	Exhibit C-2-13
18.	Distribution Integrity Management Program D/A	179-326	213.0	12.2	225.2	Exhibit C-2-14
19.	Post Retirement True-Up V/A	179-328	(49,006.6)	(2,542.6)	(51,549.2)	Exhibit C-2-15
20.	Clean Fuel Regulation Credits D/A	179-330	(35.0)	(1.8)	(36.9)	Exhibit C-2-16
21.	Indigenous Working Group D/A	179-331	268.6	12.1	280.7	Exhibit C-2-17
22.	Cloud Computing Implementation Costs D/A	179-332	-	-	-	
23.	Average Use V/A	179-333	34,494.4	2,130.6	36,625.0	Exhibit C-2-18
24.	Getting Ontario Connected V/A	179-335	14,093.7	744.7	14,838.3	Exhibit C-2-19
25.	Disposition of Property D/A	179-336	(12,804.0)	(689.4)	(13,493.4)	Exhibit C-2-20
26.	LEAP Emergency Financial Assistance D/A	179-338	1,200.8	50.6	1,251.4	Exhibit C-2-21
27.	OEB Cost Assessment V/A	179-340	2,997.0	121.9	3,118.9	Exhibit C-2-22
28.	IRP System Pruning D/A (2024 & 2025)	179-341	388.0	26.9	414.9	Exhibit C-2-23
29.	Enbridge Sustain Affiliate Recoveries V/A	179-344	-	-	-	
30.	Total Non Commodity Related Accounts		(36,010.5)	(5,803.8)	(41,814.3)	
31.	Total EGI Accounts (for clearance)		(63,783.8)	(7,416.4)	(71,200.1)	
	EGD Rate Zone Commodity Related Accounts					
32.	Storage and Transportation D/A	179-88	3,126.8	276.9	3,403.8	Exhibit D-1-1
33.	Total Commodity Related Accounts		3,126.8	276.9	3,403.8	
	EGD Rate Zone Non Commodity Related Accounts					
34.	Open Bill Extension D/A	179-325	-	-	-	
35.	Total Non Commodity Related Accounts		-	-	-	
36.	Total EGD Rate Zone (for clearance)		3,126.8	276.9	3,403.8	
	Union Rate Zones Gas Supply Accounts					
37.	Unabsorbed Demand Costs Variance Account	179-108	4,881.6	240.3	5,121.9	Exhibit E-1-1
38.	Total Gas Supply Accounts		4,881.6	240.3	5,121.9	
	Union Rate Zones Storage Accounts					
39.	Short-Term Storage and Other Balancing Services	179-70	(599.3)	(22.9)	(622.2)	Exhibit E-1-2
40.	Total Storage Accounts		(599.3)	(22.9)	(622.2)	
41.	Total Union Rate Zones (for clearance)		4,282.3	217.4	4,499.7	
42.	Total Deferral and Variance Accounts (for clearance)		(56,374.6)	(6,922.0)	(63,296.6)	
	EGI Accounts Not Being Requested For Clearance					
43.	Incremental Capital Module D/A	179-306	-	-	-	
44.	IRP Operating Costs Deferral Account	179-318	2,234.6	100.0	2,334.6	Exhibit C-2-24
45.	IRP Capital Costs Deferral Account	179-319	(3.0)	(0.1)	(3.1)	Exhibit C-2-24
46.	Panhandle Region Expansion Project V/A (2024-2025)	179-329	(10,199.5)	(643.5)	(10,843.0)	Exhibit C-2-24
47.	Site Restoration Costs Tracking Account	179-337	(15,615.7)	-	(15,615.7)	Exhibit C-2-24
48.	Asset Life Extension Costs D/A	179-343	-	-	-	

2025 ENBRIDGE GAS INC. EARNINGS DETERMINATION PROCESS

1. For the year ended December 31, 2025, Enbridge Gas Inc. (Enbridge Gas, or the Company) is in an earnings sharing position, as its achieved return on equity was higher than the threshold required for sharing. The earnings sharing calculation is shown at Exhibit B, Tab 1, Schedule 2 while supporting schedules that show the calculation of utility rate base, utility income and taxes, and the utility capital structure components, are contained in the balance of the B Exhibits. Exhibit B, Tab 1, Schedule 7 sets out a reconciliation of audited income to corporate income.

2. The earnings sharing amount was determined in accordance with the following prescribed methodology as identified within the 2024 Rebasing Phase 1[1] OEB Decision and Order, dated December 21, 2023:
    - if in any calendar year during the deferred rebasing term, Enbridge Gas's actual utility ROE is more than 100 basis points above the OEB-approved ROE for that year, then the resultant amount shall be shared equally (i.e., 50/50) between Enbridge Gas and its ratepayers;
    - further, earnings over 300 basis points above the allowed ROE will be credited to ratepayers on a 90/10 basis;
    - the allowed ROE to be used for earnings sharing purposes is the ROE embedded in base rates, which is 9.21%;
    - for the purposes of the Earnings Sharing Mechanism (ESM), Enbridge Gas shall calculate its earnings using generally accepted accounting principles (GAAP) consistent with its external reporting, including the regulatory rules prescribed by the OEB from time to time;

[1] EB-2020-0200.

- all revenues and costs that would otherwise be included in a cost of service application shall be included in the earnings sharing calculation.

3. Within Exhibit B, Tab 1, Schedule 2, the Company has calculated earnings for sharing. Column 2 within the exhibit provides references indicating where additional evidence in support of the determination of the amounts in the calculation can be found. Column 3 contains results shown in millions of dollars, or percentages.

Return on Equity

4. Net utility income applicable to common equity is first determined.

5. The $1,250.0 million (line 2) of utility income before income tax, less long term debt, short term debt and preference share costs, and utility income taxes, produces the $683.6 million of net income applicable to common equity (line 8).

6. The $683.6 million, divided by the deemed common equity level of $6,345.0 million (line 9, calculated as 38% of the $16,697.4 million rate base) produces a return on equity of 10.774% (line 11). When comparing the 10.774% achieved return on equity to the OEB-approved 2025 ESM threshold percentage of 10.21% (line 10), there is a sufficiency in ROE of 0.564% (line 12).

7. The 0.564% multiplied by the common equity level of $6,345.0 million produces a net over earnings or sufficiency of $35.8 million, which from a pre-tax perspective ($35.8 million divided by the reciprocal, 73.5%, of the corporate tax rate), results in a $48.7 million gross amount of over earnings (line 15), to be shared equally between ratepayers and the Company.

3. Process Description

8. The calculation of utility earnings starts with financial results contained within the Enbridge Gas corporate trial balance. The Company notes that the corporate trial

balance includes the elimination of transactions between each of the rate zones. This predominantly relates to the elimination of regulated and unregulated storage and transmission revenues that would have been reflected in the Union rate zones, offset by a corresponding elimination of gas costs that would have been reflected for the EGD rate zone. This reflects the fact that from a corporate perspective, EGD rate zone delivery revenues are contributing to the costs of Union rate zones regulated and unregulated storage and transmission services.

9. From there, in order to calculate the utility rate base, income, and capital structure results, and supporting evidence exhibits, various adjustments, regroupings or eliminations are required. This is accomplished by following and applying regulatory rules as prescribed by the OEB and the standards associated with cost of service rate related accounting processes. Examples are:

    - Determination of rate base amounts using the average of monthly averages value concept,
    - Elimination of corporate interest expense due to the treatment of interest expense as embedded in the capital structure balanced to rate base; and,
    - Elimination of corporate income taxes due to the determination of income taxes specific to utility results.

10. In addition, Enbridge Gas has made the appropriate adjustments in relation to non-standard rate regulated items which the OEB has either decided in the past or are required in order to determine an appropriate utility return on equity. Examples are:

    - Exclusion of non-utility or unregulated activities;
    - Elimination of approved shareholder incentives (such as Demand Side Management incentives, amounts related to short-term storage, and net optimization incentives);
    - Elimination of the shareholder portion of gains on property dispositions; and

- Elimination of Central Functions Corporate Cost Allocation Methodology (CFCAM) charges that did not pass the 3-prong test[2].

11. Further to the adjustments noted above, Enbridge Gas has reflected an adjustment to utility depreciation expense for 2025 in relation to an error identified in depreciation expense. In Q2 2026, a depreciation error was identified that resulted in an overstatement of utility depreciation expense for 2024 and 2025 as follows: 2024 - $14.5 million and 2025 - $2.8 million.

12. In Q2 2026 Enbridge Gas recognized and recorded the adjustment as an increase to net property, plant and equipment (through a reduction in accumulated depreciation) and a reduction to depreciation expense. The identified depreciation error resulted in an overstatement of depreciation expense in both 2024 and 2025. No adjustment is proposed for 2024 as it was a cost of service rebasing year and Earnings Sharing was not applicable. For 2025, the impact is reflected in the ESM calculation to ensure that earnings are measured on a basis consistent with OEB rate making principles.

13. For 2025, the depreciation adjustment of $2.8 million, as part of utility income, is reflected in Exhibit B, Tab 1, Schedule 3, column 3, line 9 as part of the utility adjustment. 2025 accumulated depreciation included as part of rate base, has also been adjusted to reflect the correction of 2024 and 2025 depreciation impacts, at Exhibit B, Tab 1, Schedule 5, page 4, line 39.

14. Additionally, Enbridge Gas has provided as a utility adjustment the elimination of 2023 Getting Ontario Connected Variance Account disallowance. In its Decision and Order in EB-2024-0125, dated September 23, 2025, the OEB disallowed the $3 million related to incremental VMS program costs from the balance to be

[2] The adjustments were described initially in EB-2022-0200, Exhibit 4, Tab 4, Schedule 3, Attachment 3, Table 6-3.

recovered from customers through disposition of this variance account. Enbridge Gas reflected the disallowance as a write-off (or reversal of deferral treatment) in its 2025 Corporate financial results. However, given that the disallowed amount pertained to 2023 Enbridge Gas' utility results, where Enbridge Gas was not in an earnings sharing position, it has been removed from 2025 utility results.

Summary
Return on Equity
Enbridge Gas Inc.

For The Year Ended December 31, 2025

Line No.	Col. 1 Description	Col. 2 Reference	Col. 3 Actual
1	Return on Equity & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax	(Ex. B, Tab 1, Sch. 3)	1,250.0
3	Less: Long Term Debt Costs	(Ex. B, Tab 1, Sch. 6)	410.8
4	Less: Short Term Debt Costs	(Ex. B, Tab 1, Sch. 6)	14.0
5	Less: Cost of Preferred Capital	(Ex. B, Tab 1, Sch. 6)	0.0
6	Net Income before Income Taxes		825.2
7	Less: Income Taxes	(Ex. B, Tab 1, Sch. 4)	141.5
8	Net Income Applicable to Common Equity	(line 6 - line 7)	683.6
9	Common Equity	(Ex. B, Tab 1, Sch. 6)	6,345.0
10	Approved ROE (including deadband before earning sharing) %	(Board-approved + 100bp)	10.210%
11	Achieved Rate of Return on Equity %	(line 8 / line 9)	10.774%
12	Resulting (Deficiency) / Sufficiency in Return on Equity %		0.564%
13	Net Earnings (Deficiency) / Sufficiency	(line 9 x line 12)	35.8
14	Provision for Income Taxes		12.9
15	Gross Earnings (Deficiency) / Sufficiency	(line 13 / 73.5%)	48.7
16	50% Earnings sharing to ratepayers	(if line 15 > 1, line 15 x 50%)	24.3

EGI Utility Income
2025 Actual

Line No.	Particulars	Reference	Col. 1 Corporate (a)	Col. 2 Unregulated Operations (b)	Col. 3 Adjustments (c)	Col. 4 Utility Income (d) = (a)-(b)+(c) ($Millions)
1	Gas sales and distribution	(Ex. B, Tab 2, Sch. 1)	5,546.4	-	(3.0) (i)	5,543.4
2	Transportation	(Ex. B, Tab 2, Sch. 2)	169.7	(1.2)	(5.6) (ii)	165.3
3	Storage	(Ex. B, Tab 2, Sch. 2)	326.8	326.8	(0.1) (iii)	(0.0)
4	Other operating revenue	(Ex. B, Tab 2, Sch. 3)	69.7	7.1	(10.8) (iv)	51.8
5	Other income	(Ex. B, Tab 2, Sch. 3)	13.8	(0.1)	(8.8) (viii)	5.1
6	Total operating revenue		6,126.3	332.6	(28.2)	5,765.5
7	Gas costs		2,660.7	103.5	5.9 (ix)	2,563.2
8	Operation and maintenance	(Ex. B, Tab 3, Sch. 1)	1,089.3	27.0	(14.3) (v)	1,048.0
9	Depreciation and amortization expense		808.2	19.2	(25.3) (vi)	763.8
10	Fixed financing costs		2.2	-	1.8 (vii)	4.0
11	Municipal and other taxes		139.2	2.7	-	136.4
12	Cost of service		4,699.6	152.2	(31.8)	4,515.5
13	Utility income before income taxes					1,250.0
14	Income tax expense	(Ex. B, Tab 1, Sch. 4)				141.5
15	Utility income					1,108.5

Notes on Adjustments:

(i)	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues	(14.7)
	2025 TVDA adjustment to reflect retroactive Bill C-15 enacted in 2026	(13.6)
	Elimination of ESM amount booked in 2025	25.3
		(3.0)
(ii)	Elimination of the shareholder portion of net optimization activity (before tax)	(5.6)
(iii)	Elimination of the Union rate zone shareholder portion of net short-term storage revenue (before tax)	(0.1)
(iv)	Elimination of demand-side management incentive	(10.8)
(v)	Elimination of donations	(3.1)
	Elimination of 2023 Getting Ontario Connected Variance Account disallowance	(3.0)
	Adjust for 2025 DSMVA correction recognized subsequent to year end Corporate financial statements	0.9
	Elimination of Central Functions Corporate Allocation Methodology (CFCAM) charges	(9.1)
		(14.3)
(vi)	Eliminate amortization of PPD (purchase price discrepancy)	(22.5)
	Adjust for 2025 depreciation correction recognized subsequent to year end Corporate financial statements	(2.8)
		(25.3)
(vii)	Interest on security deposits held during the year and included in elimination of corporate interest exp. Expense incurred to reduce bad debt. The average amount of the security deposit held during the year is applied as a reduction to the allowance for working capital in rate base	1.8
(viii)	Elimination of interest income from investments not included in utility rate base	(0.4)
	Elimination of the portion of gains on sale of assets not shared through deferral	(8.5)
		(8.8)
ix)	Adjust for 2025 S&TDA correction recognized subsequent to year end Corporate financial statements	5.9

Calculation of EGI Utility Taxable Income and Income Tax Expense
2025 Actual

Line No.	Particulars	Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1	Utility income before income taxes	1,250.0	1,250.0	
	Add			
2	Depreciation and amortization	763.8	763.8	
3	Accrual based pension and OPEB costs	(51.1)	(51.1)	
4	Other non-deductible items	2.6	2.6	
5	Total Add Back	715.3	715.3	
6	Sub-total	1,965.3	1,965.3	
	Deduct			
7	Capital cost allowance	881.1	881.1	
8	Items capitalized for regulatory purposes	125.7	125.7	
9	Amortization of share/debenture issue expense	(0.1)	(0.1)	
10	Amortization of C.D.E. and C.O.G.P.E	0.0	0.0	
11	Other	(2.6)	(2.6)	
12	Cash based pension and OPEB costs	2.2	2.2	
13	Total Deduction	1,006.4	1,006.4	
14	Taxable income	959.0	959.0	
15	Income tax rates	15.00%	11.50%	
16	Tax provision excluding interest shield	143.8	110.3	254.1
	Tax shield on interest expense			
17	Rate base	16,697.4		
18	Return component of debt	2.54%		
19	Interest expense	424.8		
20	Combined tax rate	26.50%		
21	Income tax credit			(112.6)
22	Total utility income taxes			141.5

Enbridge Gas Inc.
Summary of Capital Cost Allowance (CCA)

Line No.	Class	Particulars ($000s)	Col. 1 UCC at Prior Year Filing EB-2025-0155 (a)	Col. 2 True-up from Filing to Tax Return (b)	Col. 4 UCC At Beginning of Year (d)	Col. 5 Total Additions Qualifying for RIIP (e)	Total Additions Not Qualifying for RIIP (f)	Col. 6 Less: Lessor of Cost or Proceeds (g)	Col. 7 Eligible CCA Additions (h)	Col 8 Depreciable UCC Balance (i)	Col. 9 Rate (%) (j)	Col. 10 CCA FY2025 (k) = (i) x (j)	Col. 11 Ending UCC (l) = (d) + (e) + (f) + (g) - (k)
1	1	Buildings, structures and improvements, services, meters, mains	2,024,265.4	(29,249.2)	1,995,016.2	2,898.7	2,229.0	(4,922.1)	205.7	1,994,210.2	4%	79,768.4	1,915,453.5
2	1	Non-residential building acquired after March 19, 2007	165,851.4	28,651.9	194,503.3	48,028.8	26,551.7	-	74,580.5	293,098.3	6%	17,585.9	251,498.0
3	2	Mains acquired before 1988	120,129.3	-	120,129.3	-	-	-	-	120,129.3	6%	7,207.8	112,921.6
4	3	Buildings acquired before 1988	2,441.0	-	2,441.0	-	-	-	-	2,441.0	5%	122.0	2,318.9
5	6	Other buildings	51.4	-	51.4	-	-	-	-	51.4	10%	5.1	46.2
6	7	Compression equipment acquired after February 22, 2005	268,305.6	(3.0)	268,302.6	23,824.6	9,392.2	-	33,216.9	313,431.7	15%	47,014.8	254,504.7
7	8	Compression assets, office furniture, equipment	203,686.1	(163.7)	203,522.4	101,541.1	105,327.2	-	206,868.3	461,161.3	20%	92,232.3	318,158.5
8	10	Transportation, computer equipment	24,451.0	3.8	24,454.8	11,279.2	6,494.1	(753.0)	17,020.3	46,738.2	30%	14,021.5	27,453.6
9	12	Computer software, small tools	-	-	-	7,310.4	5,547.4	-	12,857.9	12,857.9	100%	12,857.9	-
10	13	Leasehold improvements	-	15.5	15.5	-	-	-	-	15.5		1.0	14.4
11	14.1	Intangibles	15,036.3	(145.8)	14,890.4	3,556.1	1,095.3	-	4,651.5	21,320.0	5%	1,066.0	18,475.9
12	14.1	Intangibles (pre 2017)	34,992.5	128.7	35,121.2	-	-	-	-	35,121.2	7%	2,458.5	32,662.8
13	17	Roads, sidewalk, parking lot or storage areas	360.1	-	360.1	-	-	-	-	360.1	8%	28.8	331.3
14	38	Heavy work equipment	8,992.1	1.1	8,993.2	3,709.6	2,129.0	(158.8)	5,679.8	16,448.5	30%	4,934.5	9,738.5
15	41	Storage assets	111,178.6	6.9	111,185.5	7,804.6	2,814.4	-	10,619.0	125,706.8	25%	31,426.7	90,377.8
16	45	Computers - Hardware acquired after March 22, 2004	0.6	-	0.6	-	-	-	-	0.6	45%	0.3	0.3
17	49	Transmission pipeline additions acquired after February 23, 2005	1,284,328.0	(16.3)	1,284,311.8	21,037.1	73,157.4	-	94,194.5	1,389,024.8	8%	111,122.0	1,267,384.3
18	50	Computers hardware acquired after March 18, 2007	11,952.5	(2,110.4)	9,842.1	10,052.2	4,348.1	-	14,400.2	29,268.4	55%	16,097.6	8,144.7
19	51	Distribution pipelines acquired after March 18, 2007	6,190,190.6	3,556.5	6,193,747.1	588,965.0	259,225.2	(394.9)	847,795.2	7,335,827.4	6%	443,149.0	6,598,393.4
20		Total	10,466,212.5	676.0	10,466,888.5	830,007.5	498,311.0	(6,228.7)	1,322,089.8	12,197,212.5		881,100.0	10,907,878.3

EGI Utility Rate Base
2025 Actual

Line No.	Particulars ($ millions)	Col. 1 2025 Actual	Col. 2 2024 Actual	Col. 3 Variance
	Property, Plant, and Equipment			
1	Gross property, plant, and equipment	25,349.4	24,298.0	1,051.3
2	Accumulated depreciation	(9,311.2)	(8,839.3)	(471.9)
3	Net property, plant, and equipment	16,038.2	15,458.7	579.5
	Allowance for Working Capital			
4	Materials and supplies	152.5	128.5	24.0
5	ABC receivable	(22.2)	(17.5)	(4.7)
6	Customer security deposits	(64.3)	(65.8)	1.5
7	Prepaid expenses	-	6.7	(6.7)
8	Gas in storage	624.6	609.6	15.0
9	Working cash allowance	(31.3)	(94.9)	63.6
10	Total Working Capital	659.2	566.6	92.7
11	Utility Rate Base	16,697.4	16,025.3	672.1

EGI Utility Property, Plant, and Equipment
Summary Statement - Average of Monthly Averages
2025 Actual

Line No.	Particulars ($ millions)	Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
1	Underground storage plant	1,616.0	(571.6)	1,044.4
2	Transmission plant	5,328.8	(1,854.0)	3,474.8
3	Distribution plant	17,576.5	(6,452.5)	11,124.0
4	General plant	781.2	(408.9)	372.4
5	Local storage plant	43.5	(20.9)	22.6
6	Intangible plant	3.3	(3.3)	
7	EGI Total	25,349.4	(9,311.2)	16,038.2

EGI Utility Gross Plant
Year End Balances and Average of Monthly Averages
2025 Actual

Line No.	Particulars ($ millions)	Col. 1 Opening Balance Dec.2024	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2025	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2025	Col. 7 Average of Monthly Averages
	Underground Storage Plant - EGI							
1	Land (450)	18.4	4.8	-	23.3	(1.0)	22.3	17.6
2	Land rights (451)	74.8	-	(0.5)	74.3	-	74.3	74.4
3	Structures and improvements (452)	142.5	7.7	-	150.2	(0.1)	150.1	142.7
4	Wells (453)	154.8	6.0	(0.1)	160.7	-	160.7	156.3
5	Well equipment (454)	16.9	0.3	(0.0)	17.1	-	17.1	17.1
6	Field Lines (455)	229.3	4.5	(0.0)	233.8	-	233.8	232.6
7	Compressor equipment (456)	673.9	17.2	-	691.1	(0.5)	690.6	674.9
8	Measuring and regulating equipment (457)	222.5	2.4	-	224.9	-	224.9	224.6
9	Base pressure gas (458)	75.7	-	-	75.7	-	75.7	75.7
10	Sub-Total	1,608.8	42.9	(0.6)	1,651.1	(1.5)	1,649.6	1,616.0
	Transmission Plant - EGI							
11	Land (460)	87.7	7.1	-	94.8	-	94.8	89.7
12	Land Rights (461.001)	91.7	4.5	-	96.2	-	96.2	95.6
13	Structures & improvements (462/463/464)	187.8	1.2	-	189.0	-	189.0	188.0
14	Mains (465)	3,297.8	25.8	7.7	3,331.3	-	3,331.3	3,299.7
15	Compressor equipment (466)	1,041.3	15.1	-	1,056.4	-	1,056.4	1,045.1
16	Measuring & regulating equipment (467)	563.9	120.6	-	684.6	-	684.6	584.9
17	Meters (478)	25.7	-	-	25.7	-	25.7	25.7
18	Line Pack Gas	0.2	0.0	-	0.2	-	0.2	0.2
19	Sub-Total	5,296.1	174.3	7.7	5,478.1	-	5,478.1	5,328.8
	Distribution Plant - EGI							
20	Renewable Natural Gas (461)	18.6	-	-	18.6	-	18.6	18.6
21	Land (470)	103.9	0.9	(0.3)	104.5	-	104.5	104.5
22	Land rights (471)	66.8	0.2	-	67.0	-	67.0	66.9
23	Structures and improvements (472)	355.9	81.4	(19.7)	417.7	(0.3)	417.3	386.4
24	Services - metallic (473)	655.6	45.9	(3.2)	698.3	-	698.3	679.4
25	Services - plastic (473)	5,198.6	243.8	(9.9)	5,432.5	-	5,432.5	5,299.8
26	Regulators (474)	515.7	50.5	(12.7)	553.4	-	553.4	540.1
27	Mains - metallic (475)	4,012.5	218.3	(6.5)	4,224.2	(2.2)	4,222.0	4,042.4
28	Mains - plastic (475)	3,946.9	146.2	(0.7)	4,092.4	-	4,092.4	3,990.9
29	NGV station compressors (476)	11.1	(0.0)	-	11.1	-	11.1	11.3
30	Measuring and regulating equip. (477)	1,150.9	45.7	(2.4)	1,194.1	(0.5)	1,193.6	1,164.3
31	Meters (478)	1,236.6	109.0	(36.9)	1,308.8	-	1,308.8	1,271.8
32	Sub-Total	17,273.2	941.9	(92.5)	18,122.6	(3.1)	18,119.5	17,576.5
	General Plant - EGI							
33	Investment in leased assets (101)	16.3	-	-	16.3	-	16.3	16.3
34	Land (480)	0.5	-	-	0.5	-	0.5	0.5
35	Structure & Improvements (482)	232.8	0.0	(3.9)	229.0	(0.2)	228.8	231.3
36	Office furniture and equipment (483)	28.7	0.1	(1.4)	27.4	-	27.4	28.1
37	Transportation equipment (484)	152.2	18.2	(6.1)	164.4	(0.1)	164.3	156.1
38	NGV conversion kits (484)	3.1	-	-	3.1	-	3.1	3.1
39	Heavy work equipment (485)	56.8	6.0	(0.6)	62.3	-	62.3	58.6
40	Tools and work equipment (486)	62.8	10.4	(0.2)	72.9	-	72.9	65.6
41	Rental equipment (487)	2.7	-	-	2.7	-	2.7	2.7
42	NGV rental compressors (487)	9.0	0.0	-	9.0	-	9.0	9.0
43	NGV cylinders (484 and 487)	0.6	-	-	0.6	-	0.6	0.6
44	Communication structures & equip. (488)	1.9	0.0	-	1.9	-	1.9	1.9
45	Computer equipment (490)	30.7	12.0	(8.8)	34.0	-	34.0	28.1
46	Software Aquired/Developed (491)	117.0	16.3	(24.0)	109.3	-	109.3	142.8
47	WAMS (489)	66.3	-	-	66.3	-	66.3	36.4
48	Sub-Total	781.5	63.1	(44.9)	799.7	(0.3)	799.4	781.2
	Intangible Plant - EGI							
49	Inactive services (102)	1.7	-	-	1.7	-	1.7	1.7
50	Franchises and consents (401)	1.2	-	-	1.2	-	1.2	1.2
51	Other intangible plant (402)	0.5	-	-	0.5	-	0.5	0.5
52	Sub-Total	3.3	-	-	3.3	-	3.3	3.3
	Local Storage Plant - EGI							
53	Land (440)	0.0	-	-	0.0	-	0.0	0.0
54	Structures and improvements (442)	7.4	0.8	-	8.2	-	8.2	7.8
55	Gas holders - storage (443)	7.0	0.2	-	7.2	-	7.2	7.1
56	Gas holders - equipment (443)	28.5	0.2	-	28.7	-	28.7	28.6
57	Sub-Total	42.9	1.2	-	44.1	-	44.1	43.5
58	EGI Total	25,005.8	1,223.4	(130.2)	26,098.9	(4.8)	26,094.1	25,349.4

EGI Utility Plant
Continuity of Accumulated Depreciation
Year End Balances And Average of Monthly Averages
2025 Actual

Line No.	Particulars ($ millions)	Col. 1 Opening Balance Dec.2024	Col. 2 Depreciation	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Net SRCVA	Col. 6 Adjustments & Other	Col. 7 Closing Balance Dec.2025	Col. 8 Regulatory Adjustment	Col. 9 Utility Balance Dec.2025	Col. 10 Average of Monthly Averages
	Underground Storage Plant - EGI										
1	Land and gas storage rights (451)	(49.3)	(1.1)	0.5	-	-	-	(49.8)	-	(49.8)	(49.4)
2	Structures and improvements (452)	(68.2)	(3.7)	-	0.0	0.3	(0.0)	(71.6)	0.1	(71.5)	(69.8)
3	Wells (453)	(59.0)	(6.4)	0.1	0.2	1.4	(0.0)	(63.8)	-	(63.8)	(61.4)
4	Well equipment (454)	(10.4)	(0.2)	0.0	-	-	-	(10.5)	-	(10.5)	(10.5)
5	Field Lines (455)	(92.6)	(5.5)	0.0	0.0	0.6	(0.1)	(97.5)	-	(97.5)	(95.0)
6	Compressor equipment (456)	(212.3)	(16.3)	-	1.8	(0.5)	0.1	(227.1)	0.3	(226.8)	(219.4)
7	Measuring and regulating equipment (457)	(63.5)	(5.6)	-	2.3	(1.2)	(0.0)	(68.0)	-	(68.0)	(66.1)
8	Sub-Total	(555.2)	(38.6)	0.6	4.3	0.6	(0.1)	(588.4)	0.4	(588.0)	(571.6)
	Transmission Plant - EGI										
9	Land rights (461)	(22.8)	(1.2)	-	-	-	-	(23.9)	-	(23.9)	(23.3)
10	Structures and improvements (462)	(63.0)	(4.3)	-	0.0	0.3	(0.0)	(67.0)	-	(67.0)	(65.0)
11	Mains (465)	(1,092.8)	(46.7)	(7.7)	2.0	4.6	9.2	(1,131.4)	-	(1,131.4)	(1,112.0)
12	Compressor equipment (466)	(429.4)	(34.4)	-	0.0	1.5	(0.2)	(462.4)	-	(462.4)	(445.8)
13	Measuring and regulating equipment (467)	(200.8)	(16.0)	-	0.6	0.8	0.5	(214.8)	-	(214.8)	(207.9)
14	Sub-Total	(1,808.8)	(102.6)	(7.7)	2.7	7.2	9.5	(1,899.6)	-	(1,899.6)	(1,854.0)
	Distribution Plant - EGI										
15	Renewable Natural Gas (461)	(1.5)	-	-	-	-	-	(1.5)	-	(1.5)	(1.5)
16	Land rights (471)	(15.0)	(1.1)	-	-	-	-	(16.1)	-	(16.1)	(15.5)
17	Structures and improvements (472)	(114.2)	(14.0)	19.7	(2.6)	-	(0.1)	(111.1)	0.3	(110.8)	(108.5)
18	Services - metallic (473)	(405.9)	(22.2)	2.8	(17.6)	22.5	(0.1)	(420.4)	-	(420.4)	(415.1)
19	Services - plastic (473)	(1,606.1)	(152.0)	10.3	99.2	(63.7)	0.5	(1,711.8)	-	(1,711.8)	(1,660.9)
20	Regulators (474)	(192.3)	(48.0)	12.7	0.6	(0.6)	(1.0)	(228.6)	-	(228.6)	(216.0)
21	Mains - metallic (475)	(1,515.7)	(105.2)	6.5	(1.9)	25.1	(8.5)	(1,599.6)	2.2	(1,597.4)	(1,554.2)
22	Mains - plastic (475)	(1,353.3)	(77.2)	0.7	4.6	9.9	(0.3)	(1,415.5)	-	(1,415.5)	(1,384.3)
23	NGV station compressors (476)	(6.6)	(0.4)	-	-	-	-	(6.9)	-	(6.9)	(6.8)
24	Measuring and regulating equip. (477)	(426.4)	(32.1)	2.4	9.5	(7.0)	(0.1)	(453.6)	1.1	(452.5)	(439.2)
25	Meters (478)	(616.8)	(107.1)	36.9	(0.5)	0.5	-	(687.0)	-	(687.0)	(650.5)
26	Sub-Total	(6,253.7)	(559.2)	92.2	91.3	(13.2)	(9.5)	(6,652.1)	3.6	(6,648.5)	(6,452.5)
	General Plant - EGI										
27	Investment in leased assets (101)	(1.4)	-	-	-	-	(0.6)	(2.0)	-	(2.0)	(1.7)
28	Structures & improvements (482)	(73.0)	(13.1)	3.9	-	-	(0.2)	(82.4)	0.2	(82.2)	(78.1)
29	Office furniture and equipment (483)	(23.5)	(1.3)	1.4	-	-	-	(23.5)	-	(23.5)	(23.5)
30	Transportation equipment (484)	(117.9)	(5.5)	6.1	(0.7)	0.8	-	(117.3)	0.1	(117.2)	(118.2)
31	NGV conversion kits (484)	(0.5)	(0.1)	-	-	-	-	(0.7)	-	(0.7)	(0.6)
32	Heavy work equipment (485)	(20.6)	(3.4)	0.6	(0.2)	0.2	-	(23.4)	-	(23.4)	(22.1)
33	Tools and work equipment (486)	(12.6)	(7.6)	0.2	0.0	(0.0)	-	(20.0)	-	(20.0)	(16.4)
34	Rental equipment (487)	(0.2)	(0.1)	-	-	-	-	(0.3)	-	(0.3)	(0.3)
35	NGV rental compressors (487)	(4.3)	(0.4)	-	-	-	-	(4.7)	-	(4.7)	(4.4)
36	NGV cylinders (484 and 487)	(0.6)	(0.0)	-	-	-	-	(0.6)	-	(0.6)	(0.6)
37	Communication equipment (488)	2.4	(0.5)	-	-	-	-	1.8	-	1.8	2.1
38	Computer equipment (490)	(16.9)	(5.1)	8.8	-	-	-	(13.2)	-	(13.2)	(15.4)
39	Software Aquired/Developed (491) (1)	(71.3)	(18.1)	24.0	-	-	2.3	(63.1)	-	(63.1)	(68.1)
40	WAMS (489)	(57.1)	(9.1)	-	-	-	-	(66.3)	-	(66.3)	(61.7)
41	Sub-Total	(397.5)	(64.4)	44.9	(0.9)	0.9	1.5	(415.6)	0.3	(415.3)	(408.9)
	Local Storage Plant - EGI										
42	Structures and improvements (442)	(3.2)	(0.1)	-	0.0	(0.0)	(0.0)	(3.3)	-	(3.3)	(3.2)
43	Gas holders - storage (443)	(4.4)	(0.1)	-	-	-	(0.0)	(4.4)	-	(4.4)	(4.4)
44	Gas holders - equipment (443)	(13.1)	(0.3)	-	-	-	0.0	(13.4)	-	(13.4)	(13.3)
45	Sub-Total	(20.6)	(0.5)	-	0.0	(0.0)	(0.0)	(21.2)	-	(21.2)	(20.9)
	Intangible Plant - EGI										
46	Inactive services (102)	(1.6)	(0.0)	-	-	-	-	(1.6)	-	(1.6)	(1.6)
47	Franchises and consents (401)	(1.2)	(0.1)	-	-	-	-	(1.2)	-	(1.2)	(1.2)
48	Other intangible plant (402)	(0.5)	-	-	-	-	-	(0.5)	-	(0.5)	(0.5)
49	Sub-Total	(3.3)	(0.1)	-	-	-	-	(3.4)	-	(3.4)	(3.3)
50	EGI Total	(9,039.1)	(765.4)	129.9	97.4	(4.5)	1.5	(9,580.2)	4.2	(9,575.9)	(9,311.2)

Notes:
(1) Opening balance and current year amortization have been updated to reflect adjustments related to depreciation error impacting 2024 & 2025.

EGI Working Capital Components
Month End Balances and Average of Monthly Averages
2025 Actual

Line No.	Particulars ($ millions)	Col. 1 Materials and Supplies	Col. 2 ABC Receivable	Col. 3 Customer Security Deposits	Col. 4 Gas in Storage	Col. 5 Working Cash Allowance	Col. 6 Total
1	January 1	142.5	(16.8)	(65.0)	644.0	(31.3)	673.5
2	January 31	144.2	(10.3)	(63.3)	540.1	(31.3)	579.4
3	February	145.0	(22.1)	(63.1)	453.8	(31.3)	482.2
4	March	146.5	(46.0)	(64.2)	361.4	(31.3)	366.3
5	April	153.7	(38.9)	(63.7)	411.1	(31.3)	430.9
6	May	152.7	(35.3)	(64.1)	465.0	(31.3)	486.9
7	June	153.5	(45.5)	(64.5)	569.1	(31.3)	581.3
8	July	156.0	(21.1)	(63.9)	686.4	(31.3)	726.2
9	August	156.0	(11.0)	(64.7)	794.8	(31.3)	843.8
10	September	157.7	(14.8)	(67.4)	887.6	(31.3)	931.8
11	October	157.0	(0.1)	(66.5)	886.3	(31.3)	945.4
12	November	159.1	(2.0)	(63.5)	775.9	(31.3)	838.2
13	December	155.4	(22.9)	(61.3)	683.0	(31.3)	722.9
14	Avg. of monthly avgs.	152.5	(22.2)	(64.3)	624.6	(31.3)	659.2

EGI Summary of Capital Structure & Cost of Capital
2025 Actual

Line No.	Particulars	Col. 1 Utility Capital Structure Principal	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component	Col. 5 (Col. 1x Col. 3 Interest & Return
		($Millions)	%	%	%	($Millions)
1	Long and Medium-Term Debt	9,867.5	59.10	4.16	2.460	410.8
2	Short-Term Debt	484.9	2.90	2.89	0.084	14.0
3	Total Debt	10,352.4	62.00		2.544	424.8
4	Preference Shares	-	-	-	-	-
5	Common Equity	6,345.0	38.00	10.21	3.880	647.8
6	Total Rate Base	16,697.4	100.00		6.424	1,072.7

Calculation of Cost Rates
For EGI Capital Structure Components
2025 Actual

Line No.	Particulars		Col. 1 Average of Monthly Averages ($Millions)	Col. 2	Col. 3 Carrying Cost ($Millions)
	Long and Medium-Term Debt				
1	Debt Summary		10,133.5		425.8
2	Unamortized Finance Costs		94.0		-
3	(Profit)/Loss on Redemption		-		-
4			10,227.5		425.8
5	Percentage Allocation of Debt to Unregu	3.52%	(360.0)		(15.0)
6	Net Regulated Long and Medium-Term Debt		9,867.5		410.8
7	Calculated Cost Rate			4.16%	
	Short-Term Debt				
8	Calculated Cost Rate			2.89%	
	Common Equity				
9	Board Formula ROE			9.21%	
10	Threshold before earnings sharing			1.00%	

EGI Summary Statement of Principal
and Carrying Costs of
Term Debt
2025 Actual

Line No.	Coupon Rate	Maturity Date	Col. 1 Average of Monthly Average Principal	Col. 2 Effective Cost Rate	Col. 3 Carrying Cost
			($Millions)		($Millions)
Medium Term Notes					
1	4.20%	June 2, 2044	250.0	4.24%	10.6
2	4.20%	June 2, 2044	250.0	4.27%	10.7
3	6.05%	September 2, 2038	300.0	6.10%	18.3
4	4.88%	June 21, 2041	300.0	4.92%	14.8
5	5.20%	July 23, 2040	250.0	5.27%	13.2
6	2.81%	June 1, 2026	250.0	2.87%	7.2
7	3.80%	June 1, 2046	250.0	3.84%	9.6
8	2.88%	November 22, 2027	250.0	2.95%	7.4
9	3.59%	November 22, 2047	250.0	3.64%	9.1
10	3.19%	September 17, 2025	141.7	3.26%	4.6
11	5.46%	September 11, 2036	165.0	5.49%	9.1
12	8.65%	November 10, 2025	109.4	8.77%	9.6
13	8.85%	October 2, 2025	15.8	8.97%	1.4
14	7.60%	October 29, 2026	100.0	8.09%	8.1
15	6.65%	November 3, 2027	100.0	6.71%	6.7
16	6.10%	May 19, 2028	100.0	6.16%	6.2
17	6.90%	November 15, 2032	150.0	6.95%	10.4
18	6.16%	December 16, 2033	150.0	6.18%	9.3
19	5.21%	February 25, 2036	300.0	5.18%	15.5
20	4.95%	November 22, 2050	200.0	4.99%	10.0
21	4.95%	November 22, 2050	100.0	4.73%	4.7
22	4.50%	November 23, 2043	200.0	4.20%	8.4
23	4.00%	August 22, 2044	215.0	3.89%	8.4
24	4.00%	August 22, 2044	170.0	4.44%	7.5
25	3.31%	September 11, 2025	283.3	3.62%	10.3
26	2.50%	August 5, 2026	300.0	3.42%	10.3
27	3.51%	November 29, 2047	300.0	3.53%	10.6
28	2.37%	August 9, 2029	400.0	3.23%	12.9
29	3.01%	August 9, 2049	300.0	3.03%	9.1
30	2.90%	April 1, 2030	600.0	3.41%	20.4
31	3.65%	April 1, 2050	600.0	3.67%	22.0
32	2.35%	September 1, 2031	475.0	2.94%	14.0
33	3.20%	September 1, 2051	425.0	3.22%	13.7
34	4.15%	August 17, 2032	325.0	3.15%	10.2
35	4.55%	August 17, 2052	325.0	4.52%	14.7
36	5.46%	October 6, 2028	250.0	5.54%	13.9
37	5.70%	October 6, 2033	400.0	3.70%	14.8
38	5.67%	October 6, 2053	350.0	5.08%	17.8
39	4.16%	September 12, 2035	145.8	4.16%	6.1
40	4.84%	September 12, 2055	87.5	4.83%	4.2
41	Total Term Debt		10,133.5		425.8

EGI Unamortized Debt Discount and Expense
Average of Monthly Averages
2025 Actual

Line No.	Particulars	Col. 1 Unamortized Debt Discount and Expense
		($Millions)
1.	January 1	(95.1)
2.	January 31	(93.5)
3.	February	(93.5)
4.	March	(93.5)
5.	April	(93.5)
6.	May	(93.5)
7.	June	(93.5)
8.	July	(93.5)
9.	August	(93.5)
10.	September	(95.5)
11.	October	(95.0)
12.	November	(94.9)
13.	December	(94.8)
14.	Average of Monthly Averages	(94.0)

Reconciliation of Audited EGI Income (Per Financial Statements)
To Corporate Income for Utility Income Determination Purposes
2025 Actual

Line No.	Parituclars ($ millions)	Col. 1 Audited Income (as per Financial Statements)	Col. 2 Corporate Income (as per Utility Income Schedule)	Col. 3 Variance	Col. 4 Reference
	Operating Revenues				
1.	Gas sales and distribution	5,545.5	5,546.4		
2.	Storage, transportation and other	567.0	-		
3.	Transportation	-	169.7		
4.	Storage	-	326.8		
5.	Other operating revenue	-	69.7		
6.	Other Income	102.0	13.8		
7.	Total operating revenue	6,214.5	6,126.3	(88.2)	(a)
	Operating Expenses				
8.	Gas Costs	2,660.7	2,660.7	-	
9.	Operation and maintenance	1,317.1	1,089.3	(227.8)	(b)
10.	Depreciation and amortization expense	808.2	808.2	-	
11.	Impairment of long-lived assets	-	-	-	
12.	Fixed financing costs	-	2.2	2.2	(c)
13.	Municipal and other taxes	-	139.2	139.2	(d)
14.	Cost of service	4,786.0	4,699.6	(86.4)	
15.	Income before interest and income taxes	1,428.5	1,426.7	(1.8)	
16.	Interest and financing expenses	448.1	-	(448.1)	(e)
17.	Income before income taxes	980.4	1,426.7	446.3	
18.	Income taxes	190.9	-	(190.9)	(f)
19.	Net Income	789.5	1,426.7	637.2	

Col. 2 - Corporate income as reported in Exhibit B, Tab 1, Schedule 3, Column 1

a)	Audited Total Operating Revenue	6,214.5
	Reclassify pension related other revenue to O&M	(89.0)
	Reclassify other expenses out of other income to O&M	0.4
	Reclassify bank interest to interest and financing expenses	0.3
	Rounding	0.1
	Corporate Total Operating Revenue	6,126.3
b)	Audited Operation and Maintenance	1,317.1
	Reclassify pension related other revenue to O&M	(89.0)
	Reclassify Municipal & Property Taxes out of O&M	(139.2)
	Reclassify other expenses out of other income to O&M	0.4
	Corporate Operation and Maintenance	1,089.3
c)	Audited Fixed Financing Costs	-
	Reclassify fixed financing costs from interest and financing expenses	2.2
	Corporate Fixed Financing Costs	2.2
d)	Audited Municipal and Other Taxes	-
	Reclassify Municipal and other taxes included within O&M costs	139.2
	Corporate Municipal and Other Taxes	139.2
e)	Audited Interest and Financing expenses	448.1
	Reclassify fixed financing costs from interest and financing expenses	(2.2)
	Reclassify bank interest from other revenue	0.3
	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure	(446.2)
	Corporate Interest and Financing expenses	-
f)	Audited Income Taxes	190.9
	Elimination of corporate income taxes which will be calculated on a utility stand-alone basis	(190.9)
	Corporate Income Taxes	-

Average Customers by Rate Class

Line No.	Particulars	2024 Actual Sales Service	2024 Actual Direct Purchase	2024 Actual Total	2025 Actual Sales Service	2025 Actual Direct Purchase	2025 Actual Total	Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-c)
	General Service							
1	Rate 1	2,135,254	25,993	2,161,247	2,155,832	23,636	2,179,468	18,221
2	Rate 6	147,679	23,796	171,475	150,212	23,834	174,046	2,571
3	Rate M1	1,175,355	27,897	1,203,251	1,185,658	26,822	1,212,479	9,228
4	Rate M2	5,294	3,854	9,148	5,585	3,884	9,469	320
5	Rate 01	360,504	10,043	370,547	363,227	9,652	372,879	2,332
6	Rate 10	1,550	1,001	2,551	1,555	1,007	2,562	11
7	Total General Service	3,825,635	92,584	3,918,219	3,862,068	88,834	3,950,903	32,683
	Contract							
8	Rate 100 (1)	6	15	21	7	14	21	(0)
9	Rate 110	76	398	473	83	411	494	20
10	Rate 115	0	17	17	0	16	16	(0)
11	Rate 125	0	4	4	0	4	4	0
12	Rate 135	3	40	43	4	40	45	2
13	Rate 145	1	14	15	1	14	15	(1)
14	Rate 170	0	20	20	0	20	20	(0)
15	Rate 200	1	0	1	1	0	1	0
16	Rate 300	0	0	0	0	0	0	0
17	Rate 315	0	0	0	0	0	0	0
18	Rate M4	25	196	221	34	190	224	3
19	Rate M5	11	30	42	13	29	42	0
20	Rate M7	2	68	70	3	73	77	6
21	Rate M9	1	3	4	1	3	4	0
22	Rate M10	1	0	1	0	0	0	(1)
23	Rate T1	0	37	37	0	39	39	2
24	Rate T2	0	27	27	0	26	26	(1)
25	Rate T3	0	1	1	0	1	1	0
26	Rate 20	5	60	65	5	62	67	2
27	Rate 25	27	17	43	51	55	105	62
28	Rate 30	0	0	0	0	0	0	0
29	Rate 100 (2)	0	11	11	0	9	9	(2)
30	Total Contract	159	957	1,117	202	1,005	1,207	91
31	Total Customers	3,825,794	93,542	3,919,336	3,862,270	89,840	3,952,110	32,774

Notes:
(1) EGD rate zone.
(2) Union North rate zone.

Throughput Volumes by Rate Class - Unnormalized

Line No.	Particulars (10^3m^3)	2024 Actual Sales Service	2024 Actual Direct Purchase	2024 Actual Total	2025 Actual Sales Service	2025 Actual Direct Purchase	2025 Actual Total	Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-c)
	General Service							
1	Rate 1	4,477,473	55,056	4,532,530	5,099,073	55,155	5,154,228	621,698
2	Rate 6	2,718,250	1,572,775	4,291,025	3,114,069	1,901,420	5,015,489	724,464
3	Rate M1	2,627,154	170,856	2,798,010	2,983,202	193,089	3,176,291	378,281
4	Rate M2	513,278	647,292	1,160,571	573,858	732,856	1,306,713	146,143
5	Rate 01	815,213	65,762	880,975	932,236	70,914	1,003,149	122,174
6	Rate 10	143,178	155,935	299,113	144,631	172,254	316,885	17,772
7	Total General Service	11,294,546	2,667,676	13,962,223	12,847,068	3,125,687	15,972,755	2,010,532
	Contract							
8	Rate 100 (1)	12,559	30,885	43,443	14,549	45,444	59,993	16,549
9	Rate 110	122,632	1,155,035	1,277,667	138,130	1,181,493	1,319,623	41,956
10	Rate 115	-	341,507	341,507	0	335,399	335,399	(6,108)
11	Rate 125	-	1,377,941	1,377,941	-	1,618,789	1,618,789	240,848
12	Rate 135	2,442	67,048	69,489	1,627	59,437	61,064	(8,425)
13	Rate 145	513	59,957	60,470	413	59,504	59,917	(553)
14	Rate 170	-	241,282	241,282	-	314,998	314,998	73,716
15	Rate 200	119,874	62,669	182,543	145,524	65,696	211,220	28,677
16	Rate 300	-	-	-	-	-	-	-
17	Rate 315	-	-	-	-	-	-	-
18	Rate M4	44,275	519,084	563,359	53,253	528,895	582,148	18,789
19	Rate M5	1,684	50,373	52,057	4,148	50,095	54,243	2,186
20	Rate M7	7,460	764,336	771,796	11,458	910,698	922,157	150,360
21	Rate M9	15,819	80,879	96,697	19,774	86,473	106,247	9,550
22	Rate M10	247	-	247	-	-	-	(247)
23	Rate T1	-	403,660	403,660	-	415,028	415,028	11,368
24	Rate T2	-	5,491,895	5,491,895	-	5,926,779	5,926,779	434,885
25	Rate T3	-	249,479	249,479	-	282,401	282,401	32,922
26	Rate 20	6,816	1,230,189	1,237,005	8,810	1,496,712	1,505,522	268,516
27	Rate 25	70,214	222,815	293,029	157,836	194,358	352,194	59,166
28	Rate 30	-	-	-	-	-	-	-
29	Rate 100 (2)	-	944,814	944,814	-	864,327	864,327	(80,487)
30	Total Contract	404,534	13,293,848	13,698,382	555,522	14,436,528	14,992,050	1,293,668
31	Total Throughput Volum	11,699,080	15,961,525	27,660,605	13,402,590	17,562,216	30,964,805	3,304,200

Notes:
(1) EGD rate zone.
(2) Union North rate zone.

Throughput Volumes by Rate Class - Normalized

Line No.	Particulars (10^3m^3)	2024 Actual Sales Service	2024 Actual Direct Purchase	2024 Actual Total	2025 Actual Sales Service	2025 Actual Direct Purchase	2025 Actual Total	Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-c)
	General Service							
1	Rate 1	5,010,075	61,795	5,071,871	4,855,164	52,580	4,907,744	(164,126)
2	Rate 6	2,989,982	1,743,179	4,733,161	2,992,308	1,831,663	4,823,971	90,810
3	Rate M1	2,956,058	194,443	3,150,501	2,887,822	187,111	3,074,933	(75,567)
4	Rate M2	571,616	726,100	1,297,716	553,913	717,263	1,271,176	(26,540)
5	Rate 01	919,537	73,391	992,927	907,209	69,069	976,278	(16,649)
6	Rate 10	159,083	172,926	332,009	141,210	168,025	309,235	(22,774)
7	Total General Service	12,606,350	2,971,834	15,578,184	12,337,627	3,025,711	15,363,338	(214,847)
	Contract							
8	Rate 100 (1)	12,559	30,885	43,443	14,549	45,444	59,993	16,549
9	Rate 110	122,632	1,155,035	1,277,667	138,130	1,181,493	1,319,623	41,956
10	Rate 115	-	341,507	341,507	0	335,399	335,399	(6,108)
11	Rate 125	-	1,377,941	1,377,941	-	1,618,789	1,618,789	240,848
12	Rate 135	2,442	67,048	69,489	1,627	59,437	61,064	(8,425)
13	Rate 145	513	59,957	60,470	413	59,504	59,917	(553)
14	Rate 170	-	241,282	241,282	-	314,998	314,998	73,716
15	Rate 200	119,874	62,669	182,543	145,524	65,696	211,220	28,677
16	Rate 300	-	-	-	-	-	-	-
17	Rate 315	-	-	-	-	-	-	-
18	Rate M4	44,275	519,084	563,359	53,253	528,895	582,148	18,789
19	Rate M5	1,684	50,373	52,057	4,148	50,095	54,243	2,186
20	Rate M7	7,460	764,336	771,796	11,458	910,698	922,157	150,360
21	Rate M9	15,819	80,879	96,697	19,774	86,473	106,247	9,550
22	Rate M10	247	-	247	-	-	-	(247)
23	Rate T1	-	403,660	403,660	-	415,028	415,028	11,368
24	Rate T2	-	5,491,895	5,491,895	-	5,926,779	5,926,779	434,885
25	Rate T3	-	249,479	249,479	-	282,401	282,401	32,922
26	Rate 20	6,816	1,230,189	1,237,005	8,810	1,496,712	1,505,522	268,516
27	Rate 25	70,214	222,815	293,029	157,836	194,358	352,194	59,166
28	Rate 30	-	-	-	-	-	-	-
29	Rate 100 (2)	-	944,814	944,814	-	864,327	864,327	(80,487)
30	Total Contract	404,534	13,293,848	13,698,382	555,522	14,436,528	14,992,050	1,293,668
31	Total Throughput Volum	13,010,884	16,265,683	29,276,566	12,893,149	17,462,239	30,355,388	1,078,822

Notes:
(1) EGD rate zone.
(2) Union North rate zone.

Revenue by Rate Class - Unnormalized

Line No.	Particulars ($ millions)	2024 Actual Sales Service	2024 Actual Direct Purchase	2024 Actual Total	2025 Actual Sales Service	2025 Actual Direct Purchase	2025 Actual Total	Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-c)
	General Service							
1	Rate 1	1,803.4	14.3	1,817.6	2,116.4	14.6	2,131.0	313.4
2	Rate 6	783.0	152.5	935.5	940.8	199.3	1,140.1	204.6
3	Rate M1	904.2	19.3	923.5	1,089.0	21.7	1,110.6	187.1
4	Rate M2	109.6	44.4	154.0	143.5	57.0	200.5	46.5
5	Rate 01	365.9	14.7	380.6	427.8	15.8	443.5	63.0
6	Rate 10	39.7	20.9	60.7	45.0	25.2	70.2	9.5
7	Total General Service	4,005.8	266.0	4,271.9	4,762.4	333.6	5,096.0	824.1
	Contract							
8	Rate 100 (2)	3.4	3.1	6.5	4.3	4.3	8.6	2.1
9	Rate 110	23.9	50.3	74.2	29.7	55.3	85.0	10.8
10	Rate 115	0.0	8.3	8.3	(0.0)	8.9	8.9	0.6
11	Rate 125	-	13.4	13.4	-	15.0	15.0	1.6
12	Rate 135	0.5	2.9	3.4	0.4	2.5	2.9	(0.5)
13	Rate 145	0.1	2.2	2.3	0.1	3.2	3.3	1.0
14	Rate 170	(0.4)	2.0	1.6	(0.0)	4.1	4.1	2.5
15	Rate 200	23.2	3.1	26.3	29.7	3.8	33.4	7.1
16	Rate 300	-	-	-	-	-	-	-
17	Rate 315	-	-	-	-	-	-	-
18	Rate M4	9.5	32.8	42.3	13.9	34.1	48.0	5.8
19	Rate M5	0.5	2.1	2.6	1.2	2.7	3.9	1.2
20	Rate M7	1.8	31.1	32.9	3.4	35.9	39.3	6.3
21	Rate M9	2.9	1.3	4.2	3.9	1.5	5.4	1.2
22	Rate M10	0.1	-	0.1	-	-	-	(0.1)
23	Rate T1	-	13.3	13.3	-	15.1	15.1	1.8
24	Rate T2	-	87.7	87.7	-	92.5	92.5	4.8
25	Rate T3	-	7.8	7.8	-	8.2	8.2	0.4
26	Rate 20	2.7	38.8	41.5	3.1	44.5	47.5	6.1
27	Rate 25	12.6	8.3	21.0	33.5	8.6	42.1	21.1
28	Rate 30	-	-	-	-	-	-	-
29	Rate 100 (3)	-	11.3	11.3	-	11.1	11.1	(0.2)
30	Total Contract	80.9	319.9	400.8	123.2	351.1	474.3	73.5
31	Subtotal	4,086.7	585.9	4,672.7	4,885.6	684.7	5,570.3	897.6
32	Other Adjustments (3)			31.9			(37.5)	(69.4)
33	Total Gas Sales and Distribution Revenue			4,704.5			5,532.8	828.2
	Utility Adjustments							
34	Elimination of the 2025 ESM and Union rate zones' unregulated storage cost from the EGD rate zone revenues			(18.6)			10.6	29.2
35	Total Utility Revenue			4,686.0			5,543.4	857.4

Notes:
(1) EGD rate zone.
(2) Union North rate zone.
(3) Includes adjustments that either do not have rate class detail or are not allocated between System and DP customers.

Revenue by Rate Class - Normalized

Line No.	Particulars ($ millions)	2024 Actual Sales Service	2024 Actual Direct Purchase	2024 Actual Total	2025 Actual Sales Service	2025 Actual Direct Purchase	2025 Actual Total	Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-c)
	General Service							
1	Rate 1	1,947.2	15.0	1,962.2	2,053.0	14.3	2,067.3	105.1
2	Rate 6	849.4	166.3	1,015.7	912.6	193.3	1,105.9	90.2
3	Rate M1	975.7	20.7	996.4	1,069.5	21.3	1,090.8	94.3
4	Rate M2	122.2	49.4	171.7	139.4	55.9	195.3	23.6
5	Rate 01	399.6	16.0	415.6	420.1	15.4	435.5	19.9
6	Rate 10	44.1	23.1	67.2	44.0	24.6	68.7	1.5
7	Total General Service	4,338.2	290.6	4,628.8	4,638.5	324.8	4,963.4	334.6
	Contract							
8	Rate 100 (1)	3.4	3.1	6.5	4.3	4.3	8.6	2.1
9	Rate 110	23.9	50.3	74.2	29.7	55.3	85.0	10.8
10	Rate 115	0.0	8.3	8.3	(0.0)	8.9	8.9	0.6
11	Rate 125	-	13.4	13.4	-	15.0	15.0	1.6
12	Rate 135	0.5	2.9	3.4	0.4	2.5	2.9	(0.5)
13	Rate 145	0.1	2.2	2.3	0.1	3.2	3.3	1.0
14	Rate 170	(0.4)	2.0	1.6	(0.0)	4.1	4.1	2.5
15	Rate 200	23.2	3.1	26.3	29.7	3.8	33.4	7.1
16	Rate 300	-	-	-	-	-	-	-
17	Rate 315	-	-	-	-	-	-	-
18	Rate M4	9.5	32.8	42.3	13.9	34.1	48.0	5.8
19	Rate M5	0.5	2.1	2.6	1.2	2.7	3.9	1.2
20	Rate M7	1.8	31.1	32.9	3.4	35.9	39.3	6.3
21	Rate M9	2.9	1.3	4.2	3.9	1.5	5.4	1.2
22	Rate M10	0.1	-	0.1	-	-	-	(0.1)
23	Rate T1	-	13.3	13.3	-	15.1	15.1	1.8
24	Rate T2	-	87.7	87.7	-	92.5	92.5	4.8
25	Rate T3	-	7.8	7.8	-	8.2	8.2	0.4
26	Rate 20	2.7	38.8	41.5	3.1	44.5	47.5	6.1
27	Rate 25	12.6	8.3	21.0	33.5	8.6	42.1	21.1
28	Rate 30	-	-	-	-	-	-	-
29	Rate 100 (2)	-	11.3	11.3	-	11.1	11.1	(0.2)
30	Total Contract	80.9	319.9	400.8	123.2	351.1	474.3	73.5
31	Subtotal	4,419.1	610.5	5,029.6	4,761.7	675.9	5,437.6	408.1
32	Other Adjustments (3)			31.9			(37.5)	(69.4)
33	Total Gas Sales and Distribution Revenue			5,061.5			5,400.1	338.7
	Utility Adjustments							
34	Elimination of the 2025 ESM and Union rate zones' unregulated storage cost from the EGD rate zone revenues			(18.6)			10.6	29.2
35	Total Utility Revenue			5,042.9			5,410.7	367.8

Notes:
(1) EGD rate zone.
(2) Union North rate zone.
(3) Includes adjustments that either do not have rate class detail or are not allocated between System and DP customers.

Revenue from Regulated Storage & Transportation

Line No.	Particulars ($ millions)	2024 Actual (a)	2025 Actual (b)	Variance (c) = (b-a)
	Storage			
1	Peak Storage	0.9	0.2	(0.7)
2	Off-peak Storage	2.4	0.0	(2.4)
3	Loans	(0.0)	0.0	0.0
4	Short-term Balancing	2.0	0.4	(1.6)
5	Short-term Deferral	(4.9)	(0.6)	4.3
6	Total Storage	0.4	0.0	(0.4)
	Utility Adjustment			
7	Elimination of the shareholder portion of net Short-term Storage Revenue	(0.4)	(0.1)	0.3
8	Total Storage - Utility Revenue	(0.0)	(0.0)	(0.0)
	Transportation			
9	Rate M12	94.0	95.6	1.6
10	Rate M12X	3.2	3.4	0.2
11	Rate F24T	0.6	0.7	0.1
12	Rate C1	18.7	19.6	0.9
13	Rate M13	0.5	2.1	1.6
14	Rate M16	0.6	0.7	0.1
15	Rate M17	0.5	0.6	0.0
16	Rate 331	0.2	0.2	0.0
17	Rate 332	20.0	21.9	1.9
18	Rate 401	1.5	1.7	0.1
19	Short-term Transportation	11.7	17.1	5.4
20	Upstream Transportation Optimization	5.9	6.1	0.2
21	Other	1.2	1.2	(0.0)
22	Total Transportation	158.7	170.9	12.2
	Utility Adjustment			
23	Elimination of the shareholder portion of net Upstream Optimization	(5.4)	(5.6)	(0.2)
24	Total Transportation - Utility Revenue	153.3	165.3	12.0
25	Total Storage & Transportation - Utility Revenue	153.3	165.3	12.0

Other Revenue and Other Income

Line No.	Particulars ($ millions)	2024 Actual (a)	2025 Actual (b)	Variance (c) = (b-a)
	Other Revenue			
1	Late Payment Penalties	21.9	22.7	0.8
2	Account Opening Charges	9.0	9.3	0.4
3	Other Billing Revenue	11.8	11.9	0.1
4	Customer Billing Revenue	42.7	44.0	1.3
5	Direct Purchase Administration Charges and Distributor Consolidated Billing	4.5	5.4	0.9
6	Open Bill Access Revenue	9.6	(0.0)	(9.6)
7	Rental Revenue - NGV Program	1.8	1.9	0.1
8	Other Operating Revenue	16.7	11.2	(5.5)
9	Subtotal	75.3	62.5	(12.8)
	Utility Adjustments			
10	Elimination of demand-side management incentive	(12.4)	(10.8)	1.6
11	Total Other Revenue	62.9	51.8	(11.2)
	Other Income			
12	Other Income (1)	6.1	13.9	7.8
	Utility Adjustments			
13	Elimination of interest income from investments not included in utility rate base and the portion of gains on sale of assets not shared through deferral	(0.6)	(8.8)	(8.2)
14	Total Other Income	5.4	5.1	(0.4)

Note:
(1) Includes the portion of gains on sale of assets not shared through deferral, interest income from investments not included in utility rate base, gains/losses on FX, and sales-type lease lease income related to the NGV Program.

UTILITY OPERATING AND MAINTENANCE

1. This evidence explains the drivers of the change in Utility Operating and Maintenance (O&M) expense from 2024 actual to 2025 actual.

2. Table 1 presents 2025 O&M expenses relative to 2024 O&M expenses.

3. Overall, Utility O&M expenses decreased by $44.8 million between 2024 and 2025, primarily due to the discontinuation of one-time severance costs incurred in 2024 and lower pension-related costs incurred in 2025 as compared to 2024. These decreases were partially offset by higher Energy Conservation program costs, higher professional services costs, and lower indirect overhead recoveries.

Table 1
Utility O&M
25 Actuals-24 Actuals

Line No.	Expense Categories	2024 OEB-Approved	2024 Actual ($ millions)	2025 Actual ($ millions)	2025 Actual vs 2024 Actual $ change	2025 Actual vs 2024 Actual % change
1	Compensation & Benefits	416.5	446.3	340.9	(105.4)	-23.6%
2	Outside Services	262.4	246.6	250.0	3.5	1.4%
3	Materials and Supplies	31.2	29.5	32.2	2.7	9.1%
4	Professional and Regulatory Services	18.0	26.3	43.3	17.0	64.5%
5	Other	59.0	55.8	69.7	13.9	24.9%
6	Employee Related Services	4.8	1.2	2.3	1.1	95.2%
7	Repairs & Maintenance	4.4	5.6	6.5	0.9	16.3%
8	Rents & Leases	13.1	13.2	12.7	(0.5)	-3.6%
9	Travel & Accommodation	9.1	8.7	10.9	2.2	25.3%
10	Donations & Memberships	5.1	6.2	1.1	(5.1)	-82.7%
11	Internal Allocation & Recoveries	(20.7)	(24.5)	(63.1)	(38.7)	-58.1%
12	Energy Conservation	183.1	183.1	195.1	12.0	6.6%
13	Central Functions	377.1	348.2	352.6	4.4	1.3%
14	Overhead Capitalization	(242.0)	(242.0)	(192.0)	50.0	-20.7%
15	O&M settlement reduction - ($50M net, $68M gross)	(68.4)				0.0%
16	O&M Subtotal before adjustments	1,052.8	1,104.2	1,062.3	(41.9)	-4.0%
17	Donations		(2.9)	(3.1)	(0.2)	6.0%
18	2025 DSMVA Correction			0.9	0.9	
19	Less write down of locates for 2023			(3.0)	(3.0)	
20	CF utility adjustment		(8.5)	(9.1)	(0.5)	6.4%
21	Total Unregulated/Non-Utility Eliminations		(11.5)	(14.3)	(2.9)	25%
22	Total Net Utility O&M Expense	1,052.8	1,092.8	1048.0	(44.8)	-4.3%

4. Compensation and Benefits (line 1) decreased by $105.4 million, primarily driven by the absence of $48.3 million in one-time 2024 severance costs and a $37.0 million reduction in pension expense, reflecting strong pension asset performance and lower expense requirements following interest rate cuts. Pension expense remains a deferrable amount addressed in the Post Retirement True-up variance account.

5. Professional and Regulatory Services (line 4) increased by $17.0 million, mainly due to (i) $10.0 million external consulting costs, and (ii) $10.0 million of affiliate flow-through costs, fully recoverable through Internal Allocations and Recoveries (line 11). These increases were partially offset by approximately $3.0 million of favorability related to OEB assessment costs.

6. Other (line 5) increased by approximately $15 million, primarily reflecting incremental labor costs for work performed for affiliates captured through time sheeting, which are recovered through Internal Allocations and Recoveries.

7. Internal Allocations and Recoveries (line 11) increased by $38.7 million, driven by higher recoveries from affiliates.

8. DSM (line 12) increased by $12.0 million, representing the OEB-approved year-over-year budget increase. DSM amounts above the OEB-approved budget remain a pass-through component of Utility O&M and are fully recoverable through the DSM variance account.

9. Overhead Capitalization (line 14) decreased by approximately $50 million, consistent with the OEB's 2024 Rebasing Phase 1[1] rate order, which mandates an annual $50 million reduction from the $242 million approved in 2024.

[1] EB-2022-0200.

UTILITY CAPITAL EXPENDITURES

1. This evidence provides information on Enbridge Gas's 2025 utility capital expenditures.

Table 1
Summary of Capital Expenditures 2025 Actual

Line No.	Particulars ($ millions)	Total EGI
1	Distribution Plant	840.4
2	Transmission Plant (1)	134.6
3	General & Other Plant	147.0
4	Underground Storage Plant	46.2
5	Total	1,168.2

Note:
(1) Includes PREP amounts of $8.7 million subject to levelized ratemaking treatment.

The amounts presented reflect annual capital expenditures and are comparable to the Asset Management Plan.

2. Enbridge Gas's 2025 total capital expenditure is broadly consistent with 2024 and remains aligned with the OEB's 2024 Rebasing Phase 1 Decision[1]. Through the Distribution Integrity Management Program (DIMP) and the Enhanced Distribution Integrity Management Program (EDIMP)[2] activities, Enbridge Gas has extended asset life through targeted inspection and repair, supporting prudent prioritization of capital spending in 2025. As discussed in the Phase 3 Report on Capital Reduction[3], while near-term pacing actions were implemented to achieve the 2024 capital reduction, the underlying system requirements remain. As a result, certain projects deferred in 2024 began execution in 2025, with higher capital demands expected in 2026 and beyond.

[1] EB-2022-0200, OEB Decision and Order, December 21, 2023.
[2] Exhibit G, Tab 4, Schedule 1.
[3] EB-2025-0064, Exhibit 2, Tab 5, Schedule 5.

3. Table 2 presents year-over-year (2024–2025) capital expenditure variances by asset class, with supporting commentary provided in the narrative that follows.

Table 2
Asset Class

Line No.	Asset Class ($ millions)	2024	2025	Variance
1	Compression Stations	41.5	40.7	(0.8)
2	Customer Connections	282.7	241.7	(41.0)
3	Distribution Pipe	215.4	326.2	110.9
4	Distribution Stations	25.9	58.6	32.7
5	Fleet & Equipment	19.2	37.1	17.9
6	Growth - Distribution System Reinforcement	18.8	24.2	5.4
7	Real Estate & Workplace Services	69.4	37.3	(32.1)
8	Technology Information Services (TIS)	43.4	77.7	34.3
9	Transmission Pipe and Underground Storage	228.8	113.9	(114.9)
10	Utilization	189.6	163.0	(26.5)
11	EA Fixed Overhead	39.8	37.7	(2.1)
12	Community Expansion	8.3	8.8	0.5
13	Other	17.0	1.3	(15.7)
14	Total	1,199.8	1,168.2	(31.6)

1. Descriptions of Asset Classes and Year-over-Year Variances

a) Compression Stations

- Enbridge Gas uses compressors to move natural gas throughout the natural gas transmission system by compressing natural gas into transmission pipelines designed for high pressure and flow. Compressors are also used to move gas in and out of underground storage reservoirs by providing a significant pressure increase at the expense of flow.
- Dehydration facilities are also included in the compression asset category. Dehydration facilities remove moisture from natural gas to ensure that the natural gas entering the transmission system meets the contractual standard of moisture content, and to avoid operational problems related to high moisture content. Enbridge Gas operates one liquified natural gas

(LNG) facility. The LNG facility serves to provide reserve capacity and balance operational loads during peak periods.

- Compression Stations decreased by $0.8 million which was primarily driven by timing. Dawn to Corunna spend was finished in 2024 causing a decrease of $23.7 million which was offset by increases to Condition Based Replacements $7.0 million which was driven by previously deferred projects, $6.5 million driven by opportunistic purchases of required land, Emissions Reductions Program $3.4 million and Overhauls Program $3.8 million, which included the advance procurement to support the planned 2026 Dawn D RB211 C-to-G conversion $3.7 million.

b) Customer Connections

- This asset class includes the addition of new customers based on new housing or business starts, customers converting to natural gas from another fuel source and equipment and service upgrades to accommodate load growth of existing customers. General customer growth costs include materials and installation of mains and services to attach new customers as well as the costs associated with the meter and regulator installation at the customers site.
- Customer Connections capital decreased by ($41.0 million) in 2025 compared to 2024. This reduction is primarily attributable to fewer customer additions in 2025, consistent with lower housing starts and slower activity in the new construction market. In 2025, customer additions were approximately 18% lower than in 2024, resulting in lower associated main, service, meter, and regulator installation costs.

c) Distribution Pipe

- This asset class includes the capital maintenance, replacement, enhancement and renewal of pipelines and piping components (such as

valves and fittings) used to transport natural gas within the distribution system or to end-use customers. It includes steel and plastic pipe, as well as services to customers.

- Distribution Pipe capital increased by $110.9 million in 2025 compared to 2024, primarily reflecting the execution of previously deferred work and the timing of large, planned projects, consistent with the Phase 3 Report on Capital Reduction[4] and the Asset Management Plan (AMP) 2026 Addendum[5]. The increase is driven by the commencement of construction on the St. Laurent Replacement Project included in the Proactive Vintage Steel Pipe Replacement Program, resulting in a $83.6 million increase in 2025, as well as higher Integrity spending (including EDIMP) of $11.4 million reflecting increased inspection driven repair activity. Additional increases occurred within the Proactive Service Replacement Program, which increased by $9 million to accelerate the removal of AMP fittings. Spending in the Proactive Vintage Plastic Replacement Program (Aldyl A) increased by $4.6 million, reflecting the completion of projects that had been deferred following the Phase 1 decision[6]. Overall, the variance reflects timing and execution of risk driven programs and previously deferred scope, rather than changes in program intent or risk tolerance.

d) <u>Distribution Stations</u>

- These assets are typically above grade facilities designed to reduce the operating pressure of natural gas pipeline systems through pressure control and over pressure protection. These facilities are used to transmit and/or distribute natural gas to reduced operating pressure pipeline systems which supply natural gas to cities and towns.

[4] EB-2025-0064, Exhibit 2, Tab 5, Schedule 5.
[5] EB-2020-0091.
[6] EB-2022-0200, Decision and Order, December 21, 2023.

- Distribution Stations capital increased by $32.7 million in 2025 compared to 2024, primarily reflecting the inclusion of projects that had been deferred due to the 2024 Rebasing Phase 1[7] capital reduction. The variance is primarily attributable to increased investment in the Stations with Auxiliary Equipment Replacement Program $18.1 million and the Distribution System Station Replacement Program $7.1 million. These increases reflect actions taken to address station security, resilience and operability risks, including the installation of auto-transfer generators at high-importance stations following a weather event. Additional increases were driven by Civil Replacements $3.0 million and the Customer Station Replacement Program $2.8 million, both increases are attributed to elimination of known risks. Spending also increased in the Compliance Remediation Program $1.6 million and the Obsolete Heating Equipment Program $1.2 million to eliminate known integrity, safety, and operability risks.

e) Fleet & Equipment

- The Fleet, Equipment and Tools asset class includes the vehicles, trailers, heavy equipment and tools owned by Enbridge Gas to support its business needs.
- Fleet & Equipment increased by $17.9 million in 2025 compared to 2024 driven by accelerated replacement of assets that are well beyond lifecycle replacement age, aimed at reducing operational downtime, improving fuel efficiency, and mitigating rising maintenance costs. Approximately 40% of the fleet and equipment portfolio is outside optimal replacement age, resulting in higher maintenance costs and reduced reliability compared to newer assets. In 2025, Fleet Vehicles spending increased by $5.3 million and Equipment increased by $2.1 million, reflecting execution of

[7] EB-2022-0200.

replacement activity that had been paced in prior years. In addition, Tools capital increased by $10.6 million, driven by required new and replacement tooling to ensure continued compliance with engineering and safety standards, particularly for tapping and stopping activities.

f) Growth – Distribution System Reinforcement

- The Growth asset class includes broad-based reinforcement projects designed to maintain system capacity when constraints are identified driven by forecasted load growth, evolving supply and demand patterns, and changes in system operating requirements. These reinforcements support the continued safe and reliable delivery of natural gas to existing and new customers and include projects that address new operating requirements such as hydrogen blending and hydrogen-ready infrastructure.
- The Growth – Distribution System Reinforcement asset class increased by $5.4 million in 2025 compared to 2024. This is primarily due to planning and engineering for the Hydrogen Program. Distribution System Reinforcements remain largely consistent with prior forecasts, with a modest increase between 2024 and 2025. The year-over-year change is primarily attributable to the Mississauga Reinforcement project[8] advancing from the pre-planning stage into the LTC application, preparation, and filing phase, resulting in increased development and pre-construction expenditures in 2025.

g) Real Estate and Workplace Services

- The Real Estate and Workplace Services (REWS) asset class includes properties (buildings and land) and furnishings.
- There is a base spend that supports the lifecycle replacement of building systems. Variances are driven by the specific property purchases and renovations that occur in a given year. Land acquisitions are driven by

[8] EB-2025-0073.

market availability and are aligned with the long-term strategies described in the Asset Management Plan.

- REWS capital spending decreased by ($32.1 million) in 2025 compared to 2024, primarily reflecting the completion of several large, non-recurring facilities projects that drove elevated spending in prior years. The most significant reductions relate to the Ottawa Operations Centre consolidation ($23.9 million) and the Brockville Operations Centre new build ($4.9 million), both of which were completed or substantially complete by the end of 2024 and therefore did not generate comparable capital requirements in 2025. Additional reductions are associated with the completion of other discrete site specific initiatives, including the Dryden Operations Centre ($2.8 million), VPC Security Improvements ($1.9 million), and prior year leasehold and customer care improvements. These decreases were partially offset by ongoing base investment in building systems, property upgrades, and targeted new build activities to support safe and reliable operations.

h) <u>Technology Information Services</u>

- The Technology Information Services (TIS) asset class includes:
    - General Hardware (Laptops/Desktops and Desktop sustainment equipment, networks, servers and security);
    - Specialized Hardware (to support specific business needs such as meter reading equipment, call center network devices);
    - Software assets consist of packaged applications, developed applications, and application infrastructure software; and
    - Communications assets include mobile phones and field devices (such as GPS devices, push-to-talk radios, leak survey field technology, and truck modems).

- TIS capital increased by $34.3 million in 2025 compared to 2024, primarily reflecting the execution of asset class strategies focused on addressing technology obsolescence, maintaining cyber security, and sustaining supported platforms. The largest contributor to the increase is continued investment in the Application Technology Obsolescence Program $25.3 million, including the ongoing Contract Market Modernization $21.1 million. Additional increases reflect the Core Infrastructure and Security Renewal Program $4.4 million, Field Device Renewal Program $3.1 million.

i) Transmission Pipe and Underground Storage

- This asset class includes the pipelines that form the backbone of the gas transmission system as well as the underground storage reservoirs in St. Clair Township near Sarnia, Crowland Township in Welland, and in Chatham-Kent.Transmission Pipe and Underground Storage capital decreased by ($114.9 million) in 2025 compared to 2024, primarily reflecting timing associated with the completion of Panhandle Regional Expansion Project[9], which achieved its major completion milestone and was placed into service in December 2024, resulting in $134.2 million of capital spend in 2024 that did not recur in 2025. This decrease was offset by increased spending in Class Location Program $8.5 million which was previously deferred, $4.7 million for land required for noise mitigation and to support safe operations, and Integrity $6.0 million to execute planned condition and risk-based activities.

[9] EB-2022-0157.

j) Utilization

- The utilization asset class includes meter purchases, measurement & regulation systems at customer premises, below ground and internal piping systems after the meter, and customer-owned systems[10].
- Utilization capital decreased by ($26.5 million) in 2025 compared to 2024, primarily reflecting lower meter related spending driven by reduced customer activity and inventory timing effects. The reduction is largely attributable to lower Meter Purchases ($12.5 million) resulting from fewer new customer additions and reduced spending in the Meter Exchange Government Inspection (MXGI) Program ($12.6 million). These reductions reflect volume-driven demand effects and planned inventory management, rather than changes in Utilization strategy or service standards.

k) Extended Alliance (EA) Fixed Overheads

- The EA fixed overhead asset class includes cost for Alliance partner overheads.
- EA Fixed Overhead spend decreased ($2.1 million) in 2025 compared to 2024. The decrease in this asset class in 2025 is primarily due to directly attributing costs to associated projects, partially offset by cost increases as part of the Lakeside renegotiated contract.

l) Community Expansion

- Community expansion provides natural gas services to communities not currently using natural gas. In response to the Government of Ontario's desire to expand natural gas distribution systems to communities that currently do not have access to natural gas, Enbridge Gas has filed

[10] For customer owned systems that are downstream of the meter, the asset class is accountable for inspection at the time of initial installation and after re-introduction of gas. Maintenance and remediation of these assets are the responsibility of the customer.

proposals with the OEB designed to facilitate enhanced access to natural gas for non-served rural, remote and First Nation communities, and businesses in Ontario.

- Community Expansion increased by $0.5 million in 2025 compared to 2024.The $0.5 million increase is primarily due to timing of project spend and contributions in aid of construction.

m) Other

- Other includes regulated non-core, project-specific capital investments, such as Renewable Natural Gas (RNG), Compressed Natural Gas (CNG), and Hydrogen Blending initiatives, which are advanced selectively based on business case readiness, external partnerships, and project maturity. Year-over-year variances in this category are therefore expected and reflect the timing and lifecycle stage of individual projects, rather than a steady or levelized investment profile.
- Other spend decreased by ($15.7 million) in 2025 compared to 2024. This is primarily driven by Watford (Twin Creeks) RNG pipeline project substantial completion in 2024 and reduced capital requirements in 2025 resulting in a ($16.1 million) decrease, partially offset by small increases across other projects in this asset class.

Enbridge Gas
Deferral & Variance Account
Actual & Forecast Balances

Line No.	Account Description	OEB Account Number	Col. 1 Principal ($000's)	Col. 2 Interest ($000's)	Col. 3 Total ($000's)	Col.4 Reference to Evidence
			Forecast for clearance at July 1, 2027			
	EGI Commodity Related Accounts					
1.	Upstream Transportation Optimization V/A	179-201	(34,774.9)	(1,882.5)	(36,657.4)	Exhibit C-2-1
2.	UFG Volume V/A	179-203	10,558.8	408.1	10,966.9	Exhibit C-2-3
3.	UFG Price V/A	179-204	(3,557.1)	(138.2)	(3,695.4)	Exhibit C-2-4
4.	Total Commodity Related Accounts		(27,773.2)	(1,612.6)	(29,385.8)	
	EGI Non Commodity Related Accounts					
5.	Transportation from Dawn Service D/A	179-202	70.4	3.7	74.0	Exhibit C-2-2
6.	Deferral Clearing V/A	179-302	3,529.2	174.3	3,703.5	Exhibit C-2-5
7.	Parkway Delivery Obligation V/A	179-303	2,558.2	129.5	2,687.7	Exhibit C-2-6
8.	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-	
9.	Pension & OPEB V/A	179-305	-	(4,909.1)	(4,909.1)	Exhibit C-2-7
10.	Facility Carbon Charge V/A	179-307	(742.7)	(99.8)	(842.4)	Exhibit C-2-8
11.	Customer Carbon Charge V/A	179-308	(2.1)	(0.2)	(2.2)	Exhibit C-2-9
12.	Carbon Charges Bad Debt D/A	179-309	6,948.4	417.7	7,366.1	Exhibit C-2-10
13.	Earnings Sharing Mechanism D/A	179-311	(24,300.0)	(932.7)	(25,232.7)	Exhibit C-2-11
14.	Tax V/A	179-312	(13,621.5)	(347.3)	(13,968.8)	Exhibit C-2-12
15.	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-	
16.	Green Button Initiative D/A	179-320	-	-	-	
17.	Dawn Parkway Surplus Capacity D/A	179-323	(2,260.3)	(105.1)	(2,365.4)	Exhibit C-2-13
18.	Distribution Integrity Management Program D/A	179-326	213.0	12.2	225.2	Exhibit C-2-14
19.	Post Retirement True-Up V/A	179-328	(49,006.6)	(2,542.6)	(51,549.2)	Exhibit C-2-15
20.	Clean Fuel Regulation Credits D/A	179-330	(35.0)	(1.8)	(36.9)	Exhibit C-2-16
21.	Indigenous Working Group D/A	179-331	268.6	12.1	280.7	Exhibit C-2-17
22.	Cloud Computing Implementation Costs D/A	179-332	-	-	-	
23.	Average Use V/A	179-333	34,494.4	2,130.6	36,625.0	Exhibit C-2-18
24.	Getting Ontario Connected V/A	179-335	14,093.7	744.7	14,838.3	Exhibit C-2-19
25.	Disposition of Property D/A	179-336	(12,804.0)	(689.4)	(13,493.4)	Exhibit C-2-20
26.	LEAP Emergency Financial Assistance D/A	179-338	1,200.8	50.6	1,251.4	Exhibit C-2-21
27.	OEB Cost Assessment V/A	179-340	2,997.0	121.9	3,118.9	Exhibit C-2-22
28.	IRP System Pruning D/A (2024 & 2025)	179-341	388.0	26.9	414.9	Exhibit C-2-23
29.	Enbridge Sustain Affiliate Recoveries V/A	179-344	-	-	-	
30.	Total Non Commodity Related Accounts		(36,010.5)	(5,803.8)	(41,814.3)	
31.	Total EGI Accounts (for clearance)		(63,783.8)	(7,416.4)	(71,200.1)	
	EGD Rate Zone Commodity Related Accounts					
32.	Storage and Transportation D/A	179-88	3,126.8	276.9	3,403.8	Exhibit D-1-1
33.	Total Commodity Related Accounts		3,126.8	276.9	3,403.8	
	EGD Rate Zone Non Commodity Related Accounts					
34.	Open Bill Extension D/A	179-325	-	-	-	
35.	Total Non Commodity Related Accounts		-	-	-	
36.	Total EGD Rate Zone (for clearance)		3,126.8	276.9	3,403.8	
	Union Rate Zones Gas Supply Accounts					
37.	Unabsorbed Demand Costs Variance Account	179-108	4,881.6	240.3	5,121.9	Exhibit E-1-1
38.	Total Gas Supply Accounts		4,881.6	240.3	5,121.9	
	Union Rate Zones Storage Accounts					
39.	Short-Term Storage and Other Balancing Services	179-70	(599.3)	(22.9)	(622.2)	Exhibit E-1-2
40.	Total Storage Accounts		(599.3)	(22.9)	(622.2)	
41.	Total Union Rate Zones (for clearance)		4,282.3	217.4	4,499.7	
42.	Total Deferral and Variance Accounts (for clearance)		(56,374.6)	(6,922.0)	(63,296.6)	
	EGI Accounts Not Being Requested For Clearance					
43.	Incremental Capital Module D/A	179-306	-	-	-	
44.	IRP Operating Costs Deferral Account	179-318	2,234.6	100.0	2,334.6	Exhibit C-2-24
45.	IRP Capital Costs Deferral Account	179-319	(3.0)	(0.1)	(3.1)	Exhibit C-2-24
46.	Panhandle Region Expansion Project V/A (2024-2025)	179-329	(10,199.5)	(643.5)	(10,843.0)	Exhibit C-2-24
47.	Site Restoration Costs Tracking Account	179-337	(15,615.7)	-	(15,615.7)	Exhibit C-2-24
48.	Asset Life Extension Costs D/A	179-343	-	-	-	

ACCOUNT NO. 179-201 UPSTREAM TRANSPORTATION OPTIMIZATION VARIANCE ACCOUNT

1. The Upstream Transportation Optimization Variance Account captures the variance between the ratepayers' 90% share of actual net revenues from optimization activities, and the amount refunded to ratepayers in rates. The 2025 balance in this variance account is a credit to ratepayers of $34.775 million, plus interest.

2. In setting rates for 2024, the OEB approved a forecast of optimization revenue of $17.041 million[1]. Of that amount, 90% or $15.337 million, was credited to ratepayers in the OEB-approved 2024 rates.

3. The Company earned $55.679 million in net revenues from upstream transportation optimization during 2025. In accordance with the OEB-approved sharing methodology, 90% of this net revenue, or $50.111 million, is to be credited to customers. As stated above, $15.337 million has already been credited through rates; therefore, the deferral balance is a credit to ratepayers of $34.775 million ($50.111 million less $15.337 million). The primary driver for the incremental net revenue from upstream transportation optimization is capacity constraints in the U.S. Northeast, which resulted in elevated prices and incremental demand for exchanges. The majority of the exchanges were to Iroquois (New York/Ontario border) and East Hereford (New Hampshire/Québec border).

4. Table 1 provides a summary of the calculation of the balance in this variance account.

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023.

Table 1
Upstream Transportation Optimization Variance Account

Line No.	Particulars ($ millions)	2024 OEB-Approved (a)	2024 Actual (b)	2025 Actual (c)
1	Upstream Transportation Optimization Revenue	17.0	54.1	55.7
2	Shareholder Incentive (10%)	1.7	5.4	5.6
3	Ratepayer portion (90%)	15.3	48.7	50.1
4	Less: Gas Optimization Margin included in Rates	15.3	15.3	15.3
5	Variance Account Balance (line 3 - line 4)	-	33.4	34.8

ACCOUNT NO. 179-202 TRANSPORTATION FROM DAWN SERVICE DEFERRAL ACCOUNT

1. Enbridge Gas offers a transportation service from Dawn that is available to Union North T-Service (unbundled) customers between Dawn and the TransCanada delivery area where the customers' facilities are located. This service is referred to as the Base Service. The purpose of this transportation service is to provide these customers with a method to transport gas they acquire at Dawn to their TransCanada delivery area. In order for the Company to offer this service, it had to make long-term contractual commitments with TransCanada, and customers that chose to contract for this service were required to make the same commitment to the utility. The service allows the customer to reduce their contracted transportation service quantity should there be significant reductions in their contracted distribution service.

2. This account captures the difference between revenues and costs for the excess capacity from Parkway to the Union NDA, Union NCDA and Union EDA as part of the Base Service offering of the Transportation from Dawn Service.

3. The balance in this deferral account is a debit of $0.070 million, plus interest. The balance of $0.070 million represents the difference between the TransCanada capacity costs incurred by Enbridge Gas of $1.943 million and the revenues collected from customers of $1.873 million. The net variance is driven by a reduction of 480 GJ per day of contracted quantity by Union North T-service customers.

ACCOUNT NO. 179-203 UFG VOLUME VARIANCE ACCOUNT

1. The purpose of the Unaccounted for Gas Volume Variance Account (UFGVVA) is to capture the cost associated with the volumetric variances between the actual volume of unaccounted for gas (UFG) and the OEB-approved UFG volume. The UFGVVA was established in 2024 as part of Phase 1 of the 2024 Rebasing Application[1] in recognition of the need to record gas costs associated with variances between the actual UFG volumes and the forecast UFG volumes. Enbridge Gas and ratepayers will share on a 50/50 basis the cost or credit of variances between the OEB-approved UFG volume[2] of 243,681.5 10^3m^3 included in rates and the actual UFG volumes, at the applicable gas supply reference price, up to maximum total actual UFG volume of 400,000 10^3m^3. This evidence provides details regarding 2025 balances recorded in the UFGVVA.

2. Actual UFG volumes for 2025 for Enbridge Gas were determined to be 370,109 10^3m^3. The variance between actual and forecasted UFG volumes of 126,428 10^3m^3 resulted in a debit balance of $10.6 million in the UFGVVA, plus interest. Attachment 1 provides the detailed calculations of the UFGVVA balance.

[1] EB-2022-0200.
[2] EB-2022-0200, Settlement Agreement, August 17, 2023, Exhibit O1, Tab 1, Schedule 2, Accounting Orders. p.22.

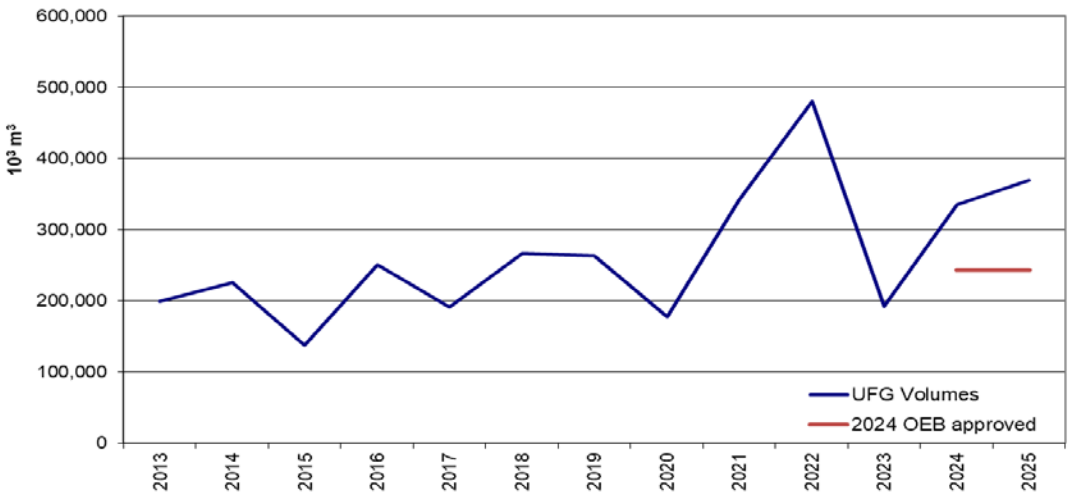
5. Table 1 provides historical UFG volumes for Enbridge Gas from 2013 to 2025.

Table 1
Historical UFG Volumes for EGI (Regulated)

Line No.	Particulars	UFG Volumes (10^3 m^3)
1	2013	199,833
2	2014	225,027
3	2015	137,110
4	2016	250,923
5	2017	190,881
6	2018	266,362
7	2019	263,407
8	2020	177,291
9	2021	342,549
10	2022	480,301
11	2023	192,110
12	2024	334,888
13	2025	370,109

6. Figure 1 shows historical UFG volumes for Enbridge Gas from 2013 to 2025 and includes the 2024 OEB-approved UFG volume forecast.

Figure 1: Historical Unaccounted For Gas Volumes (10^3m^3)

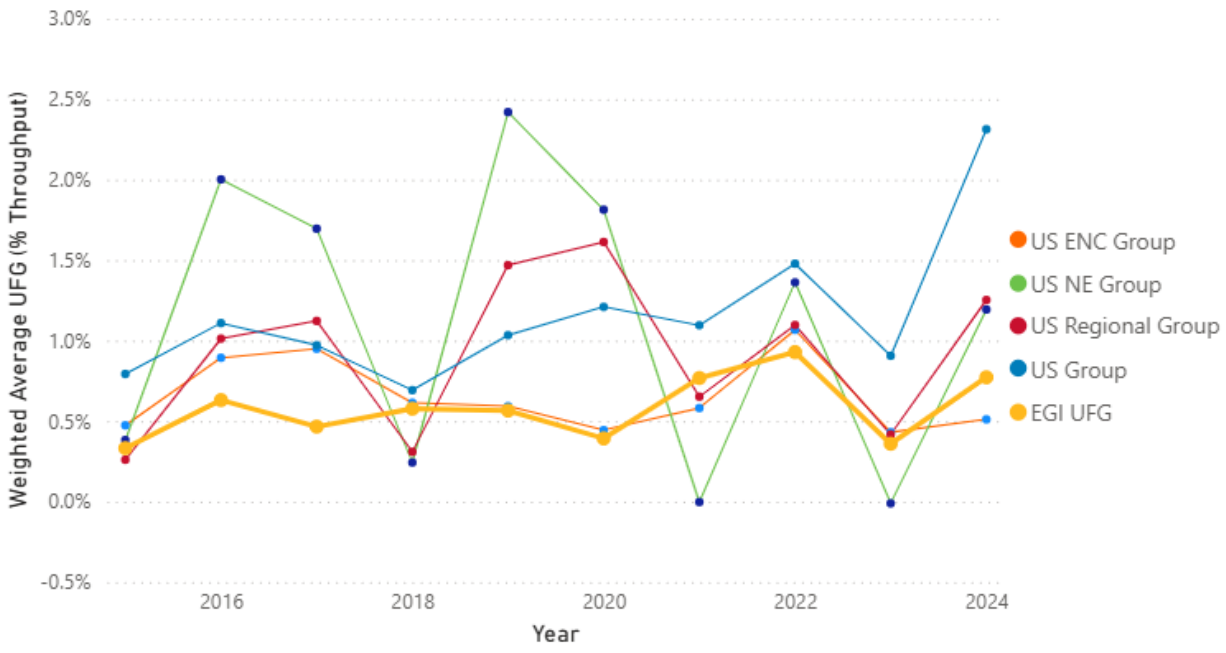


7. The 2019 Report on Unaccounted for Gas prepared by ScottMadden Management consultants filed in the Company's 2020 Rates Application (the 2019 UFG Report) included a UFG Benchmark Analysis for the period of 2008 to 2017. Based on the results of the analysis completed, ScottMadden noted that from 2008 to 2017 Enbridge Gas had demonstrated lower average UFG volumes than comparative gas utilities.

8. For the purposes of the current Application, Enbridge Gas gathered the most current publicly available data for the same comparative gas utilities (up to and including 2024 for comparative utilities and 2025 for the Company) and updated the benchmark analysis set out in the 2019 UFG Report.

9. Consistent with last year, the 2025 Benchmark Analysis represented in Figure 2 recognizes the relative size of each utility within a comparator group by determining the groups weighted average UFG by volume of throughput.

Figure 2: 2024 UFG Benchmark Analysis[3]



10. Enbridge Gas's total system (utility and non-utility) UFG in 2025 amounted to approximately 435,240 10^3m^3 compared to total system throughput for that same year of approximately 56,875,530 10^3m^3 (0.77%).

11. Figure 2 demonstrates that all utilities included in the benchmark analysis experienced similar volatility in UFG over time. As noted in its most recent Decisions regarding UFG costs and related rate riders for AltaGas and ATCO, the Alberta Utilities Commission stated:

[3] US ENC Group – Refers to the 15 largest utilities by throughput operating within the states of Illinois, Indiana, Michigan, Ohio and Wisconsin.
US NE Group – Refers to the 15 largest utilities by throughput operating within the states of New York, New Jersey, Pennsylvania, Connecticut, Massachusetts, Rhode Island, Vermont, New Hampshire and Maine.
US Regional Group – Refers to the 15 largest utilities by throughput operating within the states included in the US ENC Group or US NE Group.
US Group – Refers to the 15 largest utilities by throughput operating within the United States.

> In prior decisions, the Commission recognized that UFG is an expected element of operating a natural gas distribution system. The Commission also recognized that, due to the many factors that impact UFG, the UFG amount will fluctuate over time.[4]

12. Figure 2 reflects certain industry-wide trends across comparative utilities. It is reasonable to assume that such trends in UFG volumes may be reflective of common factors which have the potential to impact UFG volumes or costs broadly across the industry. Figure 2 shows that Enbridge Gas's UFG volumes are generally lower as a percent of throughput relative to its peers. Furthermore, the annual fluctuations in Enbridge's UFG volumes are generally less volatile than other gas utilities.

[4] Alberta Utilities Commission, Decision 27552-D01-2022 (September 12, 2022), 2022-2023 Unaccounted-For Gas Rider E and Rider H. (Apex Utilities Inc.), pp. 2-4; and Alberta Utilities Commission, Decision 28406-D01-2022 (October 17, 2022), 2023 Unaccounted-For Gas Rider D and Rider P. (ATCO Gas and Pipelines Inc.), pp.2-4.

EGI 2025 Unaccounted For Gas Variance Account

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Budget UFG (10^3m^3)	35,609	33,389	29,502	20,727	13,250	10,481	10,014	10,962	10,246	14,836	23,786	30,880	243,682
2	Weighted Average Reference Price ($/$10^3m^3$)	144.690	144.690	144.690	189.095	189.095	189.095	184.645	184.645	184.645	169.505	169.505	169.505	
3	Budget UFG ($ millions) (1)	5.2	4.8	4.3	3.9	2.5	2.0	1.8	2.0	1.9	2.5	4.0	5.2	40.2
4	Total Actual UFG (10^3m^3)	47,480	45,857	42,115	28,545	17,788	16,832	20,489	20,023	19,187	25,560	38,946	47,286	370,109
5	Weighted Average Reference Price ($/$10^3m^3$)	144.690	144.690	144.690	189.095	189.095	189.095	184.645	184.645	184.645	169.505	169.505	169.505	
6	Actual UFG ($ millions) (2)	6.9	6.6	6.1	5.4	3.4	3.2	3.8	3.7	3.5	4.3	6.6	8.0	61.5
7	UFG Volume Variance (10^3m^3) (3)	11,871	12,468	12,614	7,819	4,538	6,351	10,475	9,061	8,941	10,724	15,161	16,406	126,428
8	UFG Volume Variance ($ millions) (4)	1.7	1.8	1.8	1.5	0.9	1.2	1.9	1.7	1.7	1.8	2.6	2.8	21.3
9	50/50 Cost Sharing (5)													10.7
10	Damages Recovery ($ millions)													(0.1)
11	UFG Volume Variance ($ millions) (6)													10.6

Notes:

(1) Line 1 x Line 2.
(2) Line 4 x Line 5.
(3) Line 4 - Line 1.
(4) Line 6 - Line 3.
(5) Line 8 x 50%.
(6) Line 9 + Line 10.

ACCOUNT NO. 179-204 UFG PRICE VARIANCE ACCOUNT

1. The purpose of the UFG Price Variance Account is to capture the cost of gas associated with the price variance on gas supply purchases related to UFG. The price variance is calculated as the difference between the actual price of Enbridge Gas's gas supply purchases and the applicable gas supply reference price, applied to the actual experienced UFG volumes. The UFG Price Variance Account was established in 2024 as part of Phase 1 of the 2024 Rebasing Application[1].

2. Price variances are initially recorded in the PGVA for the respective rate zones and the portion of the price variances associated with UFG volumes is transferred from the PGVA to the UFG Price Variance Account. This transfer ensures that costs are borne by the appropriate group of ratepayers, consistent with the UFG cost allocation. The total balance in the UFG Price Variance Account is a payable to ratepayers of $3.56 million, plus interest.

1. EGD Rate Zone

3. During 2025, the Company purchased 152,715 10^3m^3 of gas supply in EGD rate zone related to actual UFG volumes on behalf of ratepayers.

4. The average actual cost of the UFG purchases in 2025 is $\$25.96/10^3m^3$ lower than the OEB-approved reference prices included in rates based on the EGD rate zone gas portfolio cost of $\$194.78/10^3m^3$. The result is a $3.96 million balance payable to ratepayers, as shown in Table 1. Attachment 1, page 1, provides the detailed calculation supporting the price variance of $\$25.96/10^3m^3$.

[1] EB-2022-0200.

Table 1
Calculation of 2025 EGD Rate Zone UFG Price Variance

Line No.	Particulars	Deferral Calculation
1	UFG Volumes (10^3m^3) – Company Supplied (1)	152,715
2	Price Variance ($/$10^3m^3$) (2)	($25.96)
3	Variance Account Balance ($ millions)	($3.96)

Notes:
(1) UFG Volumes represent gas supply related to actual UFG volumes on behalf of ratepayers who do not provide UFG in kind as part of CSF.
(2) See Attachment 1, page 1 for the price variance calculation

2. Union Rate Zone

5. During 2025, the Company purchased 123,214 10^3m^3 of gas supply in Union rate zones related to actual UFG volumes on behalf of ratepayers. The actual UFG purchases exclude the actual UFG collected from ratepayers who provide UFG in kind as part of customer supplied fuel (CSF).

6. The average actual cost of the UFG purchases in 2025 is $3.30/$10^3m^3$ higher than the OEB-approved reference prices included in rates based on the Union South rate zone gas portfolio cost of $176.88/$10^3m^3$. The result is a $0.41 million balance receivable from ratepayers, as shown in Table 2. Attachment 1, page 2, provides the detailed calculation supporting the price variance of $3.30/$10^3m^3$.

Table 2
Calculation of 2025 Union Rate Zone UFG Price Variance

Line No.	Particulars	UFG Volumes (10^3m^3)
1	Experienced Regulated UFG	217,394
2	UFG Collected through CSF	94,180
3	UFG Volumes – Company Supplied (1)	123,214
		Deferral Calculation
4	UFG Volumes (10^3m^3) – Company Supplied (1)	123,214
5	Price Variance ($/$10^3m^3$) (2)	$3.30
6	Variance Account Balance ($ millions)	$0.41

Notes:
(1) UFG Volumes represent gas supply related to actual UFG volumes on behalf of ratepayers who do not provide UFG in kind as part of CSF.
(2) See Attachment 1, page 2 for the price variance calculation.

Calculation of 2025 EGD Rate Zone Price Variance

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average Price
1	OEB-approved Reference Price ($ / 10^3m^3)	$166.82	$166.82	$166.82	$211.15	$211.15	$211.15	$208.56	$208.56	$208.56	$192.57	$192.57	$192.57	$194.78
2	Actual Purchase ($)	$220,512,467	$196,950,889	$133,099,934	$82,702,950	$86,992,488	$80,308,654	$88,636,454	$75,322,485	$59,408,282	$73,608,893	$95,513,659	$251,826,729	
3	Purchase Volumes (10^3m^3)	1,200,578	1,017,151	646,870	477,789	550,092	531,357	605,032	552,482	444,181	535,164	529,161	1,115,434	
4	Average Purchase Cost ($ / 103m3) (1)	$183.67	$193.63	$205.76	$173.09	$158.14	$151.14	$146.50	$136.33	$133.75	$137.54	$180.50	$225.77	$168.82
5	EGD Rate Zone Price Variance ($ / 10^3m^3) (2)	$16.85	$26.81	$38.94	($38.05)	($53.00)	($60.01)	($62.07)	($72.23)	($74.82)	($55.03)	($12.07)	$33.19	($25.96)

Notes
(1) Line 2 / Line 3
(2) Line 4 - Line 1

Calculation of 2025 Union Rate Zone Price Varaince

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average Price
1	OEB-approved Reference Price ($ / 10^3m^3)	$146.74	$146.74	$146.74	$199.47	$199.47	$199.47	$188.94	$188.94	$188.94	$172.39	$172.39	$172.39	$176.88
2	Actual Purchase ($)	$68,137,005	$90,060,436	$63,011,240	$42,121,343	$37,848,330	$50,299,405	$52,453,160	$49,116,287	$53,691,661	$71,681,043	$46,821,355	$120,631,336	
3	Purchase Volumes (10^3m^3)	332,359	412,940	301,545	220,221	238,320	331,657	340,535	315,000	373,621	487,698	240,498	517,483	
4	Average Purchase Cost ($ / 10^3m^3) (1)	$205.01	$218.10	$208.96	$191.27	$158.81	$151.66	$154.03	$155.92	$143.71	$146.98	$194.69	$233.11	$180.19
5	Union Rate Zone Price Variance ($ / 10^3m^3) (2)	$58.27	$71.35	$62.22	($8.20)	($40.66)	($47.81)	($34.90)	($33.01)	($45.23)	($25.41)	$22.30	$60.72	$3.30

Notes
(1) Line 2 / Line 3
(2) Line 4 - Line 1

ACCOUNT NO. 179-302 DEFERRAL CLEARANCE VARIANCE ACCOUNT

1. This account, approved by the OEB in its 2024 Rebasing Phase 1 Interim Rate Order,[1] records amount receivable from/(payable to) customers which reflects disposition variances in relation to the clearance of deferral and variance account balances authorized by the OEB. Disposition variances result from Enbridge Gas's billing systems' inability to locate and apply deferral clearance unit rates to all intended customers and/or volumes. Due to customer moves and other account changes, deferral clearance unit rates derived utilizing historical customers and volumes are not able to be assessed against all historical customers and/or volumes at the time of disposition, resulting in the balances captured in the Deferral Clearing Variance Account.

2. The balance in this variance account is a debit of $3.529 million, plus interest. The balance includes the residual amounts not disposed of from the following deferral dispositions: 2022 DSM[2] cleared between July 1, 2025 to August 31, 2025, and 2023 Federal Carbon Pricing Program cleared effective April 2025[3]. The total forecast disposition balance of these proceedings combined was a debit of $55.830 million, total recoveries were a credit of $52.301 million, resulting in a net residual debit balance of $3.529 million. A summary is provided in Table 1.

[1] EB-2022-0200, Decision on Interim Rate Order, April 11, 2024.
[2] EB-2024-0193.
[3] EB-2024-0251.

Table 1
Deferral Clearing Variance

Line No.	Proceeding	Amount ($ millions)
1	2022 DSM Deferral Disposition (1)	53.840
2	2023 Federal Carbon Pricing Program (2)	1.990
3	Subtotal – Approved for Disposition in 2025	55.830
4	Amounts disposed of in 2025 through rider and billing adjustments	(52.301)
5	Residual balance to Deferral Clearing Variance Account	3.529

Notes:
(1) EB-2024-0193.
(2) EB-2024-0251.

3. The residual balance reflects the outstanding amount resulting from the clearance of deferral and variance accounts which occurred during 2025 and the inability to locate and dispose of the approved amounts to all intended customers.

ACCOUNT NO. 179-303 PARKWAY DELIVERY OBLIGATION VARIANCE ACCOUNT

1. In Union's 2014 Rates Settlement Agreement[1], parties agreed to permanently shift the Union South direct purchase (DP) Parkway Delivery Obligation (PDO) to Dawn over time. The parties also agreed to the payment of a Parkway Delivery Commitment Incentive (PDCI) for any continuing obligated Daily Contract Quantity (DCQ) deliveries at Parkway beginning November 1, 2016. The mechanism was extended and remained in place during the 2019 to 2023 deferred rebasing term following the MAADs Decision[2]. In Phase 1 of the 2024 Rebasing proceeding[3], parties agreed to revisions to the PDO Framework and the 2024 PDCI Forecast.

2. This evidence will support the balance in the Parkway Delivery Obligation Variance Account (PDOVA) and the commitment to provide annual updates on the PDO reduction and PDCI costs from the 2024 Rebasing Phase 1 Settlement Agreement[4]. The evidence is organized as follows:
    1. 2025 PDOVA
    2. Annual PDO Reporting

1. 2025 PDOVA

3. This account records the difference between the actual Dawn Parkway System demand and fuel costs associated with any PDO shift, as well as the actual Parkway PDCI costs incurred by Enbridge Gas, and the PDO and PDCI costs included in rates as approved by the OEB. Dawn Parkway System demand and fuel costs associated with up to 89 TJ/d of Dawn Parkway surplus capacity used to reduce the PDO and already included in rates are not recorded in this account.

[1] EB-2013-0365.
[2] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018.
[3] EB-2022-0200.
[4] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1 Schedule 1, August 17, 2023.

4. The balance in this deferral account is a debit of $2.558 million, plus interest. The balance of $2.558 million represents the difference between the OEB-approved PDCI cost of $14.150 million recovered in rates and the actual PDCI cost of $16.708 million. Higher PDCI cost is primarily attributed to higher actual PDCI volumes than the forecast PDCI volumes of 79 PJ.

2. Annual PDO Reporting

5. The purpose of this section of evidence is to provide an update on PDO reduction efforts for 2025. As agreed to in the 2024 Rebasing Phase 1 Settlement Agreement[5], Enbridge Gas committed to provide details regarding:

    a. Capacity that could become available in the following two years that could be used to further reduce the PDO;
    b. Potential market-based solution alternatives to reduce the PDO;
    c. Forecast PDO volumes for the two years following the current year; and
    d. The measures considered and used to reduce the PDO in the current year.[6]

2.1 Potential Capacity Availability

6. There is no excess capacity available on the Dawn-Parkway system, and there is no capacity expected to become available to reduce the PDO over the next two years. In 2025, Enbridge Gas issued an operational notice informing shippers of a pressure restriction on the NPS 26 Trafalgar pipeline. That restriction will remain in effect until further notice.

2.2 Potential Market-based Solution Alternatives

7. As mentioned above, Enbridge Gas issued an operational notice informing shippers of a pressure restriction on the NPS 26 Trafalgar pipeline in 2025. In light of the restriction, a PDO shift to Dawn was not practical.

[5]EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023.
[6]EB-2022-0200, Exhibit 4, Tab 7, Schedule 1, p.9.

2.3 PDO Forecast

8. The DP customer PDO forecast on November 1, 2026, is 255 TJ/d, which excludes the addition of approximately 13 TJ/D for DP customers in the EGD rate zone with a PDO, as outlined in Phase 3 of the 2024 Rebasing Application[7]. The DP customer PDO forecast inclusive of customers in the EGD rate zone with a PDO on November 1, 2026, is 268 TJ/d.

9. The DP customer PDO forecast on November 1, 2027, is 265 TJ/d, which excludes the addition of approximately 13 TJ/D for DP customers in the EGD rate zone with a PDO, as proposed in Phase 3 of the 2024 Rebasing Application[8]. The DP customer PDO forecast inclusive of customers in the EGD rate zone with a PDO on November 1, 2027, is 278 TJ/d.

2.4 Measures Taken in the Current Year

10. For the reasons set out above, Enbridge Gas was not able to shift any PDO in 2025.

[7] EB-2025-0064, Exhibit 8, Tab 2, Schedule 2.
[8] Ibid.

ACCOUNT NO. 179-305 PENSION AND OPEB VARIANCE ACCOUNT

1. In the OEB Report to all regulated entities, titled *"Regulatory Treatment of Pension and Other Post-employment Benefits (OPEB) Costs",* the OEB ordered the establishment of the deferral account, effective January 1, 2018, to be used by utilities that are approved to recover their pension and OPEB costs on an accrual basis[1]. The Company recovers its pension and OPEB costs on an accrual basis.

2. The purpose of the Pension and OPEB Variance Account is to track the differences between forecast accrual pension and OPEB amounts recovered in rates, and the actual cash payments made for both pension and OPEB, on a go-forward basis from the date the account was established.

3. The forecast accrual reference amount that will be used to calculate the entries recorded assumes that the total gross accrual cost as determined by actuarial valuation is what is recorded in the Company's total operating and maintenance expense. The actual cash payments would include all cash payments the utility makes for its pension and OPEB obligations. The approved accrual amount in rates will not change or escalate during the IR term.

4. In the Phase 1 Interim Rate Order[2], the OEB approved the harmonization of the Pension and OPEB Variance Account (Account No.179-305). As part of this harmonization Enbridge Gas proposed to combine the ending December 31, 2023, cumulative primary balances for the EGD and Union rate zones, along with the associated contra balances, as a starting point for Enbridge Gas as of January 1, 2024. Interest will continue to be calculated monthly on the balance when

[1] EB-2015-0040, *Regulatory Treatment of Pension and Other Post-employment Benefits ("OPEB") Costs*, September 14, 2017, p. 2.
[2] EB-2022-0200, Decision on Interim Rate Order, April 11, 2024.

the cumulative forecasted accrual amount recovered in rates exceeds the cumulative actual cash payments, as a payable to ratepayers.

5. The OEB-approved pension expense was a credit ($1.6) million and the actual cash payments made for both pension and OPEB were $13.8 million, resulting in an annual $15.4 million debit variance. As such the variance carried forward from 2024 is a $122.8 million credit variance, plus the 2025 debit of $15.4 million result in a cumulative ending credit balance at the end of 2025 of $107.4 million credit variance through the end 2025.

6. In accordance with the OEB's Report[3], when the cumulative forecasted accrual amount recovered in rates exceeds the cumulative actual cash payments, an asymmetrical carrying charge, to be returned to ratepayers, should be accrued based on the opening monthly difference between amount recovered in rates and actual cash payments. The balance in the account for 2025 is an interest credit to ratepayers of $4.9 million to December 31, 2025.[4] Table 1 sets out the detailed calculation of the forecast accrual versus actual cash payments, and associated interest.

[3] EB-2015-0040, *Regulatory Treatment of Pension and Other Post-employment Benefits ("OPEB") Costs*, September 14, 2017.
[4] Interest is as of December 31, 2025, as interest on this account is calculated on a cumulative account balance basis.

Table 1
Details Of 2025 Interest Calculated on Forecast Accruals vs Actual Cash Payments
In Pension and OPEB Variance Account (No. 179-305)

Line No.	Particulars ($000's)	24-Dec	25-Jan	25-Feb	25-Mar	25-Apr	25-May	25-Jun	25-Jul	25-Aug	25-Sep	25-Oct	25-Nov	25-Dec	Total
1	Forecast accrual amounts		(136)	(136)	(136)	(136)	(136)	(136)	(136)	(136)	(136)	(136)	(136)	(136)	(1,633)
2	Actual cash payments		3,120	565	1,228	484	437	1,135	374	397	742	755	397	4,148	13,782
3	Monthly variance		3,256	701	1,364	620	573	1,271	510	533	878	891	533	4,284	15,415
4	Cumulative variance	(122,833)	(119,577)	(118,876)	(117,511)	(116,891)	(116,319)	(115,048)	(114,538)	(114,005)	(113,127)	(112,235)	(111,703)	(107,418)	
5	OEB prescribed CWIP rate		4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	
6	Asymmetrical interest		(0.433)	(0.422)	(0.419)	(0.414)	(0.412)	(0.410)	(0.406)	(0.404)	(0.402)	(0.399)	(0.396)	(0.394)	(4.909)

ACCOUNT NO. 179-307 - FACILITY CARBON CHARGE VARIANCE ACCOUNT

1. Enbridge Gas is requesting a credit to ratepayers of $0.74 million, plus interest, in the Facility Carbon Charge Variance Account (FCCVA).

2. In June 2018, the Greenhouse Gas Pollution Pricing Act (GGPPA) was enacted. Under the GGPPA, a federal carbon pricing program (FCPP) applies in whole or in part to any province or territory that requested it or that did not have an equivalent carbon pricing system in place by January 1, 2019. Provinces or territories can submit their own carbon pricing systems to the federal government for approval, and, if approved, are not subject to Part 1 and/or Part 2 of the GGPPA.

3. The federal government confirmed in October 2018 that the GGPPA would apply in Ontario. In March 2022, the federal government announced that, effective January 1, 2022, Ontario's carbon pricing system for industrial emitters, known as the Emissions Performance Standards (EPS) program, would be implemented in Ontario, effectively removing the province from Part 2 of the GGPPA.

4. On March 15, 2025, the federal government set the Federal Carbon Charge rate to $0.00 per cubic metre of marketable natural gas, effective April 1, 2025, through amending regulations under the federal GGPPA[1]. Accordingly, Enbridge Gas removed the Federal Carbon Charge from customer bills effective April 1, 2025.

5. In 2025, in Ontario, the FCPP was composed of two elements: (i) a charge on fossil fuels (the Federal Carbon Charge) imposed on distributors, importers, and producers; and (ii) an Ontario EPS program for prescribed industrial facilities.

[1] Government of Canada. (2025 March 15). Regulations Amending Schedule 2 to the Greenhouse Gas Pollution Pricing Act and the Fuel Charge Regulations: SOR/2025-107. gazette.gc.ca/rp-pr/p2/2025/2025-03-15-x2/html/sor-dors107-eng.html

6. Despite the federal government setting the Federal Carbon Charge rate to $0.00 per cubic metre of marketable natural gas as of April 1, 2025, the Ontario EPS program remains in effect. Enbridge Gas must continue to comply with the Ontario EPS Regulations, thus incurring facility related costs associated with the Company's annual EPS compliance obligations. Enbridge Gas will keep the FCCVA open to capture the variances between actual facility related costs and facility related costs recovered in rates.

7. In 2025, Enbridge Gas's operations as a natural gas utility in Ontario fell under the purview of the GGPPA and EPS Regulation, which resulted in facility-related costs (Facility Carbon Charge) being incurred and tracked through the FCCVA.

8. Enbridge Gas's facility-related volumes and associated costs are composed of Company Use Volumes (facilities which are not covered under the EPS) from January 1, 2025 to March 31, 2025, and EPS Volumes (facilities which are covered under the EPS) from January 1, 2025 to December 31, 2025.

9. From January 1 to March 31, 2025, Enbridge Gas's Company Use Volumes were subject to the Federal Carbon Charge. This charge applied to Enbridge Gas's own fuel use within its distribution system (i.e. its Company Use Volumes for distribution buildings, boiler/line heaters, and Natural Gas Vehicle (NGV) fleet fuel). Enbridge Gas is required to remit the Federal Carbon Charge on its Company Use Volumes to the Government of Canada monthly.

10. Enbridge Gas's EPS Volumes are related to the fuel used in the Company's natural gas transmission and storage compressor facilities. For 2025, these operations continued to fall under the Ontario EPS Regulation, requiring the Company to remit payment annually to the provincial government for any emissions that exceed the registered EPS facility's total annual emissions limit. Under the EPS Regulation, for

each tonne of emissions that exceed the annual limit, an EPS participant can either pay the excess emissions charge[2] or submit emissions performance units (EPUs) issued by the provincial government, to satisfy their annual EPS compliance obligation.

11. The costs associated with Enbridge Gas's Company Use Volumes and EPS Volumes are recovered from customers as part of the Facility Carbon Charge, which is included in delivery or transportation charges on customers' bills. As approved by the OEB through Enbridge Gas's 2024 FCPP Application, the Facility Carbon Charge rate from January 1 to March 31, 2025, was 0.0143 cents per cubic metre (cents/m^3)[3]. From April 1 to June 30, 2025, the Facility Carbon Charge rate was 0.0172 cents/m^3 as approved by the OEB through Enbridge Gas's 2025 FCPP Application[4]. On July 1, 2025, the Facility Carbon Charge rate was updated to 0.0123 cents/m^3 through the quarterly rate adjustment mechanism[5], as Company Use Volumes were no longer being subject to the Federal Carbon Charge. Based on actual customer volumes, $7.89 million in revenue was billed through the Facility Carbon Charge from January 1 to December 31, 2025.

12. Enbridge Gas's 2025 facility-related obligation was $8.76 million ($1.08 million related to Company Use Volumes and $7.68 million related to EPS Volumes), of which $7.14 million is attributable to Enbridge Gas's regulated utility operations[6].

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[2] Excess emissions charge is the price per unit in $/tCO2e. For the 2025 compliance period, the excess emissions charge is $95/tCO2e. https://www.ontario.ca/laws/regulation/190241.
[3] EB-2023-0196, OEB Decision and Order, February 8, 2024, pp.5-6.
[4] EB-2024-0251, OEB Decision and Order, February 28, 2025, pp.5-6.
[5] EB-2025-0165, OEB Decision and Interim Rate Order, pp. 7-8.
[6] Enbridge Gas's regulated costs are related to gas cost associated with the transmission and storage fuel consumed (compressor fuel) by regulated storage operations while the unregulated costs are related to the gas cost associated with the storage fuel consumed (compressor fuel) by the unregulated storage activities.

13. Enbridge Gas has recorded a 2025 facility-related variance of ($0.74 million), in the FCCVA[7]. This reflects a variance between the amount of revenue billed through the Facility Carbon Charge and Enbridge Gas's actual regulated facility-related costs, which is shown in Table 1.

Table 1
2025 FCCVA Balance

Line No.	Particulars ($ millions)	2025 Actual Costs
1	Facility Carbon Charge Revenue	$7.89
2	Company Use Costs	$(1.08)
3	EPS Costs	$(6.06)
4	Variance	$0.74

14. The main drivers of the variance, , were due to the delay in adjusting the Facility Carbon Charge rate following the unexpected change to Federal Carbon Charge and a slightly warmer than normal winter, as outlined below.

15. On April 1, 2025, Enbridge Gas retained the then-current Facility Carbon Charge rate and deferred the rate update to account for the removal of the Facility Carbon Charge on Company Use volumes, as approved by the OEB[8]. This delay in adjustment to the Facility Carbon Charge rate contributed to higher amounts of carbon charges being collected from customers between April to July in 2025. The EPS carbon costs were slightly lower than forecasted as the regulated EPS compressor fuel volumes and the associated emissions were lower than forecast due to a warmer winter with slightly lower system demands.

[7] This variance reflects consideration of: (i) applying the Federal Carbon Charge Rate for Marketable Natural Gas of 15.25 ¢/m^3 from January 1, 2025 – March 31, 2025 to actual Company Use Volumes of natural gas consumed in the operation of Enbridge Gas's facilities from January 1, 2025 to March 31, 2025; (ii) Enbridge Gas's 2025 EPS obligation of $6.06 million related to regulated utility operations for the January 1, 2025 to December 31, 2025 period; and (iii) actual billed amounts for the January 1, 2025 to December 31, 2025 period.
[8] EB-2025-0078.

1. EPS Compliance Costs

16. The $7.68 million[9] related to EPS Volumes is based on Enbridge Gas satisfying its entire 2025 EPS compliance obligation by paying the excess emissions charge of $95/t$CO_2$e. As the deadline to pay the 2025 EPS obligation is not until December 1, 2026, Enbridge Gas still has the option to satisfy its 2025 EPS obligation by purchasing EPUs from other EPS participants. EPUs typically sell at a discount to the excess emissions charge, which would reduce Enbridge Gas's 2025 EPS compliance obligation.

17. In June 2024, the provincial government introduced the Emissions Performance Program (EPP) which uses compliance payments collected through the EPS to support emissions reduction projects at eligible EPS registered facilities[10].

18. EPP funding is provisionally equal to a facility's EPS compliance payment(s) made to the provincial government in prior years. If an EPS participant purchases EPUs from another EPS participant for use towards their EPS compliance obligation, the EPS compliance payment to the provincial government would be reduced by the corresponding amount. Therefore, by utilizing EPUs for an EPS compliance obligation, an EPS facility forfeits or reduces the EPP funding that the provincial government would offer in following years.

19. Enbridge Gas will use the evaluation criteria outlined in response at Exhibit I.STAFF-2 of the 2025 FCPP Application, to determine the right balance between procuring EPUs to reduce the 2025 EPS compliance obligation or paying the excess emissions charge to secure EPP funding[11]. The ability to use EPUs to reduce the

[9] Includes costs related to both regulated and unregulated operations.
[10] Ontario Government, Available funding opportunities from the Ontario Government, Emissions Performance Program. September 4, 2024. https://www.ontario.ca/page/available-funding-opportunities-ontario-government#section-5
[11] EB-2024-0251, Exhibit I.STAFF.2 part a).

2025 EPS compliance obligation is also based on the availability of EPUs in the market, which to date have been limited.

20. Should Enbridge Gas's 2025 EPS obligation differ from what has been outlined in evidence, due to the Company procuring EPUs at a lower price than the excess emissions charge or due to any findings from the ongoing regulatory verification, any variances will be recorded in the 2026 FCCVA.

ACCOUNT NO. 179-308 - CUSTOMER CARBON CHARGE VARIANCE ACCOUNT

1. Enbridge Gas is requesting disposition of ($0.002 million), plus interest, in the Customer Carbon Charge Variance Account (CCCVA).

2. In June 2018, the Greenhouse Gas Pollution Pricing Act (GGPPA) was enacted. Under the GGPPA, a federal carbon pricing program (FCPP) applies in whole or in part to any province or territory that requested it or that did not have an equivalent carbon pricing system in place by January 1, 2019. Provinces or territories can submit their own carbon pricing systems to the federal government for approval, and, if approved, are not subject to Part 1 and/or Part 2 of the GGPPA.

3. The federal government confirmed in October 2018 that the GGPPA would apply in Ontario. In March 2022, the federal government announced that, effective January 1, 2022, Ontario's carbon pricing system for industrial emitters, known as the Emissions Performance Standards (EPS) program, would be implemented in Ontario, effectively removing the province from Part 2 of the GGPPA.

4. On March 15, 2025, the federal government set the Federal Carbon Charge rate to $0.00 per cubic metre of marketable natural gas, effective April 1, 2025, through amending regulations under the federal GGPPA[1]. Accordingly, Enbridge Gas removed the Federal Carbon Charge from customer bills effective April 1, 2025.

5. In 2025, in Ontario, the FCPP was composed of two elements: (i) a charge on fossil fuels (the Federal Carbon Charge) imposed on distributors, importers, and producers, which increased on April 1, 2024[2]; and (ii) an Ontario EPS program for prescribed industrial facilities.

[1] Government of Canada. (2025 March 15). Regulations Amending Schedule 2 to the Greenhouse Gas Pollution Pricing Act and the Fuel Charge Regulations: SOR/2025-107. gazette.gc.ca/rp-pr/p2/2025/2025-03-15-x2/html/sor-dors107-eng.html

[2] The Federal Carbon Charge rate for marketable natural gas from January 1, 2025 to March 31, 2025 was 15.25 cents per cubic metre.

6. In 2025, Enbridge Gas's operations as a natural gas utility in Ontario fell under the purview of the GGPPA and EPS Regulation. Under the GGPPA, Enbridge Gas is registered as a Distributor and was required to remit customer-related Federal Carbon Charges to the Government of Canada monthly, for volumes delivered by Enbridge Gas to its residential, commercial, and industrial customers who are not covered under the EPS. These costs were recovered as a pass-through to customers in rates, as approved by the OEB through the 2025 FCPP Application[3].\

7. Enbridge Gas tracks the variance between actual customer-related carbon costs incurred and the customer-related carbon costs recovered in rates within the OEB-approved CCCVA.

8. In Phase 1 of the 2024 Rebasing Application, Enbridge Gas proposed to harmonize the established FCPP-related deferral and variance accounts effective January 1, 2024, including the CCCVAs, due to the Company being an amalgamated entity and no longer requiring separate deferral and variance accounts for the EGD and Union rate zones[4]. As part of the 2024 Rebasing Phase 1 Settlement Agreement, parties agreed on harmonizing the CCCVAs, and the OEB approved this in its Decision on the Settlement Agreement[5]. Accordingly, effective January 1, 2024, the harmonized account is the CCCVA – Enbridge Gas Inc. [6].

9. The CCCVA balance of ($0.002 million), plus interest, is a credit to ratepayers who were subject to the Federal Carbon Charge.

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[3] EB-2024-0251.
[4] EB-2022-0200, Exhibit 9, Tab 1, Schedule 2, pp.24-25.
[5] EB-2022-0200, Settlement Agreement, August 17, 2023.
[6] Enbridge Gas Inc. Account No. 179-308, to record the variance between actual customer carbon costs and the customer carbon costs recovered in rates.

10. Under the GGPPA and associated Fuel Charge Regulations, RNG and hydrogen are not subject to the Federal Carbon Charge[7]. The variance recorded is due to deliveries of hydrogen to customers in January to March 2025, through the Company's Low Carbon Energy Project (LCEP). While the Company's renewable natural gas (RNG) OptUp program remains in effect, no purchases of RNG were carried out during the January to March 2025 period which would be eligible for exemption.

11. Due to billing system functionality constraints, Enbridge Gas was unable to reduce the Federal Carbon Charge only on the portion of a system supply customer's bill that was RNG or hydrogen. Given the limited quantity of exempt fuels delivered to customers, modifying the billing system to implement this functionality would have significantly increased administrative complexity and costs, for limited economic benefit to customers. Thus, Enbridge Gas applied the Federal Carbon Charge to all volumes of gas delivered to customers, including on RNG and hydrogen volumes. As RNG and hydrogen delivered by Enbridge Gas reduced the Company's Federal Carbon Charge obligations and subsequent remittance to the Government of Canada, any variance between the Federal Carbon Charges remitted to the Government of Canada and the amount charged to customers were tracked in the CCCVA, to be disposed to all customers subject to the Federal Carbon Charge[8].

12. The variance in the CCCVA for 2025 is minor due to hydrogen being distributed through the LCEP pilot project to a limited number of customers, which result in small volumes of hydrogen being eligible for exemption.

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[7] Under the GGPPA, biomethane, also known as RNG, is exempt from the Federal Carbon Charge and on March 27, 2023, the Fuel Charge Regulations, enacted under the GGPPA, were amended to confirm that hydrogen blended with natural gas is exempt from the Federal Carbon Charge, retroactive to August 2022, https://www.gazette.gc.ca/rp-pr/p2/2023/2023-04-12/html/sor-dors62-eng.html.
[8] EB-2020-0066, OEB Decision and Order, September 24, 2020, pp.16-17.

1. Federal Carbon Charge Removal

13. On May 26, 2025, the *Notice of Ways and Means Motion to introduce a bill respecting certain affordability measures for Canadians and another measure*[9] was issued which further amended the GGPPA and provided a schedule for its phased repeal. Repeal of the GGPPA in its entirety will occur on April 1, 2035, and as such Enbridge Gas continues to have an obligation to apply and remit FCC for natural gas delivered prior to April 1, 2025. As Enbridge Gas's Conditions of Service allow for invoices to be corrected and rebilled up to two years prior, it is expected that rebills will occur back to a period when the Federal Carbon Charge was in place. This may lead to adjustments in Enbridge Gas's previously reported Federal Carbon Charge amounts which the Company will be obligated to report and remit to the Government of Canada.

14. Enbridge Gas will keep the CCCVA open to capture potential variances that could arise due to the removal and on-going wind-down of the Federal Carbon Charge. If balances are recorded in this account going forward, Enbridge Gas will request approval to dispose of the balances through a future application.

[9] Minister of Finance and National Revenue. (2025 May 26). Notice of Ways and Means Motion to introduce a bill respecting certain affordability measures for Canadians and another measure ita-lir-0525-l-bil.pdf

ACCOUNT NO. 179-309 - CARBON CHARGES BAD DEBT DEFERRAL ACCOUNT

1. Enbridge Gas is requesting disposition of $6.95 million, plus interest, in the Carbon Charges Bad Debt Deferral Account (CCBDDA).

2. Effective January 1, 2019, the federal government applied Part 1 and Part 2 of the Greenhouse Gas Pollution Pricing Act (GGPPA) in Ontario, implementing a carbon pricing system in the province known as the federal carbon pricing program (FCPP). In March 2022, the federal government announced that, effective January 1, 2022, Ontario's carbon pricing system for industrial emitters, known as the Emissions Performance Standards (EPS) program, would be implemented in Ontario, effectively removing the province from Part 2 of the GGPPA.

3. In 2024, in Ontario, the FCPP was composed of two elements: (i) a charge on fossil fuels (the Federal Carbon Charge) imposed on distributors, importers, and producers, which increased on April 1, 2024[1]; and (ii) an Ontario EPS program for prescribed industrial facilities.

4. In 2025, Enbridge Gas's operations as a natural gas utility in Ontario fell under the purview of the GGPPA and EPS Regulation. On March 15, 2025, the federal government set the Federal Carbon Charge (FCC) rate to $0.00 per cubic metre of marketable natural gas, effective April 1, 2025, through amending regulations under the federal GGPPA[2]. Accordingly, Enbridge Gas removed the FCC from customer bills effective April 1, 2025.

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[1] The Federal Carbon Charge rate for marketable natural gas from January 1, 2025 to March 31, 2025, was 15.25 cents per cubic metre.
[2] Government of Canada. (2025 March 15). Regulations Amending Schedule 2 to the Greenhouse Gas Pollution Pricing Act and the Fuel Charge Regulations: SOR/2025-107. gazette.gc.ca/rp-pr/p2/2025/2025-03-15-x2/html/sor-dors107-eng.html

5. Prior to January 1, 2024, Enbridge Gas recorded administration costs, including carbon related bad debt, associated with the impacts of federal and provincial regulations related to greenhouse gas emissions requirements for Enbridge Gas within the two OEB-approved FCPP-related Greenhouse Gas Emissions Administration Deferral Accounts (GGEADAs)[3].

6. In the 2024 Rebasing Phase 1 Settlement Agreement, parties agreed to consolidating the GGEADAs into a single Enbridge Gas account, on the condition the GGEADA be renamed the CCBDDA and the scope of the account be limited to recording bad debt costs associated with carbon charges[4]. The OEB approved these account modifications, effective January 1, 2024, in its Decision on the Settlement Agreement[5].

7. In 2025, Enbridge Gas incurred $6.95 million bad debt costs associated with carbon charges, which was recorded in the CCBDDA. In its 2025 FCPP Application, Enbridge Gas forecast it would incur $13.05 million in incremental carbon related bad debt expenses in 2025 based on forecasted costs recoverable from customers as a result of the GGPPA and EPS Regulation[6].

8. As outlined in the 2022 Federal Carbon Pricing Program Application in the response at Exhibit I.VECC.7, the bad debt forecasting methodology distinguishes FCPP-related bad debt from “regular” bad debt by taking a percentage of the total Company bad debt based on the percentage of the total bill related to FCPP[7]. The contributing factor to the 2025 forecast variance was due to the FCC no longer being

[3] EB-2024-0251, Exhibit C, Tab 1, Schedule 1, pp.1-9.
[4] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, pp.53-55.
[5] EB-2022-0200, Settlement Agreement, August 17, 2023, p.1.
[6] EB-2024-0251, Exhibit A, Tab 2, Schedule 1, pp.7.
[7] EB-2021-0209, Exhibit I.VECC.7.

applied to customer fuel use after March 31, 2025, resulting in an overall reduction to FCPP-related bad debt.

1. Federal Carbon Charge Removal

9. On May 26, 2025, the *Notice of Ways and Means Motion to introduce a bill respecting certain affordability measures for Canadians and another measure*[8] was issued which further amended the GGPPA and provided a schedule for its phased repeal. Repeal of the GGPPA in its entirety will occur on April 1, 2035, and as such Enbridge Gas continues to have an obligation to apply and remit FCC for natural gas delivered prior to April 1, 2025. As Enbridge Gas's Conditions of Service allow for invoices to be corrected and rebilled up to two years prior, it is expected that rebills will occur back to a period when the Federal Carbon Charge was in place. This may result in a change to bad debt expenses, related to carbon charges, that continue being incurred even though the Federal Carbon Charge has been removed. In addition, there may be changes in collectability of amounts in arrears that could change the bad debt expense related to the Federal Carbon Charge. Therefore, Enbridge Gas will keep the CCBDDA open to capture any potential incremental carbon bad debt expenses that could occur, as well as any bad debt associated with the recovery of Ontario EPS program costs.

[8] Minister of Finance and National Revenue. (2025 May 26). Notice of Ways and Means Motion to introduce a bill respecting certain affordability measures for Canadians and another measure ita-lir-0525-l-bil.pdf

ACCOUNT NO. 179-339 EARNINGS SHARING MECHANISM DEFERRAL ACCOUNT

1. As part of the 2024 Rebasing Phase 2 Settlement Agreement,parties agreed to, and the OEB approved the establishment of the Earnings Sharing Mechanism (ESM) Deferral Account.[1] For the years 2025 through 2028, this account records the ratepayer share of utility earnings that results from the application of the earnings sharing mechanism. If in any year, the actual utility return on equity (ROE) exceeds the OEB-approved ROE (the 2024 allowed ROE of 9.21% embedded in base rates) by more than 100 basis points, the excess earnings will be shared equally (50/50) between ratepayers and the Company. Further, earnings over 300 basis points above the allowed ROE will be credited to ratepayers on a 90/10 basis.

2. As outlined in Exhibit B, Tab 1, Schedules 1 & 2, the Company was in an earnings sharing position for 2025, as the actual achieved ROE of 10.774% exceeded the OEB-approved earnings sharing benchmark ROE of 10.21% (9.21% approved ROE + 100 basis point deadband before sharing). This resulted in gross over earnings of $48.7 million to be shared equally between ratepayers and shareholders. Correspondingly, a credit of $24.3 million to ratepayers, plus interest, has been recorded in the Earnings Sharing Mechanism Deferral Account. Details of 2025 achieved earnings can be found throughout the B series of exhibits. The main drivers of the higher achieved ROE were colder weather and lower operating costs:

    a) Favorable weather in the year was due to a combination of a colder than normal first half of the year, as well as a much colder November and December. This resulted in higher heating demand compared to what would have occurred under normal weather conditions.

[1] EB-2024-0111, Settlement Agreement, November 29, 2024.

b) The operation and maintenance expenses of the Company were lower than expected primarily due to lower compensation and benefits costs incurred in 2025. Details of O&M are presented in Exhibit B, Tab 3, Schedule 1.

ACCOUNT NO. 179-312 TAX VARIANCE ACCOUNT

1. This account records 50% of the revenue requirement impact of any tax rate or rule changes, versus the tax rates and rules included in rates, that affect Enbridge Gas Inc., subject to the following two exceptions as per the approved accounting order:

> In accordance with the OEB's July 25, 2019, letter, Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance ("CCA"), within a sub-account of the Tax Variance Account, Enbridge Gas will record 100% of the revenue requirement impact of any changes in CCA rules that are not reflected in base rates. This will include impacts related to Bill C-97 CCA rule changes, which became effective November 21, 2018, as well as any future CCA changes instituted by relevant regulatory or taxation bodies.
>
> Enbridge Gas will also record 100% of the revenue requirement impact of any tax rates, rules, or credits (or similar mechanisms), specifically directed at energy transition activities. The determination of the appropriate sharing of any such impacts, between ratepayers and the Company, will be determined at the time of disposition.[1]

2. Further, in its letter dated May 6, 2026[2], the OEB stated that it: expects Utilities to continue to adhere to the OEB's July 25, 2019 accounting direction and continue to use the applicable CCA-related sub-account to address the revenue requirement impacts of the Re-Accelerated Investment Incentive (RII) and of any future CAA rule changes.

3. On March 26, 2026, Bill C-15 (Budget 2025 Implementation Act, No. 1) received Royal Assent and is now enacted legislation. Among other measures, Bill C-15 legislates the RII, which reinstates and expands accelerated CCA deductions for eligible depreciable property:

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[1] EB-2022-0200, Rate Order, Appendix C, p.33.
[2] Accounting and Rates Direction Regarding Bill C-15 for the Reaccelerated Investment Incentive for Capital Cost Allowance, May 6, 2026.

- suspension of the CCA half year rule (property acquired after December 31, 2024 and available for use before January 1, 2034); and
- enhanced first year CCA deductions relative to "normal" depreciation (property acquired after December 31, 2024 and available for use before January 1, 2030);

4. These measures accelerate the timing of CCA deductions but do not change the total lifetime amount of depreciation deductible for tax purposes. As such, they constitute temporary timing differences and not permanent tax savings.

5. For the 2025 taxation year, Enbridge Gas placed qualifying capital assets into service that meet the legislated requirements for RII treatment. As a result:
   - the Company's current income tax payable for 2025 was lower than would have been the case under the CCA rules assumed in rates;
   - the difference arises solely from accelerated tax depreciation, with an offsetting reduction in CCA deductions in future years; and
   - the impact is therefore temporary and fully reversible over the remaining lives of the assets.

<u>1. Modified CCA treatment under RII:</u>

6. For property that qualifies as RII, the legislation introduces two coordinated changes relative to the calculation of CCA, exclusive of any accelerated investment incentives:
   - <u>Suspension of the half year rule</u>
     RII property is not subject to the half year rule. Consequently, 100% of the capital cost of qualifying additions is included in the CCA base in the year the property becomes available for use. Note, the suspension of the half year rule

is consistent with Phase-out provision/incentive of Bill C-97 currently reflected in rates.

- <u>Enhanced first year CCA allowance</u>
  The prescribed CCA rate applicable to the relevant class is multiplied by an enhanced factor. For property placed in service before the end of the full enhancement period, this results in a first year CCA deduction equal to three times the normal first year CCA that would otherwise have been available for property subject to the half year rule.

Together, these two adjustments accelerate depreciation into earlier years while leaving the total lifetime CCA unchanged.

7. The incremental CCA attributable to RII in a given year is calculated as the difference between:
   - the enhanced CCA permitted under RII; and
   - the CCA amount that would have been deductible under the tax rules assumed in rates;
   - The income tax impact of the variance between the two is then determined and grossed up for taxes to determine the annual revenue requirement impact.

   This incremental amount represents a pure timing difference. The increase in first year CCA is fully offset by correspondingly lower CCA deductions in subsequent years.

8. Consistent with OEB direction, Enbridge Gas has recorded 100% of the incremental tax benefit arising from accelerated CCA to the TVDA. This results in a credit balance to ratepayers of $13.622 million, plus interest.

9. The details of the calculation can be found in Appendix 1.

Enbridge Gas

Calculation Of The Accelerated CCA Impact To Be Recorded In The Tax Variance Deferral Account

Line No.	2025 Year-End Particulars ($000s)		Opening UCC Accel. CCA	Opening UCC CCA in Rates	Total Additions Qualifying for Accel. CCA	Less: Lessor of Cost or Proceeds	Eligible CCA Additions	Accel. CCA Depreciable UCC Balance (1)	CCA in Rates Depreciable UCC Balance	Rate (%)	Accelerated CCA	CCA in Rates	Closing UCC Accel. CCA	Closing UCC CCA in Rates
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
								(f) = (e) x 1.5	(g) = (e) x 1		(i) = (f) x (h)	(j) = (g) x (h)	(k) = (a) + (e) - (i)	(l) = (b) + (e) - (j)
	Class													
1	1	Buildings, structures and improvements, services, meters, mains	-	-	2,898.7	(4,922.1)	(2,023.3)	(3,035.0)	(2,023.3)	4%	(121.4)	(80.9)	(1,901.9)	(1,942.4)
2	1	Non-residential building acquired after March 19, 2007	-	-	48,028.8	-	48,028.8	72,043.3	48,028.8	6%	4,322.6	2,881.7	43,706.3	45,147.1
3	2	Mains acquired before 1988	-	-	-	-	-	-	-	6%	-	-	-	-
4	3	Buildings acquired before 1988	-	-	-	-	-	-	-	5%	-	-	-	-
5	6	Other buildings	-	-	-	-	-	-	-	10%	-	-	-	-
6	7	Compression equipment acquired after February 22, 2005	-	-	23,824.6	-	23,824.6	35,736.9	23,824.6	15%	5,360.5	3,573.7	18,464.1	20,250.9
7	8	Compression assets, office furniture, equipment	-	-	101,541.1	-	101,541.1	152,311.7	101,541.1	20%	30,462.3	20,308.2	71,078.8	81,232.9
8	10	Transportation, computer equipment	-	-	11,279.2	(753.0)	10,526.2	15,789.3	10,526.2	30%	4,736.8	3,157.9	5,789.4	7,368.4
9	12	Computer software, small tools	-	-	7,310.4	-	7,310.4	7,310.4	7,310.4	100%	7,310.4	7,310.4	-	-
10	13	Leasehold improvements	-	-	-	-	-	-	-	N/A	-	-	-	-
11	14.1	Intangibles	-	-	3,556.1	-	3,556.1	5,334.2	3,556.1	5%	266.7	177.8	3,289.4	3,378.3
12	14.1	Intangibles (pre 2017)	-	-	-	-	-	-	-	7%	-	-	-	-
13	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	-	-	8%	-	-	-	-
14	38	Heavy work equipment	-	-	3,709.6	(158.8)	3,550.8	5,326.3	3,550.8	30%	1,597.9	1,065.3	1,953.0	2,485.6
15	41	Storage assets	-	-	7,804.6	-	7,804.6	11,706.9	7,804.6	25%	2,926.7	1,951.1	4,877.9	5,853.4
16	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	-	-	45%	-	-	-	-
17	49	Transmission pipeline additions acquired after February 23, 2005	-	-	21,037.1	-	21,037.1	31,555.6	21,037.1	8%	2,524.4	1,683.0	18,512.6	19,354.1
18	50	Computers hardware acquired after March 18, 2007	-	-	10,052.2	-	10,052.2	15,078.2	10,052.2	55%	8,293.0	5,528.7	1,759.1	4,523.5
19	51	Distribution pipelines acquired after March 18, 2007	-	-	588,965.0	(394.9)	588,570.1	882,855.1	588,570.1	6%	52,971.3	35,314.2	535,598.8	553,255.9
20	Total		$ -	-	830,007.5	(6,228.7)	823,778.8	1,232,013.0	823,778.8		$ 120,651.4	82,871.1	703,127.4	740,907.7

	2025
CCA Variance (i) - (j)	37,780.3
Tax Rate	26.5%
Earnings Impact of Accelerated CCA	10,011.8
Earnings Impact Grossed-up for Taxes Recorded in the TVDA (Earnings impact of Accelerated CCA grossed up at 0.735)	13,621.5

Notes:

(1) Equals 1.5x of the Eligible CCA Additions in Column (e), except Class 12, which is 1.0x of Column (e) amount since Class 12 has a CCA rate of 100%.

ACCOUNT NO. 179-323 DAWN PARKWAY SURPLUS CAPACITY DEFERRAL ACCOUNT

1. As part of the 2024 Rebasing Phase 1 Settlement Agreement, parties agreed to, and the OEB approved[1], the establishment of the Dawn Parkway Surplus Capacity Deferral Account. This account records the actual revenue from the sale of all or a portion of the 89 TJ/d Dawn Parkway System surplus capacity forecast. Dawn Parkway System surplus capacity used to reduce the Parkway Delivery Obligation (PDO) is not considered a sale of surplus capacity and reduces the 89 TJ/d Dawn Parkway System surplus capacity for purposes of determining actual revenue for this account.

2. In 2025, Enbridge Gas recognized $2.3 million of revenue from the sale of surplus capacity. Details of the sale of surplus capacity are provided in Table 1. In 2025, Enbridge Gas issued an operational notice informing shippers of a pressure restriction on the NPS 26 Trafalgar pipeline. That restriction will remain in effect until further notice and eliminates the ability to sell incremental Dawn Parkway capacity beyond the 51,098 GJ/day already contracted.

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, pp.55-56.

Table 1
2025 Dawn Parkway Surplus Capacity

Line No.	Particulars	Volume (GJ/d)	Unit Rate ($/GJ)	Revenue ($000s)
		(a)	(b)	(c) = (a x b)
1	January	35,696	4.098	146.3
2	February	35,696	4.098	146.3
3	March	35,696	4.098	146.3
4	April	35,696	4.098	146.3
5	May	51,098	4.098	209.4
6	June	51,098	4.098	209.4
7	July	51,098	4.098	209.4
8	August	51,098	4.098	209.4
9	September	51,098	4.098	209.4
10	October	51,098	4.098	209.4
11	November	51,098	4.098	209.4
12	December	51,098	4.098	209.4
13	Total			2,260.3

ACCOUNT NO. 179-326 DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM VARIANCE ACCOUNT

1. On August 17, 2023, the OEB approved the 2024 Rebasing Phase 1 Settlement Agreement[1]. As part of the Settlement Agreement, the Parties agreed to the establishment of a new variance account for Distribution Integrity Management Program (DIMP) and Enhanced Distribution Integrity Management Program (EDIMP) costs. The new variance account is referred to as the DIMP Variance Account (DIMPVA). Parties also agreed to the filing of DIMP and EDIMP Annual Reports (at Exhibit G, Schedule 4, Tab 1), which provide evidence of the customer benefits achieved through DIMP and EDIMP activities..

2. The purpose of the DIMPVA is to track the variance between Enbridge Gas's spending each year on the DIMP and EDIMP programs and the costs included in rates. Parties agreed that $12.5 million is included in the 2024 O&M budget for these programs, and that variances from this $12.5 million will be recovered from or credited to ratepayers on an annual basis from 2024 until Enbridge Gas's next rebasing[2].

3. For 2025 Enbridge Gas escalated the base comparator from 2024 to $12.976 million incorporating PCI plus growth factors[3]. The balance of the 2025 DIMPVA that is being requested for clearance within this proceeding is a debit of $0.213 million, plus interest.

4. In terms of detailing out the budget, the 2024 DIMP and EDIMP workplan originally submitted as part of the EB-2025-0155 proceeding[4] is not the most current or

[1] EB-2022-0200, Settlement Agreement, August 17, 2023.
[2] EB-2022-0200, Settlement Agreement, August 17, 2023, Exhibit O1, Tab 1, Schedule 1, p.31.
[3] 2024 Base Rate Locate Budget ($12.5 million) x Inflation plus Growth factor ((1+(3.33% + 0.48%)) = 1.0381)
[4] EB-2025-0155, Exhibit C, Tab 2, Schedule 13, p. 2, Table 1

accurate comparator as it does not properly reflect the bucketing of costs as defined by Enbridge Gas throughout this evidence (i.e., administrative costs include all Internal Integrity Resource costs, inclusive of those supporting project/program execution and those supporting project/program oversight and administration). Enbridge Gas refined and updated the categorization of the 2024 DIMP and EDIMP costs as planning progressed and resource requirements became better understood. While the overall budget amount remained unchanged, the composition of costs within the budget was refined to reflect a more accurate understanding of the resources required to deliver the planned work.

5. In particular, under the original workplan, which was primarily developed to estimate the costs associated with individual 2024 DIMP and EDIMP objectives, costs for Internal Integrity Resources not solely dedicated to DIMP and EDIMP programs were included within the Project cost category. As the budget was refined and resource requirements became better understood, these costs were recategorized to the Administrative cost category to align with the established cost-tracking methodology used by the Integrity team. Under this approach, Internal Integrity Resource costs are tracked at the program level (e.g., DIMP, EDIMP, or other Integrity programs) rather than to individual projects.

6. As noted in the Administrative Costs section below, the categorization of these costs within the Administrative category is not indicative of these costs being of an overhead or indirect support nature, as many of these resources perform technical activities that directly contribute to the planning, assessment, prioritization, and execution of DIMP and EDIMP work. Table 1 illustrates this refinement in the budget categorization by showing the transfer of these costs from the Project category to the Administrative category.

Table 1
2024 DIMPVA Budget Recategorization

Line No.	Description	2024 Workplan ($ millions)	2024 Budget ($ millions)	Variance ($ millions)
1	DIMP Admin	0.699	1.556	0.857
2	EDIMP Admin	1.053	0.989	(0.064)
3	Total Admin	1.752	2.545	0.793
4	DIMP Projects	1.754	1.448	(0.306)
5	EDIMP Projects	8.995	8.507	(0.488)
6	Total Projects	10.749	9.955	(0.793)
7	Total DIMPVA	12.500	12.500	0

7. This updated budget breakdown represents Enbridge Gas's view of the expected distribution of DIMP and EDIMP expenditures and provides a more appropriate basis for comparison against actual results.

8. The finalized budget breakdown for the DIMP and EDIMP costs was previously filed with the OEB in July 2024 in response to a Consumers Council of Canada interrogatory in Phase 2 of the 2024 Rebasing Application.[5] This refined and updated budget breakdown formed the basis for development of the 2025 DIMP/EDIMP budget.

9. Table 2 provides a breakdown of the 2025 DIMP and EDIMP expenditures and variances against budget. Descriptions of the work types and significant contributing factors to the variances within each work type are described below.

[5] EB-2024-0111, Exhibit I.1.17-CCC-35, p.2, Table 1

Table 2
2025 DIMPVA Breakdown

Line No.	Description	2025 Escalated Budget ($ millions)	2025 Actuals ($ millions)	Variance ($ millions)
	DIMP Admin (Internal Integrity Resources)			
1	Admin	1.615	1.561	(0.055)
	DIMP Projects (External Integrity Resources)			
2	Investigations & Assessments	0.326	0.579	0.253
3	Pipe Inspections	0.379	0.271	(0.108)
4	Station Inspections	0.093	0.106	0.012
5	Regulator Set Inspections	0.647	0.870	0.224
6	DIMP Carryovers	0.058	0.007	(0.051)
7	Total DIMP	3.118	3.394	0.276
	EDIMP Admin (Internal Integrity Resources)			
8	Admin	1.027	0.946	(0.081)
	EDIMP Projects (External Integrity Resources)			
9	In-line Inspection (ILI)	7.937	7.818	(0.119)
10	Corrosion Survey	0.471	0.380	(0.091)
11	Digs (Validation)	0.276	0.423	0.147
12	Assessments & Consulting	0.147	0.233	0.086
13	EDIMP Carryovers	0.000	(0.004)	(0.004)
14	Total EDIMP	9.858	9.795	(0.063)
15	Total DIMPVA	12.976	13.189	0.213

1. Administrative Costs

10. In its EB-2025-0155, Decision and Order, the OEB expressed concerns regarding the level of Administrative costs recorded for the DIMP and EDIMP programs.

11. The OEB concluded that *"…the allocation of administrative costs is excessive…[and] is not persuaded by Enbridge Gas's explanation that the variance is attributed to budget reclassification…"*[6]

12. Enbridge Gas would like to clarify that the Administrative category is not solely comprised of overhead or indirect support functions. It also includes substantial technical engineering and integrity management work that directly enables DIMP and EDIMP outcomes.

13. Administrative costs reflect the delivery of technical work through Internal Integrity Resources instead of external contractors. If the same activities were completed by external consultants, these costs would be reported as Project costs despite producing the same technical outputs and integrity outcomes.

14. Table 3 provides a breakdown of Administrative costs for the DIMP and EDIMP programs, split into the following categories: Internal Integrity Resource costs, Oversight / Administrative costs and Other Administrative costs.

[6] EB-2025-0155, Decision and Order, June 25, 2026, p.14.

Table 3
2025 Administrative Cost Breakdown

Description	Internal Integrity Resource Costs ($ millions)	Oversight / Administrative Costs ($ millions)	Other Admin Costs ($ millions)	Total Admin Costs ($ millions)
DIMP Admin	1.122	0.391	0.047	1.561
EDIMP Admin	0.568	0.352	0.025	0.946
Total DIMPVA Admin	1.690	0.744	0.073	2.506

15. Oversight / Administrative Costs reflect the supervisory and management resources required to provide technical oversight, direction, and governance of the work performed by individual contributors.

16. The Other Administrative Costs category captures non-labour administrative expenditures, including travel and accommodation (T&A), training, professional dues, and any other materials or supplies required to enable the DIMP and EDIMP portfolios.

17. Internal Integrity Resource Costs consist of full-time employee (FTE) and contingent worker (CWR) labour. The resources in this category include professional engineers and engineers-in-training who perform technical work that directly enables the delivery of DIMP and EDIMP program objectives.

18. Examples of project-related activities performed by these Internal Integrity Resources include:
    - Risk and reliability modeling, including ongoing model enhancements and refinements;
    - Risk-informed prioritization of asset inspections, assessments, and remediation activities;

- Development and management of inspection and assessment scopes;
- Execution and support of integrity management projects;
- Technical review and analysis of inspection and assessment results; and
- Determination of mitigation requirements, remediation planning, and integrity management recommendations.

19. These activities are essential components of DIMP and EDIMP program delivery and are directly tied to integrity outcomes, risk reduction, and rate payer benefits.

1.1 Classification of Internal Integrity Resources as Administrative vs Projects Costs

20. Internal Integrity FTE and CWR resources often work on multiple integrity projects and activities simultaneously. Enbridge Gas manages and tracks these labour costs at a program level (DIMP vs. EDIMP) rather than at a project level and has therefore presented these costs as Administrative costs.

21. In contrast, DIMP and EDIMP Project costs consist of payments to external service providers and project execution resources that are not part of Enbridge's Integrity team (e.g. operations, construction, etc.). These expenditures can be reported at the project level.

22. However, in situations where it is determined that certain activities can be delivered more efficiently using incremental Internal Integrity Resources, as compared to external service providers, costs may be incurred and captured as part of the Administrative cost category to facilitate the work instead of the Project cost category. Although costs are shifted from the Projects category in these instances, the DIMP and EDIMP programs continue to deliver the intended program outcomes. Consequently, the relative proportion of Administrative and Project costs should not be interpreted as evidence of increased overhead or diminished customer value.

Rather, they reflect prudent management decisions that optimize the use of internal expertise, reduce overall program costs, and maximize value delivered to rate payers while maintaining the integrity objectives of the DIMP and EDIMP programs.

23. For example, Quantitative Risk Assessments (QRA) conducted on EDIMP pipelines are completed by internal technical staff whose costs are recorded within the Administrative category. These assessments directly enable integrity management decision-making and risk mitigation efforts. The effectiveness of these activities is illustrated in the DIMP/EDIMP Annual Report[7], which outlines capital cost avoidances of approximately $77.1 million, $34.3 million, and $5.4 million associated with the NPS 12 Wilson Avenue, NPS 12 Martin Grove, and NPS 8 St. Thomas pipelines, respectively.

24. The 2025 escalated budget for DIMP and EDIMP administrative costs was estimated at $2.642 million. Actual spend was $2.506 million for a variance of ($0.136 million). The variance is primarily due to staff vacancies.

2. DIMP Projects

25. DIMP Projects consists of five distinct work categories: Investigations & Assessments; Pipe Inspections; Station Inspections; Regulator Set Inspections; and DIMP Carryovers. The 2025 escalated budget for DIMP Projects was estimated at $1.503 million and actual spend was $1.833 million for a variance of $0.330 million.

26. The Investigations and Assessments work cost $0.579 million to complete, and the $0.253 million variance to the budget was primarily driven by investigations of heavier hydrocarbon contamination of polyethylene (PE) pipe and a plastic pipe records review.

[7] Exhibit G, Tab 4, Schedule 1.

27. The Pipe Inspections work focused on isolated steel services and steel riser inspections. Isolated steel service lines and steel risers that have the potential to be electrically disconnected from a cathodically protected steel pipeline system have a higher likelihood of leaks from corrosion. The total variance for this category was ($0.108 million).

28. The Station Inspections plan focused on identifying potential hazards at distribution stations, with a focus on the cathodic protection of below ground piping at the station. This work accounted for a variance of $0.012 million.

29. Regulator Set Inspections focused on service extensions, local and remote first cut regulator sets, greater than 400 series regulator sets, 200 & 400 series regulator sets, and bulk meters. This work category resulted in a variance of $0.224 million.

30. Forecast 2024 DIMP Carryover costs reflected estimated work performed but not accrued in 2024. Only $0.007 million of the escalated budgeted amount of $0.058 million DIMP carryover costs materialized in 2025, resulting in a variance of ($0.051 million).

3. EDIMP Projects

31. EDIMP Projects consists of five distinct work categories: In-line Inspection (ILI); Corrosion Survey; Digs (Validation); Assessments & Consulting; and EDIMP Carryovers. The 2025 escalated budget for EDIMP Projects was estimated at $8.831 million and actual spend was $8.849 million for a variance of $0.018 million.

32. The 2025 ILI budget mainly consisted of in-line pipeline inspections. The Digs work category involved mitigating/repairing any Phase 1 (immediate response) anomalies that were discovered as part of the ILI work. The ILI work category had a variance of ($0.119 million), which was offset by the Digs variance of $0.147 million for a

combined variance of $0.028 million. The total variance was driven by higher integrity dig costs, which was partially offset by three cancelled ILI runs on the NPS 20 Queensway pipeline.

33. The Corrosion Survey work category included above-ground surveys such as Cathodic Protection (CP) system surveys and non-intrusive pipeline assessments (NIPA). This work category had a variance of ($0.091 million) which was driven by lower costs on CP surveys, and was partially offset by higher costs due to challenges and uncertainties around NIPA surveys.

34. The Assessments & Consulting work category was used to hire a consultant to perform a desktop study to produce an inventory of geotechnical and hydrotechnical areas of concern. A total of eight pipelines were assessed along with an investigation into QRA model development. This work category had a variance of $0.086 million. The higher costs were due to some geohazard sites needing detailed investigation and field assessments, as well as the inclusion of the QRA model development project within this category.

35. Forecasted 2024 EDIMP Carryover costs would generally include expected residual costs for EDIMP projects commenced in 2024 but not concluded until 2025.

4. DIMP/EDIMP Annual Reporting

36. As part of the Settlement Agreement, Enbridge Gas also agreed to provide annual reporting on DIMP and EDIMP actual costs, setting out the work done (and associated costs), listing the projects/facilities where work was done, describing what facilities work was deferred or avoided or otherwise impacted as a result and discussing the cost/benefit analysis of the DIMP and EDIMP work done during the past year.[8]

[8] EB-2022-0200, Settlement Agreement, August 17, 2023, Exhibit O1, Tab 1, Schedule 1, p.56.

37. The DIMP/EDIMP Annual Report provides evidence of the customer benefits achieved through DIMP and EDIMP activities, including field inspections, integrity and risk assessments, remediation activities and repairs, and long-term mitigation strategies that support the safe and reliable operation of the distribution system. The effectiveness of these activities is demonstrated by the combined capital cost avoidances of approximately $116.8 million associated with the NPS 12 Wilson Avenue, NPS 12 Martin Grove, and NPS 8 St. Thomas pipelines. The DIMP/EDIMP Annual Report is included at Exhibit G, Tab 4, Schedule 1.

ACCOUNT NO. 179-328 POST RETIREMENT TRUE-UP VARIANCE ACCOUNT

1. As part of the 2024 Rebasing Phase 1 Settlement Agreement, parties agreed to, and the OEB approved, the establishment of the Post-Retirement True-Up Variance Account (PTUVA).[1] This account records the difference, in excess of a $10 million deadband (debit or credit), between the revenue requirement impact of actual pension and other post-employment benefits (OPEB) costs (accrual and cash-based amounts) and the revenue requirement impact of pension and OPEB costs (accrual and cash-based amounts) included in rates.

2. The OEB-approved forecast revenue requirement impact of pension and OPEB costs (accrual and cash-based amounts) embedded in rates for 2025 is a credit of $8.6 million[2]. For the year ended December 31, 2025, the actual revenue requirement impact that resulted from pension and OPEB costs (accrual and cash-based amounts) was a credit of $67.6 million. The 2025 PTUVA balance, which represents the difference between the OEB-approved forecast and actual revenue requirement impact of pension and OPEB costs in excess of the agreed upon $10 million deadband, is a credit to ratepayers of $49.0 million, plus interest. A breakdown of the forecast and actual revenue requirement as well as the derivation of the $49.0 million PTUVA balance is provided at Attachment 1.

3. The variance between the OEB-approved forecast and the actual revenue requirement impact of pension and OPEB costs is primarily due to a higher actual return on plan assets versus the return forecast as part of the cost reflected in rates.

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[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, p.56.
[2] Escalation of $8.3M base 2024 amount equals base x PCI + Growth factor for 2025: $8.3M x ((1+(3.33%+0.48%)) = $8.6M.

2025 Pension True-Up Variance Account (PTUVA)

Line No.	Particulars ($ millions)	Actual 2025 (a)	OEB Approved[1] 2025 (b)	Variance (a) - (b)
	Incremental Operating Expenses:			
1	Operating and Maintenance Expenses	(46.5)	(1.7)	(44.8)
2	Depreciation Expense	-	-	-
3	Property Taxes	-	-	-
4	Total Incremental Operating Expenses	(46.5)	(1.7)	(44.8)
	Incremental Income Taxes:			
5	Income (Loss) before Income Taxes	46.5	1.7	44.8
6	Utility/Tax Timing Difference:			
7	Add-back: Accruals	(46.5)	(1.7)	(44.8)
8	Deduct: Cash Contributions	(12.1)	(17.5)	5.4
9	Taxable Income (Loss)	(12.1)	(17.5)	5.4
10	Income Taxes Payable (Benefit) (line 16 * 26.5% Tax Rate)	(3.2)	(4.6)	1.4
11	Net Revenue Deficiency (Sufficiency) (line 11 + line 17)	(49.7)	(6.3)	(43.4)
12	Grossed-up Revenue Requirement (line 18 / (1-0.265))	(67.6)	(8.6)	(59.0)
13	Deferral Deadband +/- $10M			(10.0)
14	Total PTUVA Deferral Receivable (Payable) (line 19 - line 20)			(49.0)

Notes:

1) Escalation of base 2024 base amounts in lines 1 & 8 = base amount x PCI + Growth factor (1.0381)

ACCOUNT NO. 179-330 CLEAN FUEL REGULATION CREDITS DEFERRAL ACCOUNT

1. On August 17, 2023, the OEB issued its Decision on the 2024 Rebasing Phase 1[1] Settlement Agreement. The Decision approved the establishment of a new deferral account to record revenues and incremental costs associated with the Federal Clean Fuel Regulation (CFR)[2]. The new deferral account is referred to as the CFR Credits Deferral Account.

2. The purpose of the CFR Credits Deferral Account is to record the revenues obtained by Enbridge Gas from the sale of CFR credits, net of any incremental offsetting credit formation, certification and transaction administration costs. These administration costs could include incremental staffing costs, consulting costs, legal costs, and other costs such as training, conferences and market monitoring subscriptions.

3. The objective of the CFR is to reduce the carbon intensity of liquid fuels produced and imported into Canada. Entities subject to the CFR satisfy their obligations through the submission of CFR credits to the Government of Canada. CFR credits can be created through three main categories of credit-creating actions:

    1. Actions that reduce the carbon intensity of liquid fossil fuels throughout their lifecycle,
    2. Supplying low-carbon fuels in Canada, and
    3. Supplying fuel and energy in advanced vehicle technologies.

4. As a gaseous fuel supplier, Enbridge Gas does not have an obligation under the CFR; however, Enbridge Gas is able to participate in the CFR on a voluntary basis.

[1] EB-2022-0200.
[2] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, pp.56-57.

Enbridge Gas is registered under the CFR as a Registered Creator and can create credits through end-use fuel switching in vehicles, an eligible credit creation activity.

5. In 2025, Enbridge Gas created credits under the CFR from its compressed natural gas (CNG) vehicle activities during the 2024 compliance period. Enbridge Gas sold the credits in 2025 and recorded the revenue from the sale in the CFR Credits Deferral Account, as a payable of $0.035 million, plus interest.

ACCOUNT NO. 179-331 INDIGENOUS WORKING GROUP DEFERRAL ACCOUNT

1. The purpose of the Indigenous Working Group (IWG) Deferral Account is to record incremental capacity funding amounts associated with the IWG as described in and established pursuant to Issue 4 in the 2024 Rebasing Phase 1 Settlement Agreement.[1]

2. During 2025, the IWG met in person at the Enbridge Gas Toronto office on May 14, and September 23. The IWG also met virtually on July 15 and November 26, 2025. In 2025, the IWG's key initiatives were to advance reconciliation-related dialogue (including discussion of reconciliation principles and the updated IRAP), improve Enbridge Gas processes affecting Indigenous communities (particularly the LTC environmental/archaeology processes), and begin structured engagement planning for upcoming major filings and programs (including 2029 rebasing and related planning work). The IWG Annual Report found at Exhibit G, Tab 3, Schedule 1, sets out more details on the activities of the IWG for 2025.

3. The balance in the IWG Deferral Account for 2025 is a debit of $0.269 million plus interest. Table 1 outlines the amounts paid in 2025, by IWG participant.

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.18.

Table 1
IWG Incremental Capacity Funding - 2025

Line No.	Participant	Amount ($000s)
1	The Brattle Group Canada ULC	124.2
2	Resilient LLP	79.7
3	Woodward and Co	38.9
4	Three Fires Group	12.5
5	Mississaugas of Scugog Island First Nation	9.0
6	Chippewas of the Thames First Nations	4.3
7	Total	$ 268.6

ACCOUNT NO. 179-333 AVERAGE USE VARIANCE ACCOUNT

1. The purpose of this evidence is to provide information in support of the 2025 Average Use Variance Account (AUVA)[1] balance. This account applies to all general service rate classes of Enbridge Gas, specifically, Rate 1, Rate 6, Rate M1, Rate M2, Rate 01 and Rate 10.

2. The AUVA records the revenue impact, exclusive of gas costs, of the volumetric difference between the actual weather-normalized average use experienced during the year and the forecast average use per customer embedded in OEB-approved rates for general service customers in Rate 1, Rate 6, Rate M1, Rate M2, Rate 01 and Rate 10[2].

3. The 2025 actual average use is weather normalized using 2025 forecasted heating degree days (HDD) which were produced using the same methodologies that underpin the 2024 OEB-approved volumetric forecast.

4. For Rate 1, the 2025 actual weather-normalized average use was 2.5% lower than the 2025 forecast, resulting in a total debit[3] from ratepayers of $12.1 million, plus interest.

5. For Rate 6, the 2025 actual weather-normalized average use was 1.6% higher than the 2025 forecasted average use, resulting in a total credit to ratepayers of $4.9 million, plus interest.

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[1] EB-2022-0200, OEB Decision and Order, December 21, 2023, Section 5.5.1, p.121.
[2] EB-2024-0111, OEB Decision on Settlement and Interim Rate Order, November 29, 2024, Appendix C.
[3] A credit in the AUVA deferral account indicates a refund to ratepayers and a debit indicates a collection from ratepayers.

6. For Rate M1, the 2025 actual weather-normalized average use was 4.2% lower than the 2025 forecasted average use, resulting in a total debit from ratepayers of $9.2 million, plus interest.

7. For Rate M2, the 2025 actual weather-normalized average use was 11.2% lower than the 2025 forecasted average use, resulting in a total debit from ratepayers of $9.9 million, plus interest.

8. For Rate 01, the 2025 actual weather-normalized average use was 3.3% lower than the 2025 forecasted average use, resulting in a total debit from ratepayers of $4.4 million, plus interest.

9. For Rate 10, the 2025 actual weather-normalized average use was 12.9% lower than the 2025 forecasted average use, resulting in a total debit from ratepayers of $3.9 million, plus interest.

10. Based on 2025 actual results, Rate 1, Rate M1, Rate M2, Rate 01, and Rate 10 experienced declines that were steeper than historical trends, resulting in variances higher than those observed historically. Rate 6 on the other hand represents a relatively modest variance.

11. The 2025 forecast average use was developed using actuals up to 2023 and assumed historical trends would continue. Enbridge Gas will continue to monitor the recent changes in average use trends for the affected rate classes as additional actual data becomes available.

12. Attachment 1 details the calculation of the 2025 AUVA by rate class that results in a net debit from ratepayers of $34.5 million, plus interest.

Enbridge Gas
Average Use Variance Account (AUVA) (1)
Account No. 179-333

Line No.	Particulars	Unit of Measurement	Rate 1	Rate 6	Rate M1	Rate M2	Rate 01	Rate 10	Net Account Balance
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Forecast Average Use	(m^3)	2,310	27,236	2,649	151,411	2,710	139,738	
2	Actual Normalized Average Use	(m^3)	2,252	27,659	2,538	134,418	2,619	121,726	
3	Average Use Variance (Line No. 1 minus Line No. 2)	(m^3)	58	(423)	111	16,994	91	18,012	
4	2024 OEB-approved average number of customers (2)	(#)	2,163,088	172,974	1,204,177	8,077	369,594	2,204	
5	Normalized Volumetric Variance (Line No. 3 multiplied by Line No.4)	($10^6 m^3$)	126.3	(73.1)	133.9	137.3	33.5	39.7	
6	Net Annual Weighted Average Unit Rate (3)	($/$m^3$)	$0.095692	$0.066792	$0.068405	$0.071866	$0.131001	$0.097914	
7	Annual AUVA Balance Amount (Line No. 5 multiplied by Line No. 6) (4)	($ millions)	$12.1	($4.9)	$9.2	$9.9	$4.4	$3.9	$34.5

Notes:

(1) Harmonized Average Use Variance Account (AUVA) as per EB-2022-0200 Decision and Order, Section 5.5.1. Reference to 'normalized' in Table 1 implies weather normalization based on 2025 Forecast Heating Degree Days (HDD).

(2) Refers to 2024 OEB-approved annual average number of customers including adjustment for customer numbers agreed to in the 2024 Rebasing Phase 1 Settlement Proposal (EB-2022-0200).

(3) Represents the volume-weighted average of OEB-approved monthly unit rates in effect.

(4) (+) value reflects a debit (collection) from ratepayers and refund to Enbridge Gas which results when forecasted average use is higher than the actual normalized average use.
(-) value reflects a credit (refund) to ratepayers and collectable from Enbridge Gas which results when the forecasted average use is lower than the actual normalized average use.

ACCOUNT NO. 179-335 – GETTING ONTARIO CONNECTED ACT VARIANCE ACCOUNT

1. Establishment of the Getting Ontario Connected Act (GOCA) Variance Account was approved by the Ontario Energy Board (OEB) in the Request for Generic Variance Account Decision.[1]. The purpose of the GOCA Variance Account is to track incremental pipeline locate costs resulting from the enactment of Bill 93 on April 14, 2022. Bill 93 included amendments to the Ontario *Underground Notification System Act, 2012*[2] and the *Building Broadband Faster Act, 2021*[3]. The GOCA Variance Account is intended to continue for each year of the current IR term (2024 to 2028).

2. In the Request for Generic Variance Account Decision[4], the OEB issued an accounting order for gas utilities to establish the GOCA Variance Account to record the variance between locate costs resulting from Bill 93 and the approved cost included in base rates. According to the OEB:

   > This account includes costs incurred to enable the locate activities. Utilities are expected to track costs at a sufficiently detailed level to assist in a review of the costs incurred, materiality, and causation related to Bill 93 at the time of disposition. Specifically, utilities are to demonstrate that recorded amounts in their accounts are both incremental to the base rates and are a direct result of Bill 93.[5]

   Enbridge Gas has recorded in the GOCA, the incremental 2025 locating costs, in excess of the 2025 budget, that are directly attributable to the impacts of Bill 93.

3. The balance of the 2025 GOCA Variance Account that is being requested for clearance is a debit of $14.093 million, plus interest. The background and methodology employed on arriving at this amount are outlined in detail below.

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[1] EB-2023-0143, Decision and Order, October 31, 2023.
[2] Bill 8, Ontario Underground Infrastructure Notification System Act, 2012, June 19, 2012. https://www.ola.org/en/legislative-business/bills/parliament-40/session-1/bill-8
3 Bill 257, Supporting Broadband and Infrastructure Expansion Act, April 12, 2021 https://www.ola.org/en/legislative-business/bills/parliament-42/session-1/bill-257
[4] EB-2023-0143, Decision and Order, October 31, 2023.
[5] EB-2023-0143, Decision and Order, Schedule B, October 31, 2023.

4. Enbridge Gas's unit cost for locating was ~ $32 in 2021 based on actuals prior to the enactment of Bill 93. Post enactment, locate unit costs increased by over 100%. The increase in cost was a direct result of Bill 93 which imposed a five-business-day deadline for completing standard locate requests and introduced absolute liability including administrative penalties for infrastructure owners failing to comply. Bill 93 has resulted in incremental locating costs to meet this compliance mandate that are not covered by current rates. This evidence outlines the drivers behind Bill 93 cost increases as well as the incremental cost calculations for 2025.

Table 1
2019-2025 External Locate Costs

Line No.	Particulars	2019	2020	2021	2022	2023	2024	2025
1	Total Locates (millions)	1.1	1.01	1.07	1.02	0.98	0.99	0.94
2	Total External Costs for Locate Delivery ($ millions)	$38.4	$33.5	$34.5	$39.9	$65.8	$66.0	$67.2
3	Average Cost per Locate ($ dollars)	$35	$33	$32	$39	$67	$67	$71

5. During Phase 1 of the 2024 Rebasing Application, Enbridge Gas acknowledged that the approved 2024 locate budget would not fully capture the incremental costs associated with Bill 93, given the considerable uncertainty of its full impacts at the time.[6] To address this, Enbridge Gas proposed the creation of a variance account to record differences between actual external locating costs and the approved 2024 budget.[7] Enbridge Gas withdrew its variance account request when the OEB initiated the generic proceeding which established the GOCA Variance Account. The 2024 base budget, which was prepared in early to mid-2022, incorporated allowances for typical cost drivers—such as inflation, typical wage increases, and general market pressures—as well as an increase for anticipated, but then-unknown, Bill 93 related

[6] EB-2022-0200, Exhibit I.4.4-STAFF-122.
[7] EB-2022-0200, Exhibit 9, Tab 1, Schedule 3, pp.8-11.

impacts. The 2024 approved budget appropriately captured all foreseeable and controllable financial pressures at the time. For 2025, the budget in rates has been determined by escalating the 2024 approved budget by PCI and customer growth, which should generally account for typical inflationary increases in locating costs. The $14.093 million recorded is in excess of the 2025 budget in rates and is directly and solely attributable to structural changes in the locate industry driven by Bill 93.

1. Drivers Behind Bill 93 Cost Increases

6. Locate costs have increased due to the new legislated locate delivery timelines resulting from Bill 93 and the absolute liability introduced for non-compliance. Enbridge Gas's average locate delivery times were 13 days and 15 days in 2021 and 2022 respectively. Bill 93 legislates a 5 day locate delivery mandate which put tremendous stress on the locating industry. To meet the new legislated locate timelines, Locate Service Providers (LSP) were required to onboard a significant amount of new locators, as well as increase locator wages to attract and retain qualified talent under tight labour market conditions. LSPs renewed unionized labour contracts in 2022 and based on the new operating environment unionized wages increased significantly. The single utility locating rate paid by Enbridge Gas increased by 128% on average due to these renegotiated wage increases with various LiUNA locals. All these factors – driven by Bill 93 – led to a material increase in average external locating unit costs between 2023 and 2025. Enbridge Gas has included only incremental external locating costs in the variance account.

7. It is also important to consider that, effective May 1, 2024, Ontario Regulation 136/24 introduced a separate category of "specified locate requests" for large excavation or dig sites and prescribed a 10-business-day completion period for those requests, which are submitted to Ontario One Call as Advanced Requests. This change may affect the comparability of reported locate volumes in 2024 to 2025 and beyond for certain large-scale excavation activities, as work associated with multi-property or

corridor-type projects can now be reflected through a single specified request rather than multiple standard requests, which may reduce the number of recorded locates for this subset of work. However, this change does not necessarily reduce the underlying workload or total effort required to complete locate activities for that work. While the relationship between locate volumes and total cost is not linear, the consolidation of multiple individual locates into single locate requests will, in some cases, contribute to higher observed average cost per locate.

8. As outlined in Table 2, Enbridge Gas has cost reducing mechanisms in place aimed at reducing the ongoing external costs related to locating. Alternative Locate Agreements (ALAs), generating $10.4 million in locating cost avoidance in 2025, are contractual agreements between Enbridge Gas and other infrastructure owners that allow excavations to occur in certain circumstances without requiring an LSP to provide a locate. Enbridge Gas has also established a locate screening centre where locate requests are reviewed prior to being sent to LSPs. The screening centre has resulted in $1.7 million in locate savings in 2025. Approximately $6.5 million (the cost avoidance average from 2020 to 2022) was factored into the 2024 locating budget. The further increase in cost avoidance achieved in 2025 (~$5.6 million) reduced what otherwise would have been included in the deferral account balance.

Table 2
2020-2025 Estimated Locating Cost Avoidance

Line No.	Particulars ($ millions)	2020	2021	2022	2023	2024	2025
1	ALA	5.9	6.5	6.4	11.6	11.9	10.4
2	Locate Screening	0.1	0.3	0.3	0.6	1.0	1.7
3	Total Locating Cost Avoidance	6.0	6.8	6.7	12.2	12.8	12.1

9. Table 3 outlines the 2025 GOCA balance calculation.

Table 3
2025 Budget vs. Actuals

Line No.	Particulars ($ millions)	Amount
1	2025 Locate Budget[8]	53.1
2	2025 Locate Actuals	67.2
3	2025 GOCA Variance Balance	14.1

10. It should be noted that Enbridge Gas has not included any Vital Main Standby (VMS) costs in the 2025 GOCA balance. This is in keeping with the OEB's Decision for the 2023 GOCA balance[9].

[8] 2024 Base Rate Locate Budget ($51.1 million) x Inflation plus Growth factor ((1+(3.33% + 0.48%)) = 1.0381)

[9] EB-2024-0125, Decision and Order, September 23, 2025. As explained in evidence in 2024 (EB-2025-0155, Exhibit C, Tab 2, Schedule 18, pp.5-6), Enbridge Gas continues to assert that the VMS cost increases are directly related to Bill 93 and continue to represent a significant ongoing cost pressure.

ACCOUNT NO. 179-336 DISPOSITION OF PROPERTY DEFERRAL ACCOUNT

1. As part of the 2024 Rebasing Phase 1 Decision[1] the OEB ordered the establishment of the Disposition of Property Deferral Account (DPDA). This account records 50% of the grossed-up after-tax gain/loss resulting from the disposition of non-depreciable land. The after-tax gain/loss is calculated as the difference in proceeds (sale price net of any transaction costs) and the regulatory book value of the property, less applicable capital gain/loss taxes. The ratepayers share of the net gain (50% of the capital gain net of capital gains tax) is grossed up to reflect the income tax deductibility/benefit provided by the amount returned to ratepayers.

2. Proceeds from the disposition of depreciable assets such as buildings will be 100% to the benefit of ratepayers and the gain/loss is reflected in the combined balances of accumulated depreciation and the Site Restoration Cost Variance Account and are beyond the scope of this deferral account.

3. For 2025 a total of 7 properties were sold in the following locations: Brampton, Dryden, Iroquois Falls, Nipigon, Ottawa, St. Thomas & Stratford. These sales resulted in a total grossed-up after-tax gain recorded in the DPDA of $12.804 million, plus interest. A detailed breakdown of how the DPDA balance is derived is provided in Attachment 1.

4. Enbridge Gas allocates proceeds between land and building based on independent broker evaluations or comparable valuation evidence that reflects the fair value of each component within the overall transaction on a sale by sale basis. Broker

[1] EB-2022-0200, OEB Decision and Order, December 21, 2023.

evaluations provide an objective, market-based assessment of the relative value of land and building components.

5. Details of each property disposition are provided below:

   a) Brampton
   In August 2025, Enbridge Gas entered into an Agreement of Purchase and Sale for the property located at Steeles Avenue West, west of Heritage Road and legally described as lands designated as Part 1 on 43R-41479, City of Brampton, Regional Municipality of Peel, Ontario for $53,410. The transaction represents a taking initiated by the Region of Peel for road allowance purposes.

   b) Dryden
   On May 8, 2025, Enbridge Gas closed the sale of the property located at 304 Kennedy Road, Dryden, Ontario, for proceeds of $209,000. The sale followed the completion and commissioning of a new Dryden operations facility, rendering the legacy property surplus to operational requirements.

   c) Iroquis Falls
   On November 27, 2025, Enbridge Gas entered into an Agreement of Purchase and Sale for the disposition of land in Iroquois Falls, Ontario, for proceeds of $54,886. The property had been acquired for future operational use; however, after funding for the associated capital project was removed from the Capital Plan, the municipality exercised its contractual buy-back right under the original Agreement of Purchase and Sale, as construction had not commenced within the stipulated timeframe.

d) Nipigon

On February 27, 2025, Enbridge Gas closed the sale of the property located at 2 Wadsworth Drive, Nipigon, Ontario, for proceeds of $200,000. The sale followed the consolidation of facilities, rendering the legacy property surplus to operational requirements.

e) Ottawa – Coventry Road

In January 2025 Enbridge Gas entered into an Amended Agreement of Purchase and Sale for the property located at 400 Coventry Road, Ottawa, Ontario for a final sales price of $20,000,000.

The Coventry Road and SMOC facilities were replaced with a single, right-sized operations site to address underutilization, eliminate overlapping service coverage, and improve operational efficiency and location access.

f) St. Thomas

On August 21, 2025, Enbridge Gas closed the sale of the property located at 25 Sparling Road, St. Thomas, Ontario, for proceeds of $1,600,000. The sale followed the consolidation of operational depot facilities, rendering the legacy property surplus to operational requirements.

g) Stratford

On September 15, 2025, Enbridge Gas closed the sale of the property located at 827 Erie Street, Stratford, Ontario, for proceeds of $2,000,000. The sale followed the consolidation of operational depot facilities, rendering the legacy property surplus to operational requirements.

Enbridge Gas
Summary of Property Dispositions
For the Year December 31, 2025

Line No.	Description	Reference	Brampton	Dryden	Iroquois Falls	Nipigon	Ottawa	St Thomas	Stratford	Total
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Sale Price		$ 53,410	$ 209,000	$ 54,886	$ 200,000	$ 20,000,000	$ 1,600,000	$ 2,000,000	$ 24,117,296
2	Closing Costs		$ -	$ 15,164	$ 5,024	$ 14,931	$ 265,248	$ 83,521	$ 103,274	$ 487,161
3	Net Proceeds	Line 1 - Line 2	$ 53,410	$ 193,836	$ 49,862	$ 185,069	$ 19,734,752	$ 1,516,479	$ 1,896,726	$ 23,630,134
4	Percentage of Sale Allocated to Land		100%	14%	100%	20%	100%	52%	68%	
5	Land Proceeds	Line 3 X Line 4	$ 53,410	$ 27,823	$ 49,862	$ 37,014	$ 19,734,752	$ 788,569	$ 1,289,774	$ 21,981,204
6	NBV of Land		$ 78,896	$ 6,435	$ 74,995	$ 900	$ 87,874	$ 13,219	$ 22,121	$ 284,441
7	Gain/(Loss) on Sale of Land	Line 5 - Line 6	$ (25,486)	$ 21,388	$ (25,133)	$ 36,114	$ 19,646,879	$ 775,350	$ 1,267,652	$ 21,696,763
8	Less: Capital Gains Tax	Line 7 X 50% X 26.5%	$ (3,377)	$ 2,834	$ (3,330)	$ 4,785	$ 2,603,211	$ 102,734	$ 167,964	$ 2,874,821
9			$ (22,110)	$ 18,554	$ (21,803)	$ 31,329	$ 17,043,667	$ 672,616	$ 1,099,688	$ 18,821,942
10	50% Ratepayer Portion	Line 9 X 50%	$ (11,055)	$ 9,277	$ (10,902)	$ 15,664	$ 8,521,834	$ 336,308	$ 549,844	$ 9,410,971
11	Gross-Up For Taxes	1 - 26.5%	73.5%	73.5%	73.5%	73.5%	73.5%	73.5%	73.5%	73.5%
12	Gross Amount Credited to Ratepayers	Line 10 / Line 11	$ (15,040)	$ 12,622	$ (14,832)	$ 21,312	$ 11,594,332	$ 457,562	$ 748,087	$ 12,804,042

ACCOUNT NO. 179-338 LEAP EMERGENCY FINANCIAL ASSISTANCE FUNDING DEFERRAL ACCOUNT

1. On February 12, 2024, the OEB announced changes to the Low-income Energy Assistance Program Emergency Financial Assistance (LEAP EFA)[1]. The OEB also included two deferral accounts, one each for the rate-regulated electricity and gas distributors to record prudently incurred LEAP EFA contributions that exceed the funding amounts embedded in rates.

2. As part of the 2024 Rebasing Phase 1 Interim Rate Order[2], the OEB approved the establishment of the Enbridge Gas LEAP EFA Funding Deferral Account, its purpose to record incremental LEAP EFA contributions made on or after March 1, 2024 (the effective date of the account), that are beyond the amount currently embedded in distribution rates.

3. Based on the LEAP EFA programs funding mechanism Enbridge Gas is required to contribute the greater of 0.12% of the Company's total OEB-approved distribution revenue requirement or $2,000 each year to LEAP EFA.[3] Enbridge Gas contributed $4.7 million in total, which exceeded the base LEAP EFA funding requirement for 2025 of $3.5 million[4].

4. In 2025, Enbridge Gas was required to add incremental funding of $1.2 million above the generic LEAP EFA funding requirement to ensure that no eligible LEAP EFA applicant was denied assistance due to lack of funding above the base 0.12% provided through generic funding. As a result, Enbridge Gas has recorded the incremental $1.2 million, plus interest in the LEAP EFA Funding Deferral Account for 2025.

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[1] EB-2023-0135.
[2] EB-2022-0200, Interim Rate Order, April 11, 2024, Appendix C, p.58.
[3] EB-2008-0150, Report of the OEB, March 10, 2009, pp. 8-11.
[4] 0.12% of 2025 Delivery Revenue as approved in EB-2024-0111, Draft Rate Order, November 4, 2024, Working Papers, Schedule 3, column (h), line 29.

ACCOUNT NO. 179-340 OEB COST ASSESSMENT V/A

1. As part of the 2024 Rebasing Phase 2 Settlement Agreement[1], parties agreed to, and the OEB approved the establishment of the OEB Cost Assessment Variance Account (OEBVA). For the years 2025 through 2028, this account records the variances in actual OEB Cost Assessment amounts incurred as compared to the $9.4 million that was included in the Company's 2024 O&M budget, subject to the following parameters. The $9.4 million threshold will be adjusted each year using the IRM formula. Each year, Enbridge Gas will be entitled to recover any amounts that are more than $2 million above the annual threshold amount. In any year where the actual OEB Cost Assessment amounts are below the annual threshold amount, Enbridge Gas will credit all amounts below the threshold to ratepayers. This account is effective January 1, 2025.

2. For 2025 the annual threshold is set at $9.758[2] million. Based on this threshold, the balance recorded in the OEBCA is a debit (or receivable) of $2.997 million plus interest. The details of the difference between the actual annual OEB cost assessment amounts for 2025 and the applicable annual threshold amount are set out in Table 1.

[1] EB-2024-0111, Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, November 29, 2024, p.11.
[2] Escalation of $9.4M base 2024 amount equals base x PCI + Growth factor for 2025: $9.4M x ((1+(3.33%+0.48%)) = $9.758M.

Table 1
2025 OEB Cost Assessment Variance
($ millions)

Line No.	Period	OEB Cost Assessment
1	Q1	3.477
2	Q2	3.477
3	Q3	3.477
4	Q4	4.325
5	Total	14.755
6	OEB Approved	9.758
7	Variance	4.997
8	Threshold	2.000
9	Deferred Variance	2.997

ACCOUNT NO. 179-341 IRP SYSTEM PRUNING DEFERRAL ACCOUNT

1. On November 4, 2024, Enbridge Gas filed the Settlement Proposal for Enbridge Gas' Rebasing Phase 2, where parties agreed that a new Integrated Resource Planning (IRP) System Pruning Deferral Account with a $5 million cap would be created for recording incremental costs incurred to develop and implement one or two IRP system pruning pilot projects for later recovery.[1]

2. The balance in the IRP System Pruning Deferral Account for 2024 is $0.022 plus interest and for 2025 is $0.366 plus interest, for a total debit of $0.388 million, plus interest. Costs are associated with developing a System Pruning pilot approach and implementation of the pilot.

3. As noted in the evidence for this account in the 2024 Deferral and Variance Account Clearance Application[2], recovery of the 2024 amounts would be requested in a future application.

4. As part of the 2024 Rebasing Phase 2 Settlement Proposal approved by the OEB, parties agreed that Enbridge Gas would develop its approach to system pruning in consultation with the IRP Technical Working Group by the end of Q2 of 2025 and begin implementation on one or two pilots by the end of Q1 of 2026. [3] On July 4, 2025, Enbridge Gas filed its 2024 IRP Annual Report, with the System Pruning approach filed as Appendix G.[4] Enbridge Gas subsequently began pilot implementation. As the milestone conditions of the Settlement Proposal have been

[1] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, p.20.
[2] EB-2025-0155, Exhibit C, Tab 2, Schedule 20, p.9-10.
[3] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, p.19-20
[4] EB-2025-0064, Exhibit I.1.13-ED-4 Attachment 1, p.108.

met, Enbridge Gas is proposing to recover the balance in the IRP System Pruning Deferral Account related to System Pruning pilot costs incurred in 2024 and 2025.

1. 2024 Costs

5. The costs incurred include the following activities related to the System Pruning pilot:
    a) Jurisdictional Scan – costs associated with conducting a jurisdictional scan on system pruning activities. Enbridge Gas, in consultation with the IRP Technical Working Group (TWG), engaged Det Norske Veritas (DNV) Canada Ltd, where the study was conducted for, and on behalf of, Enbridge Gas, OEB staff, other members of the IRP TWG and, ultimately, all Enbridge ratepayers. The objective of the report is to provide a greater understanding and insight into how gas utilities are approaching pruning of their gas distribution pipelines. This report is intended to provide Enbridge Gas, the IRP TWG and the OEB, with a foundational understanding of system pruning approaches, best practices and lessons learned to assist in the development of a potential system pruning framework and pilot in Ontario.

2. 2025 Costs

6. The costs incurred include the following activities related to the System Pruning pilot.
    a) Jurisdictional Scan – costs associated with conducting a jurisdictional scan on system pruning activities. The scan was completed on August 15, 2025.[5]
    b) Customer Research – costs associated with customer research to inform the development of the pilot approach. This included qualitative research (focus groups) and quantitative research (customer survey) to understand

[5] System Pruning Jurisdictional Scan, Enbridge Gas, August 15, 2025, (link).

engagement approaches, offer considerations, customer attitudes, and perceptions.

c) Customer Engagement – costs associated with the pre-screen outreach to customers for implementation of the pilot. This included informational material about the pilot and pre-screen form, sent via courier and email, for customers to express their interest level in participating in the pilot.

d) Incremental Staff – costs associated with 1 incremental position responsible for leading the pilot. This resource is incremental to the IRP roles that are in O&M base rates.

7. Table 1 provides the breakdown of these expenditures.

Table 1
Breakdown of Expenditures – System Pruning Pilot Costs

Line No.	Item	Description	Millions ($)
1	Jurisdictional Scan	Completion of scan	0.124
2	Customer Research	Qualitative and quantitative research	0.057
3	Customer Engagement	Pre-screen implementation	0.038
4	Incremental Staff	Salaries, loadings and expenses	0.146
5	Total		0.366

ACCOUNTS NOT BEING REQUESTED FOR CLEARANCE

1. The following 2025 accounts have no balance, and are therefore not requested for clearance to customers:

    - Unauthorized Overrun Non-Compliance Deferral Account
    - Incremental Capital Module Deferral Account
    - Expansion of Natural Gas Distribution Systems Variance Account
    - Green Button Initiative Deferral Account
    - Cloud Computing Implementation Costs Deferral Account
    - Asset Life Extension Costs Deferral Account
    - Enbridge Sustain Affiliate Recoveries Variance Account
    - Open Bill Extension Deferral Account

2. Consistent with past annual deferral and variance account clearance proceedings, Enbridge Gas Inc. has not listed accounts that will be reviewed through other processes in Exhibit C, Tab 1, Schedule 1, and these accounts are not addressed in this proceeding. Examples include gas supply accounts (i.e. PGVA) cleared through QRAM proceedings, and DSM related accounts.

1. Account No. 179-304 Unauthorized Overrun Non-Compliance Deferral Account

3. With regard to the Unauthorized Overrun Non-Compliance Deferral Account, in its 2024 Rebasing Phase 1 Decision[1], the OEB approved harmonization of certain deferral accounts of EGD and Union. This included harmonization of the Unauthorized Overrun Non-Compliance Deferral Account. The purpose of the account is to record any unforecasted penalty revenue received from interruptible distribution customers who do not comply with a distribution interruption. In 2025,

[1] EB-2022-0200, OEB Decision and Order, December 21, 2023.

there were 4 interruption events called in the EGD rate zone for a total of 183.9 days, and 5 interruption events called in the Union North rate zone for a total of 37.1 days. There were no interruption events called in the Union South rate zone. The EGD rate zone had 1 customer who failed to comply with their interruptions (2 events), resulting in approximately $0.05 million in non-compliance charges. In the absence of a harmonized gas supply plan in 2025, EGI continued to record the EGD RZ non-compliance charges in the Purchase Gas Variance Account – EGD Rate Zone. Until such time as the harmonized gas supply plan is implemented, EGI will continue with this process. All Union rate zone customers were able to comply with each interruption event, therefore incurring no non-compliance charges in 2025.

2. Account No. 179-344 Enbridge Sustain Affiliate Recoveries Variance Account

4. The purpose of the Enbridge Sustain Affiliate Recoveries Variance Account is to record, on an asymmetrical basis, any additional amounts above $1 million (as adjusted annually according to the IRM formula) paid or payable by Enbridge Sustain to Enbridge Gas for goods or services provided in each year of the 2024-2028 IRM term.

5. In the 2024 Rebasing Phase 2 Decision on Settlement Proposal and Interim Rate Order[2] the Parties agreed that Enbridge Gas will implement a $1 million base rate adjustment for 2024, to reflect amounts paid by Enbridge Sustain to Enbridge Gas for services received that have not been included in base rates. The Parties further agreed that a new asymmetrical Enbridge Sustain Affiliate Recoveries Variance Account will be created that will credit ratepayers with any additional amounts over $1 million paid or payable by Enbridge Sustain to Enbridge Gas for goods or services received each year of the 2024-2028 IRM term.[3]

[2] EB-2024-0111 Decision on Settlement Proposal and Interim Rate Order, November 29, 2024.
[3] EB-2024-0111 Decision on Settlement Proposal and Interim Rate Order, November 29, 2024, p.10.

6. During 2025, Enbridge Sustain received services at a total cost of $0.7 million. As such, when compared to an escalated base of $1.038 million[4], there is no balance recorded in the Enbridge Sustain Affiliate Recoveries Variance Account for 2025.

7. Table 1 defines the gross eligible costs paid or payable by Enbridge Sustain to Enbridge Gas for goods or services received in 2025.

Table 1

Amounts paid by Enbridge Sustain to Enbridge Gas for services received in 2025

Line No.	Cost Types	2025 Actual ($ millions)	Comments
1	Indirect Costs	$0.45	EGI Full Time Employees (FTE) providing services to Enbridge Sustain at a Fully Allocated Cost (FAC).
2	Direct Allocation: Real Estate	0.23	Real Estate costs for Ontario occupancy of Enbridge Sustain employees.
3	Direct Allocation: TIS	0.02	Shared IT support costs.
4	Total	$0.70	

8. Additionally, in each annual Deferral Account Clearance Application, Enbridge Gas has agreed to file (i) financial information relating to the business of Enbridge Sustain to provide context for the OEB to assess the affiliate transactions information provided; and (ii) a detailed list of all of the resources of Enbridge Gas that are used by Enbridge Sustain, all of the resources of Enbridge Sustain that are used by the utility, and all of the resources of any person that are shared between the utility and Enbridge Sustain, including an explanation of the cost allocation methodology for each.[5]

[4] Escalation at Price Cap Index of 3.33% (PCI) plus Growth of 0.48% = Base $1M x 1.0381 = $1.038 million.
[5] EB-2024-0111, Decision on Settlement Proposal and Interim Rate Order, November 29, 2024, p.57.

9. Table 2 presents the 2025 financial information for Sustain on an actuals basis.

Table 2

2025 Financial Information – Enbridge Sustain

Line No.	Cost Types	2025 Actual ($ millions)	Comments
1	Direct Costs	$10.5	Paid directly: does not flow through Utility
2	HR Benefits	2.4	Paid directly: does not flow through Utility
3	Indirect Costs[1]	0.5	Charged to Enbridge Sustain from Regulated Utility at Fully Allocated Cost Rate (FAC)
4	Corporate Cost Allocations	2.1	Paid directly: does not flow through Utility
5	Direct Allocations[2]	0.2	Direct charge to Enbridge Sustain at actual cost incurred
6	Total	$15.7	

Notes:
1) see Table 1 'Indirect Costs', as well as Table 3 for further details
2) see Table 1 'Direct Allocation: Real Estate' and 'Direct Allocation: TIS'

10. Table 3 presents Indirect Labour Costs at a Fully Allocated Cost Rate (FAC), broken down by department.

Table 3

2025 Details of Indirect Labour Charges – Enbridge Gas to Enbridge Sustain

Line No.	Department	Total Hours	Cost ($ millions)
1	Commercial & Regulatory Services	13	$0.005
2	Engineering	28	0.004
3	Finance	415	0.066
4	Legal	215	0.042
5	Operations	116	0.016
6	Public Affairs	17	0.003
7	Supply Chain	179	0.026
8	TIS	1,976	0.286
9	Business Development	200	0.023
10	Human Resources	8	0.002
11	Total	3,167	$0.473

11. All Enbridge Gas employees track hours worked for Enbridge Sustain and provide this information to Finance on a monthly basis. The Fully Allocated Cost Rates are then applied to their hours worked and charged to Enbridge Sustain. A corresponding credit is applied to Enbridge Gas's Regulated Line of Business to remove these costs from Enbridge Gas regulated OM&A.

3. Account No. 179-325 Open Bill Extension Deferral Account

12. The final balance in the account was brought forward for disposition in the 2024 Utility Earnings and Disposition of Deferral and Variance Account proceeding[6]. The program was discontinued as of October 31, 2024, and no balance will be recorded

[6] EB-2025-0155, Exhibit D, Tab 1, Schedule 2.

in the account going forward. As such, Enbridge Gas requests that this account be approved for closure.

13. The following accounts have balances but are not requested for clearance, however information supporting each balance is provided for information purposes:

- IRP Operating Costs Deferral Account
- IRP Capital Costs Deferral Account
- Panhandle Regional Expansion Project Variance Account
- Site Restoration Costs Variance Account

4. Account No. 179-318 - IRP Operating Costs Deferral Account

14. In its Decision and Order dated June 25, 2026, the OEB defers consideration of the costs incurred in the Southern Lake Huron project on the basis that it is premature to consider those costs given that the Southern Lake Huron project is not sufficiently advanced to determine if it is appropriate for ratepayers to pay the costs incurred. When Enbridge Gas is in a position to report on the results from the project, it can seek disposition of the associated balance at that time, as part of a DVA application.[7]

15. As a result, Enbridge Gas has included the cumulative operating costs attributable to the Southern Lake Huron (SLH) Pilot Project as not requested for clearance and will bring the balances forward in a future proceeding. See Table 4 below for details.

[7] EB-2025-0155, Decision and Order, p.11.

Table 4

Southern Lake Huron Project Operating Costs

Line No.	Particulars ($000's)	Actuals
1	2023 Operating Costs	34.0
2	2024 Operating Costs	78.0
3	2025 Operating Costs	2,122.6
4	Cumulative Total	2,234.6

5. Account No. 179-319 - IRP Capital Costs Deferral Account

16. As with the treatment of the IRP Operating Costs Deferral Account above, Enbridge Gas is also including the 2025 revenue requirement recorded in the IRP Capital Costs Deferral Account as a balance not being requested for clearance. The balance in the account is a credit of $3.0 thousand, plus interest. This amount is attributable to the SLH Pilot Project, as outlined below. Table 5 provides the calculation of the 2025 IRP Capital Costs Deferral Account balance.

Table 5
IRP Capital – SLH Pilot
Revenue Requirement Summary

Line No.	Particulars	2025
	Rate Base Investment:	
1	Capital Expenditures	158,914
2	Cumulative Capital Expenditures	158,914
3	Average Investment	6,621
	Revenue Requirement Calculation:	
	Operating Expenses:	
4	Operating and Maintenance Expenses	-
5	Depreciation Expense (1)	-
6	Property Taxes	-
7	Total Operating Expenses	-
8	Required Return (2)	403
9	Total Operating Expense and Return	403
	Income Taxes:	
10	Income Taxes - Equity Return (3)	84
11	Income Taxes - Utility Timing Differences (4)	(3,438)
12	Total Income Taxes	(3,354)
13	Total Revenue Requirement	(2,951)

Notes

(1) Depreciation is recorded in the month following the in-service date. SLH went into service in December 2025, therefore, depreciation will commence in January 2026.
(2) The required return assumes a capital structure of 62% long-term debt at 4.17% and 38% common equity at the 2024 OEB Formula return of 9.21%. The annual required return calculation is as follows: Average Investment (line 3)* 62% * 4.17% plus Average Investment (line 3)* 38% * 9.2
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year. Does not include Accelerated CCA as per RIIP/Bill C-15; RIIP/Bill C-15 impacts are captured in the TVDA, see Exhibit C, Tab 2, Schedule 12.

6. Account No. 179-329 Panhandle Regional Expansion Project Variance Account (PREPVA)

17. In its 2024 Rebasing Phase 1 Decision[8], the OEB approved the establishment of the PREPVA. This account records the difference between the actual net revenue requirement for the Panhandle Regional Expansion Project (PREP) and the actual revenues collected through the levelized PREP unit rate approved by the OEB. The actual net revenue requirement includes costs associated with the capital investment, including return on rate base, depreciation expense, and associated income taxes, as well as incremental operation and maintenance costs and property taxes, offset by transmission margin revenue associated with incremental demands served by the project. The actual revenues will be those collected through the PREP unit rate approved by the OEB for the Company.

18. In the 2024 Rebasing Phase 2 Settlement Agreement[9] the OEB approved unit rates reflecting levelized rate treatment for the PREP starting in 2025.

19. With the approval of the levelized rate treatment and PREPVA, Enbridge Gas will accumulate in the PREPVA over the IR term the net annual variance between the actual net revenue requirement and the amounts collected in rates based on the levelized rate. This variance will accumulate in the account and the net residual amount will be brought forward in Enbridge Gas's next rebasing application for disposal.

20. The Panhandle Regional Expansion Project went into service in December 2024 with an in-service cost of $234.0 million and an associated actual net revenue sufficiency (or credit) of $14.3 million for 2024. The balance in the PREPVA as of December 31, 2025 of $10.2 million, reflects the revenue sufficiency credit of $14.3

[8] EB-2022-0200, OEB Decision and Order, December 21, 2023, p.124.
[9] EB-2024-0111, Settlement Agreement, November 29, 2024, p.15.

million in 2024, partially offset by a revenue deficiency of $4.1 million in 2025, which will be carried forward and accumulated with each year's net amount through the IR term as noted above. There was an additional $8.5 million of capital expenditures in 2025 that were deferred from 2024, resulting in total cumulative capital expenditures of $242.4 million compared to the originally approved amount of $250.8 million. The lower than forecast (or approved) level of expenditures required for the project has resulted in lower depreciation expense as well as a lower required return and also affected the timing of tax impacts. Please see Table 6 for details of the revenue requirement for 2025 and Table 7 for the cumulative variance that has been recorded in the deferral account to date.

Table 6
Panhandle Regional Expansion Project
2025 Revenue Requirement Summary

Line No.	Particulars ($000s)	2025 Actual	2025 OEB-Approved	Variance
		(a)	(b)	(c)
	Rate Base Investment			
1	Capital Expenditures	8,464	0	8,464
2	Cumulative Capital Expenditures	242,439	250,830	(8,391)
3	Average Investment	237,489	248,759	(11,270)
	Revenue Requirement Calculation			
4	Operating & Maintenance Expenses	127	127	0
5	Depreciation Expense	3,467	3,678	(211)
6	Property Taxes	927	855	72
7	Total Operating Expenses	4,520	4,659	(139)
8	Required Return	14,448	15,133	(685)
9	Total Operating Expenses and Return	18,968	19,792	(824)
	Income Taxes			
10	Income Taxes - Equity Return	2,997	3,139	(142)
11	Income Taxes - Utility Timing Differences	(5,157)	(4,692)	(465)
12	Total Income Taxes	(2,161)	(1,553))	(608)
13	Total Revenue Requirement	16,807	18,240	(1,433)
14	Incremental Project Revenue	4,182	4,000	182
15	Net Revenue Requirement	12,625	14,240	(1,615)

Table 7
Panhandle Regional Expansion Project
Cumulative Revenue Requirement Continuity (2024-2028)

Line No.	Particulars ($ millions)	2024 Actual	2025 Actual
		(a)	(b)
	Rate Base Investment		
1	Capital Expenditures	234.0	8.5
2	Cumulative Capital Expenditures	234.0	242.4
3	Average Investment	8.8	237.5
	Revenue Requirement Calculation		
4	Operating & Maintenance Expenses	0	0.1
5	Depreciation Expense	0	3.5
6	Property Taxes	0.3	0.9
7	Total Operating Expenses	0.3	4.5
8	Required Return	0.5	14.4
9	Total Operating Expenses and Return	0.9	19.0
	Income Taxes		
10	Income Taxes - Equity Return	0.1	3.0
11	Income Taxes - Utility Timing Differences	(15.0)	(5.2)
12	Total Income Taxes	(14.9)	(2.2)
13	Total Revenue Requirement	(14.0)	16.8
14	Incremental Project Revenue	0.3	4.2
15	Net Revenue Requirement	(14.3)	12.6
16	Actual Revenue Collected in Rates	0.0	8.5
17	Variance	(14.3)	4.1
18	Cumulative Variance	(14.3)	(10.2)

7. Account No. 179-337 Site Restoration Costs Variance Account (SRCVA)

21. In its 2024 Rebasing Phase 1 Interim Rate Order,[10] the OEB approved the establishment of the SRCVA and directed Enbridge Gas to discontinue using site restoration amounts collected through depreciation recovered in rates to offset other costs and instead segregate monies collected through rates for site restoration beginning in 2024.

22. Commencing January 1, 2024, the purpose of this account is to record and track the cumulative amount of site restoration costs collected through depreciation in rates versus actual spending related to site restoration, net of any proceeds from disposition. A net credit balance will represent amounts available to offset future decommissioning, abandonment, or site restoration costs. A net debit balance in the account, reflecting actual site restoration costs exceeding amounts recovered via depreciation expense, will reflect an offset to the cumulative pre 2024 SRC liability, of $1.718 billion, currently reflected in accumulated depreciation. The balance in the account will not be brought forward for annual disposition since the purpose of the funds is to offset future decommissioning, abandonment, or site restoration. However, the balance will be presented in the Company's annual application to dispose of deferral and variance account balances.

23. The amount of site restoration costs recovered in rates is derived by applying the net salvage component in approved depreciation rates to actual gross plant values. Where the cumulative amount of site restoration amounts recovered exceeds the cumulative actual cost of decommissioning, abandonment, and site restoration (net of any proceeds), the net balance will be set aside and maintained in a distinct interest-bearing bank account for the duration of the incentive rate-setting

[10] EB-2022-0200, Decision on Interim Rate Order, April 11, 2024, p.11.

mechanism term. The cash balances in this bank account will earn interest income based on the prime rate, less a discount, set by Canadian financial institutions and influenced by the Bank of Canada. Any after-tax interest earned on the balance set aside, as well as any related fees, is recorded in the SRCVA. Income generated from the balance set aside will effectively reduce or offset the total amount of site restoration funds required to be collected in the future. This will benefit ratepayers through future depreciation rates.

24. At the end of 2024 Enbridge Gas had a net credit balance of $19.430 million in the SRCVA account. As at December 31, 2025, the cumulative balance in the SRCVA is a credit of $15.616 million. During 2025, Enbridge Gas recovered and recorded $95.495 million of site restoration in depreciation rates, and incurred $100.019 million of decommissioning, abandonment, and site restoration costs (net of any proceeds), resulting in a net debit activity amount of $4.524 million. The total after-tax interest generated during 2025 (net of bank fees) on the net cumulative credit balance totaled $0.710 million. A summary of the SRCVA balance is provided in Table 8.

Table 8
2025 Site Restoration Cost Variance Account (SRCVA)

Line No.	Particulars ($ millions)	2025 Actuals
1	Opening Balance	(19.430)
2	Site Restoration Recovered in Depreciation Rates	(95.495)
3	Decommissioning, Abandonment, and Site Restoration Costs	100.019
4	Interest Income (After-Tax)	(0.710)
5	Net SRCVA Balance as of Dec 31, 2025	(15.616)

ACCOUNT NO. 179-88 STORAGE & TRANSPORTATION DEFERRAL ACCOUNT EGD RATE ZONES

1. The purpose of the 2025 Storage & Transportation Deferral Account (S&TDA) is to record the difference between the forecast cost of market-based storage (MBS) included in the Company's approved rates and the actual cost of MBS incurred by the Company. The S&TDA also records amounts allocated to the EGD rate zone from the disposition of Union rate zone deferral and variance account balances related to services rendered to EGD rate zone customers.

2. The balance in the 2025 S&TDA that the Company is proposing to collect from customers is $3.1 million, plus interest. A detailed breakdown of the S&TDA is provided at Table 1.

Table 1
Breakdown of the 2025 S&TDA - EGD rate zone

Line No.	Particulars ($ millions)	Forecasted Costs	Actual Costs	Variance
		(a)	(b)	(c)
1	Market-Based Storage	20.2	24.2	4.0
2	2023 ESM/DVA Disposition (1)	-	(0.9)	(0.9)
3	Total	20.2	23.3	3.1

Notes:
(1) Disposition of 2023 Deferral and Variance Account (EB-2024-0251) refund balance related to the EGD rate zone: M12 transportation of $0.9 million, M16 transportation of $0.001 million.

3. The primary driver for the balance in the 2025 S&TDA is higher than forecasted MBS costs in 2025 of $24.2 million, which is $4.0 million higher than the OEB-approved 2025 MBS costs of $20.2 million, partially offset by an OEB-approved $0.9 million refund from the Union rate zones to the EGD rate zone.[1] The increase in 2025 MBS costs was driven by the higher average storage cost in 2025 of $1.21

[1] Disposition of 2023 Deferral and Variance Account (EB-2024-0251) balances-related refund to the EGD rate zone: M12 transportation of $0.9 million, M16 transportation of $0.001 million.

CAD/GJ compared to the average storage cost included in the OEB-approved 2025 MBS costs of $0.78 CAD/GJ, partially offset by a reduction in total MBS contracted in 2025 from 26 PJ to 17 PJ.[2] As part of the Company's OEB-approved 2024 Rebasing Phase 2 Settlement Agreement, Enbridge Gas committed to report annually on its MBS and load balancing costs.[3,4]

1. Market Based Storage

4. In 2025, Enbridge Gas held 199.7 PJ of cost-based storage reserved for in-franchise customers to meet their planned load balancing requirements: 99.7 PJ for the EGD rate zone, and 100 PJ for the Union rate zones. In addition, the Company held 26 PJ of MBS until March 31, 2025, and 17 PJ of MBS effective April 1, 2025, for the EGD rate zone (including 270 TJ/d and 178 TJ/d, respectively, of related maximum MBS withdrawal capabilities).

5. The reduction in MBS effective April 1, 2025, is consistent with the commitment made by Enbridge Gas as part of its 2024 Rebasing Phase 2 Settlement Agreement where the Company agreed to reduce MBS from 26 PJ to 18 PJ (a reduction of 8 PJ) by not-renewing a portion of expiring MBS service contracts in 2025, and to manage load balancing requirements above 217.7 PJ in a manner the Company deems appropriate.[5] As outlined in the Company's 2026 Annual Gas Supply Plan Update and discussed in further detail below,[6] Enbridge Gas elected to further reduce its contracted MBS by 1 PJ in 2025 and instead procure an additional 1 PJ of planned supply at Dawn through the Company's typical commodity RFP process during the winter 2025/26 season, as needed.

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[2] The average storage cost in 2024 of $1.09 CAD/GJ was also higher than the average storage cost included in the OEB-approved 2024 MBS costs (EB-2025-0155, Exhibit D, Tab 1, Schedule 1).
[3] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, pp.23-24.
[4] Load balancing reporting included at Exhibit G, Tab 5, Schedule 1.
[5] EB-2024-0111, Exhibit N, Tab 1, Schedule 1, pp.9-10 & 23-24.
[6] EB-2026-0092, Enbridge Gas 2026 Annual Gas Supply Plan, Section 3.4.

6. The cost in rates for 199.7 PJ of cost-based storage is set through a cost-of-service rate application. The cost in rates of MBS is forecast in a cost-of-service rate application with cost variances recorded in the S&TDA. In 2025, the forecast cost in rates and actual cost of MBS contracted for the EGD rate zone was $20.2 million and $24.2 million, respectively, as shown in Table 1.

7. As discussed recently in the Company's 5-Year Gas Supply Plan,[7] Enbridge Gas purchases MBS services on behalf of customers in the EGD rate zone through a competitive blind RFP process. On February 5, 2025, a third-party RFP manager initiated the RFP process for MBS services at Dawn by distributing an RFP letter to storage service providers (see Exhibit D, Tab 2, Schedule 1) requesting offers for firm storage services of up to 2 PJ, terms of up to five years commencing April 1, 2025, and firm injections from May to September and firm withdrawals from December to March (the 2025 Blind RFP). The RFP responses were received by the RFP manager on behalf of Enbridge Gas on February 26, 2025, after which the RFP manager made a procurement recommendation based on the Company's evaluation criteria.[8]

8. The 2024 Rebasing Phase 2 Settlement Agreement included the requirement for Enbridge Gas to consider alternatives to MBS available at the time storage contracting decisions were made and to report on the alternatives assessed (including pricing) as part of the Company's annual deferral and variance account disposition proceedings. Accordingly, Table 2 provides a comparison of the price of alternatives assessed at the close of the 2025 Blind RFP process. The alternatives assessed include High-Flexibility and Low-Flexibility storage services (based on service offering(s) bid in the Blind RFP and forward market settlement prices on

[7] EB-2025-0065, Enbridge Gas 5-year Gas Supply Plan, pp.45-48.
[8] The details of all MBS service offerings received and recommended by the RFP manager are outlined at Confidential Exhibit D, Tab 2, Schedule 2.

February 26, 2025) and Delivered Supply at Dawn (based on forward market settlement prices on February 26, 2025).

Table 2[9]
Comparison of MBS and Alternatives

Line No.	Particulars ($CAD/GJ)	Annualized Cost
		(a)
1	High-Flexibility MBS	5.68
2	Low-Flexibility MBS	5.43
3	Delivered Supply	6.21

9. Recognizing its reliability and cost-effectiveness, and consistent with the Company's 2024/25 gas supply plan, Enbridge Gas procured 1 PJ of High-Flexibility MBS services for a five-year term through the Blind RFP process in 2025 to maintain sufficient storage capacity and related late winter season deliverability. The Company's decision was informed by the following factors:

   (i) The RFP manager's recommendation to contract for up to 2 PJ of High-Flexibility MBS services for a five-year term (as detailed in Confidential Exhibit D, Tab 2, Schedule 2).

   (ii) The forecast storage requirement for the 2025/26 gas year using the aggregate excess methodology was 3 PJ lower than the storage requirement that informed the Company's 2024 Rebasing forecast (215 PJ vs. 218 PJ, respectively). The storage requirement was forecast to increase by 3 PJ for the 2027/28 gas year (to 218 PJ again).

[9] The costs set out in Table 2 are based on the price of the storage service offerings recommended by the blind RFP manager and average forward NYMEX and Dawn basis prices (five-year average of monthly prices from May-September from 2025-2029 used for storage services, and one-year average of monthly prices from December-February 2025/26 used for delivered supply only). Enbridge Gas did not speculate on the future price differences that may occur between delivered supply purchased on a fixed-price contract vs. indexed-price contract. Commodity price detail underlying the information presented in Table 2 is proprietary in nature.

(iii) The Company's goal of re-establishing a consistent balance of MBS contract term diversification within three years (limiting ratepayer exposure to annual storage service price fluctuations).[10] To improve the contract term diversity of the MBS services portfolio in 2025, Enbridge Gas sought to contract for services with a five-year term.[11]

(iv) The Company's preference (in the 2025 Blind RFP) for High-Flexibility MBS services because of the additional operational flexibility they typically afford, the fact that no bid for Low-Flexibility MBS services with a five-year term was offered,[12] and Enbridge Gas's goal as described in (iii) to re-establish balanced MBS contract term diversity.[13]

(v) The results of Enbridge Gas's assessment of alternatives (see Table 2 and Confidential Exhibit D, Tab 2, Schedule 2), which indicate that no amount of Low-Flexibility MBS services with a five-year term was available, and that Delivered Supply contracted in the forward market at that time would be higher cost than MBS services (High or Low-Flexibility).

[10] Due to the changes made as part of the Company's 2024 Rebasing Phase 2 Settlement Agreement to reduce the volume of MBS services contracted, Enbridge Gas anticipated that it would take at least 3 years to adjust MBS contract service terms to achieve a consistent volume of third-party storage service purchases annually.
[11] See the Company's 2026 Gas Supply Plan Annual Update for a summary of MBS contract volumes and terms at EB-2026-0092, Section 3.4, Table 10.
[12] See Confidential Exhibit D, Tab 2, Schedule 2.
[13] In the Company's experience, Low-Flexibility storage service providers typically only bid/contract for service terms of three years or less.

Enbridge Gas
50 Keil Drive North
Chatham, Ontario N7M 5M1
Canada

February 5, 2025

Dear Recipient,

Subject: Storage at Dawn, Injections commencing April 1, 2025

Enbridge Gas Inc. operating as Enbridge Gas Distribution (Enbridge Gas) is seeking to procure firm natural gas storage services with injections commencing April 1, 2025.

This storage service request for proposal (RFP) is being administered by Ernst & Young LLP on behalf of Enbridge Gas.

Enbridge Gas is seeking storage services that meet or exceed the characteristics set out below, including services providing higher withdrawal capabilities and access to multiple daily nomination windows.

Storage Service Characteristics

To be considered, Enbridge Gas requires that all storage service offerings meet the following minimum service specifications:

- **Term:** Enbridge Gas's preference is to contract for a combination of 3-year and 5-year service terms, commencing April 1, 2025. However, service offerings including up to five (5) years will be considered. The volume and term of storage services ultimately contracted will be at Enbridge Gas's sole discretion.

- **Location:** Enbridge Gas will deliver natural gas volumes to the Storage Provider at Union Dawn for injection, and the Storage Provider will re-deliver natural gas volumes to Enbridge Gas at Union Dawn for withdrawal. If any transportation capacity is included as part of the storage service offering to facilitate Dawn injections and withdrawals, please include a detailed description of the characteristics of the transportation service.

- **Firm Injections:** Must include the months from May 1 through September 30. Service offerings that require Enbridge Gas to inject into storage during the months of November and December will be considered non-conforming.

- **Firm Withdrawals:** Enbridge Gas maintains a portfolio of storage services with either high or low withdrawal flexibility and is seeking offers of both types of services in this RFP.
    - **High Flexibility Services:** Minimum of 1.2% firm peak withdrawal capability. Must include the months from December 1 through March 31.

- **Low Flexibility Services:** Minimum 0.826% withdrawal rights to fully empty storage from December 1st through March 31st. Service offerings that require Enbridge Gas to withdraw from storage during other months will be considered non-conforming.

Storage Service Offerings

Storage service offerings should adhere to the format set out, and include all of the details requested, within the attached Microsoft Excel form, including delivery points, service term, maximum storage balance (MSB), price (including demand and commodity charges), a detailed description of all relevant service attributes, and sample invoices.[1]

Prior to contract execution, storage service providers must have established sufficient credit with Enbridge Gas. Counterparties are encouraged to contact Enbridge Gas's credit department to discuss their credit position via email to egicredit@Enbridge.com.

Please submit any questions regarding Enbridge Gas's RFP, as well as your storage service offering(s) to the attention of Chester Mercier via email to chester.mercier@EY.com.

- The deadline to submit any questions regarding Enbridge Gas's RFP is **12 p.m. (noon) Eastern Time (ET) on February 10, 2025**. A record of all questions received and all responses delivered will be distributed to all participants as promptly as possible in advance of the deadline to submit storage service offerings.
- The deadline to submit storage service offerings is **9 a.m. Eastern Time (ET) on February 26, 2025**.[2]

DO NOT CONTACT ENBRIDGE GAS PERSONNEL DIRECTLY REGARDING THIS RFP

[1] This storage service request may have Dodd Frank Act implications and may require specific clauses to be included in any storage agreement between the parties. Any such storage agreement will not be binding until a definitive agreement is executed by the parties.

[2] Please note that successful storage service providers must meet all of Enbridge Gas's credit criteria. Enbridge Gas, in its sole discretion and for whatever reason, may accept or reject any and all offerings. Enbridge Gas reserves the right at any time after the deadline for offerings, to conduct negotiations with one or more of the participants to the exclusion of others, and such negotiations may include changes to the storage service characteristics described in this letter.

Additional Information

Enbridge Gas invites all potential participants to review a presentation that has been posted to the Storage and Transportation section of its website at the following hyperlink: https://www.enbridgegas.com/storage-transportation/news-presentations.

Enbridge Gas will contact successful bidders following the close of the RFP process.

Sincerely,

Chester Mercier

Ernst & Young LLP

2025 Storage RFP - Issued on 2/05/2025; Responses on 02/26/2025 ; Bid Refreshed on 02/27/2025 - All responses summary

=RFP Manager recommendations

Response	Total cost (CAD/GJ)	Total Annual cost - 1 turn - CAD	Total Annual cost - 1PJ - CAD	Term (years)	Volume (GJ)	High/Low flexibility	Max Withdrawal rights - %	Ratchet score / # of days to w/d	max Injection rate (GJ/day)	max Withdrawal rate (GJ/day)	Days to Inject	Notes
[redacted]												

ACCOUNT NO. 179-108 UNABSORBED DEMAND COSTS VARIANCE ACCOUNT UNION RATE ZONES

1. The balance in the Unabsorbed Demand Cost (UDC) Variance Account is a debit from ratepayers of $4.882 million, plus interest. The $4.882 million debit balance is the difference between the actual UDC incurred and the amount of UDC costs collected in rates for the Union rate zones. There was no change to how the account operated in 2025 as compared to prior years.

1. Background

2. As discussed in Enbridge Gas's 2025 5-Year Gas Supply Plan,[1] the Company maintains a portfolio of upstream transportation assets to meet the design day demand requirements of its customers. Enbridge Gas plans for unutilized pipeline capacity in the Union North rate zones because the amount of transportation capacity needed to meet average annual demand requirements is less than the capacity required to meet design day demand requirements. Accordingly, Enbridge Gas's 2025 rates include costs associated with 14.4 PJ of planned unutilized pipeline capacity (UDC) for the Union North rate zones (3.1 PJ for Union North East, and 11.3 PJ for Union North West).[2]

3. On an actual basis, UDC costs may be incurred in any of the Union rate zones, including Union South. For example, in a warmer than normal year, additional UDC may be incurred in Union North, and UDC may be incurred in Union South, to balance supply with lower demands. Enbridge Gas manages its portfolio of upstream transportation assets on an integrated basis and decisions as to which

[1] EB-2025-0065, Enbridge Gas's 2025 5 Year Gas Supply Plan, p.44.
[2] Based on the annual gas supply plan filed as part of Enbridge Gas's Dawn Reference Price proceeding: EB-2015-0181, Exhibit A, Tab 2, Appendix A, Schedule 1.

pipeline to leave unutilized are primarily based on the least cost option and consideration of operational constraints.[3]

4. The following sections detail 2025 UDC capacity, costs, and related revenues generated through the release of unutilized pipeline capacity to secondary markets as well as the balances recorded in the UDC Variance Account for which Enbridge Gas is seeking disposition.

2. UDC Volumes, Costs & Capacity Release Revenues

5. Table 1 provides total actual UDC capacity, associated UDC costs incurred, and related capacity release revenues generated by Enbridge Gas in 2025 assigned to each rate zone based on the unutilized capacity allocation in rates. Enbridge Gas experienced UDC amounting to 32,516 TJ in 2025, due to a range of factors, including but not limited to planned UDC (as explained above), supply interruptions/curtailment and weather-driven variability in customer consumption. Enbridge Gas incurred gross UDC costs associated with the UDC capacity of $15.792 million. Enbridge Gas generated revenues by releasing a portion of this unutilized pipeline capacity to secondary markets of $4.645 million.[4]

[3] Some unutilized upstream transportation capacity may be released and sold on the secondary market to minimize UDC costs. The revenues generated from transportation capacity released is credited to the UDC Variance Account mitigating the overall impact of UDC costs to ratepayers as shown in Table 2.
[4] Not all unutilized upstream transportation capacity is released and sold on the secondary market (e.g., unplanned interruptions or curtailment may preclude timely capacity release, or there may be operational reasons not to release unutilized capacity).

Table 1
Actual 2025 UDC Capacity, Costs & Capacity Release Revenues
Rate Zone Presentation Based on Unutilized Capacity Allocation in Rates

Line No.	Particulars	Union North East	Union North West	Union South	Total
		(a)	(b)	(c)	(d)
1	UDC Capacity (TJ)	13,922	10,655	7,939	32,516
2	UDC Costs Incurred ($000s)	5,010	5,069	5,713	15,792
3	Capacity Release Revenues ($000s)	0	(4,581)	(64)	(4,645)

3. Derivation of 2025 UDC Variance Account Balances

6. Table 2 derives UDC variance account balances by rate zone by calculating the difference between UDC costs collected in rates and net UDC costs incurred by Enbridge Gas in 2025, including interest. Enbridge Gas collected $6.266 million in rates for UDC in 2025.[5] Enbridge Gas allocated UDC costs of $15.792 million and revenues generated through capacity release of $4.645 million to each rate zone in proportion to the actual supply and demand variances by rate zone,[6] resulting in net UDC costs of $11.147 million.[7] The variance between the UDC costs collected in rates and net UDC costs incurred, results in a net debit from ratepayers in the UDC Variance Account of $4.882 million, plus interest.

[5] The 2025 OEB-approved rates include $6.232 million of UDC costs associated with 14.4 PJ of planned unutilized pipeline capacity in the Union North East and Union North West rate zones, and TCPL Mainline tolls effective January 1, 2025. On an actual basis in 2025, Enbridge Gas recovered $6.266 million of UDC costs from customers in the Union North East and Union North West rate zones.
[6] Union North East = 31%, Union North West = 13%, Union South = 56%.
[7] Net UDC costs are removed (credited) from the Gas Cost Deferral Accounts, where transportation demand charges are recorded, and reallocated (debited) to the UDC Variance Account monthly to ensure that costs are assigned to the appropriate deferral account and eliminate risk of double counting.

Table 2

UDC Variance Account Balances by Rate Zone

Line No.	Particulars ($000s)	Union North East	Union North West	Union South	Total
		(a)	(b)	(c)	(d)
1	UDC Costs Collected in Rates	(1,318)	(4,947)	-	(6,266)
2	UDC Costs Incurred (1)	4,937	2,015	8,840	15,792
3	Capacity Release Revenues (1)	(1,452)	(593)	(2,600)	(4,645)
4	Net UDC Costs Incurred (Line 2 + Line 3)	3,485	1,422	6,240	11,147
5	UDC Cost Variance (Line 1 + Line 4)	2,166	(3,525)	6,240	4,882

Note:

(1) UDC Costs Incurred (Table 1, Line No. 2) and Released Capacity Revenue (Table 1, Line No. 3) re-allocated to Union North East (31%), Union North West (13%), and Union South (56%) rate zones in proportion to the actual supply and demand variances by rate zone.

ACCOUNT NO. 179-70 SHORT-TERM STORAGE AND OTHER BALANCING SERVICES – UNION RATE ZONES

1. In Phase 1 of the 2024 Rebasing Application, Enbridge Gas proposed that the excess utility storage space that previously existed in the Union rate zones would be used to serve all Enbridge Gas in-franchise customers as part of the consolidated gas supply plan[1].

2. In accordance with the 2024 Rebasing Phase 1 Settlement Agreement[2] matters related to storage would be determined in Phase 2 and parties agreed that Enbridge Gas would maintain its current levels of market-based storage until the determination on storage was made in Phase 2. The 2024 Rebasing Phase 2 Settlement Agreement[3] reduced the level of market-based storage to be held by Enbridge Gas. The reduction in market-based storage levels was completed by way of contracts which expired on March 31, 2025.

3. Enbridge Gas continued to maintain excess utility storage space in the Union rate zones until the implementation of the storage space outcomes of the 2024 Rebasing Phase 2 Settlement Agreement[4] effective April 1, 2025. During the period up to April 1, 2025, Enbridge Gas continued to record the net ratepayer benefit from the sale of excess utility storage in the Short-Term Storage Deferral Account.

4. The Short-Term Storage and Other Balancing Services Deferral Account includes revenues from C1 Short-Term Firm Peak Storage, C1 Off-Peak Storage, Loans, and Balancing Services. The deferral account balance is comprised of the actual gross revenues from short-term and other balancing services from the sale of available excess utility storage space, less the net shareholder incentive. The balance in this

[1] EB-2022-0200, Exhibit 4, Tab 2, Schedule 1.
[2] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023.
[3] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024.
[4] Ibid.

deferral account is a payable to ratepayers of $0.599 million, plus interest.

5. As shown in Table 1, the balance is calculated by adding the ratepayer 90% share of the actual 2025 Short-Term Storage and Other Balancing Services revenue (line 6) plus the shareholder 10% portion of the actual 2025 Short-Term Storage and Other Balancing Services cost (line 11). The 2024 Test Year Forecast included in rates assumed no excess utility space and ratepayers have paid 100% of the costs associated with excess utility space. As such, Enbridge Gas will credit the 10% shareholder portion of the costs to the ratepayer as part of the determination of the deferral account balance.

Table 1

Breakdown of Short-term Storage Deferral Account

Line No.	Particulars ($ millions)	Actual 2025 (a)
	Revenue	
1	Peak Storage	0.20
2	Off-Peak Storage	0.01
3	Loans	0.00
4	Short-term Balancing	0.41
5	Total Revenue	0.61
6	Ratepayer portion of revenue (90%)	0.55
	Costs	
7	O&M (1)	0.04
8	UFG (2)	0.32
9	Compressor Fuel (3)	0.11
10	Total Costs	0.46
11	Ratepayer refund of costs (10%)	0.05
12	Deferral Balance Payable to Ratepayers	0.60

Notes:
(1) Revenue Requirement on 11.3 PJ of 2013 OEB-approved excess in-franchise storage capacity.
(2) Based on short-term storage volumes in proportion to total volumes.
(3) Based on short-term storage activity in proportion to actual storage activity.

6. There is no longer excess utility space and any changes in customer storage requirements are managed through the gas supply plan.

2. Sale of Non-Utility Storage Space

7. As described above, in 2025, Enbridge Gas did not sell non-utility short-term peak storage. The excess utility space that was sold in 2024 expired March 31, 2025. Table 2 details the short-term peak storage revenue from January 1 to March 31, 2025.

Table 2
2025 Allocation of Short-Term Peak Storage Revenues Between Utility and Non-Utility

Line No.	Particulars	Utility Storage Space (PJ)	Space Sold (PJ) (1)	Revenue ($ millions)
		(a)	(b)	(c)
1	Short-Term Peak Storage		-	0.7
2	Utility Storage Space	100.0		
3	Utility Space Requirement	100.0		
4	Excess Utility Storage Space	-		
5	Utility Short-Term Peak Storage Sales		-	0.2
6	Non-Utility Short-Term Peak Storage Sales		-	0.5

ALLOCATION AND DISPOSITION OF 2025 DEFERRAL AND VARIANCE ACCOUNT BALANCES

1. The purpose of this evidence is to address the allocation and disposition of 2025 deferral and variance account balances identified at Exhibit C, Tab 1, Schedule 1.

2. Enbridge Gas proposes to dispose of the 2025 deferral and variance account balances with the first QRAM application following the OEB's approval, as early as July 1, 2027.

3. This exhibit of evidence is organized as follows:
   1. Allocation of Deferral and Variance Accounts
      - 1.1 EGI Accounts
      - 1.2 EGD Rate Zone Accounts
      - 1.3 Union Rate Zones' Accounts
   2. Disposition of Deferral and Variance Accounts
   3. General Service Bill Impacts

1. Allocation of Deferral and Variance Accounts

4. In accordance with the 2024 Rebasing Phase 1 Settlement Agreement[1], Phase 1 Decision[2], and Phase 2 Settlement Agreement[3], the OEB approved the establishment of new and harmonized Enbridge Gas deferral and variance accounts that apply to both the EGD rate zone and Union rate zones effective January 1, 2024. Certain existing standalone gas supply accounts specific to the EGD rate zone and Union rate zones will continue until harmonized rates are implemented, which is expected sometime in 2027.

[1] EB-2022-0200, Settlement Agreement, August 17, 2023.
[2] EB-2022-0200, Decision and Order, December 21, 2023.
[3] EB-2024-0111, Settlement Agreement, November 29, 2024.

1.1. EGI Accounts

5. The 2025 EGI deferral and variance account balances to be cleared, including the split of account balances by rate zone, are included at Exhibit F, Tab 1, Schedule 3.

6. As part of Phase 3 of the 2024 Rebasing Application[4], the Company requested approval of a Rate Harmonization Plan, including a harmonized cost allocation study. The OEB has approved the 2024 Rebasing Phase 3 Settlement Proposal[5], and the Company expects to implement the Rate Harmonization Plan sometime in 2027. Enbridge Gas will review and update the allocation of all deferral and variance accounts following the implementation of the Rate Harmonization Plan.

7. In the interim, Enbridge Gas proposes to allocate the deferral and variance account balances in a consistent manner with previous OEB-approved methodologies, where possible. Exhibit F, Tab 1, Schedule 2 provides a summary of the deferral and variance accounts included in this Application, the proposed allocation methodology, and reference to the history of each account (if applicable). The proposed allocation methodologies for new accounts with balances for disposition are described below.

8. Enbridge Gas is not requesting to dispose of the 2025 balances in the Incremental Capital Module Deferral Account, IRP Operating Costs Deferral Account, IRP Capital Costs Deferral Account, Panhandle Regional Expansion Project Variance Account, Site Restoration Costs Tracking Account, or Asset Life Extension Costs Deferral Account as part of this Application. There is no balance in the Unauthorized Overrun Non-Compliance Deferral Account, Expansion of Natural Gas Distribution Systems Variance Account, Green Button Initiative Deferral Account, Cloud Computing

[4] EB-2025-0064.
[5] EB-2025-0064, Decision on Settlement Proposal and Rate Order, March 26th, 2026.

Implementation Costs Deferral Account, Enbridge Sustain Affiliate Recoveries Variance Account, Open Bill Extension Deferral Account, Incremental Capital Module Deferral Account and Asset Life Extension Costs Deferral Account as shown at Exhibit C, Tab 1, Schedule 1.

9. The 2025 Earnings Sharing Deferral Account balance, including interest, is a credit of $25.233 million. Enbridge Gas proposes to split the balance between the EGD and Union rate zones in proportion to actual 2018 OEB-approved rate base. Further, Enbridge Gas proposes to allocate the respective balances to rate classes in proportion to rate base from the last OEB-approved cost allocation study for each rate zone. The proposed allocation factor is appropriate as it is consistent with the previous OEB-approved approach for the allocation of earnings sharing amounts for the EGD and Union rate zones.

10. The 2025 Tax Variance Account balance, including interest, is a credit of $13.969 million. Enbridge Gas proposes to split the balance between the EGD and Union rate zones in proportion to actual 2018 OEB-approved rate base. Further, Enbridge Gas proposes to allocate the respective balances to rate classes in proportion to rate base from the last OEB-approved cost allocation study for each rate zone. The proposed allocation factor is appropriate as taxes are allocated to rate classes in proportion to rate base.

11. The IRP System Pruning Deferral Account balance, including interest, is a debit of $0.415 million, consisting of a debit of $0.024 million related to the 2024 deferral balance and a debit of $0.391 million related to the 2025 deferral balance. Enbridge Gas proposes to split the 2024 and 2025 combined deferral balance of $0.415

million in proportion to the 2018 actual OEB-approved rate base for each rate zone[6] and allocate the respective balances to rate classes using rate base from the last OEB-approved cost allocation study for the EGD and Union rate zones[7]. Splitting the debit balance results in a debit of $0.219 million being allocated to the EGD rate zone and a debit of $0.196 million being allocated to the Union rate zones.

12. The 2025 Disposition of Property Deferral Account balance, including interest, is a credit of $13.493 million, consisting of a credit of $12.203 million to the EGD rate zone and a credit of $1.291 million to the Union rates zones based on the location of disposed property. Enbridge Gas proposes to allocate the respective balances to rate classes in proportion to the allocation of distribution-related land gross plant costs from the last OEB-approved cost allocation study for the EGD and Union rate zones.

13. The 2025 OEB Cost Assessment Variance Account balance, including interest, is a debit of $3.119 million. Enbridge Gas proposes to split the balance between the EGD and Union rate zones in proportion to actual 2018 OEB-approved rate base. Further, Enbridge Gas proposes to allocate the balance related to the EGD rate zone to EGD rate classes in proportion to rate base from the last OEB-approved cost allocation study for the EGD rate zone. Enbridge Gas proposes to allocate the balance related to the Union rate zones to Union rate zone rate classes in proportion to the allocation of Administrative and General O&M expenses from the last OEB-approved cost allocation study for the Union rate zones. The proposed allocation factors are appropriate as it is consistent with the previous OEB-approved approach

[6] EGD rate zone as per EB-2019-0105, Exhibit B, Tab 2, Appendix B, Schedule 1. Union rate zones as per EB-2019-0105, Exhibit C, Tab 2, Appendix A, Schedule 4.
[7] EGD rate zone as per EB-2017-0086, Exhibit G2, Tab 5, Schedule 1, line 8, columns (2-14). Union rate zones as per EB-2011-0210, Exhibit G3, Tab 2, Schedule 2, updated.

for the allocation of OEB Cost Assessment amounts for the EGD and Union rate zones.

14. The 2025 Customer Carbon Charge Variance Account balance, including interest, is a credit of $0.002 million. Based on the account activity, the balance has been direct assigned to the EGD rate zone and allocated to EGD rate classes based on actual 2025 volumes subject to the Federal Carbon Charge. Enbridge Gas proposes to change the disposition methodology to include the rate class allocations of this account as part of the derivation of delivery unit rates for disposition as the balance is not significant enough to generate a unit rate based on 2025 volumes subject to the Federal Carbon Charge.

1.2 EGD Rate Zone Accounts

15. The 2025 deferral and variance account balances to be cleared to the EGD rate zone are provided at Exhibit F, Tab 1, Schedule 3.

16. The 2025 EGD rate zone deferral and variance account balances are allocated to rate classes using the same methodologies as approved by the OEB in previous years.

17. The allocation of account balances to EGD rate classes is provided at Exhibit F, Tab 2, Schedule 2.

1.3 Union Rate Zones' Accounts

18. The 2025 deferral and variance account balances to be cleared to the Union rate zones are provided at Exhibit F, Tab 1, Schedule 3.

19. The 2025 Union rate zones' deferral and variance account balances are allocated to rate classes using the same methodologies as approved by the OEB in previous years.

20. The allocation of account balances to Union South and Union North rate classes is provided at Exhibit F, Tab 3, Schedule 2.

2. Disposition of Deferral and Variance Accounts

21. Enbridge Gas proposes to dispose of the 2025 deferral and variance account balances with the first QRAM application following the OEB's approval.

22. Enbridge Gas proposes to dispose of the 2025 deferral and variance account balances as a one-time billing adjustment. The billing adjustment will appear as a separate line item on customers' bills. The billing adjustment will be derived for each customer by applying the disposition unit rates to each customer's actual consumption volume or contract demand, as applicable, for the period January 1, 2025, to December 31, 2025.

23. The unit rates for disposition by rate class and service type for the EGD rate zone are provided at Exhibit F, Tab 2, Schedule 1 and Schedule 3. The unit rates for disposition by rate class and service type for the Union rate zones, including a summary of the balances to be disposed of to ex-franchise rate classes are provided at Exhibit F, Tab 3, Schedule 1 and Schedule 3.

3. General Service Bill Impacts

24. For a Rate 1 sales service and western T-service customer in the EGD rate zone with annual consumption of 2,400 m^3, the one-time billing adjustment credit is $18.94.

25. For a Rate M1 sales service residential customer in Union South with annual consumption of 2,200 m^3, the one-time billing adjustment charge is $7.76. For a Rate M1 bundled direct purchase (DP) residential customer, the one-time billing adjustment charge is $0.42.

26. For a Rate 01 sales service and bundled DP residential customer in Union North West with annual consumption of 2,200 m^3, the one-time billing adjustment credit is $22.10.

27. For a Rate 01 sales service and bundled DP residential customer in Union North East with annual consumption of 2,200 m^3, the one-time billing adjustment credit is $7.28.

28. Bill impacts of the proposed disposition are provided at Exhibit F, Tab 2, Schedule 4 for the EGD rate zone and Exhibit F, Tab 3, Schedule 4 for the Union rate zones.

Enbridge Gas Inc.
Summary of Deferral and Variance Account Allocation Factors

Line No.	Account Description	Acct. No.	Reference	Allocator to Rate Zone	Allocator to Rate Class
			(a)	(b)	(c)
	EGI Commodity Related Accounts				
1	Upstream Transportation Optimization V/A	179-201	EB-2022-0200	Direct assigned in proportion to 2025 actual optimization activity	Allocation of actual optimization activity to the EGD rate zone rate classes in proportion to actual Sales and Western BT volumes. Allocation of actual optimization activity to the Union North rate zone rate classes in proportion to the optimization credit included in rates. Allocation of actual optimization activity to the Union South rate zone rate classes in proportion to Sales Service volumes.
2	UFG Volume V/A	179-203	EB-2022-0200	Direct assignment by rate zone	Allocation to EGD rate zone rate classes in proportion to actual volumes. Allocation to Union rate zone rate classes in proportion to the 2013 OEB approved allocation of UFG volumes, updated for 2025 activity.
3	UFG Price V/A	179-204	EB-2022-0200	Direct assignment by rate zone	Allocation to EGD rate zone rate classes in proportion to actual volumes. Allocation to Union rate zone rate classes in proportion to volumes consistent with the 2013 OEB approved allocation of UFG costs, updated for 2025 activity based on actual UFG gas supply purchases in 2025.
	EGI Non Commodity Related Accounts				
4	Transportation from Dawn Service D/A	179-202	EB-2022-0200	Direct assigned to the Union North rate zone	Allocation in proportion to the prescribed capacity of the Base service offering of the Transportation from Dawn service.
5	Deferral Clearing V/A	179-302	EB-2022-0200		Actual volumes
6	Parkway Delivery Obligation V/A	179-303	EB-2022-0200	Direct assignment to the Union South rate zone	2013 Dawn-Parkway firm design day demands
7	Unauthorized Overrun Non-Compliance D/A	179-304	EB-2022-0200	No 2025 balance for disposition	No 2025 balance for disposition
8	Pension & OPEB V/A	179-305	EB-2022-0200	Allocation to rate zones in proportion to 2018 actual rate base	Allocation to the EGD rate zone rate classes in proportion to 2018 rate base. Allocation to the Union rate zones rate classes in proportion to 2013 rate base.
9	Facility Carbon Charge V/A	179-307	EB-2022-0200	Direct assignment by rate zone	Actual volumes
10	Customer Carbon Charge V/A	179-308	EB-2022-0200	Direct assignment by rate zone	Actual volumes subject to Federal Carbon Charge
11	Carbon Charges Bad Debt D/A	179-309	EB-2022-0200	Direct assignment by rate zone	Allocation to the EGD rate zone rate classes in proportion to actual number of customers. Allocation to the Union rate zones rate classes in proportion to the allocation of Administrative & General O&M expenses.
12	Earnings Sharing Mechanism D/A	179-311	EB-2022-0200	Allocation to rate zones in proportion to 2018 actual rate base	Allocation to the EGD rate zone rate classes in proportion to 2018 rate base. Allocation to the Union rate zones rate classes in proportion to 2013 rate base.
13	Tax V/A	179-312	EB-2022-0200	Allocation to rate zones in proportion to 2018 actual rate base	Allocation to the EGD rate zone rate classes in proportion to 2018 rate base. Allocation to the Union rate zones rate classes in proportion to 2013 rate base.
14	Expansion of Natural Gas Distribution Systems V/A	179-317	O. Reg. 24/19 s.4	No 2025 balance for disposition	No 2025 balance for disposition
15	Green Button Initiative D/A	179-320	EB-2020-0183	No 2025 balance for disposition	No 2025 balance for disposition
16	Dawn Parkway Surplus Capacity D/A	179-323	EB-2022-0200	Direct assigned to the Union rate zones	Distance weighted Dawn-Parkway design day demands
17	Distribution Integrity Management Program **V**/A	179-326	EB-2022-0200		Total O&M expense excluding cost of gas
18	Post Retirement True-Up V/A	179-328	EB-2022-0200	Allocation to rate zones in proportion to 2018 actual rate base	Allocation to the EGD rate zone rate classes in proportion to 2018 rate base. Allocation to the Union rate zones rate classes in proportion to 2013 rate base.
19	Clean Fuel Regulation Credits D/A	179-330	EB-2022-0200		Total O&M expense excluding cost of gas
20	Indigenous Working Group D/A	179-331	EB-2022-0200		Total O&M expense excluding cost of gas
21	Cloud Computing Implementation Costs D/A	179-332	Accounting Order (003-2023)	No 2025 balance for disposition	No 2025 balance for disposition
22	Average Use V/A	179-333	EB-2022-0200	Direct assignment by rate zone	Direct assignment to General Service rate classes Rate 1, Rate 6, Rate 01, Rate 10, Rate M1 and Rate M2.
23	Getting Ontario Connected V/A	179-335	EB-2023-0143	Allocation to rate zones in proportion to 2024 actual locates	Allocation to the EGD rate zone rate classes in proportion to the allocation of 2018 system distribution operating costs. Allocation to the Union rate zones rate classes in proportion to the allocation of 2013 mains and services distribution operating costs.
24	Disposition of Property D/A	179-336	EB-2022-0200	Direct assignment by rate zone	Allocation to the EGD rate zone rate classes in proportion to 2018 Distribution Land Gross Plant. Allocation to the Union rate zones rate classes in proportion to 2013 Distribution Land Gross Plant

Enbridge Gas Inc.
Summary of Deferral and Variance Account Allocation Factors

Line No.	Account Description	Acct. No.	Reference	Allocator to Rate Zone	Allocator to Rate Class
			(a)	(b)	(c)
25	LEAP Emergency Financial Assistance D/A	179-338	EB-2023-0135	No rate zone specific allocation.	Allocation in proportion to 2025 Proposed Delivery Revenue
26	OEB Cost Assessement V/A	179-340	EB-2024-0111	Allocation to rate zones in proportion to 2018 actual rate base	Allocation to the EGD rate zone rate classes in proportion to 2018 rate base. Allocation to the Union rate zones rate classes in proportion to the allocation of **2013** Administrative & General O&M expenses.
27	IRP System Pruning D/A	179-341	EB-2024-0111	Allocation to rate zones in proportion to 2018 actual rate base	Allocation to the EGD rate zone rate classes in proportion to 2018 rate base. Allocation to the Union rate zones rate classes in proportion to 2013 rate base.
28	Enbridge Sustain Affiliate Recoveries V/A	179-344	EB-2024-0111	No 2025 balance for disposition	No 2025 balance for disposition
	EGD Rate Zone Commodity Related Accounts				
29	Storage and Transportation D/A	179-88		Direct assigned to the EGD rate zone	Split of deferral balance in proportion to total Space and Deliverability cost. Allocation of Space costs to rate classes in proportion to Space allocation. Allocation of Deliverability costs to rate classes in proportion to Deliverability allocation.
	EGD Rate Zone Non Commodity Related Accounts				
30	Open Bill Extension D/A	179-325	EB-2022-0200	No 2025 balance for disposition	No 2025 balance for disposition
	Union Rate Zones Gas Supply Accounts				
31	Unabsorbed Demand Costs Variance Account	179-108		Direct assigned to the Union rate zones in proportion to UDC costs incurred	Allocation to the Union North rate zone rate classes in proportion to UDC collected in rates. Allocation to the Union South rate zone rate classes in proportion to Actual Sales Service volumes.
	Union Rate Zones Storage Accounts				
32	Short-Term Storage and Other Balancing Services	179-70		Direct assigned to the Union rate zones in proportion to Storage Excess	Allocation to the Union North rate zone rate classes in proportion to Excess Peak over Average Day demands. Allocation to the Union South rate zone rate classes in proportion to Total Design Day demands.
	EGI Accounts Not Being Requested For Clearance				
33	Incremental Capital Module D/A	179-306	EB-2022-0200		
34	IRP Operating Costs D/A	179-318	EB-2020-0091		
35	IRP Capital Costs D/A	179-319	EB-2020-0091		
36	Panhandle Region Expansion Project V/A	179-329	EB-2022-0200		
37	Site Restoration Costs Tracking Account	179-337	EB-2022-0200		
38	Asset Life Extension Costs D/A	179-343	EB-2024-0111		

Enbridge Gas Inc.
Split of EGI Account Balances to Rate Zones

Line No.	Account Description	Acct. No.	Account Balance Including Interest EGD ($000's)	Union ($000's)	Total (1) ($000's)
			(a)	(b)	(c) = (a+b)
	EGI Commodity Related Accounts				
1	Upstream Transporation Optimization V/A	179-201	(38,863.2)	2,205.9	(36,657.4)
2	UFG Volume V/A	179-203	(182.7)	11,149.6	10,966.9
3	UFG Price V/A	179-204	(4,118.1)	422.7	(3,695.4)
4	Total Commodity Related Accounts		(43,164.0)	13,778.2	(29,385.8)
	EGI Non Commodity Related Accounts				
5	Transportation from Dawn Service D/A	179-202	-	74.0	74.0
6	Deferral Clearing V/A	179-302	1,692.5	2,011.0	3,703.5
7	Parkway Delivery Obligation V/A	179-303	-	2,687.7	2,687.7
8	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-
9	Pension & OPEB V/A	179-305	(2,591.4)	(2,317.7)	(4,909.1)
10	Facility Carbon Charge V/A	179-307	(1,650.4)	808.0	(842.4)
11	Customer Carbon Charge V/A	179-308	(2.2)	-	(2.2)
12	Carbon Charges Bad Debt D/A	179-309	4,478.7	2,887.4	7,366.1
13	Earnings Sharing D/A	179-311	(13,319.8)	(11,912.8)	(25,232.7)
14	Tax V/A	179-312	(7,373.9)	(6,595.0)	(13,968.8)
15	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-
16	Green Button Initiative D/A	179-320	-	-	-
17	Dawn Parkway Surplus Capacity D/A	179-323	-	(2,365.4)	(2,365.4)
18	Distribution Integrity Management Program V/A	179-326	124.1	101.2	225.2
19	Post Retirement True-Up V/A	179-328	(27,211.9)	(24,337.4)	(51,549.2)
20	Clean Fuel Regulation Credits D/A	179-330	(20.3)	(16.6)	(36.9)
21	Indigenous Working Group D/A	179-331	154.6	126.1	280.7
22	Cloud Computing Implementation Costs D/A	179-332	-	-	-
23	Average Use V/A	179-333	7,642.6	28,982.3	36,624.963
24	Getting Ontario Connected V/A	179-335	9,127.9	5,710.4	14,838.3
24	Disposition of Property D/A	179-336	(12,202.7)	(1,290.7)	(13,493.4)
25	LEAP Emergency Financial Assistance D/A	179-338	731.6	519.8	1,251.4
26	OEB Cost Assessment V/A	179-340	1,646.4	1,472.5	3,118.9
27	IRP System Pruning D/A (2024 & 2025)	179-341	219.0	195.9	414.9
28	Enbridge Sustain Affiliate Recoveries V/A	179-344	-	-	-
29	Total Non Commodity Related Accounts		(38,555.2)	(3,259.1)	(41,814.3)
30					
31	Total EGI Accounts (for clearance)		(81,719.2)	10,519.1	(71,200.1)
	EGD Rate Zone Commodity Related Accounts				
32	Storage and Transportation D/A	179-88	3,403.8	-	3,403.8
33	Total Commodity Related Accounts		3,403.8	-	3,403.8
34	EGD Rate Zone Non Commodity Related Accounts				
35	Open Bill Extension D/A	179-325	-	-	-
36	Total Non Commodity Related Accounts		-	-	-
37	Total EGD Rate Zone (for clearance)		3,403.8	-	3,403.8
38	Union Rate Zones Gas Supply Accounts				
39	Unabsorbed Demand Costs Variance Account	179-108	-	5,121.9	5,121.9
40	Total Gas Supply Accounts		-	5,121.9	5,121.9
41	Union Rate Zones Storage Accounts				
42	Short-Term Storage and Other Balancing Services	179-70		(622.2)	(622.2)
43	Total Storage Accounts		-	(622.2)	(622.2)
44	Total Union Rate Zones (for clearance)		-	4,499.7	4,499.7
45	Total Deferral and Variance Accounts (for clearance)		(78,315.5)	15,018.8	(63,296.6)

Notes:
(1) Exhibit C, Tab 1, Schedule 1.

Enbridge Gas Inc.
EGD Rate Zone
Unit Rate and Type of Service

Line No.	Particulars	Sales Service (cents/m^3)	Ontario T-Service (cents/m^3)	Dawn T-Service (cents/m^3)	Western T-Service (cents/m^3)	Unbundled Service (cents/m^3/d)
		(a)	(b)	(c)	(d)	(e)
	Bundled Services:					
1	Rate 1	(0.7890)	(0.3381)	(0.3381)	(0.7890)	
2	Rate 6	(0.8111)	(0.3602)	(0.3602)	(0.8111)	
3	Rate 100	(0.7065)	(0.2556)	(0.2556)	(0.7065)	
4	Rate 110	(0.5206)	(0.0697)	(0.0697)	(0.5206)	
5	Rate 115	(0.5390)	(0.0881)	(0.0881)	(0.5390)	
6	Rate 135	(0.5284)	(0.0775)	(0.0775)	(0.5284)	
7	Rate 145	(0.5653)	(0.1144)	(0.1144)	(0.5653)	
8	Rate 170	(0.0501)	(0.0501)	(0.0501)	(0.0501)	
9	Rate 200	(0.5192)	(0.0683)	(0.0683)	(0.5192)	
	Unbundled Services:					
10	Rate 125					(0.0042)
11	Rate 300					-
12	Rate 332					(5.5398)

Enbridge Gas Inc.
EGD Rate Zone
Classification and Allocation of Deferral and Variance Account Balances

Line No.	Particulars ($000's)	Acct No.	Rate 1	Rate 6	Rate 100	Rate 110	Rate 115	Rate 125	Rate 135	Rate 145	Rate 170	Rate 200	Rate 300	Rate 332	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Upstream Transportation Optimization V/A	179-201	(23,013)	(14,439)	(66)	(680)	(0)	-	(7)	(2)	-	(656)	-	-	(38,863)
2	Total Gas Supply Related Deferrals		(23,013)	(14,439)	(66)	(680)	(0)	-	(7)	(2)	-	(656)	-	-	(38,863)
3	Storage and Transportation D/A	179-88	1,787	1,503	16	41	7	-	-	(2)	11	39	-	-	3,404
4	Total Storage Related Deferrals		1,787	1,503	16	41	7	-	-	(2)	11	39	-	-	3,404
5	Transportation from Dawn Service D/A	179-202	-	-	-	-	-	-	-	-	-	-	-	-	-
6	UFG Volume V/A	179-203	(75)	(73)	(1)	(19)	(5)	-	(1)	(1)	(5)	(3)	-	-	(183)
7	UFG Price V/A	179-204	(1,694)	(1,648)	(20)	(434)	(110)	-	(20)	(20)	(104)	(69)	-	-	(4,118)
8	Deferral Clearing V/A	179-302	616	600	7	158	40	194	7	7	38	25	-	-	1,692
9	Parkway Delivery Obligation V/A	179-303	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Pension & OPEB V/A	179-305	(1,700)	(718)	(8)	(31)	(11)	(25)	(1)	(3)	(4)	(6)	-	(84)	(2,591)
12	Facility Carbon Charge Variance Account	179-307	(527)	(513)	(6)	(135)	(34)	(165)	(6)	(6)	(32)	(22)	-	(204)	(1,650)
13	Customer Carbon Charge Variance Account	179-308	(1)	(1)	(0)	(0)	(0)	-	(0)	(0)	(0)	-	-	-	(2)
14	Carbon Charges Bad Debt Deferral Account	179-309	4,146	331	0	1	0	0	0	0	0	0	-	0	4,479
15	Tax V/A	179-312	(4,837)	(2,042)	(23)	(89)	(32)	(71)	(4)	(7)	(10)	(18)	-	(239)	(7,374)
16	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Green Button Initiative D/A	179-320	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Dawn Parkway Surplus Capacity D/A	179-323	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Open Bill Extension D/A	179-325	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Distribution Integrity Management Program D/A	179-326	84	33	-	3	1	1	0	1	1	0	-	0	124
21	Post Retirement True-Up V/A	179-328	(17,851)	(7,537)	(85)	(327)	(120)	(262)	(15)	(27)	(38)	(68)	-	(883)	(27,212)
22	Clean Fuel Regulation Credits D/A	179-330	(14)	(5)	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	(0)	(20)
23	Indigenous Working Group D/A	179-331	104	41	-	3	1	2	0	1	1	0	-	0	155
24	Cloud Computing Implementation Costs D/A	179-332	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Average Use Variance Account	179-333	12,829	(5,187)	-	-	-	-	-	-	-	-	-	-	7,643
26	Getting Ontario Connected V/A	179-335	5,717	2,988	-	155	66	163	0	6	6	25	-	-	9,128
27	Disposition of Property D/A	179-336	(8,991)	(2,877)	(0)	(125)	(50)	(120)	(3)	(7)	(9)	(21)	-	-	(12,203)
28	LEAP Emergency Financial Assistance D/A	179-338	490	209	1	17	3	6	1	1	1	2	-	-	732
29	OEB Cost Assessment V/A	179-340	1,080	456	5	20	7	16	1	2	2	4	-	53	1,646
30	IRP System Pruning D/A	179-341	144	61	1	3	1	2	0	0	0	1	-	7	219
31	Enbridge Sustain Affiliate Recoveries V/A	179-344	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Total Delivery Related Deferrals (Lines 5 through 31)		(10,478)	(15,881)	(128)	(801)	(244)	(261)	(40)	(53)	(151)	(150)	-	(1,350)	(29,536)
33	Total Storage and Delivery Disposition (line 4 + line 32)		(8,690)	(14,378)	(112)	(760)	(237)	(261)	(40)	(55)	(139)	(111)	-	(1,350)	(26,132)
34	Earnings Sharing D/A	179-311	(8,738)	(3,689)	(41)	(160)	(59)	(128)	(7)	(13)	(18)	(33)	-	(432)	(13,320)
35	Grand Total (line 2 + line 33 + line 34)		(40,440)	(32,507)	(219)	(1,600)	(295)	(389)	(55)	(70)	(158)	(800)	-	(1,782)	(78,315)

Enbridge Gas Inc.
EGD Rate Zone
Unit Rates for One-Time Adjustment - Delivery

Line No.	Particulars	2025 Deferral Balances ($000's)	2025 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2025 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
		(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
	Bundled Services:					
1	Rate 1	(8,690)	(8,738)	(17,428)	5,154,228	(0.3381)
2	Rate 6	(14,378)	(3,689)	(18,068)	5,015,489	(0.3602)
3	Rate 100	(112)	(41)	(153)	59,993	(0.2556)
4	Rate 110	(760)	(160)	(920)	1,319,623	(0.0697)
5	Rate 115	(237)	(59)	(295)	335,399	(0.0881)
6	Rate 135	(40)	(7)	(47)	61,064	(0.0775)
7	Rate 145	(55)	(13)	(69)	59,917	(0.1144)
8	Rate 170	(139)	(18)	(158)	314,998	(0.0501)
9	Rate 200	(111)	(33)	(144)	211,220	(0.0683)
	Unbundled Services:					
10	Rate 125	(261)	(128)	(389)	9,260,357	(0.0042)
11	Rate 300	-	-	-	-	-
12	Rate 332	(1,350)	(432)	(1,782)	32,162	(5.5398)

Enbridge Gas Inc.
EGD Rate Zone
Unit Rates for One-Time Adjustment - Sales and WBT

Line No.	Particulars	2025 Deferral Balances ($000's)	2025 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2025 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
		(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
	Bundled Services:					
1	Rate 1	(23,013)	-	(23,013)	5,103,594	(0.4509)
2	Rate 6	(14,439)	-	(14,439)	3,202,298	(0.4509)
3	Rate 100	(66)	-	(66)	14,549	(0.4509)
4	Rate 110	(680)	-	(680)	150,874	(0.4509)
5	Rate 115	(0)	-	(0)	0	(0.4509)
6	Rate 135	(7)	-	(7)	1,627	(0.4509)
7	Rate 145	(2)	-	(2)	413	(0.4509)
8	Rate 170	-	-	-	-	-
9	Rate 200	(656)	-	(656)	145,524	(0.4509)

Enbridge Gas Inc.
EGD Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Annual Volume (m^3)	Bill Impact ($)
		(a)	(b)	(c)
	Rate 1 - Small Customer			
1	Delivery	(0.3381)	2,400	(8.12)
2	Sales & WBT	(0.4509)	2,400	(10.82)
3	Sales Service Impact			(18.94)
4	Bundled Direct Purchase Impact - OTS			(8.12)
5	Bundled Direct Purchase Impact - DTS			(8.12)
6	Bundled Direct Purchase Impact - WTS			(18.94)
	Rate 6 - Average Customer			
7	Delivery	(0.3602)	22,606	(81.43)
8	Sales & WBT	(0.4509)	22,606	(101.93)
9	Sales Service Impact			(183.37)
10	Bundled Direct Purchase Impact - OTS			(81.43)
11	Bundled Direct Purchase Impact - DTS			(81.43)
12	Bundled Direct Purchase Impact - WTS			(183.37)
	Rate 6 - Large Customer			
13	Delivery	(0.3602)	339,124	(1,221.64)
14	Sales & WBT	(0.4509)	339,124	(1,529.14)
15	Sales Service Impact			(2,750.78)
16	Bundled Direct Purchase Impact - OTS			(1,221.64)
17	Bundled Direct Purchase Impact - DTS			(1,221.64)
18	Bundled Direct Purchase Impact - WTS			(2,750.78)
19	Rate 100 - Small Customer			
20	Delivery	(0.2556)	339,188	(867)
21	Sales & WBT	(0.4509)	339,188	(1,529)
22	Sales Service Impact			(2,396)
23	Bundled Direct Purchase Impact - OTS			(867)
24	Bundled Direct Purchase Impact - DTS			(867)
25	Bundled Direct Purchase Impact - WTS			(2,396)

Enbridge Gas Inc.
EGD Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Annual Volume (m^3)	Bill Impact ($)
		(a)	(b)	(c)
	Rate 110 - Small Customer			
26	Delivery	(0.0697)	598,568	(417)
27	Sales & WBT	(0.4509)	598,568	(2,699)
28	Sales Service Impact			(3,116)
29	Bundled Direct Purchase Impact - OTS			(417)
30	Bundled Direct Purchase Impact - DTS			(417)
31	Bundled Direct Purchase Impact - WTS			(3,116)
	Rate 110 - Large Customer			
32	Delivery	(0.0697)	9,976,121	(6,951)
33	Sales & WBT	(0.4509)	9,976,121	(44,983)
34	Sales Service Impact			(51,934)
35	Bundled Direct Purchase Impact - OTS			(6,951)
36	Bundled Direct Purchase Impact - DTS			(6,951)
37	Bundled Direct Purchase Impact - WTS			(51,934)
	Rate 115 - Small Customer			
38	Delivery	(0.0881)	4,471,609	(3,938)
39	Sales & WBT	(0.4509)	4,471,609	(20,163)
40	Sales Service Impact			(24,101)
41	Bundled Direct Purchase Impact - OTS			(3,938)
42	Bundled Direct Purchase Impact - DTS			(3,938)
43	Bundled Direct Purchase Impact - WTS			(24,101)
	Rate 125 - Average Customer			
44	Delivery Demand	(0.0042)	2,315,000	(97)
45	Unbundled Impact			(97)
	Rate 135 - Average Customer			
46	Delivery	(0.0775)	598,567	(464)
47	Sales & WBT	(0.4509)	598,567	(2,699)
48	Sales Service Impact			(3,163)
49	Bundled Direct Purchase Impact - OTS			(464)
50	Bundled Direct Purchase Impact - DTS			(464)
51	Bundled Direct Purchase Impact - WTS			(3,163)

Enbridge Gas Inc.
EGD Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Annual Volume (m^3)	Bill Impact ($)
		(a)	(b)	(c)
	Rate 145 - Large Customer			
52	Delivery	(0.1144)	598,567	(685)
53	Sales & WBT	(0.4509)	598,567	(2,699)
54	Sales Service Impact			(3,384)
55	Bundled Direct Purchase Impact - OTS			(685)
56	Bundled Direct Purchase Impact - DTS			(685)
57	Bundled Direct Purchase Impact - WTS			(3,384)
	Rate 170 - Average Customer			
58	Delivery	(0.0501)	9,976,121	(4,997)
59	Sales & WBT	-	9,976,121	-
60	Sales Service Impact			(4,997)
61	Bundled Direct Purchase Impact - OTS			(4,997)
62	Bundled Direct Purchase Impact - DTS			(4,997)
63	Bundled Direct Purchase Impact - WTS			(4,997)
	Rate 200 - Average Customer			
64	Delivery	(0.0683)	69,832,850	(47,669)
65	Sales & WBT	(0.4509)	69,832,850	(314,882)
66	Sales Service Impact			(362,551)
67	Bundled Direct Purchase Impact - OTS			(47,669)
68	Bundled Direct Purchase Impact - DTS			(47,669)
69	Bundled Direct Purchase Impact - WTS			(362,551)

Enbridge Gas Inc.
Union Rate Zones
Unit Rate and Type of Service

Line No.	Particulars	Sales Service (cents/m^3)	Bundled DP (cents/m^3)	T-Service (cents/m^3)
		(a)	(b)	(c)
	Union North West			
1	Rate 01	(1.0044)	(1.0044)	(0.1586)
2	Rate 10	0.3921	0.3921	0.9613
3	Rate 20 - Commodity	(0.0390)	(0.0390)	(0.0390)
4	Rate 20 - Demand	(3.0491)	(3.0491)	-
5	Rate 25	(0.0347)	(0.0347)	(0.0416)
6	Rate 100	(0.0572)	(0.0572)	(0.0572)
7	Bundled-T Storage Service ($/GJ)	-	-	(0.003)
	Union North East			
8	Rate 01	(0.3310)	(0.3310)	(0.1586)
9	Rate 10	0.7009	0.7009	0.9613
10	Rate 20 - Commodity	(0.0390)	(0.0390)	(0.0390)
11	Rate 20 - Demand	(4.9700)	(4.9700)	-
12	Rate 25	(0.0427)	(0.0427)	(0.0416)
13	Rate 100	(0.0572)	(0.0572)	(0.0572)
14	Bundled-T Storage Service ($/GJ)	-	-	(0.003)
15	North T-Service Transportation from Dawn Base Service ($/GJ)	-	-	0.040
	Union South			
16	Rate M1	0.3526	0.0191	
17	Rate M2	1.0788	0.7106	
18	Rate M4	0.3251	(0.0228)	
19	Rate M5	(0.4306)	(0.6835)	
20	Rate M7	0.7024	0.0354	
21	Rate M9	0.3257	0.0284	
22	Rate T1			(0.0330)
23	Rate T2			0.0131
24	Rate T3			0.0062

Enbridge Gas Inc.
Union Rate Zones
Classification and Allocation of Deferral and Variance Account Balances

Line No.	Particulars ($000's)	Acct No.	Union North					Union South															
			Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	M1	M2	M4	M5A	M7	M9	T1	T2	T3	M12	M13	C1	M16	M17	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
1	Unabsorbed Demand Costs Variance Account	179-108	(1,203)	(166)	(57)	-	-	5,358	1,031	96	7	21	36	-	-	-	-	-	-	-	-	5,122
2	Upstream Transportation Optimization V/A	179-201	(2,393)	(880)	(371)	-	6	4,590	1,082	90	3	56	23	-	-	-	-	-	-	-	-	2,206
3	Transportation from Dawn Service D/A	179-202	-	-	49	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74
4	Total Gas Supply Related Deferrals		(3,596)	(1,046)	(379)	25	6	9,948	2,113	185	10	76	59	-	-	-	-	-	-	-	-	7,402
5	Short-Term Storage and Other Balancing Services	179-70	(85)	(24)	(13)	-	-	(194)	(73)	(33)	(0)	(18)	(3)	(14)	(148)	(16)	-	-	-	-	-	(622)
6	Total Storage Related Deferrals		(85)	(24)	(13)	-	-	(194)	(73)	(33)	(0)	(18)	(3)	(14)	(148)	(16)	-	-	-	-	-	(622)
7	Customer Carbon Charge Variance Account	179-308	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	UFG Volume V/A	179-203	122	38	17	-	13	1,015	417	186	17	295	34	120	1,464	102	4,412	9	2,822	60	6	11,150
9	UFG Price V/A	179-204	19	6	3	-	2	157	64	29	3	45	5	-	-	-	-	1	87	1	-	423
10	Deferral Clearing V/A	179-302	120	38	180	103	42	380	156	70	6	110	13	50	709	34	-	-	-	-	-	2,011
11	Parkway Delivery Obligation V/A	179-303	-	-	-	-	-	1,364	459	133	1	61	22	66	427	155	-	-	-	-	-	2,688
12	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Pension & OPEB V/A	179-305	(414)	(64)	(45)	(35)	(12)	(905)	(137)	(34)	(29)	(12)	(2)	(24)	(104)	(14)	(481)	(0)	(4)	(1)	-	(2,318)
14	Facility Carbon Charge Variance Account	179-307	15	5	22	13	5	47	19	9	1	14	2	6	87	4	338	1	216	5	0	808
15	Customer Carbon Charge Variance Account	179-308	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Carbon Charges Bad Debt Deferral Account	179-309	581	50	43	38	17	1,464	138	51	57	14	2	37	103	11	273	0	6	0	-	2,887
16	Tax V/A	179-312	(1,179)	(182)	(129)	(99)	(35)	(2,575)	(390)	(97)	(82)	(34)	(6)	(67)	(297)	(39)	(1,368)	(1)	(12)	(2)	-	(6,595)
17	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Green Button Initiative D/A	179-320	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Dawn Parkway Surplus Capacity D/A	179-323	(89)	(23)	(6)	(0)	-	(136)	(46)	(13)	(0)	(6)	(2)	(7)	(42)	(15)	(1,979)	-	-	-	-	(2,365)
20	Distribution Integrity Management Program D/A	179-326	20	2	2	2	1	50	5	2	2	1	0	1	4	0	9	0	0	0	0	101
21	Post Retirement True-Up V/A	179-328	(4,350)	(670)	(475)	(366)	(130)	(9,502)	(1,440)	(358)	(304)	(125)	(24)	(248)	(1,097)	(145)	(5,050)	(3)	(45)	(6)	-	(24,337)
22	Clean Fuel Regulation Credits D/A	179-330	(3)	(0)	(0)	(0)	(0)	(8)	(1)	(0)	(0)	(0)	(0)	(0)	(1)	(0)	(1)	(0)	(0)	(0)	(0)	(17)
23	Indigenous Working Group D/A	179-331	25	2	2	2	1	63	7	2	3	1	0	2	5	0	11	0	0	0	0	126
24	Cloud Computing Implementation Costs D/A	179-332	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Average Use Variance Account	179-333	4,654	4,127	-	-	-	9,728	10,473	-	-	-	-	-	-	-	-	-	-	-	-	28,982
26	Getting Ontario Connected V/A	179-335	929	79	59	52	17	3,824	331	83	113	27	-	57	141	-	-	-	-	-	-	5,710
26	Disposition of Property D/A	179-336	(264)	(55)	(58)	(52)	(16)	(594)	(116)	(32)	(44)	(8)	-	(22)	(31)	-	-	-	-	-	-	(1,291)
27	LEAP Emergency Financial Assistance D/A	179-338	107	14	14	5	2	259	41	16	1	14	1	6	36	4						520
28	OEB Cost Assessment V/A	179-340	296	26	22	19	9	747	70	26	29	7	1	19	52	6	139	0	3	0	-	1,472
29	IRP System Pruning D/A (2024)	179-341	35	5	4	3	1	76	12	3	2	1	0	2	9	1	41	0	0	0	-	196
30	Enbridge Sustain Affiliate Recoveries V/A	179-344	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Total Delivery Related Deferrals		624	3,398	(345)	(315)	(83)	5,453	10,064	75	(222)	405	45	(1)	1,463	104	(3,658)	6	3,073	58	7	20,152
32	Total Storage and Delivery Disposition (line 6 + line 33)		539	3,374	(358)	(315)	(83)	5,259	9,991	43	(222)	387	42	(15)	1,315	88	(3,658)	6	3,073	58	7	19,530
33	Earnings Sharing D/A	179-311	(2,129)	(328)	(232)	(179)	(64)	(4,651)	(705)	(175)	(149)	(61)	(12)	(121)	(537)	(71)	(2,472)	(2)	(22)	(3)	-	(11,913)
34	Grand Total (line 4 + line 34 + line 35)		(5,187)	2,000	(970)	(470)	(141)	10,556	11,399	53	(360)	403	89	(137)	778	17	(6,130)	5	3,051	55	7	15,019

Enbridge Gas Inc.
Union Rate Zones
Allocation of Gas Supply Related Deferral Accounts by Union North East and Union North West

Line No.	Particulars ($000's)	Acct No.	Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (sum b:f)
	Union North West							
	Gas Supply Related Deferrals:							
1	Unabsorbed Demand Costs Variance Account	179-108	(2,994)	(582)	(123)	-	-	(3,699)
2	Upstream Transportation Optimization V/A	179-201	650	167	69	-	8	894
3	Total Gas Supply Related Deferrals		(2,345)	(415)	(54)	-	8	(2,806)
	Storage Related Deferrals:							
4	Short-Term Storage and Other Balancing Services (1)	179-70	(24)	(6)	(1)	-	-	(32)
5	Total North West Deferral Account Disposition (Line 3 + Line 4)		(2,369)	(421)	(55)	-	8	(2,837)
	Union North East							
	Gas Supply Related Deferrals:							
6	Unabsorbed Demand Costs Variance Account	179-108	1,792	416	66	-	-	2,273
7	Upstream Transportation Optimization V/A	179-201	(3,043)	(1,047)	(440)	-	(2)	(4,532)
8	Total Gas Supply Related Deferrals		(1,251)	(631)	(374)	-	(2)	(2,258)
	Storage Related Deferrals:							
9	Short-Term Storage and Other Balancing Services (1)	179-70	(61)	(18)	(8)	-	-	(87)
10	Total North East Deferral Account Disposition (Line 8 + Line 9)		(1,312)	(649)	(382)	-	(2)	(2,345)
	Total North							
	Gas Supply Related Deferrals:							
11	Unabsorbed Demand Costs Variance Account	179-108	(1,203)	(166)	(57)	-	-	(1,426)
12	Upstream Transportation Optimization V/A	179-201	(2,393)	(880)	(371)	-	6	(3,638)
13	Total North Gas Supply Related Deferrals		(3,596)	(1,046)	(428)	-	6	(5,064)
	Storage Related Deferrals:							
14	Short-Term Storage and Other Balancing Services (1)	179-70	(85)	(24)	(9)	-	-	(118)
15	Total North Deferral Account Disposition (Line 13 + Line 14)		(3,681)	(1,070)	(437)	-	6	(5,182)

Notes:
(1) Excludes allocation to Rate 20/100 bundled storage service.

Enbridge Gas Inc.
Union Rate Zones
Unit Rates for One-Time Adjustment - Delivery

Line No.	Particulars	2025 Deferral Balances ($000's)	2025 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2025 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
		(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
	Union North					
1	Rate 01	539	(2,129)	(1,591)	1,003,149	(0.1586)
2	Rate 10	3,374	(328)	3,046	316,885	0.9613
3	Rate 20	(354)	(232)	(587)	1,505,522	(0.0390)
4	Rate 100	(315)	(179)	(495)	864,327	(0.0572)
5	Rate 25	(83)	(64)	(147)	352,194	(0.0416)
	Union South					
6	Rate M1	5,259	(4,651)	608	3,176,291	0.0191
7	Rate M2	9,991	(705)	9,286	1,306,713	0.7106
8	Rate M4	43	(175)	(133)	582,148	(0.0228)
9	Rate M5	(222)	(149)	(371)	54,243	(0.6835)
10	Rate M7	387	(61)	326	922,157	0.0354
11	Rate M9	42	(12)	30	106,247	0.0284
12	Rate T1	(15)	(121)	(137)	415,028	(0.0330)
13	Rate T2	1,315	(537)	778	5,926,779	0.0131
14	Rate T3	88	(71)	17	282,401	0.0062

Enbridge Gas Inc.
Union Rate Zones
Unit Rates for One-Time Adjustment - Gas Supply Commodity

Line No.	Particulars	2025 Deferral Balances ($000's)	2025 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2025 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
		(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
	Union South					
1	Rate M1	9,948	-	9,948	2,983,202	0.3335
2	Rate M2	2,113	-	2,113	573,858	0.3681
3	Rate M4	185	-	185	53,253	0.3479
4	Rate M5	10	-	10	4,148	0.2529
5	Rate M7	76	-	76	11,458	0.6671
6	Rate M9	59	-	59	19,774	0.2973

Enbridge Gas Inc.
Union Rate Zones
Unit Rates for One-Time Adjustment - Gas Supply Transportation and Bundled Storage

Line No.	Particulars	2025 Deferral Balances ($000's)	2025 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2025 Actual Volume/ Demand	Billing Units	Unit Rate (cents/m^3)
		(a)	(b)	(c) = (a + b)	(d)		(e) = (c / d) * 100
	Gas Supply Transportation Charges						
	Union North West						
1	Rate 01	(2,345)	-	(2,345)	277,189	10^3m^3	(0.8458)
2	Rate 10	(415)	-	(415)	72,948	10^3m^3	(0.5692)
3	Rate 20	(54)	-	(54)	1,764	$10^3m^3/d$	(3.0491)
4	Rate 25	8	-	8	112,058	10^3m^3	0.0069
	Union North East						
5	Rate 01	(1,251)	-	(1,251)	725,960	10^3m^3	(0.1724)
6	Rate 10	(631)	-	(631)	242,308	10^3m^3	(0.2604)
7	Rate 20	(374)	-	(374)	7,527	$10^3m^3/d$	(4.9700)
8	Rate 25	(2)	-	(2)	163,611	10^3m^3	(0.0010)
	North T-Service Transportation from Dawn						
9	Rate 20/100 Base Service ($/GJ)	74	-	74	186,720	GJ/d	0.040
	Storage Charges						
10	Rate 20/100 Storage Service ($/GJ)	(4)	-	(4)	141,504	GJ/d	(0.003)

Enbridge Gas Inc.
Union Rate Zones
Storage and Transportation Service Amounts for Disposition

Line No.	Particulars ($000's) (1)	2025 Deferral Balances	2025 Earnings Sharing Mechanism	Deferral Balance for Disposition
		(a)	(b)	(c) = (a + b)
1	Rate M12	(3,658)	(2,472)	(6,130)
2	Rate M13	6	(2)	5
3	Rate C1	3,073	(22)	3,051
4	Rate M16	58	(3)	55
5	Rate M17	7	-	7

Notes:
(1) Ex-franchise customer specific amounts determined using approved deferral account allocation methodologies.

Enbridge Gas Inc.
Union North West Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Annual Volume (m^3)	Bill Impact ($)
		(a)	(b)	(c)
	Rate 01 - Small Customer			
1	Delivery	(0.1586)	2,200	(3.49)
2	Transportation - NW	(0.8458)	2,200	(18.61)
3	Sales Service Impact			(22.10)
4	Bundled Direct Purchase Impact			(22.10)
	Rate 10 - Average Customer			
5	Delivery	0.9613	93,000	894.00
6	Transportation - NW	(0.5692)	93,000	(529.32)
7	Sales Service Impact			364.68
8	Bundled Direct Purchase Impact			364.68
	Rate 20 - Small Customer			
9	Delivery	(0.0390)	3,000,000	(1,169)
10	Transportation Demand - NW	(3.0491)	14,000	(5,123)
11	Sales Service Impact			(6,292)
12	Bundled Direct Purchase Impact			(6,292)
	Rate 20 - Large Customer			
13	Delivery	(0.0228)	15,000,000	(3,416)
14	Transportation Demand - NW	(3.0491)	60,000	(21,954)
15	Sales Service Impact			(25,370)
16	Bundled Direct Purchase Impact			(25,370)
	Rate 25 - Average Customer			
17	Delivery	(0.0416)	2,275,000	(947)
18	Transportation - NW	0.0069	2,275,000	158
19	Sales Service Impact			(790)
20	Bundled Direct Purchase Impact			(790)
	Rate 100 - Small Customer			
21	Delivery	(0.0572)	27,000,000	(15,450)
22	Unbundled Direct Purchase Impact			(15,450)
	Rate 100 - Large Customer			
23	Delivery	(0.0572)	240,000,000	(137,332)
24	Unbundled Direct Purchase Impact			(137,332)

Enbridge Gas Inc.
Union North East Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Annual Volume (m^3)	Bill Impact ($)
		(a)	(b)	(c)
	Rate 01 - Small Customer			
1	Delivery	(0.1586)	2,200	(3.49)
2	Transportation - NE	(0.1724)	2,200	(3.79)
3	Sales Service Impact			(7.28)
4	Bundled Direct Purchase Impact			(7.28)
	Rate 10 - Average Customer			
5	Delivery	0.9613	93,000	894.00
6	Transportation - NE	(0.2604)	93,000	(242.15)
7	Sales Service Impact			651.85
8	Bundled Direct Purchase Impact			651.85
	Rate 20 - Small Customer			
9	Delivery	(0.0390)	3,000,000	(1,169)
10	Transportation Demand - NE	(4.9700)	14,000	(8,350)
11	Sales Service Impact			(9,519)
12	Bundled Direct Purchase Impact			(9,519)
	Rate 20 - Large Customer			
13	Delivery	(0.0228)	15,000,000	(3,416)
14	Transportation Demand - NE	(4.9700)	60,000	(35,784)
15	Sales Service Impact			(39,200)
16	Bundled Direct Purchase Impact			(39,200)
	Rate 25 - Average Customer			
17	Delivery	(0.0416)	2,275,000	(947)
18	Transportation - NE	(0.0010)	2,275,000	(23)
19	Sales Service Impact			(970)
20	Bundled Direct Purchase Impact			(970)
	Rate 100 - Small Customer			
21	Delivery	(0.0572)	27,000,000	(15,450)
22	Unbundled Direct Purchase Impact			(15,450)
	Rate 100 - Large Customer			
23	Delivery	(0.0572)	240,000,000	(137,332)
24	Unbundled Direct Purchase Impact			(137,332)

Enbridge Gas Inc.
Union South Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m³)	Annual Volume (m³)	Bill Impact ($)
		(a)	(b)	(c)
	Rate M1 - Small Customer			
1	Delivery	0.0191	2,200	0.42
2	Commodity	0.3335	2,200	7.34
3	Sales Service Impact			7.76
4	Bundled Direct Purchase Impact			0.42
	Rate M2 - Average Customer			
5	Delivery	0.7106	73,000	518.76
6	Commodity	0.3681	73,000	268.74
7	Sales Service Impact			787.50
8	Bundled Direct Purchase Impact			518.76
	Rate M4 - Small Customer			
9	Delivery	(0.0228)	875,000	(199)
10	Commodity	0.3479	875,000	3,044
11	Sales Service Impact			2,845
12	Bundled Direct Purchase Impact			(199)
	Rate M4 - Large Customer			
13	Delivery	(0.0228)	12,000,000	(2,733)
14	Commodity	0.3479	12,000,000	41,745
15	Sales Service Impact			39,012
16	Bundled Direct Purchase Impact			(2,733)
	Rate M5 - Small Customer			
17	Delivery	(0.6835)	825,000	(5,639)
18	Commodity	0.2529	825,000	2,087
19	Sales Service Impact			(3,552)
20	Direct Purchase Impact			(5,639)

Enbridge Gas Inc.
Union South Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m³)	Annual Volume (m³)	Bill Impact ($)
		(a)	(b)	(c)
	Rate M5 - Large Customer			
21	Delivery	(0.6835)	6,500,000	(44,430)
22	Commodity	0.2529	6,500,000	16,441
23	Sales Service Impact			(27,988)
24	Direct Purchase Impact			(44,430)
	Rate M7 - Small Customer			
25	Delivery	0.0354	36,000,000	12,733
26	Commodity	0.6671	36,000,000	240,148
27	Sales Service Impact			252,881
28	Direct Purchase Impact			12,733
	Rate M7 - Large Customer			
29	Delivery	0.0354	52,000,000	18,392
30	Commodity	0.6671	52,000,000	346,881
31	Sales Service Impact			365,273
32	Direct Purchase Impact			18,392
	Rate M9 - Small Customer			
33	Delivery	0.0284	6,950,000	1,972
34	Commodity	0.2973	6,950,000	20,662
35	Sales Service Impact			22,634
36	Direct Purchase Impact			1,972
	Rate M9 - Large Customer			
37	Delivery	0.0284	20,178,000	5,724
38	Commodity	0.2973	20,178,000	59,990
39	Sales Service Impact			65,714
40	Direct Purchase Impact			5,724
	Rate T1 - Small Customer			
41	Delivery	(0.0330)	7,537,000	(2,485)
42	Direct Purchase Impact			(2,485)

Enbridge Gas Inc.
Union South Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m³)	Annual Volume (m³)	Bill Impact ($)
		(a)	(b)	(c)
	Rate T1 - Average Customer			
43	Delivery	(0.0330)	11,565,938	(3,813)
44	Direct Purchase Impact			(3,813)
	Rate T1 - Large Customer			
45	Delivery	(0.0330)	25,624,080	(8,448)
46	Direct Purchase Impact			(8,448)
	Rate T2 - Small Customer			
47	Delivery	0.0131	59,256,000	7,782
48	Direct Purchase Impact			7,782
	Rate T2 - Average Customer			
49	Delivery	0.0131	197,789,850	25,974
50	Direct Purchase Impact			25,974
	Rate T2 - Large Customer			
51	Delivery	0.0131	370,089,000	48,600
52	Direct Purchase Impact			48,600
	Rate T3 - Large Customer			
53	Delivery	0.0062	272,712,000	16,825
54	Direct Purchase Impact			16,825

2025 SCORECARD RESULTS – ENBRIDGE GAS

1. The purpose of the scorecard is to measure and monitor performance of the utility. The scorecard is produced annually and includes measures in four categories: customer focus, operational effectiveness, public policy responsiveness, and financial performance. Enbridge Gas provides five years of scorecard results (2021 to 2025), at Exhibit G, Tab 1, Schedule 2.

2. For 2024, in accordance with the 2024 Rebasing Phase 2 Settlement Agreement,[1] parties agreed to the addition of new reporting metrics to be included in the OEB scorecard. The new reporting metrics will identify the in-year avoided capital costs of an investment as a result of the implementation of an "asset life extension (ALE) alternative" or "integrated resource planning (IRP) alternative", without targets set for the rate term. The purpose of these new metrics is to provide reporting and information transparency. In 2025, there were no IRP alternatives implemented. For ALE, Enbridge Gas began identifying opportunities to avoid capital costs in 2025, following the evaluation of several alternatives to mitigate high-risk pipeline segments identified after 2024 inspections. The resulting capital avoidance is expected to be reported in 2026 to align with the timing of the final mitigation decisions.

3. In 2025, Enbridge Gas met or exceeded all elements of the scorecard except for the Meter Reading Performance Measurement (MRPM).

4. The Meter Reading Performance Measurement (MRPM) metric measures the percentage of meters with no read for four consecutive months. As set out in the GDAR, the annual standard for MRPM is not to exceed 0.5% on an annual basis. The MRPM achieved for 2025 was 1.0%. The metric does not consider why Enbridge Gas has not read a meter.

[1] EB-2024-0111, Settlement Agreement, November 29, 2024.

5. Enbridge Gas is committed to the MRPM target and is taking all reasonable steps necessary to improve the metric as noted in the Assurance of Voluntary Compliance (AVC)[2]. Enbridge Gas shared its 2022 MRPM Mitigation Plan[3] with the OEB as part of Phase 1 of the 2024 Rebasing Application highlighting initiatives to improve the MRPM target. Since 2022, mitigation initiatives have included increased hiring of meter readers, reduced staff attrition, extended working hours, collaboration with meter reading vendors to conduct regular performance reviews, process improvements, advancements in meter reading technology and targeted marketing campaigns. Enbridge Gas further provided the 2024 MRPM Mitigation Plan[4] as part of Phase 2 of the 2024 Rebasing Application outlining additional strategies to improve the MRPM metric.

6. These actions have resulted in a sustained improvement in MRPM performance. The annual MRPM decreased from 4.1% in 2022 to 1.3% in 2023, 0.9% in 2024, and 1.0% in 2025. Customer complaints related to billing issues declined significantly from 1,093 in 2023 to 435 in 2024 and 312 in 2025. Enbridge Gas remains committed to continued progress through effective workforce management, enhanced customer outreach initiatives and the continued deployment of Automated Meter Reading meters and Encoder Receiver Transmitters where feasible.

7. Despite significantly improving this metric, there are ongoing challenges beyond Enbridge Gas's control that limit meter access and affect the ability to achieve this target. These include customer related access barriers such as locked gates, inside meters where tenants or landlords are unresponsive, customer sensitivity, and obstruction. In 2025, if these inaccessible meters were removed, the MRPM would have been 0.48%, in line with the targeted metric. Seasonal weather also impacts

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[2] EB-2022-0188, EGI-Assurance-of-Voluntary-Compliance-20220912.pdf (oeb.ca), https://www.oeb.ca/sites/default/files/EGI-Assurance-of-Voluntary-Compliance-20220912.pdf
[3] EB-2022-0200, Exhibit 1, Tab 7, Schedule 1, pp.18-21; and Attachment 4.
[4] EB-2024-0111, Exhibit 1, Tab 7, Schedule 1, Attachment 4.

accessibility, during the winter months meter inaccessibility increases. In 2025, 53% of meters with four consecutive estimated reads occurred during winter, which in 2025 had snowfalls significantly exceeding the historical average[5]. Historically, these meters are successfully read once weather conditions improve.

8. In Phase 2 of the 2024 Rebasing Application, Enbridge Gas proposed that meters with access issues caused by or within the control of the customer be excluded from the MRPM calculation.[6] Customer behaviour impacting the number of inaccessible meters includes locked gates, inside meters with unresponsive tenants or landlords, customer sensitivity, and obstruction.[7] OEB denied this request and confirmed that the MRPM standard requiring that no more than 0.5% of active meters go without a read for four or more consecutive months remains in effect. However, the OEB granted a temporary exemption for 2025 results to provide Enbridge Gas additional time to meet the metric. Enbridge Gas continues to make efforts to achieve the 0.5% target, which remains a stretch objective given the unknown conditions caused by customer behaviour.[8]

[5] Canada's snow season turns historic as multiple cities top 500 cm - The Weather Network, https://www.theweathernetwork.com/en/news/weather/forecasts/canadas-snow-season-turns-historic-as-multiple-cities-top-500-cm
[6] EB-2024-0111, Exhibit 1, Tab 7, Schedule 1, pp.5-6.
[7] EB-2024-0111, Exhibit 1, Tab 7, Schedule 1, pp.10-13, and Attachment 3.
[8] EB-2024-0111, Decision and Order, May 29, 2025, pp. 11-12.

EGI OEB Scorecard 2021 - 2025

#	Performance Measure	Target	Actual 2025 EGI	Actual 2024 EGI	Actual 2023 EGI	Actual 2022 EGI	Actual 2021 EGI
	CUSTOMER FOCUS (Service Quality & Customer Satisfaction)						
1	**Reconnection Response Time (# of days to reconnect a customer)** (# of reconnections completed within 2 business days/# of reconnections completed)	85.0%	98.7%	99.2%	99.3%	98.1%	96.9%
2	**Scheduled appointments met on time (appointments met within designated time period)** (# of appointments met within 4hrs of the scheduled date/# of appointments scheduled in the month)	85.0%	97.2%	97.4%	96.3%	95.4%	94.5%
3	**Telephone calls answered on time (call answering service level)** (# of calls answered within 30 seconds / # of calls received)	75.0%	83.8%	85.2%	89.5%	75.9%	64.3%
4	**Customer Complaint Written Response (# of days to provide a written response)** # of complaints requiring response within 10 days / # of complaints requiring a written response	80.0%	100.0%	66.7%	100.0%	90.0%	100.0%
5	**Billing accuracy** 'The requirement states that utilities should complete manual checks of their bills to verify data when a meter read demonstrates excessively high or low usage.'		279,449 manual checks completed as per QAP	258,017 manual checks completed as per QAP	331,489 manual checks completed as per QAP	390,246 manual checks completed as per QAP	384,858 manual checks completed as per QAP
6	**Abandon Rate (# of calls abandon rate)** (# of calls abandoned while waiting for a live agent / # of calls requesting to speak to a live agent)	10.0%	3.9%	2.6%	1.4%	7.1%	16.0%
7	**Time to Reschedule Missed Appointments** (% of rescheduled work within 2 hours of the end of the original appointment time)	98%[1]	99.3%	98.5%	97.8%	93.8%	97.0%
#	**OPERATIONAL EFFECTIVENESS (Safety, System Reliability, Asset Management & Cost Control)**						
8	**Meter Reading Performance** # of meters with no read for 4 consecutive months / # of active meters to be read	0.5%	1.0%	0.9%	1.3%	4.1%	5.0%
9	**% of Emergency Calls Responded within One Hour** (# of emergency calls responded within 60 minutes / # of emergency calls)	90.0%	94.3%	96.0%	95.3%	94.1%	95.2%
10	**Compression Reliability** % reliable for transmission compression		99.5%	100.0%	100.0%	100.0%	99.7%
11	**Damages per 1000 locate requests**		2.21	1.91	2.10	2.31	1.95
12	**Total Cost per Customer** ($ / Customer)		762.9	756.5	745.7	683.2	643.9
13	**Total Cost per km of Distribution Pipe** ($ / km of Distribution Pipe)		19,653.3	19,492.6	19,079.6	17,480.7	16,639.6
	PUBLIC POLICY RESPONSIVENESS (Conservation & Demand Management & Connection of Renewable Generation)						
14	**Total Cumulative Cubic Meters of Natural Gas Saved (Net)** (Cumulative Lifetime Natural Gas saving) (Millions)		1665.7 [2]	2708.0 [3]	1759.6 [4]	1,385.9	1,654.9
	FINANCIAL PERFORMANCE (Avoided Capital Costs)						
15	**Integrated Resource Plan (IRP)** (Capital Cost of Facility Alternative) - (Capital Cost of IRP Alternative)		$0[5]	$0[6]	NA[7]	NA[7]	NA[7]
16	**Asset Life Extension (ALE)** (Capital Cost for Total Replacement) - (Capital Cost for Asset Life Extension)		$0[8]	$0	NA[7]	NA[7]	NA[7]
	FINANCIAL PERFORMANCE (Financial Ratios)						
17	**Current Ratio** (Current Assets / Current Liabilities)		0.56	0.61	0.92	0.84	0.71
18	**Debt Ratio** (Total Debt / Total Assets)		0.38	0.37	0.39	0.42	0.41
19	**Debt to Equity Ratio** (Total Debt / Shareholders' Equity)		0.96	0.93	0.97	1.10	1.06
20	**Interest Coverage** (EBIT / Interest Charges)		3.14	2.28	1.75	2.54	2.55
21	**Financial Statement Return on Assets** (Net Income / Total Assets)		2.66%	1.72%	1.20%	2.03%	2.07%
22	**Financial Statement Return on Equity** (Net Income / Shareholders' Equity)		6.71%	4.31%	3.00%	5.37%	5.32%

[1] Time to Reschedule Missed Appointment target was 100% prior to the Phase 1 Decision.
[2] 2025 data is draft and subject to OEB approval.
[3] 2024 is audited, and subject to OEB approval.
[4] 2023 is OEB approved and updated from last submission.
[5] There were no IRP alternatives implemented in 2025, therefore no capital costs have been avoided.
[6] There were no IRP alternatives implemented in 2024, therefore no capital costs have been avoided.
[7] Historical information is not available.
[8] There were no capital costs avoided in 2025.

Estimated Billing and Meter Reading Performance Report

Date: August 24, 2026

Life Takes Energy

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1. Executive Summary

Enbridge Gas continues to improve meter reading performance and customer experience while maintaining an appropriate balance among billing accuracy, operational reliability and customer affordability.

In its EB-2025-0155 Decision and Order, regarding the 2024 Deferral and Variance Account Disposition and Earning Sharing (2024 DVA) proceeding for Enbridge Gas Inc. (Enbridge Gas or Company), the Ontario Energy Board (OEB) directed Enbridge Gas in its next DVA proceeding to provide a detailed report on the measures it has taken to address the OEB's ongoing concern about estimated customer bills. Enbridge Gas has prepared this report to be responsive by describing:

- How actual and estimated meter readings are used in the billing process;
- The safeguards in place to prevent billing errors;
- Meter reading performance metric (MRPM) results and challenges;
- Customer complaint data and trends related to estimated billing; and
- Actions Enbridge Gas has taken and continues to take to improve customer experience and meter reading performance.

Estimated billing is a standard utility practice used to support cost-effective operations and maintain regular billing cycles. Enbridge Gas uses a combination of actual meter readings, customer-submitted readings and estimation methodologies to ensure customers receive timely and accurate bills.

While estimated bills are a normal outcome of a bi-monthly meter reading model, Enbridge Gas recognizes the importance of minimizing estimates and ensuring customers are billed based on actual consumption whenever possible. Customer-submitted readings, meter reading validation processes and ongoing investments in remote meter reading technologies all contribute to improving billing accuracy.

The data demonstrates that estimated bills do not create persistent under or overbilling over time because accounts are reconciled once an actual meter reading is obtained. Importantly, estimated bills are not a significant factor contributing to customer concerns, as demonstrated by complaint data and trends. Enbridge Gas continues to make significant efforts to address and improve meter reading performance despite ongoing challenges with inaccessible meters and the cumulative nature of the MRPM calculation that compound extreme weather impacts on meter reading performance.

The report also demonstrates that Enbridge Gas has achieved improvement of more than 75% in MRPM results since 2022, while weather, meter accessibility and customer access-related constraints continue to affect performance and annual results. Ongoing efforts include enhanced billing validation, expanded customer communications, escalation support, continued customer outreach and deployment of remote meter reading technologies, including more than 148,000 Advanced Meter Reading (AMR) meters since January 2025. As Enbridge Gas continues to advance AMR and other remote meter reading technologies, the Company looks forward to further interim discussions with the OEB regarding the operation of the MRPM framework and the extent to which it appropriately reflects meter accessibility, customer affordability and long-term technology solutions.

2. Background

As part of the 2024 DVA, Energy Probe Research Foundation (Energy Probe) raised concerns regarding the relationship between estimated customer bills and Unaccounted for Gas (UFG). Specifically, Energy Probe questioned whether increases in estimated billing may have contributed to the growth in UFG balances and proposed that a portion of the UFG-related balance associated with estimated billing be treated differently for recovery purposes. The OEB considered these submissions and Enbridge Gas' evidence regarding the causes of UFG and the role of estimated billing.

In its Decision and Order, the OEB did not accept Energy Probe's proposal, finding that the evidence supported Enbridge Gas' position that estimated bills do not create persistent UFG balances over time. However, the OEB noted that the issues raised by Energy Probe were related to its broader and ongoing interest in estimated customer bills and meter reading performance. As a result, the OEB directed Enbridge Gas to provide a detailed report outlining the measures undertaken to address these matters.

The OEB stated:

> The OEB does not accept Energy Probe's proposal to defer a portion of the UFGVVA balance associated with estimated billing. The evidence supports Enbridge Gas's position that estimated bills do not create persistent UFG balances over time. Having said that, Energy Probe has raised questions that relate to the OEB's ongoing concern about estimated customer bills. The OEB directs Enbridge Gas to provide a detailed report on the measures it has taken to address this issue as part of its next DVA application considering its annual performance scorecard.[1]

This report has been prepared in response to that direction. It provides an overview of the role of estimated billing within the customer billing process, meter reading performance trends and challenges, customer impacts and complaint trends, and the actions Enbridge Gas has taken and continues to take to improve meter reading performance and customer experience in relation to estimated bills.

3. The Role of Estimation in Billing

3.1 Estimation is a necessary and accepted practice

Estimated billing is a standard and necessary component of natural gas utility operations. It is used throughout the utility industry to support the timely issuance of customer bills when an actual meter reading is unavailable or impractical to obtain. Estimation enables utilities to bill customers on a regular basis while balancing operational efficiency, customer affordability and meter reading realities.

Importantly, estimated billing does not determine a customer's final consumption. Rather, it provides an interim calculation of usage until a valid meter reading becomes available. Once an actual meter reading is obtained, the customer's account is automatically reconciled to ensure billing reflects actual gas consumption.

[1] EB-2025-0155, Decision and Order, p.9.

The use of estimated bills is considered within the OEB's Gas Distribution Access Rule (GDAR), which recognizes that utilities

> may choose to estimate the meter read for various reasons which may include limited access (e.g., a customer has an inside meter or the access to the meter is restricted) and the expense of actual meter reads. It is cost prohibitive to get actual meter reads each month.[2]

3.2 Estimation Protects Customers

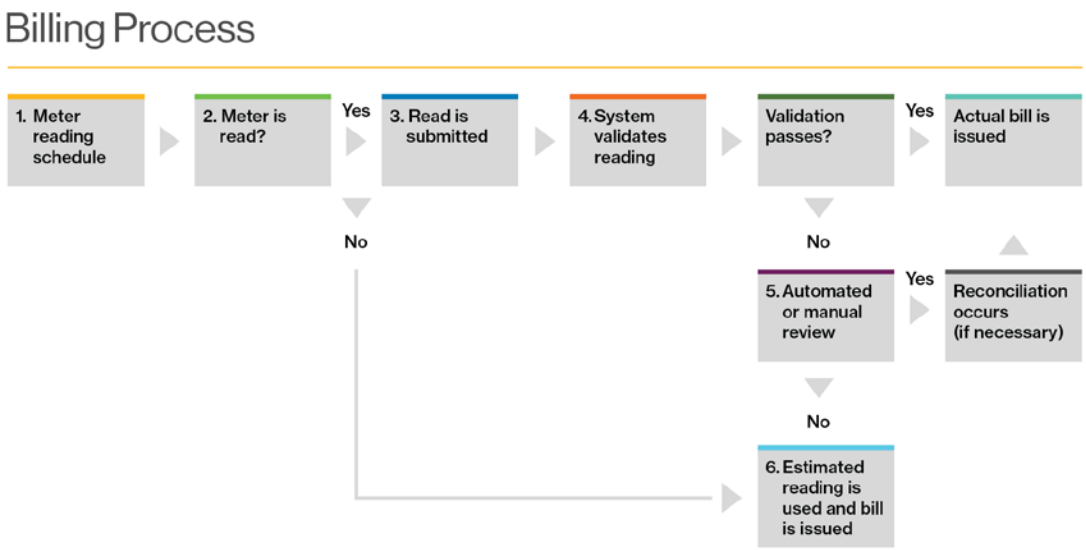
While estimation is often associated with situations where a meter cannot be read, it also serves as an important customer protection mechanism. Before a meter reading is used for billing purposes, Enbridge Gas utilizes automated validation controls within its SAP Customer Information System (SAP CIS) designed to identify readings that appear inconsistent with a customer's expected usage.

Where a submitted reading falls outside established thresholds, these readings are referred to as implausible readings and are flagged for review rather than being automatically used for billing. In these situations, an estimated bill may be issued while the reading is investigated. This approach minimizes the risk of customers receiving bills based on inaccurate readings, data entry errors or abnormal consumption values that have not yet been validated.

3.3 Billing Process

The Enbridge Gas billing process, as shown in Figure 1, involves the following steps to ensure customers receive accurate bills:

Figure 1 – Billing Process



[2] GDAR, Section 7.3.3 Meter Reading Performance, p. 20.

Step 1: Meter Reading Schedule

Enbridge Gas utilizes a bi-monthly meter reading model. Under this approach, approximately half of all customers are scheduled for an actual meter reading in any given month, with the alternate month being an off-read month (estimated reading) unless a customer provides a meter reading. This approach balances operational efficiency and customer affordability while ensuring that customer accounts are regularly reconciled to actual consumption.

Step 2: Meter is Read

Actual meter readings may be obtained from three sources:

- a meter reader;
- a customer self-read; or
- an Enbridge Gas service representative.

Regardless of the source, all meter readings are subject to the same validation processes and billing rules.

Step 3: Read is Submitted

Customer readings may be submitted at any time during the billing cycle. However, whether a customer reading appears as an "actual" read on the bill depends on the timing of the submission relative to the customer's scheduled meter reading window.

The meter reading window is the scheduled period during which meter readings are obtained for billing. This window generally occurs at the same time each month and supports consistent billing periods of approximately 24 to 35 days. The length of the window may vary depending on operational schedules, weekends and statutory holidays.

Readings obtained within the meter reading window and within the acceptable meter reading tolerance are used as actual billing reads. Readings received outside the scheduled window may not display as actual reads on the customer's bill but are still used by the billing system to improve billing accuracy, validate previous readings and support future consumption calculations. Approximately 91% of customer-submitted readings are received within the required timeframe and appear as actual meter readings on customer bills.

The scheduled reading window aligns with customer communications and meter reading operations. Customers are provided with multiple options to determine and monitor their meter reading window, including:

- meter reading reminder notifications by text or email;
- logging into their MyAccount;
- the Enbridge Gas website Submit meter reading | My gas meter | Enbridge Gas, by entering their account number and postal code; and
- contacting Enbridge Gas' direct customer service support.

Step 4: System Validation

Before any meter reads are used for billing, they undergo automated validation within SAP CIS.

The validation process is designed to ensure that meter reads are reasonable, accurate and consistent with expected customer consumption.

SAP CIS evaluates submitted readings using information such as:

- historical consumption patterns;
- seasonal usage trends;
- billing period length;
- property characteristics; and
- previous meter readings.

These controls help identify reads that may require additional review before being used for billing purposes.

Step 5: Automated or Manual Review (Implausible Reads)

A meter reading may be identified as "implausible" when it differs significantly from the level of consumption expected for a particular customer during a billing period.

SAP CIS automatically establishes customer-specific thresholds based on factors such as historical consumption and account characteristics. As a result, there is no single threshold that applies to all customers. If a submitted reading falls outside the expected range for that customer, the system generates an exception requiring further review.

For example, if a customer typically consumes approximately 100 m^3 during a billing period and a submitted reading indicates consumption of 1,000 m^3, the system will identify the reading as requiring validation before it is used for billing purposes.

This process serves as an important customer protection measure. Rather than automatically issuing a potentially incorrect bill, the reading is reviewed to determine whether it reflects actual consumption or whether further investigation is required.

During this review period, an estimated bill may be issued. Once a valid meter reading is confirmed, the account is reconciled as necessary to ensure the customer is billed based on actual consumption.

As a result, a bill may be identified as estimated even though a meter reading was received. This occurs because the reading could not be validated at the time of billing and additional review was necessary to protect the customer from potential billing inaccuracies.

Step 6: Estimated Reads

In the absence of an actual read within the reading window, an estimated read is used for billing. The absence of an actual read can be due to the bi-monthly reading schedule or an inability to read the meter (see section 4 below).

Estimation is applied in three primary scenarios:

1. <u>Scheduled Bi-Monthly Estimation:</u> The most common reason for an estimated bill is the Company's bi-monthly meter reading schedule. In months when a customer is not scheduled to receive a physical meter read, the billing system uses historical consumption information to estimate usage for the billing period. This allows customers to continue receiving regular monthly bills while avoiding the significant cost of monthly

meter reading. Once the next actual meter reading is obtained, the account is automatically reconciled to reflect actual consumption.

2. Reads Outside the Reading Window: Customer-submitted meter reads received outside the scheduled meter reading window may not be used as the actual billing read shown on the bill. However, these readings are still used to update the customer's account and improve billing accuracy.

   For example, if a customer's scheduled meter reading window is June 26 to June 30 and the customer submits a meter reading on June 20, the reading is received too early to serve as the billing read for that cycle. In this situation, the billing system uses the June 20 reading as the most recent known consumption value and estimates only the customer's consumption between June 20 and the scheduled billing date. Rather than estimating consumption for the entire period since the previous bill, only the final portion of the billing period is estimated.

   As a result, the bill may be identified as containing an estimated reading, even though a customer-provided meter reading was used to calculate a significant portion of the billed consumption. This approach improves the accuracy of the bill by reducing the number of days for which consumption must be estimated.

3. Implausible Reads: As described in Step 5: Automated or Manual Review (Implausible Reads), a meter reading may be identified as requiring further review when it falls outside the range of consumption reasonably expected for a customer based on historical usage and account characteristics.

   Where a submitted meter reading cannot be validated before the billing process is completed, an estimated read is used while the reading is reviewed and confirmed. This approach helps prevent potentially inaccurate bills from being issued to customers based on readings that require additional investigation.

   Once the review is completed and a valid meter reading is confirmed, the account is reconciled as necessary to ensure the customer is ultimately billed based on actual consumption.

3.4 Estimated Billing Volumes and Trends

Because Enbridge Gas uses a bi-monthly meter reading model, estimated billing is an expected and recurring component of normal operations.

Monthly estimated bill volumes exhibit a consistent seasonal pattern. Higher volumes typically occur during winter and early spring, while lower volumes are generally observed during late spring and summer.

This trend reflects seasonal challenges associated with obtaining meter readings, including:

- Snow and ice accumulation;
- Severe weather conditions;

- Reduced accessibility;
- Limited daylight hours; and
- Operational safety considerations.

During warmer months, challenges such as vegetation growth, high temperatures, aggressive animals, air quality and access restrictions may also affect meter reading activities.

As outlined in Figure 2 and 3, the consistency of estimated billing volumes over time demonstrates that estimation is an established component of the meter reading process rather than an indication of systemic billing issues.

Figure 2: Number of Estimate Bills per Month

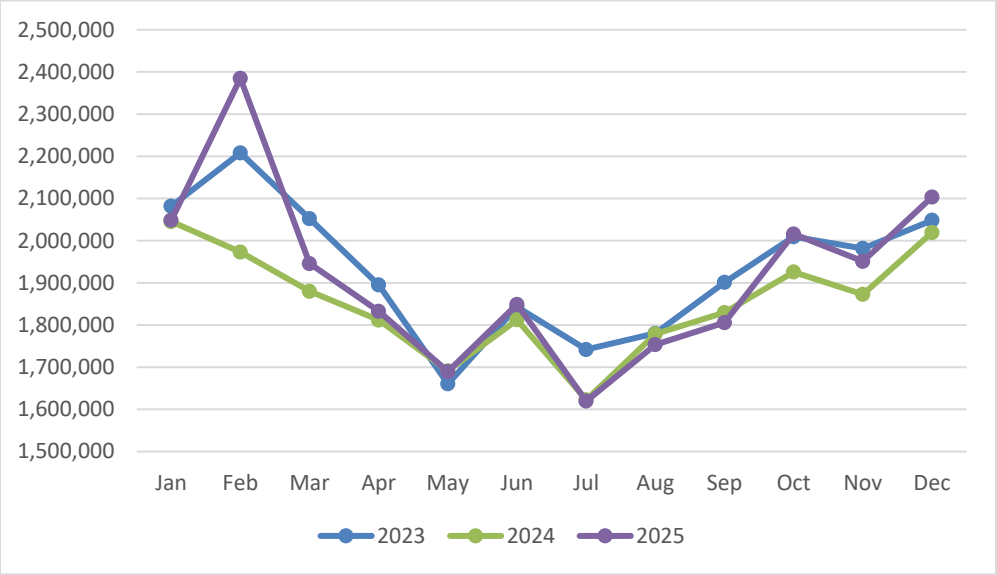
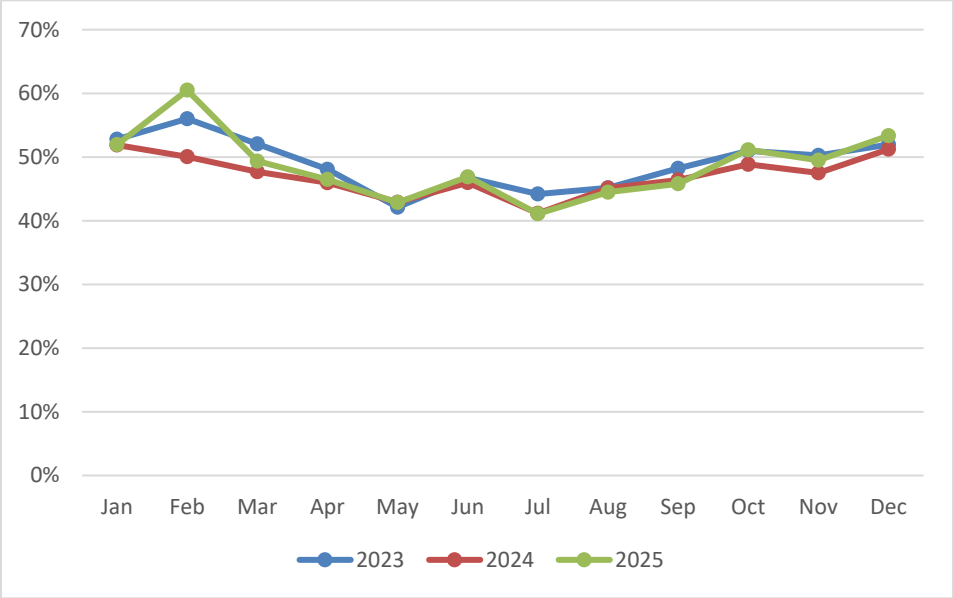


Figure 3: Percentage of Estimated Bills vs Total Customers



3.5 Controls and Ongoing Improvements

As part of its ongoing commitment to customer experience, Enbridge Gas has initiated several billing and communication enhancements designed to improve transparency, strengthen validation processes and reduce the potential for customer confusion.

These measures include:

- customer meter reading reminder programs;
- expanded self-read options;
- automated validation controls within SAP CIS;
- investigation and review of implausible readings;
- meter reading process improvements;
- ongoing monitoring of meter reading performance metrics;
- customer education initiatives; and
- continued evaluation of technologies that improve access to actual meter readings.

Collectively, these measures are intended to ensure that estimated billing is used appropriately, customer impacts are minimized and customer accounts continue to be reconciled to actual consumption in a timely and accurate manner.

3.5.1 Enhanced Review of Implausible Meter Readings

As part of its ongoing continuous improvement efforts, Enbridge Gas has identified opportunities to further strengthen the review and validation of implausible meter readings before billing adjustments are applied.

Enhancements under review or development include additional safeguards that evaluate:

- historical customer consumption patterns;
- previous actual meter readings;
- seasonal usage trends;
- account characteristics; and
- other relevant customer information.

The objective of these enhancements is to further improve confidence that unusual readings are appropriately validated before adjustments are made.

3.5.2 Reduced Automated Re-Estimation

Enhancements are being implemented to reduce circumstances where actual meter readings may be subsequently replaced through automated estimation processes.

Under the revised approach, the system will only automatically re-estimate one actual meter reading within a six-month period, providing additional protection against unnecessary replacement of actual consumption information.

For example, if an actual meter reading appears inconsistent with historical consumption patterns, the SAP CIS system may automatically replace the actual meter reading with an estimated reading. Any subsequent actual meter reading for the same account that requires further review within the next six months will be reviewed manually rather than automatically

replaced with another estimate. This increases the number of actual meter readings retained in the billing record and reduces the use of estimated consumption data.

3.5.3 Expanded Customer Communications

Enbridge Gas has enhanced customer communications to provide greater transparency and proactively engage customers when billing validation activities occur.

These enhancements include communications designed to:

- verify unusual meter readings before billing adjustments are made;
- notify customers when submitted readings appear inconsistent with expected consumption;
- alert customers when actual consumption differs significantly from historical patterns;
- provide clearer explanations when billing adjustments occur; and
- offer payment arrangements where appropriate.

For example, customers whose consumption patterns indicate a potential four-times (4x) billing adjustment, are proactively contacted, and encouraged to verify consumption and discuss potential causes prior to the adjustment being applied. Enbridge Gas has also developed targeted communications for customers with seasonal consumption profiles, such as pool heater usage, encouraging customers to contact Enbridge Gas when usage patterns change significantly, so billing records can be reviewed and validated.

Future opportunities currently being evaluated include enhancements to bill presentation, increased visibility of estimated meter readings, and additional customer education regarding the relationship between estimated billing, meter reading, and account reconciliation.

These efforts are intended to ensure customers not only receive accurate bills but also have a clear understanding of how their bills are calculated, and how actual consumption is ultimately reflected in their account.

3.5.4 Enhanced Escalation Support

The Company has also strengthened its escalation processes to ensure customers requiring additional review or support receive timely follow-up. Customer requests involving billing corrections or complex account reviews may now be escalated through enhanced support channels that provide direct follow-up and additional review where required.

3.6 Customer Billing Consideration

<u>Equal Monthly Payment Plan (EMPP) Installment Calculation</u>: The EMPP helps customers manage seasonal fluctuations in natural gas consumption by providing a consistent monthly payment amount throughout the year. Monthly installments are calculated using the previous 12 months of consumption history at the property together with anticipated future usage. Plans are reviewed semi-annually and monthly payment amounts are adjusted in the event of material changes in a customer's gas consumption or gas charges.

At the end of the plan year, the account is reconciled to actual consumption. Because customers on EMPP pay the same amount each month regardless of monthly usage, the

impacts of bi-monthly meter reading, estimated billing and subsequent reconciliations are significantly reduced. Approximately 27% of Enbridge Gas customers participate in EMPP and are generally not significantly affected by the timing of actual meter reads or consecutive estimates.

3.7 Billing Conclusion

Estimated billing is a necessary, regulated and well-established component of utility operations. It supports timely billing, protects customers from inaccurate readings and provides a cost-effective means of managing a large-scale meter reading program.

Enbridge Gas has implemented extensive controls within its meter reading and billing processes to ensure estimates are used appropriately and that customers are ultimately billed based on actual consumption.

The consistency of estimated bill volumes, the validation processes embedded within SAP CIS, and the account reconciliation process collectively demonstrate that estimated billing is a controlled and effective practice that supports both billing accuracy and customer protection.

4. Meter Reading Performance Measurement (MRPM)

4.1 Importance of Meter Reading

Obtaining actual meter reads remains an important component of the billing process. While estimated billing provides a necessary and cost-effective mechanism to support regular customer billing, actual meter reads enable customer accounts to be reconciled to measured consumption and provide ongoing validation of estimated usage.

Enbridge Gas' bi-monthly meter reading model balances billing accuracy, operational efficiency and affordability for customers while supporting the timely issuance of bills across a service territory consisting of approximately 4 million customer accounts.

The OEB's MRPM is intended to assess a utility's ability to obtain meter readings on a regular basis. Specifically, the metric measures the percentage of meters that have not received an actual meter read for four consecutive months or longer. The performance target established by the OEB is 0.5%.

Although Enbridge Gas has faced challenges achieving this target in recent years, the Company's performance must be considered in the context of significant and persistent access challenges that affect meter reading activities across the service territory. Despite these challenges, Enbridge Gas continues to maintain a robust meter reading program and has implemented numerous initiatives to improve performance and reduce consecutive estimates.

4.2 MRPM Results

While annual MRPM performance remains above the GDAR target, Table 1 shows that results have improved by more than 75% since 2022. This demonstrates the effectiveness of the

mitigation activities Enbridge Gas has implemented. Performance has improved significantly from the elevated levels experienced during and immediately following the pandemic period.

In the OEB's 2024 Rebasing Phase 2, Decision and Order, the OEB noted:

> In addition to recognizing that Enbridge Gas has improved its performance against this metric, the OEB also recognizes that Enbridge Gas still has work to do to achieve compliance with the metric target and may not achieve compliance in 2025.[3]

Since the 2024 Rebasing Phase 2 proceeding, Enbridge Gas has continued to implement mitigation measures and invest in initiatives intended to improve meter reading performance. However, despite these efforts, MRPM performance has largely plateaued since 2024, with results at or around 1%.

The remaining population of consecutive estimate accounts is increasingly comprised of meters affected by customer access restrictions and other factors outside of Enbridge Gas' direct control. As a result, the Company believes that further operational mitigation efforts are unlikely to improve the MRPM metric relative to those achieved since 2022.

Table 1
Annual MRPM Results 2019 - 2025

Target (%)	2019	2020	2021	2022	2023	2024	2025
0.5	0.7	4.4	5.0	4.1	1.3	0.9	1.0

The MRPM metric is a cumulative calculation because performance is measured and reported monthly, with each month's results contributing to the annual result. In addition, accounts that remain on the consecutive estimates list continue to be reflected in the metric each month until an actual meter read is obtained. As a result, a single meter may contribute to the annual metric multiple times across consecutive reporting periods, rather than being counted only once.

Consequently, performance challenges experienced during winter months can have a lasting impact on annual results even after access conditions improve. For example, if severe weather prevents a meter from being read in January, that account may remain on the consecutive estimates list and continue to affect the metric each month until an actual read is obtained. In northern Ontario, where winter conditions can persist into the spring, a single account could contribute to the metric for several consecutive months before meter reading access is restored.

Following the weather-related impacts experienced during the first quarter of 2026, as shown in Table 2, Enbridge Gas reduced the number of accounts on the consecutive estimate list by approximately 75% between March and May. The Company anticipates continued improvement throughout the remainder of the year and currently expects year-end performance to improve significantly from first-quarter levels.

[3] EB-2024-0111, Decision and Order, p.12.

Table 2
2026 MRPM Results by Month

Target (%)	Jan	Feb	Mar	Apr	May	Jun	Jul	YTD
0.5	1.4	2.9	3.6	2.2	0.8	0.5	0.5	1.7

However, based on MRPM results from January to March 2026, Enbridge Gas has already exceeded the annual volume of consecutive estimates that would be consistent with achieving the 0.5% MRPM target. To meet the metric, the allowable number of missed meter reads is approximately 240,000 annually. Because the annual MRPM result is derived from the accumulation of monthly results throughout the year, approximately 314,000 consecutive estimates were recorded during the winter months alone, exceeding the annual volume associated with achieving the target. Although the number of accounts on the consecutive estimates list has declined significantly and is expected to continue improving, the consecutive estimates recorded during the first quarter of 2026 remain part of the annual calculation and cannot be offset by stronger performance later in the year.

4.3 Access Challenges and Consecutive Estimates

The majority of customers on the consecutive estimate list are not the result of operational scheduling issues but rather circumstances that prevent meter readers from safely or reasonably accessing the meter. Access-related issues have become an increasingly significant contributor to consecutive estimates in recent years, as outlined in Table 3.

Table 3
Percentage of consecutive estimates due to access issues

2022	32%
2023	49%
2024	62%
2025	53%
2026 YTD[4]	35%

These results demonstrate that access limitations continue to be one of the most significant obstacles to obtaining actual meter readings and achieving the MRPM target.

4.4 Meter Reading Challenges

4.4.1 Customer Access Challenges

Since the pandemic in 2020, Enbridge Gas observed several changes in customer behaviour and property accessibility that have increased the difficulty of obtaining meter readings. These changes include:

[4] Weather was the largest contributor to consecutive estimates during the first quarter of 2026. Based on current trends, Enbridge Gas anticipates the 2026 year-end results to align more closely with 2025 performance levels.

- increased numbers of customers working from home leading to denied access to meter;
- greater customer concern regarding crime, trespassing and personal security;
- expanded use of residential surveillance systems;
- increased skepticism toward individuals attending a property, partly driven by fraud schemes and impersonation attempts affecting the utility sector;
- more locked gates and restricted property access;
- increased numbers of inside meter locations;
- obstructed meters resulting from landscaping, construction projects and vegetation growth; and
- Vacant properties and seasonal residences, where obtaining an actual meter read may depend on subsequent customer contact and access availability.

Collectively, these factors have reduced the ability of meter readers to safely access properties and obtain actual meter readings.

In 2025, access alone accounted for 53% of all missed consecutive reads, if inaccessible meters are removed, Enbridge Gas' MRPM metric would have been 0.48%.

4.4.2 Weather and Environmental Factors

Weather continues to be one of the most significant external factors affecting meter reading performance.

Winter weather presents particular challenges for meter reading activities. Reduced daylight hours, snow, ice, freezing rain and extreme cold can limit the time available to safely complete scheduled routes and create conditions where access to meters cannot be safely or reasonably obtained during the normal billing cycle. These constraints affect route productivity and meter accessibility regardless of the number of meter readers deployed.

Seasonal impacts continue throughout the year. Spring flooding and road closures may restrict access to certain areas, while summer heat events can present health and safety risks requiring modified work practices or temporary interruptions to field activities.

In 2026, Ontario experienced significant winter weather conditions, including snowfall levels substantially above seasonal norms in several regions. These conditions contributed to higher numbers of customers appearing on the consecutive estimate list during February and March as meter readers encountered difficulties accessing meters due to snow accumulation, frozen gates and other access constraints.

In northern Ontario, additional spring flooding events affected access to certain communities and further complicated meter reading activities.

4.4.3 Animal Safety Considerations

Dogs continue to present an access and safety challenge for meter reading personnel. Although meter readers receive animal awareness training, meter readings cannot be safely completed when unattended animals prevent access to the meter. In these circumstances, the safety of employees and contractors must remain the primary consideration.

4.5 Mitigation Efforts

Enbridge Gas recognizes the importance of obtaining actual meter reads and continues to significantly invest in programs and technologies designed to improve meter reading performance and reduce consecutive estimates while maintaining reasonable costs for customers.

Key improvement initiatives include:

1. Customer Outreach and Engagement:
   - Proactive outreach to customers on the consecutive estimate list through automated calling campaigns, email notifications and written correspondence.
   - Customer education initiatives designed to encourage self-read submissions.
   - Enhanced awareness of meter reading options through My Account, paper bill messaging and other communication channels.

2. Enhanced Field Activities:
   - Increased focus by meter reading vendors on accounts approaching consecutive estimate thresholds.
   - Expanded use of appointment scheduling and customer contact attempts.
   - Cross-training field personnel to obtain reads during other field visits whenever possible.
   - Increased focus on difficult-to-access accounts.

3. Remote Meter Reading Technology:
   Enbridge Gas continues to expand the deployment of remotely readable meter technologies, including Automated Meter Reading (AMR), Encoder Receiver Transmitter (ERT) and related technologies. These technologies enable meter consumption data to be collected remotely, reducing the need for physical meter access and helping mitigate customer access and weather-related reading challenges.

   AMR and ERT technologies generally allow meter readings to be collected remotely on a periodic basis, reducing reliance on manual meter reading activities. More advanced technologies, such as Advanced Metering Infrastructure (AMI), provide enhanced communications capabilities that support more frequent and automated collection of meter consumption data, as well as additional operational functionality.

   Since January 2025, more than 148,000 AMR meters have been installed across the service territory. Deployment has been prioritized in areas with known access challenges, including northern communities that regularly experience severe winter weather and significant snowfall accumulation.

Additional initiatives underway in 2026 include:

- continued deployment of AMR and ERT technology in northern and rural communities, particularly in areas where winter conditions may increase the likelihood of accessing meters;
- leveraging existing meter exchange programs to prioritize customers with known meter access challenges and facilitate AMR installations where opportunities are identified; and

- continued efforts to obtain customer-supplied meter readings for accounts on the consecutive estimate list.

4.6 Balancing Accuracy, Reliability and Affordability

Enbridge Gas recognizes the importance of actual meter readings in supporting billing accuracy and continues to pursue initiatives that improve meter reading performance. While the Company has achieved improvements in recent years, its experience, mitigation efforts, and regulatory evidence demonstrate that the primary challenge associated with achieving further improvements in MRPM performance is not the frequency of meter reading activity, but rather the increasing prevalence of meter access constraints and other factors outside the Company's direct control.

The current bi-monthly meter reading program costs approximately $26.9 million annually. While increasing meter reading frequency may create additional opportunities to attempt meter reads, it would not eliminate many of the underlying causes of consecutive estimates, including inaccessible meters, customer access restrictions, vacant or seasonal properties, severe weather conditions and other operational barriers. As a result, significant additional investment in traditional meter reading activities are not expected to produce meaningful improvements in MRPM performance and would ultimately increase costs for ratepayers. The GDAR also recognizes that monthly meter reads are cost prohibitive.[5]

Importantly, operating experience does not indicate that estimated billing is creating widespread customer impacts. Estimated bills remain an established component of utility billing operations and are supported by estimation methodologies, billing validation controls, customer self-read options, and account reconciliation processes designed to ensure customers are ultimately billed based on actual consumption. While the Company recognizes that individual customer concerns may arise and treats those matters seriously, complaint volumes associated with estimated billing remain very low relative to approximately four million customer accounts and the tens of millions of bills issued annually. Complaint volumes have also declined in recent years, suggesting that estimated billing is not driving widespread customer dissatisfaction or systemic customer experience concerns.

Recognizing that the primary challenge relates to meter accessibility rather than billing accuracy, Enbridge Gas is increasingly focused on solutions that address the root cause of the issue. The Company continues to expand the deployment of AMR and ERT technologies, which reduce reliance on physical meter access and improve the ability to obtain meter readings in locations where traditional meter reading activities are more challenging. Enbridge Gas has also continued to evaluate AMI technologies, which represent the most comprehensive long-term solution by enabling remote and automated meter reading capabilities. More than 148,000 AMR meters have been installed since January 2025, with deployment prioritized in areas experiencing known accessibility challenges.

However, broader deployment of remote meter reading technologies requires customer engagement, meter replacement opportunities, field resources, capital investment and several years for implementation. Even where these technologies are pursued aggressively, deployment would occur gradually across a large and geographically diverse service territory.

[5] GDAR, Section 7.3.3.

As a result, remote meter reading technologies represent a sustainable long-term solution to meter accessibility challenges, but they do not provide an immediate remedy to the MRPM metric.

As discussed in section 3 of this report, estimated billing and bi-monthly meter reading have long been established utility practices that allow utilities to provide accurate and timely billing in a cost-effective manner. When combined with customer self-read programs, billing validation controls, account reconciliation processes and ongoing investments in remote meter reading technology, the current approach delivers an appropriate balance between service quality, billing accuracy and affordability for customers.

4.7 MRPM Conclusion

Meter reading remains a critical component of the billing process and Enbridge Gas continues to make significant efforts to improve meter reading performance. Since 2022, the Company has achieved a more than 75% improvement in MRPM results through a combination of targeted mitigation measures, customer engagement initiatives, enhanced field activities and investments in remote meter reading technologies. These efforts have been increasingly focused on the underlying drivers of consecutive estimates, including customer access challenges, weather-related impacts and other high-risk accounts.

The evidence demonstrates that these initiatives have been effective in materially reducing consecutive estimates. However, the remaining population of consecutive estimate accounts is increasingly concentrated among locations affected by persistent access constraints, severe weather conditions and other circumstances that limit Enbridge Gas' ability to obtain actual meter readings. As a result, further improvements are expected to become increasingly challenging, as the remaining opportunities are tied to longer-term technology investments and deployment strategies rather than traditional operational mitigation activities. The Company may also consider customer enforcement measures, such as charging for inaccessible meters and disconnection of repeat offenders.

Enbridge Gas remains committed to improving meter reading performance and will continue to evaluate opportunities to further reduce consecutive estimates. The Company's experience since 2022 suggests that a significant portion of the remaining MRPM population is driven by customer access and other external factors.

Despite ongoing intensive and targeted efforts, Enbridge Gas remains unable to meet the MRPM. Enbridge Gas will address this further with the OEB, likely through a request that the OEB Chief Executive Officer convene a review of GDAR to consider whether and how the MRPM target should be re-set. Alternately, Enbridge Gas may file an application or request an exemption from the MRPM target for 2026 and beyond as the Company continues with its implementation of AMR and ERT technologies and its AMI implementation plan.

5. Customer Complaint

5.1 Customer Complaint Trends

While the number of active Enbridge Gas customers remained relatively stable over time, the number of complaints and escalations associated with estimated billing has declined significantly. This trend suggests that the controls, validation processes and customer support mechanisms currently in place are generally effective in supporting a positive customer experience.

Enbridge Gas' complaint data demonstrates that estimated billing is not a significant driver of customer complaints. While estimated billing continues to be a normal and necessary component of the billing process, complaints related to estimated bills and consecutive estimated bills have declined materially since 2023, as shown in Table 4.

Table 4
Customer Complaints to Enbridge Gas Ombuds 2023-2026 YTD

Complaints to Ombuds*	Number of Bills Generated	Consecutive Estimates	Estimates	High Bill-Actual**	Total
2023	46,842,400	203	240	650	1093
2024	46,773,829	180	76	179	435
2025	46,943,501	91	81	140	312
June 2026 YTD	28,450,340	41	18	45	104
Complaints through OEB to Ombuds	Number of Bills Generated	Consecutive Estimates	Estimates	High Bill-Actual**	Total
2023	46,842,400	45	46	145	236
2024	46,773,829	42	14	20	76
2025	46,943,501	18	14	25	57
June 2026 YTD	28,450,340	14	3	5	22

*includes Complaints through OEB to Ombuds
**may include other items unrelated to estimated bills

It is important to distinguish between the complaint categories presented in Table 4:

- Consecutive Estimates: refers to complaints where customers received multiple estimated bills in succession. This category represents the scenario most likely to create customer dissatisfaction because billing variances may accumulate over a longer period before an actual meter read is obtained.
- Estimates: refers to complaints related to estimated billing generally, including situations involving a single estimated bill.
- High Bill – Actual: While a customer could have a complaint about a high bill after an estimated month, this category also includes additional matters unrelated to estimated billing and can arise from a variety of factors including seasonal consumption, weather impacts, changes in customer usage, catch-up billing following an actual meter read,

pricing impacts, or other billing-related inquiries. Accordingly, the High Bill – Actual category should not be viewed as a direct measure of dissatisfaction with estimated billing practices.

Both estimate-related categories show substantial improvement over the reporting period. Complaints to the Ombuds related to Consecutive Estimates declined from 203 complaints in 2023 to 91 complaints in 2025 and 41 complaints through June 2026 YTD, representing an approximately 80% reduction from 2023 levels. Complaints related to Estimates declined from 240 complaints in 2023 to 81 complaints in 2025 and 18 complaints through June 2026 YTD, representing an approximately 93% reduction from 2023 levels.

A similar trend is evident in complaints escalated through the OEB to the Ombuds, where complaints related to Consecutive Estimates decreased from 45 in 2023 to 14 through June 2026 YTD, while complaints related to Estimates decreased from 46 to 3 over the same period.

These reductions occurred while estimated billing continued to be used as part of normal billing operations. If estimated bills or consecutive estimated bills were a significant source of customer dissatisfaction, complaint volumes would be expected to remain stable or increase. Instead, complaint volumes have continued to decline materially, suggesting that estimated billing is not resulting in widespread customer concern for the vast majority of customers.

The majority of customer inquiries and complaints related to estimated billing are resolved through explanation of the bi-monthly meter reading schedule, the reason an actual meter read was not obtained, and how any required billing adjustment is calculated and applied across the period between actual meter reads. In many instances, providing this information addresses the customer's concerns and no further action is required.

A smaller number of complaints involve situations where an actual meter reading was not obtained for an extended period, resulting in a larger billing adjustment when a subsequent actual meter reading is acquired. In these cases, customers typically do not dispute the accuracy of the meter reading or the associated consumption but may express concerns regarding the timing and magnitude of the resulting adjustment. To mitigate customer impacts, Enbridge Gas works directly with affected customers to establish appropriate payment arrangements and, where eligible, provides information regarding available financial assistance programs such as the Low-income Energy Assistance Program (LEAP). These measures help customers manage the financial impact of billing adjustments while ensuring charges accurately reflect actual gas consumption.

When viewed in the context of approximately four million customer accounts and approximately 48 million bills issued annually, complaint volumes related to estimated bills and consecutive estimates remain low. In 2025, Enbridge Gas received 172 Ombuds complaints related to estimated billing or consecutive estimates (91 and 81 complaints, respectively), representing approximately 0.0043% of customer accounts or roughly 1 complaint for every 279,000 bills issued. This suggests that estimated billing is not a significant driver of customer complaints overall.

5.2 Customer Complaint Conclusion

Customer complaint data demonstrates that estimated billing is not a significant source of customer dissatisfaction and that complaint volumes related to estimated billing and consecutive estimates have declined substantially in recent years. Estimated billing continues to support a positive customer experience for the vast majority of customers, while ongoing improvements in meter reading performance, validation controls and customer communications continue to strengthen the overall customer experience.

Where isolated concerns arise, Enbridge Gas uses those opportunities to identify enhancements to its processes, communications and controls. This commitment to continuous improvement helps ensure that estimated billing remains a reliable, transparent and customer-focused component of the Company's overall billing framework.

Integrated Resource Planning (IRP)

2025 Annual Report

May 29, 2026

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Section 1 – Introduction

This Enbridge Gas Inc. ("Enbridge Gas" or the "Company") 2025 IRP Annual Report ("Report") encompasses the period from January 1, 2025, through to December 31, 2025.

This Report complies and is consistent with the Ontario Energy Board ("OEB") Integrated Resource Planning ("IRP") Decision and Order dated July 22, 2021 ("IRP Decision") establishing an IRP Framework for Enbridge Gas ("IRP Framework"), where the OEB stated:[1]

> "Enbridge Gas shall file an annual IRP report with the OEB as part of its annual Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, the proceeding in which it may seek disposition of balances in the IRP Costs deferral accounts.
>
> The OEB does not intend to approve the annual IRP report, but it could impact the OEB's findings on the disposition of amounts in the IRP Costs deferral accounts or inform future proceedings.
>
> The annual IRP report and the report from the IRP Technical Working Group ("TWG") are to be filed for information regardless of whether Enbridge Gas is seeking approval to clear any balances in the IRP Costs deferral accounts.
>
> The annual IRP report should include the following information:
>
> - A summary of IRP stakeholdering activities from the past year
> - A summary of IRP engagement or consultation activities with Indigenous peoples
> - Updates on IRP pilot projects underway
> - Updates on incorporating IRP into asset management planning
> - Updates on status of potential IRP Plans
> - Updates on status of approved IRP Plans, including details of adjustments made by Enbridge Gas
> - Annual and cumulative summaries of actual peak demand reductions/energy savings generated by each IRP Plan to-date, including comparisons to the initial forecast reduction/energy savings and the actual amount of expenditure on each IRP Plan to-date
> - The most recent results of Enbridge Gas's IRP Assessment Process for system needs, including reporting on those system needs where a negative binary screening or technical/economic evaluation resulted in no further assessment of Integrated Resource Plan Alternatives ("IRPAs")
> - A summary of best available information on demand-side IRPAs, including types of IRPAs, estimates of cost, peak demand savings, status in Ontario, potential role and relevance to Enbridge Gas's system, and learnings from pilot projects and other jurisdictions
> - Efforts taken to explore the use of interruptible rates for meeting system needs, including how customers have been provided the opportunity to consider this option
> - Any other IRP-related matters established by the OEB."

[1] EB-2020-0091, OEB Decision and Order, Appendix A, p. 22.

Section 2 – IRP Integration Update

Enbridge Gas has integrated IRP cross-functionally by embedding resources within its Asset Management ("AM"), Distribution Optimization Engineering ("DOE"), financial analysis, Customer Policy and Strategy ("CP&S"), regulatory, municipal and stakeholder engagement departments, as well as within the IRP team. These resources directly support the implementation of the IRP Decision, which includes:

- Binary screening and technical evaluations of facility projects in the Asset Management Plan ("AMP") and optimization of the AMP to include IRP Plans;
- Economic analysis of those projects with a technically feasible IRP alternative ("IRPA");
- Support for the technical and economic evaluation of enhanced targeted energy efficiency ("ETEE") and demand response ("DR") IRPAs, as well as for the design, delivery, and ongoing monitoring and evaluation of OEB-approved IRP Plans, including IRP Pilot Projects;
- Development and implementation of regional, geo-targeted and pilot-specific IRP stakeholder engagement activities, as well as an increased level of direct engagement with a number of key IRP stakeholders; and,
- Regulatory support for IRP Plans and for Leave to Construct ("LTC") proceedings.

Enbridge Gas built upon the progress made in 2024 by continuing to enhance cross-functional processes, including the following:

- **Refinement of Technical and Economic Evaluation Process for IRPAs**
  Enbridge Gas continued to develop/refine the technical and economic evaluation process in 2025, including automating data population of the technical evaluation form, evolving the documented list of key inputs and assumptions to be used in the DCF+ model and developing templates to support the economic assessments, which will help to streamline the evaluation process. This included developing templates to be used when evaluating an IRPA's economic feasibility and to improve the process of gathering, consolidating and documenting inputs from various internal departments to support the assessments. This contributed to the streamlined technical evaluation of 77 investments and supported the subsequent economic evaluation of a total of 20 investments in the Enbridge Gas AMP Addendum 2026 filed on October 30, 2025. Further details on the IRP Evaluation are outlined in Section 3.

- **Development/Refinement of ETEE Model**[2]
  Enbridge Gas refined the ETEE model that supports assessment of savings potential and costs associated with the implementation of an ETEE program. This model scales down an Ontario-wide demand-side management ("DSM") forecast to estimate DSM participation in a specific geographic region by considering the region's customer base, prior participation in DSM programs and average consumption. The model subsequently estimates the increased participation, savings and costs associated with an ETEE program in that region, incremental to the regional estimated DSM participation. This incremental ETEE data is incorporated into the DCF+ model as an input. The ETEE model was used to support the economic evaluation of the 16 investments passing the technical evaluation and for which ETEE implementation had the potential to impact project scope.

- **Implementation of IRP Pilot Projects**
  In 2025 Enbridge Gas completed the hiring for the incremental resources required to lead the design, execution and evaluation of the Southern Lake Huron Pilot Project approved by the OEB in March 2025 (EB-2022-0335). A dedicated team of four was established within the IRP department, and incremental

[2] At TWG Meeting #56 on June 25, 2025, Enbridge Gas provided a walkthrough of the ETEE model, including the key assumptions considered in the model (link – slide 30). Enbridge Gas also provided a follow-up in TWG Meeting #59 to confirm the consistency of the forecasting approach, basis of the peak to annual savings factor, and how diversification of load is considered (link).

resources were embedded within the DOE and Marketing and Customer Insights departments to execute on the Pilot Project requirements. Additionally, a resource was hired to lead the requirements for the System Pruning Pilot Project which has proceeded in accordance with the Rebasing Phase 2 Settlement Agreement (EB-2024-0111). This resource works cross-functionally across departments to execute on the requirements for the System Pruning Pilot.

Section 3 – IRPA Evaluation and AMP Update

The AMP Addendum 2026 from 2025 to 2034 was filed on October 30, 2025.[3]

Investment project scopes in the capital plan are determined through Enbridge Gas's system analysis and optimization of all traditional facility alternatives to meet the forecasted system need in the most cost-effective manner to ensure the safety, reliability and affordability of the Company's operations.

As described in the AMP, Enbridge Gas follows the Asset Investment Planning & Management ("AIPM") process to initiate the IRP assessment process of investments within the capital plan. The status of the IRP assessment for investments is provided in Appendix B of the AMP.

The IRP assessment process is detailed below:

1. **Initial Screening**
   Non-gas-carrying asset investments are screened out from the list of 2025-2034 AMP investments that would proceed to the binary screening phase.

2. **Binary Screening**
   Investments are screened out as per Section 5.2 of the IRP Framework. Investments under the Asset Class of Customer Connections are also screened out at Binary Screening stage.

3. **Technical Screening & Evaluation**
   Investments undergo an initial technical screening to determine whether a detailed technical evaluation is required.

   Investments that have passed technical screening will be evaluated for whether an investment could have a technically feasible IRPA(s). To assess the technical potential of IRPAs to meet a system need, Enbridge Gas calculates the required demand reduction and/or incremental supply by determining the difference between the required and current system capacity. Where IRPAs have the technical potential to defer, reduce or offset the required capacity through either a reduction in the design hour/day demand or incremental supply within the required timeframe, and without compromising the safety and reliability of the system, these investments pass the technical evaluation.

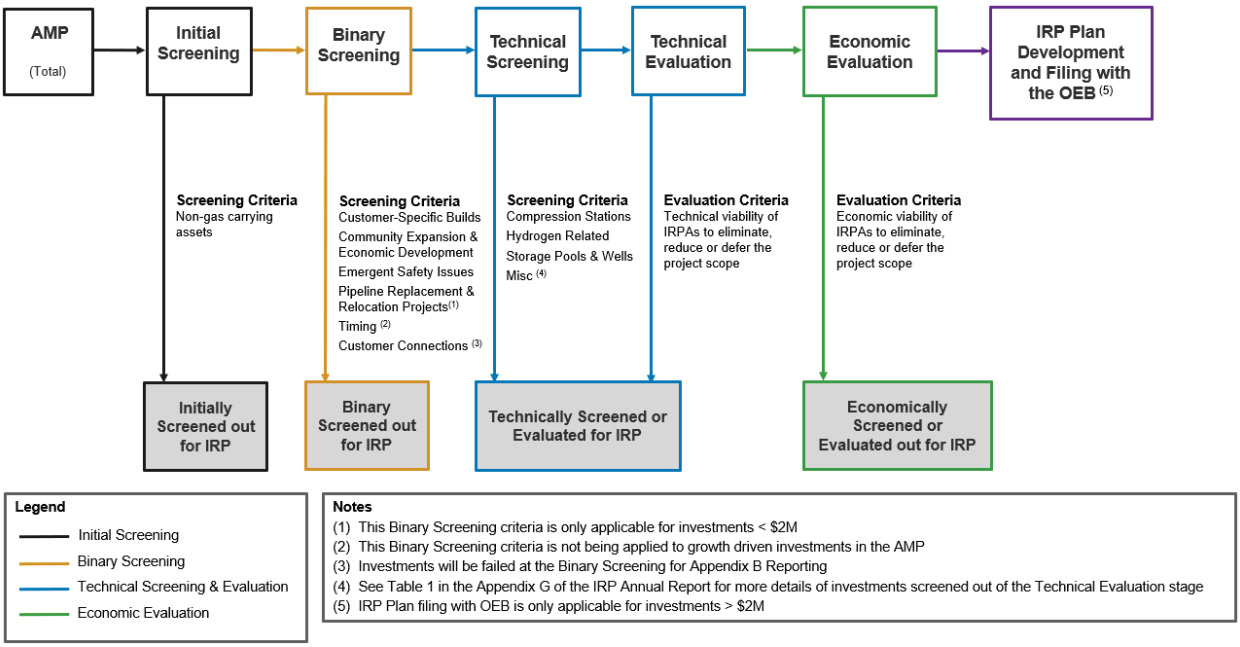
4. **Economic Evaluation**
   Investments that have passed technical evaluation are economically evaluated using the DCF+ test. The DCF+ test compares each technically feasible IRPA and the identified baseline facility project to a 'do nothing' scenario. The DCF+ results for the IRPAs and the baseline facility alternative are then compared to one another to determine the optimal alternative or combination of alternatives to meet the system need. If it is determined that the most optimal option includes one or more IRPAs, an IRP Plan will be developed where applicable.

   See Section 9 for updates on the DCF+ test used for economic evaluations. See Section 6 for Non–Pilot IRP Plan Updates.

[3] EB-2020-0091, Enbridge Gas AMP Addendum 2026, October 30, 2025 (link)

Further details on the IRP assessment screening and evaluation process can be found in Appendix F. The current IRP screening and evaluation process is outlined in Figure 3.1.

Figure 3.1 – IRP Assessment Process



2025 IRP Assessment Update

Enbridge Gas continually evolves its system models to improve the modelling methodology. This includes gathering and considering newly available and relevant information, data, and insights. This ensures that Enbridge Gas' system models reflect the best available information regarding Ontario's projected future demand for natural gas.

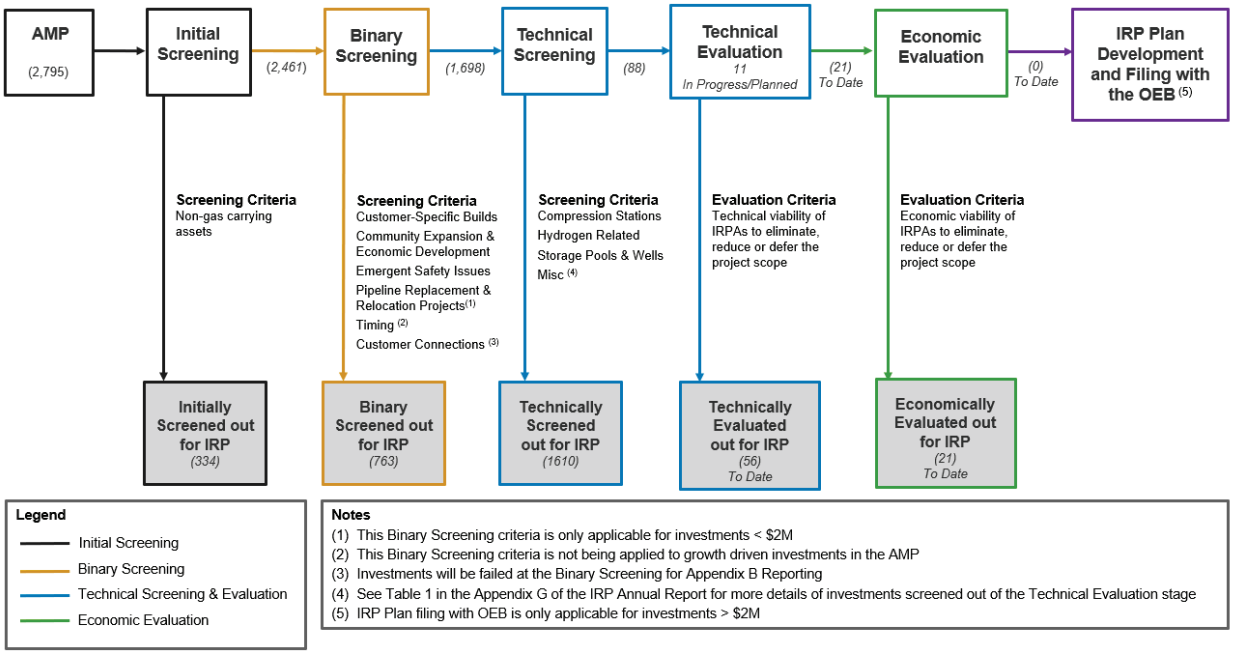
The 10-year forecast for the 2025-2034 AMP Appendix B incorporates the following key factors:

1. System Reinforcement Plan ("SRP") Update
    - A refresh to the SRP was completed in Q1 2025. The process included an update to the customer connection forecast, updates to customer load, new connections and new proposals with actuals, and updated customer load values for new customers.

2. Energy Policy and Market ("EP&M") Adjustments
    - As summarized in Enbridge Gas's 2024 Rebasing Application (EB-2022-0200), Enbridge Gas introduced adjustments to its demand forecasts (for existing customers, customer additions and average annual use) and design elements (design hour and design day) to account for potential changes to natural gas demand in the 10-year forecast period. These demand forecasts and design elements are routinely used in various business planning processes such as the SRP, AMP, Gas Supply Plan, etc. The adjustments are based on external factors related to policy signals (federal/provincial/municipal), market trends (builder and consumer preferences) and stakeholder feedback (customer, municipal and Indigenous). Annually Enbridge Gas will review and update, as needed, the adjustments to account for new and/or updated external signals and/or development.

A summary of the number of investments at each stage of the IRP screening and evaluation process is outlined in Figure 3.2

Figure 3.2 – Overview of IRP Evaluation Results – 2025-2034 AMP



In 2025, Enbridge Gas completed the IRP screening and evaluation of all investments in the AMP that had a defined scope. A summary of the IRP screening and evaluation process on the 2,795 investments in the AMP Addendum 2026 is provided below:

- 334 investments were screened out using initial screening.
- 763 investments were screened out using binary screening.
- 1610 investments were screened out using technical screening.
- 77 investments underwent a complete technical evaluation, including all investments under the Asset Class of Growth and Distribution Pipe.
    - 56 investments did not pass technical evaluation.
    - 21 investments passed technical evaluation.
- 11 investments remain to undergo technical evaluation or have the evaluation currently in progress as of the time of filing.
    - 5 investments under the Asset Class of Transmission Pipe & Underground Storage have an IRP evaluation status of “In-Progress”. Due to the broad scope and scale of these investments, supply-side alternatives have a significant potential for technical feasibility but are inherently responsive to market conditions, and therefore, will be assessed closer to the forecasted in-service date. The assessment of demand-side alternatives is currently in progress. The corresponding IRP evaluation and results will be included in either an LTC application or IRP Plan.
    - 3 investments in the EDIMP have a technical evaluation status of “In Progress” and are awaiting further integrity assessment to confirm project scope and timing. The IRP evaluation will proceed once project scope and timing has been established. Based on the status of the integrity assessments, Enbridge Gas anticipates IRP evaluation will be conducted later in 2026.
    - 3 Investments under the Asset Class of Growth have an IRP evaluation stage of “In Progress” and are currently being rescoped. IRP evaluation will resume once the revised scope is confirmed.

- 21 investments passed the technical evaluation, where 20 have undergone an economic evaluation. There is 1 investment under the Asset Class of Growth for the IRP pilot project that is not applicable for economic evaluation.
    - 20 investments failed economic evaluation for an IRPA to be an optimal alternative.
        - 4 investments under the Asset Class of Growth with an in-service date ("ISD") of 2025 or 2026. The facility alternative has been identified as the optimal solution and will be implemented accordingly.
        - 10 investments under the Asset Class of Growth with an ISD of 2028 and beyond. The facility alternative has been identified as the optimal solution, and the project scope will be monitored. Annual review of the facility and IRP alternatives will be conducted to confirm the optimal solution prior to alternative implementation. Contract customer engagement within the area of benefit, where applicable, will be conducted closer to the forecasted ISD.
        - 6 investments under the Asset Class of Distribution Pipe with an ISD of 2028 and beyond. The facility alternative has been identified as the optimal solution, and the project scope will be monitored. Annual review of the facility and IRP alternatives will be conducted to confirm the optimal solution prior to alternative implementation. Contract customer engagement within the area of benefit, where applicable, will be conducted closer to the forecasted ISD.

Enbridge Gas has provided a high-level breakdown of the investments screened or evaluated out of the AMP Addendum 2026 for IRP including the associated 2025-2034 Forecast in Appendix C.

Section 4 – IRP Pilot Project Update

Southern Lake Huron Pilot Project

On March 27, 2025, the OEB issued its Decision and Order approving the Southern Lake Huron ("SLH") Pilot Project scope, contents, costs, and proposed accounting treatment of costs as filed by Enbridge Gas, subject to the various changes as detailed in the Decision and Order ("Pilot Decision").[4] The key changes in the Pilot Decision related to the delivery of the SLH Pilot Project are to:

- Reject funding for advanced gas technologies, namely hybrid heating, natural gas heat pumps and natural gas thermal energy storage. Recognizing that thermal energy storage can utilize electricity, the pilot funding was approved for thermal energy storage, on the condition that it utilizes electricity and does not require or incent the customer to install, modify, or upgrade gas-fired space heating or water heating equipment.
- Reallocate the funding for the denied advanced gas technologies (hybrid heating and gas heat pumps) to the budget for Limited Electrification Measures. Enbridge Gas was directed to increase the number of participants for its electrification offerings.
- Collect and include in the pilot's Evaluation, Measurement & Verification ("EM&V") plans the weather normalized gas consumption data from the estimated 320 customers that have Encoder Receiver Transmitter ("ERT") technology and cold climate air source heat pumps ("ccASHP") and compare this to their weather normalized gas consumption before the heat pumps were installed, to the extent that the data is available. Enbridge Gas was also directed to include the weather normalized consumption data from a representative sample of those customers in the SLH Pilot Project study area with the ERT technology who have not installed heat pumps.

On the same date, the OEB issued a Notice of Review on the OEB's own motion (EB-2025-0124), initiating a proceeding to review the Pilot Decision in respect of three questions relating to the findings on electricity IRPAs and the exclusion of funding for gas-fired technologies.

On April 15, 2025, Enbridge Gas filed a letter to the OEB to request clarification and expansion of the scope of the pending Review Motion. This letter outlined that Enbridge Gas does not believe that it is appropriate to proceed with the aspects of the proposal that are subject to the OEB's Review Motion. The letter requested that the OEB indicate that the following aspects of the Pilot Decision are stayed or suspended pending the outcome of the Review Motion: the direction to reallocate the IRP Pilot budget related to natural gas-based technologies to the expansion of electric solutions, any aspect of the Pilot Decision that purports to amend the IRP Framework and/or DSM Framework, the direction to analyze and develop potential additional IRP pilot projects, and the direction to consult with the IRP TWG on such potential opportunities.

On April 22, 2025, in response to a letter submitted by Pollution Probe, Enbridge Gas filed a letter confirming the Company was proceeding with the implementation of the IRP Pilot Project including the electrification measures at the limited participation levels proposed by Enbridge Gas in the Pilot Application. The stay request that specifically relates to the IRP Pilot Project is only in relation to the direction in the Pilot Decision to redirect funds relating to advanced natural gas technologies to electrification IRPAs as that item is clearly at issue in the Review Motion. Furthermore, Enbridge Gas confirmed that it will not include any advanced natural gas technology IRPAs (including thermal energy storage) without further direction from the OEB.

On July 4, 2025, Enbridge Gas filed its 2024 IRP Annual Report.[5] Within it, Enbridge Gas fulfilled the direction in the Pilot Decision to include a detailed Pilot project plan. The SLH Pilot Program Design and Implementation Plan ("SLH

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[4] As per the OEB Decision on the IRP Pilot Project, Enbridge Gas engaged with the IRP Technical Working Group ("TWG") to file an updated detailed project plan and estimated unit rate, and bill impact associated with the forecast 2025 pilot costs for typical customers by rate class in the 2024 IRP Annual Report. See EB-2025-0155, 2024 Utility Earnings and Disposition of Deferral & Variance Account, Exhibit G, Tab 2, Schedule 1

[5] EB-2025-0064 Exhibit I.1.13-ED-4 Attachment 1

project plan") included all approved offers (ETEE offers, Limited Electrification offer, Demand Response offer) but not the Advanced Gas Technology offer at issue in the Review Motion. As directed, Enbridge Gas engaged with the IRP TWG to develop the SLH project plan and update it on a rolling basis.

On December 11, 2025, the OEB issued a decision indicating that it will not proceed on its own Review Motion as it did not consider the review to result in the most just, expeditious and efficient determination of the matters before the OEB. The OEB noted that the questions raised are best considered in the context of a broader review of IRP policies but acknowledged that its conclusion does not necessarily extend to a different review motion filed by a different party.

On December 22, 2025, Enbridge Gas filed its own Notice of Motion to Review (EB-2025-0333) requesting the following variation of the Pilot Decision:

- Approve the inclusion of advanced gas technologies in the SLH IRP Pilot Project;
- Remove the direction to re-allocate the budget for the denied advanced gas technologies to electrification measures;
- Remove or correct the broader statements in the Pilot Decision supporting the determination not to approve initiatives that would result in the adoption of gas fired appliances and continue the use of natural gas; and,
- Remove the direction to consult with the IRP TWG on a second IRP pilot project on specified proposed measures, pending further direction from the current and ongoing EB-2025-0125 IRP Framework Review.

On May 14, 2026, the OEB issued its Decision on the Motion to Review.[6] The OEB did not vary its original Decision to reject incentives for advanced gas technologies in the SLH Pilot Project. However, the OEB clarified that this component of the Decision is specific to the SLH Pilot Project. The role of gas technologies as IRP alternatives in IRP is a matter that can be addressed in the broader IRP Framework Review and the OEB does not consider the Decision in the SLH Pilot Project to have predetermined or prejudged the outcome of that proceeding. The OEB did vary the original Decision by not requiring reallocation of the $1.5 million advanced gas technologies budget to electrification measures. The Decision also found that it does not consider it efficient or cost-effective to have Enbridge Gas and TWG members begin discussions on a second pilot project in parallel with the IRP Framework Review. Matters related to a second IRP pilot project and any further IRP pilot projects will be addressed as part of the IRP Framework Review.

SLH Pilot Program Design and Implementation Updates

Enbridge Gas launched the SLH Pilot offers as described in the SLH project plan under the name "Sarnia Saves" on the following dates:

- July 31, 2025. Commercial and Industrial Custom Offer[7]
- September 22, 2025. Residential Whole Home Offer[8]
- September 22, 2025. Residential Single Measure Attic Insulation Offer
- September 22, 2025. Residential Limited Electrification Offer
- October 8, 2025. Commercial and Industrial Direct Install Offer
- October 8, 2025. Commercial and Industrial Prescriptive Downstream Offer
- February 20, 2026. Residential Demand Response Offer

The OEB's Pilot Decision states that the detailed SLH project plan should be updated on a rolling basis. The following section identifies the changes made to the design, delivery, marketing, stakeholdering, and EM&V efforts relative to

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[6] EB-2022-0333, OEB Decision and Order, May 14, 2026.
[7] The Sarnia Saves website for all SLH IRP Pilot commercial offers is accessible at www.enbridgegas.com/sarniasaves/business
[8] The Sarnia Saves website for all SLH IRP Pilot residential offers is accessible at www.enbridgegas.com/sarniasaves

the sections of the SLH project plan filed in the 2024 IRP Annual Report as Appendix H.[9] All other elements of the SLH project plan remain unchanged.

i. SLH Project Plan pilot area update

Section of Plan	As filed	Change	Justification
Overview (2024 IRP Annual Report, Appendix H, pp. 241)	• City of Sarnia and Village of Point Edward (N7S, N7T, N7V, N7W, N7X) • Brights Grove (N0N 1C0)	The pilot area was clarified by adding highway boundaries • City of Sarnia and Village of Point Edward (postal codes starting with N7S, N7T, N7V, N7W, N7X) that are north of Highway 25 and west of Highway 26 and Brights Grove (N0N 1C0)	Ensures consistency with the pilot area in the Pilot Project application.

ii. SLH Project Plan Offer updates

Commercial, Industrial Direct Install and Prescriptive Offers

Section of Plan	As filed	Change	Justification
Table 4 – SLH Pilot Direct Install Incentive Structure by Measure (2024 IRP Annual Report, Appendix H, pp. 247) Table 7 – SLH Pilot Prescriptive Downstream Incentive Structure by Measure (2024 IRP Annual Report, Appendix H, pp. 252)	Each measure has a unique maximum equipment and installation incentive.	Measures are no longer subject to specific equipment and installation incentive maximums. Measures are eligible to receive 100% of relevant project costs (equipment and installation), up to $100,000 per project.	This change was made to simplify the “free upgrade” messaging and promote the installation of larger more complex projects.
Commercial Direct Install offer – Delivery Approach (2024 IRP Annual Report, Appendix H, pp. 248)	The delivery agent will recruit and onboard local trade allies, coordinate outreach efforts, identify opportunities, connect customers with these trade allies, and provide support throughout the process from engagement to equipment installation.	The delivery agent will continue with these activities, but Enbridge Gas has expanded the recruitment of trade allies by leveraging its existing DSM trade ally relationships.	Expanding recruitment efforts has helped onboard more trade allies faster and facilitated the generation of more project leads.

[9] EB-2025-0064 Exhibit I.1.13-ED-4 Attachment 1

Commercial and Industrial Custom Offer

There were no changes to the IRP Pilot Commercial and Industrial custom offer's design, delivery or incentive structure outlined in the SLH project plan.

Residential Whole Home Offer

Section of Plan	As filed	Change	Justification
Table 13 – SLH Pilot Residential Whole Home Incentive Structure by Measure (2024 IRP Annual Report, Appendix H, pp. 263)	Incentive offered for Windows/Doors/Skylights/Sliding Doors is $50 per rough opening	Incentive offered for Windows/ Doors/ Skylights/ Sliding Doors was updated to $100 per rough opening	As noted in the SLH project plan, Pilot incentive amounts will be updated to remain consistent with the in-field DSM offer.

Residential Single Measure Attic Insulation Offer

There were no changes to the IRP Pilot Residential Single Measure Attic Insulation Offer's design, delivery or incentive structure outlined in the SLH project plan.

Residential Limited Electrification Offer

Section of Plan	As filed	Change	Justification
Table 19 – Key Features of the SLH Pilot Electrification Offer (2024 IRP Annual Report, Appendix H, pp. 270)	Offer requires customers to fully switch from natural gas space heating to electricity after the heat pump installation without any back up natural gas space heating options. Participants do not need to disconnect their natural gas service.	An exception to this eligibility criteria was made that allows participants to keep natural gas fireplaces.	This exception was made after consultation with the TWG.[10] Enbridge Gas and the TWG member who raised this exception agreed that even if a natural gas fireplace is kept, most peak demand reduction benefits would likely still be achieved.
Table 19 – Key Features of the SLH Pilot Electrification Offer (2024 IRP Annual Report, Appendix H, pp. 270)	N/A	A new participation restriction was added. If a customer receives an incentive for an electric cold climate air source heat pump ("ccASHP") or electric ground source heat pump ("GSHP") through the SLH Pilot Electrification Offer,	This new participation restriction was added after consultation with the TWG.[11] TWG members agreed that if a participant were to get a heat pump, it would be counterintuitive for Enbridge Gas to also pay for the participant's building envelope improvements

[10] IRP TWG Meeting Notes, Meeting #55, (link)
[11] IRP TWG Meeting Notes, Meeting #60, (link), IRP TWG Meeting Notes, Meeting #55, (link)

		they cannot also participate in the SLH Pilot Residential Whole Home or SLH Pilot Residential Single Measure offer	because there is no added gas peak load reduction. Enbridge Gas agreed and added this new restriction.

Residential Demand Response Offer

Section of Plan	As filed	Change	Justification
Incentive Structure (2024 IRP Annual Report, Appendix H, pp. 274)	"Bonus" Participation Incentive: For each heating season that participants remain enrolled in the program and meet eligibility requirements, participants will enter a draw for a chance to win $2000.	The "bonus" participation incentive was reframed as an annual participation incentive. It was also changed to be a $20 annual incentive rather than a chance to win $2000.	Enbridge Gas's Demand Response delivery agent recommended the shift in incentive to $20 offered to all participants to align with incentive best practices. The incentive level was set to align with the IESO Peak Perks incentive for simplicity for the market.
Incentive Structure (2024 IRP Annual Report, Appendix H, pp. 274)	"Bonus" Participation Incentive eligibility requirements include participation in at least 50% of DR event hours each heating season.	For the 2025/2026 heating season, participants will get $20 if they enroll in the program by March 30, 2026. There is no requirement to participate in at least 50% of DR event hours for that heating season. The requirement to participate in at least 50% of DR event hours to receive the $20 incentive remains in effect for the 2026/2027 heating season.	The 50% participation requirement was removed for the 2025/2026 heating season to simplify and maximize first time signups into this new Enbridge Gas offer.

iii. SLH Project Plan Marketing Updates

Residential Marketing Tactics Updates (2024 IRP Annual Report, Appendix H, pp. 275)

Tactic	Objectives	Description	Status
Residential ETEE offers – Pre-launch			
SLH pilot residential webpage	Awareness and method of applying to residential offers	The webpage acts as a hub for SLH pilot residential offers. All residential marketing tactics drive customers here to learn more about the offers and sign up.	Completed September 8th, 2025
Community photo and video shoot	Awareness	A custom image and video shoot captured local community footage and reaction to pilot design features.	Launched on September 16, 2025, to December 30, 2026. Active on YouTube and program landing page.

Residential ETEE offers – Post-launch			
Customer-facing brochures for all ETEE pilot residential offers	Awareness	The customer-facing brochure highlights all pilot residential offers and outlines incentive amounts, pilot features, and specific calls to action.	Completed October 8, 2025
Direct Mail focusing on launch of ETEE pilot residential offers	Awareness and collection of engagement data	Direct mail was sent to approximately 25,000 residential customers to introduce the pilot residential offers, and outline incentive amounts, pilot features and specific call to action.	Completed October 15, 2025
Direct mail — follow-up postcard	Awareness and collection of engagement data	The postcard was meant to reinforce the direct mail campaign	The postcard was not needed. The intent of the postcard was to boost early leads into the residential pilot offers. Early marketing generated a large number of leads into the residential pilot offers. To prevent a backup of processing customers into the pilot, the postcard was not sent.
Eblasts (x3) promoting pilot ETEE residential offers	Awareness and collection of engagement data	Targeted emails promoted all pilot residential offers.	An eblast was sent to residential customers in the pilot project area on September 25, 2025, with a follow-up on October 2, 2025. Early marketing generated a large number of leads into the residential pilot offers. To prevent a backup of processing customers into the pilot, a third eblast was not sent in 2025.
Google Search	Awareness and collection of engagement data	The Google search campaign promoted the pilot offers to Google users searching for energy rebate information.	Launched September 23, 2025, to March 9, 2026
Digital campaign (Summer and Fall)	Awareness and collection of engagement data	Digital marketing tactics were implemented to target the local population, utilizing platforms such as Google and Meta.	Launched from September 21 to December 1, 2025.
Radio	Awareness	Two 30 second spots were run for approximately 5 weeks to promote the residential offers.	Launched from September 22 to November 15, 2025.

Out of home (OOH) marketing campaign	Awareness	Geo-targeted marketing targeted commuters, drivers and walking traffic. Tactics included transit shelters, bus advertisements, and digital screens.	Launched from September 22 to November 15, 2025.
Print ads	Awareness	Local newspaper advertisement was meant to promote pilot offers.	Early marketing generated a large number of leads into the residential pilot offers. To prevent a backup of processing customers into the pilot, print ads were not run in 2025.
Events	Awareness	Events will be attended by Enbridge Gas staff or pilot delivery agents to promote the offers, and distribute printed marketing material.	The pilot will have a presence at the 2026 Sarnia Home Show on April 10, 2026. Enbridge Gas continues to explore other events to promote the residential pilot offers.
Scam awareness eblast	Awareness	An email awareness campaign was sent to residential customers in the pilot area warning against unauthorized and illegitimate third parties posing as Sarnia Saves.	Completed February 4, 2026
Residential Demand Response			
Demand Response webpage[12]	Awareness, collection of engagement data and directing customers to the third-party microsite	The webpage promotes the Demand Response offer and directs customers to the third-party microsite	Completed February 20, 2026
Demand Response third-party microsite[13]	Awareness, collection of engagement data and enrollment process	The third-party microsite is run by the Demand Response delivery agent EnergyHUB. It is required to manage enrollment, incentive payments and Demand Response events	Completed February 20, 2026
Eblast promoting Demand Response	Awareness and collection of engagement data	Targeted emails promoting the Demand Response offer.	Completed February 27, 2026
Google search campaign	Awareness and collection of engagement data	The Google Search campaign will run for 17 weeks, maintaining sustained visibility among customers actively searching for smart	Starting February 27, 2026

[12] https://www.enbridgegas.com/ontario/sarnia-saves/smart-rewards/
[13] https://greatergrid.com/enroll/programs/thermostats/enbridge-gas/

		thermostat–related offers and incentives	
Digital marketing campaign	Awareness and collection of engagement data	Demand Generation and Meta campaigns will run for 10 weeks, leveraging audience targeting to reach eligible customers in the pilot region and reinforce awareness	Starting February 27, 2026
Direct in-app promotion to smart thermostats in the pilot region	Awareness and directing customers to the third-party microsite	Device Partners (Amazon, Google Nest, Honeywell, Ecobee etc.) will promote Demand Response to customers in pilot area with a Partner-brand smart thermostat.	Late February and early March 2026
Device Partner eblasts	Awareness and directing customers to the third-party microsite	Device partners will send an email to promote Demand Response to customers in pilot area with a Partner-brand smart thermostat.	Late February and early March 2026

Commercial Marketing Tactics Updates (2024 IRP Annual Report, Appendix H, pp. 277 and pp. 279)

The original plan presented Small Business ("SMB") and Commercial/Industrial ("CI") customers as distinct segments. This was revised by combining marketing to these groups. Combined marketing simplified the approach to market and customer participation, and made it easier to communicate a complete picture of all pilot commercial offers.

Segmentation remained where it helped target messaging to specific audiences. This included having separate direct mail material for restaurants and general commercial customers, and separate LinkedIn campaigns for small and large commercial customers.

Commercial Marketing Tactics

Tactic	Objectives	Description	Status
Commercial offers – Pre-launch			
SLH pilot commercial webpage	Awareness and method of applying into commercial offers	The webpage acts as a hub for SLH pilot commercial offers. All commercial marketing tactics drive customers here to learn more about the offers and sign up.	Completed on September 8, 2025
Community photo and video shoot	Awareness	A custom image and video shoot captured local community footage for use in marketing material.	Completed September 16, 2025
Customer-facing brochures and Sales sell-	Awareness	The customer-facing brochure and sell sheet highlight all pilot commercial offers and outline	Completed on September 8, 2025

sheet for all pilot commercial offers		incentive amounts, pilot features, and specific call to action.	
Commercial offers – Post-launch			
Direct Mail focusing on launch of pilot commercial offers	Awareness	Direct mail was sent to promote the commercial pilot offers. Two versions were prepared – one for restaurant and food services with Demand Control Kitchen Ventilation (DCKV) information, and another for general businesses.	Completed October 15, 2025
LinkedIn Digital campaign	Awareness and collecting engagement data	LinkedIn campaign targeted professionals and businesses interested in rebates, energy efficiency, and sustainability.	Launched October 10 to December 3, 2025
Events	Awareness	Events will be attended by Enbridge Gas staff or pilot delivery agents to promote the offers, and distribute printed marketing material.	Enbridge Gas participated in two events to present attendees with the details of the commercial pilot offers: • Sarnia-Lambton Leadership Legacy Summit (Oct 22, 2025) • Sarnia Lambton Chamber of Commerce Business Showcase (Nov 19, 2025)
Eblasts x 2	Awareness and collecting engagement data	Targeted emails promoted all pilot commercial offers.	Completed on October 8 and December 4, 2025

iv. SLH Project Plan Stakeholder Engagement Activities – progress on engagement items listed in the filed plan (2024 IRP Annual Report, Appendix H, pp. 280)

Engagement items	Objectives	Description	Status
Pre-launch			
Detailed stakeholder lists	Coordination, Awareness	Develop detailed stakeholder contact lists for Tier 1-3 entities[14]	Complete
Briefing collateral	Awareness	Build briefing material toolkit for Tier 1, 2 priority audiences	Complete
External communications collateral	Awareness	Develop communications collateral to be used by Tier 1, 2 priority audiences across their community-facing channels to support broad public awareness	Complete
Advance notifications of Pilot launch to select stakeholders	Engagement; Awareness	Notify key municipal (elected and staff-side), Indigenous, MPP/MP constituency stakeholders about the Pilot; provide campaign overview	Complete
Launch			
Conduct priority stakeholder briefings	Awareness, information sharing	Tier 1, 2 priority briefings to occur (in advance of launch of marketing campaign where possible); capture feedback	Complete
Pilot launch event	Awareness	Execute a launch event with local-area stakeholders (supported by media materials)	Rather than a launch event, Enbridge Gas executed individual briefings with stakeholders in advance of marketing launch and leveraged individual/ organizational awareness channels. Enbridge Gas also participated in two post-launch events to present attendees with the details of the pilot offers: • Sarnia-Lambton Leadership Legacy Summit (Oct 22, 2025) • Sarnia Lambton Chamber of Commerce Business Showcase (Nov 19, 2025)

[14] Tier 1-3 reflects the mapping of stakeholders outlined in the Stakeholder Mapping section of the filed Pilot delivery Plan. Stakeholder groups are prioritized into three tiers based on their ability to influence the uptake and outcome of the Pilot.

Sustained engagement	Awareness	Tier 3 briefings to generate interest, awareness, information sharing across channels; capture feedback	Complete
Channel amplification	Awareness	Encourage Tier 1-3 stakeholders to promote the Pilot through organic owned/ earned channels (e.g. social, newsletters, e-blasts) Create additional lift around milestone activities (e.g. back to school planning)	Residential and Commercial ETEE offers were promoted in local groups including: • Online article in Living in Lambton • Village of Point Edward CiviKit • Bluewater Power Energy Conservation site • Sarnia Lambton Economic Partnership emails and Facebook promotion
Visibility with Tier 3 community	Awareness	Work with local business associations, chambers, identify speaking opportunities to address members and leverage respective engagement channels	Complete, inclusive of the two post-launch events noted above. Ongoing for 2026
Additional (Fall) media push	Awareness; uptake	Drive seasonal messaging through media and public-facing channels; leverage case studies, testimonials	Complete, inclusive of channel amplification examples above. Ongoing for 2026
Post-launch			
Sustainment activities	Awareness, information sharing	Ongoing touchpoints with the municipality, and Tier 1-3 stakeholders to ensure they remain engaged around the Pilot's progress, issues, and next steps. This phase will be supplemented by additional media activations to support marketing/ consumer-facing activities.	Ongoing
Webinars	Awareness, information sharing	The SLH pilot offers were presented as part of four regional IRP webinars delivered by Enbridge Gas	Completed December 2025 and January 2026

v. SLH Project Plan Objective 1 EM&V Plan and Activities (2024 IRP Annual Report, Appendix H, pp. 287)

Enbridge Gas hired Dunsky Energy + Climate Advisors ("Dunsky") through an RFQ process to evaluate the peak hour demand changes for Objective 1. The IRP TWG was engaged for their input on the plan, and it was finalized in Q1 2026. The objectives, methodology, and evaluation timelines are summarized below from the EM&V plan. See Appendix G for the detailed plan.

Evaluation Objectives

The evaluation focuses on enabling Enbridge Gas to develop a clear understanding of how ETEE and DR programs impact system peak hour demand.[15] Specifically, the evaluation will:

- Quantify actual peak-hour flow reductions (m^3/h) from ETEE and DR by comparing pre- and post-program load by customer type.
- Assess DR event performance, including the reliability, magnitude, and persistence of customer response.
- Identify factors that influence achieved impacts (weather, building characteristics, measure types).
- Extrapolate observed impacts to design-hour conditions using Enbridge Gas's regression methods.

These findings will support future IRP Plans by improving assumptions, refining modeling techniques, and informing the feasibility of using demand-side IRPAs in lieu of traditional system reinforcement projects.

Evaluation Methodology

The evaluation applies a set of coordinated analytical approaches to estimate program impacts.

- Load-vs-temperature regression to measure normalized pre/post load changes and validate Enbridge Gas's regression approach.
- Participant vs non-participant comparisons using hourly interval meter data.
- DR event analysis using smart thermostat telemetry matched to consumption records.
- Impact disaggregation by customer type and measure where statistically reliable.
- Load curve analysis to examine peak shifting, rebound effects, and system-level peak relief.

As part of this approach, customer demand extrapolation will be led by Enbridge Gas, with Dunsky providing methodological review and collaboration. This collaborative approach enables the evaluation to leverage Enbridge Gas's expertise in system design, demand profiling, and historic Ontario design-day practice, while also incorporating Dunsky's experience in DR, regression-based load modeling, and large dataset evaluation.

All analyses will incorporate rigorous data validation and transparency regarding uncertainty levels, underlying assumptions, and extrapolation techniques. The evaluation relies on hourly meter data, weather data (temperature, wind), smart thermostat event records, and program tracking datasets.

[15] The baseline used to estimate system impacts is pre-ETEE hourly consumption data, which is analyzed using regression methods and compared against post-intervention conditions. This approach is described in the EM&V report (Section 7.6.3).

vi. SLH Project Plan Objective 2 EM&V Plan and Activities (2024 IRP Annual Report, Appendix H, pp. 290)

The timing of Pilot Objective 2 activities was shifted to align with pilot offer launch dates. In some cases, the cadence of activities was also changed as described in the table below. The approach to Objective 2 activities is consistent with the filed plan.

Updated timeline and cadence of Objective 2 evaluation plan activities (2024 IRP Annual Report, Appendix H, pp. 300 and pp. 314)

Activity	Cadence	Fieldings To-Date	Next Fielding	Notes
Evaluation plan	Complete – Filed in Pilot project plan			
Program & peer research	Once	Nov 2025	Q1 2026	A jurisdictional scan of North American DR programs was completed in November 2025.
Enbridge staff interviews	Quarterly	July 2025; Jan 2026	April 2026	
Res/Com Delivery Agent interviews	Quarterly	Dec 2025	Feb 2026	Surveys were upgraded to interviews to get better details on delivery agent responses
Res/Com Contractor & Energy Advisor interviews	Quarterly	Jan 2026	April 2026	Surveys were upgraded to interviews to get better details on contractor responses. Residential Energy Advisors interviews were added.
Broad-based Residential/ Commercial Surveys	Annually	Sept 2025	Fall 2026	The DSM broad-based participant surveys were expanded to include non-participants. Cadence was updated from quarterly to annual. Annual cadence avoids over-surveying the customer base and is sufficient to gather baseline data
ETEE Pilot Participant Interviews	Quarterly	Jan/Feb 2026	April 2026	Timing for participant interviews shifted to ensure there was enough participation in the Pilot from which to pull a sample
ETEE Participant Surveys	Quarterly	NA	Q2 2026	Timing for participant surveys shifted to ensure there was enough participation in the Pilot from which to pull a sample
DR Participant Surveys	Twice	NA	Q2 2026	
ETEE Near-Participant Surveys	Twice	NA	Q2 2026	Cadence was updated from quarterly to twice. This cadence is sufficient to gather the data needed
DR Opt-Out Surveys	Twice	NA	Q2 2026	
ETEE/DR Non-Participant Surveys	Once	NA	Q1 2027	The cadence has shifted from twice to once. Non-participation in pilot offers can only be confirmed after the pilot has ended.
Cost Analysis	Twice	NA	Q2 2026	
Quarterly memos	Quarterly	Nov 2025	Q1 2026	
Interim report	Once	NA	Q2 2026	
Final report	Once	NA	Q4 2027	The timing has shifted to allow for sufficient time to explore DR events that end Q1 2027

System Pruning Pilot Project

In the Rebasing Phase 1 Decision, the OEB provided the following commentary on IRP alternatives to address potential stranded asset risk relating to system renewal activities through the consideration of system pruning;

> "System pruning, for example, converting a subdivision from natural gas to electricity for space and water heating, is another option. Under this option, existing gas customers would replace their gas equipment with electric equipment. This could be supported by an IRP solution, which would consider various alternatives to avoid the need to replace the facilities. The IRP process could offer alternatives through pilot projects for the OEB to consider, including incentives to be paid to the customers to defray the cost of replacing their gas equipment, or investment by the utility to cover the cost of the electric equipment to be recovered over time, with a return on that investment."[16]

In the Company's submission for Phase 2 of its 2024 Rebasing Application, Enbridge Gas confirmed it is committed to working with the IRP TWG and other relevant stakeholders to consult on system pruning processes. It was also proposed that a jurisdictional scan be completed to identify how utilities in other jurisdictions are approaching natural gas system pruning to identify best practices, where applicable.[17]

In the Settlement Proposal for Phase 2 of the Company's 2024 Rebasing Application, all parties agreed that Enbridge Gas would develop and implement a system pruning pilot project. Specifically, Enbridge Gas would develop its approach to system pruning in consultation with the IRP TWG by the end of Q2 2025 and begin implementation on one or two pilots by the end of Q1 2026. Additionally, the Parties agreed that for these one or two pilots OEB approval is not required if the combined costs of these pilots are $5 million or less and the pilot(s) are supported by the IRP TWG. Further, the parties agreed that a new IRP System Pruning Deferral Account with a $5 million cap would be created for recording the incremental costs related to these activities for later recovery. Should Enbridge Gas forecast that the incremental costs of the IRP System Pruning pilot project(s) will exceed $5 million, then Enbridge Gas would be expected to request OEB approval through an IRP Plan application.[18] The OEB accepted the Settlement Proposal on November 29, 2024.[19]

In Q1 2025, Enbridge Gas consulted with the IRP TWG on the system pruning workplan and draft scope of work for the system pruning jurisdictional scan. OEB Staff confirmed a subcommittee of the IRP TWG ("TWG Subgroup") would be established for detailed consultation on the jurisdictional scan and pilot approach.

Enbridge Gas developed a workplan on the key elements required for the System Pruning pilot approach to meet the Q2 2025 deliverable, identifying the timing as to when elements would be brought forward to the TWG Subgroup for input and feedback, and when they would be shared with the full TWG to ensure alignment. With the provincial election occurring in February, consultation activities were put on pause during the writ period between January 31 to March 19, 2025, which impacted the timing of consultation with the TWG Subgroup on specific elements. Enbridge Gas continued to provide informational updates during this period, however discussion on items was deferred until consultation and cost-award eligibility were reinstated by OEB Staff. Following the end of the writ period, Enbridge Gas continued to engage with the TWG Subgroup and full TWG to finalize the approach and confirm support by the end of June 2025 for the System Pruning approach elements.[20] On July 4, 2025, Enbridge Gas filed its 2024 IRP Annual Report, with the System Pruning approach filed as Appendix G.[21]

In parallel to the development of the approach, DNV was engaged to conduct a jurisdictional scan on behalf of Enbridge Gas and the IRP TWG. A subcommittee of the IRP TWG was established for detailed consultation on the

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[16] EB-2022-0200, Phase 1 Decision and Order, December 21, 2023, p. 52
[17] EB-2024-0111. Phase 2, Exhibit 1, Tab 17, Schedule 1, April 26, 2024, p.17-27
[18] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1 Schedule 1, November 4, 2024, p.20-21.
[19] EB-2024-0111, Decision on Settlement Proposal and Interim Rate Order, November 29, 2024.
[20] Engage with Us, OEB (link) System Pruning Subgroup Meetings #2, 3, 4 (January 12, 2025, March 20, 2025, April 17, 2025), TWG Meetings #50 (March 26, 2025), Meeting #52 (April 23, 2025), Meeting #53 (May 7,2025), Meeting #54 (May 21, 2025), Meeting #55 (June 4, 2025), Meeting #56 (June 25, 2025).
[21] EB-2025-0064 Exhibit I.1.13-ED-4 Attachment 1

jurisdictional scan and approach. The scan was completed on August 15, 2025.[22] The purpose of this study was to better understand and gain insights into how gas utilities among North American and European jurisdictions are approaching pruning to their gas distribution pipelines, where informative to the Ontario context. The study was intended to provide a foundational understanding of system pruning approaches, best practices and lessons learned to assist in the development of pilots in Ontario. While the full jurisdictional scan report results were not available as the system pruning approach was being developed, as DNV was a participant in meetings of the system pruning TWG Subgroup and full TWG, input was provided in relation to the jurisdictional scan work in progress. The scan covered six utilities/jurisdictions – five were selected as they have planned or undertaken system pruning or non-pipeline activities, and one was selected because of their successful collaboration activities amongst their gas and electric utilities within that jurisdiction. Of the six studied jurisdictions, only two (California and New York) have completed actual system pruning projects. The study found that system pruning is a utility action in its infancy. "Among the reviewed jurisdictions, the primary driver of system pruning or Non-Pipeline Alternative (NPA) activities is a policy framework centered around climate and equity. Although considerations about system cost is a concern, it was not explicitly cited as the driver to policies that promote system pruning and NPAs."[23]

2025 Project Implementation Update

Following the TWG's support of the System Pruning approach in July 2025, implementation of the pilot began in Q3 2025, which included the following activities:

- **Contractor Engagement**
  Enbridge Gas engaged a contractor to serve as the delivery agent for the System Pruning Pilot. The Home Inspectors Group was selected through a Request for Proposal process which, amongst other criteria, sought contractors that were knowledgeable and unbiased about natural gas and electric equipment and appliances.

- **Pilot Candidate Selection**
  Enbridge Gas conducted an initial pre-screen with customers that met the selection criteria outlined in the Approach. This preliminary outreach provided information on the pilot and a pre-screen form for customers to express their interest level in participating in the pilot. Based on the results of the pre-screen, the contractor then initiated discussions with customers who had indicated that they were "Definitely Likely" to participate in the pilot, had confirmed they consent to Enbridge Gas sharing their contact information with the contractor to proceed to the next step and are the last customer at the end of a natural gas main (meaning that their disconnection would allow for decommissioning of their service and the associated main to their home, thus avoiding the eventual replacement of that portion of main and their service). Learnings from these "Definitely Likely" customers will inform next steps.

- **Electric Local Distribution Company ("LDC") Engagement**
  Enbridge Gas met with two LDCs to understand their processes and perspectives as they relate to the System Pruning pilot. Discussions with these LDCs included:
  - The degree to which system constraints are localized and can only be determined once specific addresses for pilot candidates are known
  - The fact that the LDCs are resource-constrained and would not be able to support prioritization of candidates based on network capacity
  - The standard processes that would be followed (and varied as required) should customer(s) convert off of natural gas

[22] Engage with us, OEB (link)
[23] DNV, System Pruning Jurisdictional Scan – Final Report (August 15, 2025), Key Findings section.

- How customers would contribute if network enhancements were required to support their conversion off of natural gas.
- The standard assumptions LDCs consider for subdivision planning, inclusive of natural gas for space and water heating

As implementation continues, engagement through these processes will be incorporated into the work of the contractor with the customer.

Enbridge Gas has continued to update and consult with the TWG on key elements of the pilot implementation.[24]

[24] Engage with us, OEB (link), IRP TWG Meeting #57 (July 30, 2025), Meeting #61 (December 3, 2025)

Section 5 – IRP Stakeholder and Indigenous Engagement Update

As part of the OEB's IRP Decision, the OEB determined that "the three components of Enbridge Gas's proposed Stakeholder Engagement Process will provide valuable input into Enbridge Gas's IRP activities and shall be incorporated in the IRP Framework. The three-component process includes: gathering of stakeholder engagement data and insight, stakeholder days, and targeted engagement. The OEB also directed the establishment of a website by Enbridge Gas to facilitate the broad sharing of information on IRP stakeholder efforts".[25]

Regional Engagement

Enbridge Gas conducted four regional webinars from December 2025 through January 2026. The format, which was previously delivered through multiple region-specific sessions, was revised to a single session offered on multiple days to provide flexibility for participants. Invitations to the webinar were sent to individuals subscribed to IRP updates, with a more targeted emphasis on those involved in energy and infrastructure planning, such as municipal staff and planners, community leaders, technical professionals, IESO Integrated Regional Resource Plan working group members, regulatory or policy representatives, along with others interested in the assessment and implementation of non-pipeline alternatives. This updated approach supported a broader review of the IRP evaluation results, including the key learnings from the process and the determination that no specific regional projects were identified to proceed with an IRP alternative.

The webinars covered topics including an overview of IRP and the assessment process along with updates on the AMP Addendum 2026, regional projects and IRP pilot projects. Each session concluded with a Question-and-Answer segment and information on how to stay engaged, including sharing feedback via the IRP mailbox. The total attendance across the four webinars was 51 participants. An additional 11 stakeholders not able to attend a session requested the webinar recording from Enbridge Gas.

During each session, attendees were encouraged to view the IRP webpage for additional information and opt-in to the mailing list to receive future email updates on project information and upcoming events. The feedback and responses shared during the webinars have been documented and shared on the IRP webpage, along with copies of the presentation deck and webinar recording.[26]

Following the webinars, an IRP newsletter was issued to IRP subscribers, and provided a summary of the regional webinars and pilot updates, with information on how to engage the IRP team and remain engaged.[27]

Municipal Engagement

Enbridge Gas engages with a wide cross-section of municipal audiences and stakeholders on an ongoing basis through a dedicated Municipal and Stakeholder Engagement (MSE) team, including at regional and province-wide municipal conferences as part of engagement on IRP within existing stakeholder engagement channels:

- ROMA (Rural Ontario Municipal Association) – January 2025
- NOMA (Northwestern Ontario Municipal Association) – April 2025
- OSUM (Ontario Small Urban Municipalities) – May 2025
- NODSA (Northern Ontario Service Deliverers Association) – June 2025
- AMO (Association of Municipalities) – August 2025
- OEMC (Ontario East Municipal Conference) – September 2025
- WOWC (Western Ontario Wardens Caucus) – October 2025

Additionally, Enbridge Gas participates in 50+ local events and symposiums throughout the year with local chambers of commerce, boards of trade, associations, and municipalities (e.g. the City of Toronto's Community Environment Days). During

[25] EB-2020-0091, IRP Proposal OEB Decision and Order, July 22, 2021, p. 66.
[26] Regional Planning & Engagement | Enbridge Gas
[27] Integrated Resource Planning (IRP) 2025 Newsletter

these conferences and events, dedicated members of the MSE team are on-hand to engage directly with attendees and answer questions related to IRP and IRP pilots (including ways to remain engaged). The relationships and contacts established at these forums support the development of the targeted IRP distribution list to ensure that dedicated municipal leads and subject matter experts can be engaged for regional stakeholder activities and targeted engagement where applicable.

Costs for exhibiting at conferences and events on an ongoing basis, such as booth costs, are not attributed to IRP as they represent an opportunity to leverage existing channels. Costs for events that are specific to an IRP initiative, such as the Chamber of Commerce Business Showcase noted in the SLH Project Plan Stakeholder Engagement Activities, are attributed to IRP, with Chamber of Commerce Business Showcase expenditures allocated to the SLH Pilot Project.

Targeted / Project-Specific Engagement

Enbridge Gas has proactively initiated engagement activities with local distribution companies (LDCs) in areas of high growth that could trigger an LTC project as part of the Company's approach regarding coordinated energy system planning. The purpose of these engagements is to develop understanding of each sector's planning approaches, share and discuss the basis for each sector's demand forecasts and, for Enbridge Gas, to determine if there is a need to adjust the Company's demand forecast and system design based on the shared information. Additionally, these engagement activities establish communication channels with LDCs which can support future information sharing and discussion. While a formal coordination framework has not yet been established, these engagements have resulted in meaningful discussion and collaboration between the gas and electricity sectors. This work is intended to enhance the comparability and clarity of key planning inputs and to support more effective coordination going forward. Enbridge Gas will continue to monitor the OEB's implementation of the Minister's Directive related to the government's Integrated Energy Plan.

Additionally, when applicable, Enbridge Gas implements a Non-Binding Expression of Interest (EOI) / Reverse Open Season (ROS) process to gather potential additional customer demands and identify opportunities to reduce existing contract customer demands, which ensures that the best available customer demand information informs project requirements and potential IRP opportunities. An EOI/ROS is triggered on a case-by-case basis for increased demand-driven LTC projects, and for defined geographic areas of benefit where Enbridge Gas contract rate customers have identified a need for increased or decreased capacity via their regular ongoing discussions with their Enbridge Gas account managers. IRP relevant questions have been embedded within the EOI/ROS form, including:

- Customer's interest in converting existing firm distribution service to interruptible distribution service if the ability to negotiate lower than posted interruptible rates was available.
- Customer's consideration of energy conservation activities in their bid amounts and existing demand and the customer's interest in considering additional energy conservation activities as it relates to reduction in contract bids or existing demand. This process will involve additional engagement with specific contract customers to discuss on-going DSM energy efficiency projects, as well as whether there are incremental opportunities for IRP alternatives, to ensure that the bid put forward is inclusive of consideration of both DSM and IRP.

Further details on project specific consultation are described in Section 6.

IRP Pilot Project

For the IRP Pilot Project, Enbridge Gas conducted stakeholder engagement with the local municipalities, municipal agencies, business associations, LDC, IESO and the local community to provide an overview of the pilot and to garner feedback on the proposed IRP alternatives in support of the initial filing of the application in 2023 and 2024. Refer to Section 4, of the Southern Lake Pilot Project for the stakeholder engagement conducted in 2025.

Indigenous Engagement

IRP has continued to provide Enbridge Gas's Indigenous Engagement team with informational materials for use during informal discussions, and during their normal course of engagements to highlight the Regional Engagement sessions and to promote registrations for engagement events that may be happening in their areas. This included incorporating IRP updates and the latest developments on the pilot projects within the summer edition of the Indigenous newsletter, Figure 5.5.

Additionally, contact details to address any further questions or to promote registration for updates were sent out by the Indigenous advisor for each region.

Figure 5.5 – Excerpt of the IRP section in the 2025 Indigenous newsletter

Pilot Project Updates from Integrated Resource Planning (IRP)

What is IRP:

IRP is an enhanced natural gas planning strategy and process where Enbridge Gas evaluates non-pipeline alternatives that could be used to defer or avoid implementing a traditional pipeline project to meet system needs.

Southern Lake Huron (SLH) Pilot Project:

The Ontario Energy Board approved the Southern Lake Huron Pilot Project subject to certain modifications.

Be sure to sign up to be part of our mailing list so you can be kept informed of all things IRP.

IRP was also discussed as part of the Indigenous Working Group ("IWG"), in response to a recommendation in The Brattle Group report that led to the suggestion that IRP be added as a standing item to the IWG agenda.[28] Enbridge Gas IRP staff participated in two IWG meetings on March 4 and July 15, 2025. The IWG meeting dated March 4 included a brief discussion on IRP activities, the IRP pilots, and IRP stakeholder activities, as well as a discussion item raised by Enbridge Gas on the potential for an IWG standing IRP agenda item to engage on future IRP activities and discussion. Enbridge Gas also advised that the Indigenous Nations, serviced by Enbridge Gas, received the information on the IRP webinars through their Community and Indigenous Engagement Advisor.

Additionally, a member of the IWG advised there was no Indigenous participation on the IRP TWG led by OEB staff, and suggested Enbridge Gas and the IWG jointly ask the OEB to be involved in the group. Enbridge Gas conveyed the request to OEB Staff in March 2025 and provided the IWG contact to OEB staff so they can discuss the request.

At the July 15, 2025 meeting Enbridge Gas discussed IRP and asked for member feedback on the best process to engage the IWG moving forward, as well as on the initial priority areas of focus for engagement. It was suggested by an IWG member that a smaller sub-group be established going forward to discuss IRP and the IWG and Enbridge Gas agreed on this approach. There was also a discussion on the engagement process and objectives for the Southern Lake Huron Pilot Project. Following the meeting Enbridge Gas shared the Pilot Project Application identifying the section outlining Indigenous group engagement and asked IWG members to indicate their interest in joining an IRP sub-group. Enbridge Gas subsequently sought input from the interested members on what topics would be of interest for discussion; however, no responses were received.

As such, at the November 26, 2025 IWG meeting, Enbridge Gas suggested removing IRP as a standing agenda item and that IRP be discussed at future meetings as requested. The IWG agreed. Additionally, where Enbridge Gas identifies IRP alternative opportunities that would include First Nations communities in the area of benefit, it would seek to work with First Nations in the development of its detailed approach, including through the IWG.

[28] The Brattle Group Report Recommendations, EB-2025-10-30, EB-2025-0155, Exhibit G, Tab 3, Schedule 1, Page 6 and Page 34 of 49

Section 6 – Non–Pilot IRP Plan Updates

IRP Plans will be developed for projects with technically and economically feasible IRPAs, where the IRPA is determined to be the preferred alternative to address a system need. This section provides an update on the status of IRP Plans in-flight and in development in 2025.

In 2025, Enbridge Gas completed the IRP screening and evaluation of all investments in the AMP that had a defined scope. At the economic evaluation stage, no potential IRP alternatives were identified as the optimal solution and the facility alternative was the solution in the best interests of Enbridge Gas and its customers to address the system need. Consequently, Enbridge Gas did not file any non-Pilot IRP Plan applications with the OEB.

Enbridge Gas will be monitoring the project scopes and annual review of the facility and IRP alternatives will be conducted to confirm the optimal solution prior to alternative implementation. Additionally, contract customer engagement within the area of benefit, where applicable, will be conducted closer to the forecasted in-service date. Table 6.1 summarizes the IRPA implemented since 2022.

Table 6.1 – Summary of IRP Solutions Implemented

Project Name	Project Description	IRP Alternative Identified	IRP Implementation Status	Facility Cost vs. IRPA Cost	IRP Implementation Outcome
East Kingston Creekford Reinforcement	Installation of 6.2km of NPS 8	Demand-side IRPA – contract demand turnback Supply Side IRPA –CNG	Completed	Forecasted facility cost = $24.3M Supply-side IRPA (CNG) cost = $0.6M	CNG was procured for the winters of 2022/2023 and 2023/2024, where the CNG agreement provided time for Enbridge Gas to implement a contract turnback to reduce contract demand and in turn avoid the facility project. The turnback was confirmed by the Contract Customer on November 11, 2022. This capacity was sufficient to defer the reinforcement; however, it was not received in time to avoid a CNG contract back-up solution.[29]

[29] EB-2023-0092, Exhibit C, Tab 1, June 14, 2023, p.20-25.

Section 7 – Integrated Resource Planning Alternatives Update

In its Decision and Order establishing an IRP Framework for Enbridge Gas, the OEB found that a "document on best available information for demand-side alternatives would promote more timely development of IRP Plans and directs Enbridge Gas to include a listing in its annual IRP Report."[30]

To provide an overview of the types of alternatives considered when addressing system needs, a summary of traditional facility alternatives, alongside the non-pipeline IRP alternatives, has been included in Table 7.1.

Enbridge Gas routinely evaluates traditional facility alternatives, where applicable, as part of project scoping to ensure the optimal alternative is reflected in the AMP. Enbridge Gas also incorporates forecast gas supply contracts into the development of the AMP. These contracts may influence the timing of transmission projects and, by providing firm supply at known transmission locations, may have the potential to avoid or reduce the need for new infrastructure. Enbridge Gas designs transmission facility requirements to integrate these firm deliveries.

IRP alternatives are assessed after the consideration of traditional facility alternatives and are evaluated against the established project scope in the AMP. Given the dynamic nature of facility planning and the evolving demand forecast, the assessment process can be iterative. Project scopes for both traditional facility and IRP alternatives are periodically reassessed to ensure up to date information is captured.

Table 7.1 - Summary of Facility and IRP Alternatives

Traditional Facility Alternatives	Loop existing pipeline (system reinforcement)
	Replace existing pipeline with a larger pipeline (system reinforcement)
	Install a new pipeline (with consideration for different routes)
	Add / upgrade stations serving system area
	Increasing system pressure (when applicable)
	Add compression to increase pipeline capacity (when applicable)
Supply-side IRP Alternatives	Compressed Natural Gas (CNG) / Liquefied Natural Gas (LNG)
	Market-based supply
Demand-side IRP Alternatives	Enhanced Targeted Energy Efficiency (ETEE)
	Demand Response (DR)
	Electrification Measures (specific to the pilot projects) *

* As part of the first-generation IRP Framework, the OEB determined that it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs. However, a limited number of electrification measures are included in the Southern Lake Huron pilot project and System Pruning pilot.

[30] EB-2020-0091, IRP Planning OEB Decision and Order, July 22, 2021, p. 36

Appendix B: Integrated Resource Planning Alternatives provides additional information on both demand-side and supply-side IRP alternatives including “types of IRPAs, estimates of cost, peak demand savings, status in Ontario, the potential role and relevance to Enbridge Gas’s system, and learnings from pilot projects and other jurisdictions.”

Enbridge Gas expects the IRP pilot projects to provide additional information to refine and update the impacts of the IRP alternatives identified.

Section 8 – Technical Working Group Summary

In the IRP Decision, the OEB directed that an IRP TWG be established and led by OEB staff, to provide input on IRP issues that will be of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework.

All documents and presentations concerning the IRP TWG can be found on the OEB website.[31]

Attached in Appendix E: Technical Working Group Report is a report prepared by the IRP TWG.

[31] Natural Gas Integrated Resource Planning (IRP) | Engage with Us (oeb.ca)

Section 9 – DCF+ Methodology Update

In the IRP Decision, the OEB concluded that the DCF+ test should be the economic evaluation test used under the IRP Framework. Further, within its IRP Decision, the OEB recognized that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRPAs and clarify how these costs and benefits should be considered within the DCF+ test. The OEB directed Enbridge Gas to study the IRP DCF+ test and encouraged consultation with the TWG, which includes representatives from Enbridge Gas, OEB staff, and non-utility members.[32] Below is a summary of the key topics discussed in 2025 and the resulting outcomes that informed the economic evaluation of IRPAs, particularly in light of changes to the federal fuel charge.

On March 15, 2025, the Government of Canada enacted regulations with an effective date of April 1, 2025, to set the value of the federal fuel charge to $0 and to remove the requirement for provinces and territories to have a consumer-facing carbon price. In response to these changes, Enbridge Gas updated the enhanced DCF+ test to reflect the zeroing of the federal fuel charge and removal of the consumer-facing fuel charge rates.

At the March 19, 2025, TWG meeting, Enbridge Gas discussed the refinements to the DCF+ as outlined in its written responses provided to the TWG on January 16, 2025. In these refinements, Enbridge Gas confirmed that the DCF+ would follow a nominal approach in which revenues would be escalated in accordance with the approved price cap index (PCI) escalator, costs would reflect the best forecast available or reflect a 2% inflation in the absence of a forecast, and that the weighted average cost of capital (WACC) would remain at a nominal rate. TWG members were supportive of the proposed changes, as they agreed it aligned the costs and discount rate appropriately. The changes also served to address concerns regarding additivity of Phase 1 and Phase 2. TWG members remained concerned, however, about the additivity of Phase 3, as they said Phase 3 includes benefits calculated using the GDP multiplier, and that this multiplier accounts for incremental economic activity which is distinct from project-specific costs and benefits that are included in Phase 1 and Phase 2. In response, Enbridge Gas noted that they would present Phase 1 and Phase 2 separately and additively, and present Phase 3 independently.

Members of the TWG also noted that the social cost of carbon is a distinct cost that should be reflected in Phase 3. They expressed concern that setting the consumer carbon cost to zero could understate carbon-related impacts and that presenting Phase 3 separately may further de-emphasize those impacts. In addition, members of the TWG suggested exploring other non-energy benefits (NEBs), like employment impacts, in addition to GDP multipliers.

Reliability was raised as a topic requiring further discussion, particularly whether it should be included in the DCF+ test or separately as an additional consideration. Enbridge Gas noted that reliability is already reflected in the IRP alternative design considerations. Members also suggested quantifying the cost of service interruption associated with different options.

At the March 26, 2025, TWG Meeting, Enbridge Gas presented its DCF+ test results, incorporating the nominal adjustments it had described in the March 19, 2025, TWG meeting. Enbridge Gas outlined its proposed approach to identifying the most cost-effective alternative, which was to augment consideration of DCF+ Phase 1 results with the sum of DCF+ Phase 1 and Phase 2 results – and then prioritize the alternative with the highest combined net present value ("NPV"). Enbridge Gas noted that this approach optimized investment value while minimizing costs to all customers. To enhance efficiency, Enbridge Gas also discussed a potential threshold approach under which a sensitivity analysis would only be conducted for projects where the NPV differential is less than the absolute cost of lowest-cost alternative.

Discussion continued in the April 9, 2025, meeting, with TWG members' feedback focused on the proposed sensitivity threshold and sensitivity analysis applied to the updated economic test results that now reflected the zeroing of the federal fuel charge. In particular, the change in fuel charge prompted TWG members to consider whether the DCF+ test remained the appropriate starting point for assessing IRPAs, or whether an alternative

[32] EB-2020-0091, IRP Planning OEB Decision and Order, July 22, 2021, p. 56-57.

approach could better support productive discussion and consensus-building where agreement was not reached (e.g. how to assess economic development and job impacts, and whether rate impacts or broader customer impact should be prioritized). Enbridge Gas continues to agree with the OEB's decision on the IRP Framework that the three-phase DCF+ is the economic evaluation to be used for IRP as it appropriately reflects the costs and benefits to ratepayers, participants, and society, with particular focus on rate impacts. The decision confirms that the test "best aligns with the goal and purpose of IRP planning, which is to address the system needs of Enbridge Gas's regulated operations and identify and implement the solution that is in the best interest of Enbridge Gas and its customers."[33] The fuel charge is only one input among the costs and benefits included in the test. Changing the value of an input, in accordance with prevailing policy, is not an appropriate basis for challenging the methodology. Enbridge Gas and other TWG members acknowledged that despite remaining differences, meaningful progress has been made in refining some aspects of the DCF+ through multi-year TWG consultation.

With respect to the mechanics of the DCF+ calculation, a TWG member suggested a secondary criterion to the sensitivity threshold that would identify the magnitude of cost reduction required for each alternative to achieve NPV parity with the preferred alternative. TWG members also noted the need for considerations beyond the combined Phase 1 and Phase 2 results, including whether Phase 2 results should be weighted given the IRP Framework's emphasis on rate impacts as assessed in Phase 1. In its review of Phase 3, Enbridge Gas confirmed that the fuel charge rate was set to $0 in accordance with the zeroing of the customer-facing federal fuel charge and that no alternative valuation of carbon could be incorporated into the economic test. Enbridge Gas asserted that the pricing of carbon should be aligned with government legislation and policy in all aspects of the calculation. TWG members agree with this approach for Phase 1 and 2, but expressed concerns with applying this approach to Phase 3 of the DCF+ since the purpose of Phase 3 is to reflect societal costs that are not reflected in Phases 1 and 2.

At the July 30, 2025 TWG meeting, Enbridge Gas presented DCF+ results for several new projects, incorporating additional considerations to support alternative selection. These considerations included identification of the lowest cost alternative and associated bill impacts, the alternative with the highest Phase 1 NPV, the alternative with the highest combined Phase 1 + Phase 2 NPV, and the projected demand profile over time. Based on the assessment of project cost, Phase 1 NPV and combined Phase 1 and 2 NPV, and the persistence and trajectory of demand[34], Enbridge Gas identified whether projects would be slated to proceed with the facility alternative or continue to be monitored for changes in forecast demand. Four projects were identified to proceed as a facility alternative and were included in the AMP Addendum 2026.

In the review of the alternatives' economic analyses, the TWG members reiterated concerns regarding not quantifying the social carbon costs in Phase 3. In addition, one TWG member noted that the Phase 3 multipliers used do not provide an accurate measure of impacts on jobs and the broader economy. Enbridge Gas restated its position that (1) the DCF+ test should include economic costs and benefits, consistent with OEB's jurisdiction and government policy, and (2) the GDP multiplier reflects the quantifiable flow of economic spending across sectors and is, therefore, an appropriate measure of these benefits. In this meeting Enbridge Gas and the TWG concluded that extensive consultation had been conducted on DCF+ test enhancements, that the positions of parties were well understood and that these positions have been considered. It was, therefore, determined that there was not value in having further discussion on the DCF+ test, and that any further discussion regarding the DCF+ methodology would be best had as part of a proceeding. Enbridge Gas will bring forward its application of the DCF+ methodology through the IRP Framework review and Implementation Plan.

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[33] EB-2020-0091, OEB Decision and Order, Enbridge Gas Inc. Integrated Resource Planning, July 22, 2021, p. 56.
[34] See Appendix F for more detail on the economic evaluation approach and selection considerations as part of the overall screening process.

Section 10 – IRP Planning for 2026

This section provides a high-level summary of the work streams that Enbridge Gas expects to build upon and evolve further in 2026. These work streams are continuations of the work done in 2025.

External Stakeholder Outreach

Enbridge Gas will continue with its external stakeholder efforts including ongoing engagement with municipalities through existing stakeholder engagement relationships, as opportunities to engage on IRP and further develop targeted stakeholder lists.

Enbridge Gas will schedule regional or general stakeholder engagement sessions to support broader understanding of IRP and its process, provide updates on the IRP evaluations on the latest AMP and ongoing IRP initiatives. Feedback received from these stakeholder engagement sessions will be reviewed and considered for subsequent stakeholder sessions. As outlined in Section 5, engagement sessions will be accompanied by a newsletter to ensure subscribers remain informed on material IRP developments.

Enbridge Gas will continue to conduct Indigenous engagement through sharing ongoing IRP updates via the Enbridge Community and Indigenous Engagement newsletter as outlined in Section 5.

As Enbridge Gas continues the monitoring and review of the AMP, additional project specific engagement will be considered as applicable to the project scope. This includes engagement with municipalities, local LDCs and IESO to discuss demand forecasts and constraints in the area, as well as additional engagement with contract customers. Refinements to these processes will be considered with further experience.

Enhancements to the IRP webpage will continue, inclusive of updates to the IRP Pilot Project page, noted in Section 4.

Continued IRP Evaluation and Project Monitoring

Enbridge Gas will continue to conduct IRP screening and evaluation for projects within the capital plan.

An update on the projects reviewed from the AMP Addendum 2026 for the 2025-2034 period will be provided in the AMP Addendum 2027, anticipated to be filed in Fall 2026.

For projects that pass both the technical and economic evaluation, Enbridge Gas would develop and subsequently file a stand-alone non-Pilot IRP Plan application and supporting evidence with the OEB for approval where applicable.

Enbridge Gas will continue to work with Posterity Group as appropriate on updates to the IRP model through refreshing data inputs and refining modelling approaches, assumptions, and methodologies to improve forecasting of peak hourly flow reduction potential and costs. Additionally, Enbridge Gas will continue to refine the assumptions for ETEE and DR based on learnings and findings from the pilot as they become available.

DCF+ Test

Enbridge Gas will continue to consider feedback received in 2025 from the IRP TWG concerning the DCF+ enhancements and will file a submission on the DCF+ test as part of its first non-pilot IRP Plan application.[35]

Pilot Projects

As noted in Section 4, the OEB issued a Decision on the Southern Lake Huron IRP Pilot Project on March 27, 2025. In 2026, Enbridge Gas will continue to execute the SLH IRP Pilot plan included as Appendix H in the 2024 IRP Annual Report and updated as detailed in Section 4. The SLH IRP Pilot will continue to be updated, as necessary, as the IRP Pilot Project is implemented and evaluated. Enbridge Gas will continue to engage the IRP TWG for input and

[35] EB-2020-0091, IRP Planning Decision and Order, July 22, 2021, p. 56-57

review over the term of the pilot. The Pilot ETEE offers are expected to end by December 31, 2026, and the Pilot DR offer is expected to end by March 31, 2027. Pilot final reporting is expected in Q4 2027.

System Pruning

As noted in Section 10, Enbridge Gas has developed the approach for the pilot(s) in consultation with the TWG and initiated implementation of the pilot in 2025. Enbridge Gas will continue with field implementation of the pilot in 2026, inclusive of updating and consulting with the TWG on key elements as appropriate.

Policy Proposals

As per the Rebasing Phase 2 Settlement Proposal, Enbridge Gas agreed to propose an IRP incentive mechanism in its next IRP Plan application to the OEB, to be filed within one year of the date of filing of the Settlement Proposal (November 4, 2024). Enbridge Gas filed its IRP Incentive Mechanism application on November 4, 2025, where it also requested that the application be put into abeyance until the outcome of the IRP Framework Review proceeding is known. On December 22, 2025, the OEB granted the request, and the application currently remains in abeyance.

Framework Consultation

The OEB released a letter on March 27, 2025, outlining it was launching a consultation to support a review and evaluation of its IRP Framework for Enbridge Gas (EB-2025-0125). An OEB Staff report assessing progress implementing the IRP Framework and proposed updates to the IRP Framework was released in October 2025 and a stakeholder meeting was hosted on October 22, 2025, to discuss the proposed updates and solicit verbal comments. In response to the proposed updates, Enbridge Gas filed a written response to OEB staff's Discussion Paper on November 19, 2025. On April 28, 2026, the OEB issued a letter on the next steps for the IRP Framework, concluding its consultation and determining that Enbridge Gas should file an updated IRP Framework for adjudicative review by August 31,2026.

Appendix A: OEB IRP Directives and Progress Towards 2025 Priorities

The table below provides Enbridge Gas's progress toward meeting the Directives as ordered by the OEB in the IRP Decision. This is further described in detail in Rebasing Phase 3 (EB-2025-0064), Exhibit 1, Tab 13, Schedule 5.

Directive Item	Directive	Status
Interruptible rates	The OEB directs Enbridge Gas to study its interruptible rates to determine how they might be modified to increase customer adoption of this alternative service.	Completed – filed with Enbridge Gas's 2024 Rebasing Application (EB-2022-0200, Exhibit 8, Tab 4, Schedule 7). As part of the approved Settlement Proposal, Enbridge Gas received approval to implement negotiated interruptible rates as part of an IRP plan (EB-2022-0200, Decision on Settlement Proposal, Schedule A, Page 50, Issue 28). Enbridge Gas filed the rate design for harmonized- franchise contract rate classes in EB-2025-0064, Phase 3 Exhibit 8, Tab 2, Schedule 2 for OEB approval. The proposed harmonized rate design for interruptible customers provides an increased price spread between firm and interruptible rates compared to the current rate design. The harmonized rate design also provides a predictable cost outcome for customers who choose to elect interruptible service by reducing the variance in the spread of firm and interruptible rates between rate classes and between individual rate classes in each rate class.
Documentation of demand-side IRPAs	The OEB concludes that a document on the best available information for demand-side alternatives would promote more timely development of IRP Plans and directs Enbridge Gas to include a listing in its annual IRP Report. The OEB agrees with Enbridge Gas that supply-side alternatives require case-by-case examination and therefore are not required to be included in the listing.	Completed – list included since 2022 IRP Annual Report. Updated list included in Appendix B - Integrated Resource Plan Alternatives.
Asset Management Plan	The OEB directs that the AMP include information about Enbridge Gas' system needs. This includes providing the status of consideration of IRP Plans regarding meeting system needs, the result of the binary screening, and details on the evaluation.	Completed – most recent version filed with the Enbridge Gas Ontario Asset Management Plan Addendum – 2026 (EB-2020-0091)

DCF+ test enhancement	The OEB directs Enbridge Gas to study improvements to the DCF+ test for IRP and, as applicable, file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.	In progress – will be filed as part of Enbridge Gas's first non-pilot IRP Plan application. The report Use of the Discounted Cash Flow-Plus Test in Integrated Resource Planning (IRP): Report of the IRP Technical Working Group presents the TWG's views on applying the DCF+ economic evaluation methodology.
IRP Website	The OEB also directs the establishment of a website by Enbridge Gas to facilitate the broad sharing of information on IRP stakeholder engagement efforts.	Phase 1 – Completed Phase 2 – Completed See Section 5 for more details on stakeholder engagement.
Technical Working Group	Establishment of a TWG with the OEB directing that membership should include Enbridge Gas, OEB staff, independent experts, and experienced non-utility stakeholders	Completed. The TWG members were selected by OEB Staff as of December 6, 2021 with meetings commencing January 2022. The TWG membership, Terms of Reference and meeting folders with materials and minutes is available at Natural Gas Integrated Resource Planning (IRP) | Engage with Us (oeb.ca)
IRP Deferral accounts	The OEB directs Enbridge Gas to prepare a Draft Accounting Order for the two IRP Costs deferral accounts, consistent with the direction of this decision.	Completed. On August 12, 2021, Enbridge Gas filed its draft accounting orders for the IRP Operating Costs Deferral Account and IRP Capital Cost Deferral Account. From the OEB Settlement Decision for 2024 Rebasing Phase 1 (EB-2022-0200), parties agreed to the modifications made to the IRP Operating Costs Deferral Account and IRP Capital Cost Deferral Account.[36] From the OEB Settlement Decision for 2024 Rebasing Phase 2 (EB-2024-0111), parties agreed that a new IRP System Pruning Deferral Account with a $5 million cap will be created for recording

[36] EB-2022-0200, Exhibit O1, Tab 1, Schedule 2, September 12, 2023, p. 39 and 40,

		incremental costs related to these activities for later recovery.[37]
IRP Pilot projects	The OEB expects that the IRP pilot projects will be selected and deployed by the end of 2022 as proposed by Enbridge Gas. The detailed consideration of IRP pilot projects should commence shortly after the issuance of the IRP Framework with input being sought from the IRP Technical Working Group described in Chapter 10 ("Stakeholder Outreach and Engagement Process").	In progress – See Section 4 for a summary on Pilot Project implementation which will continue as a multi-year priority. The requirement for Enbridge Gas to consult with the IRP TWG on a potential second IRP pilot is currently stayed by the OEB [38]

The table below provides Enbridge Gas's progress toward meeting the 2025 priorities as defined in the 2024 IRP Annual Report and 2024 IRP Technical Working Group report.

Priority	Activity	Status
External Stakeholder Outreach	External stakeholder outreach (including broader discussions with municipalities, regional engagement sessions, and geotargeted engagement in pilot areas)	Completed: • See Section 4 for a summary of the activities completed for the Southern Lake Huron Pilot Project and System Pruning Pilot Project. • See Section 5 for a summary of the activities completed for the stakeholder engagement process and Indigenous engagement.
Continued IRP Evaluations	IRP binary screening, and technical and economic evaluations of system needs in the AMP.	Completed: • See Section 3 for a summary of the IRP Assessment for investments in the AMP Addendum 2026. See Appendix C for a high-level breakdown of the investments screened or evaluated out of the AMP Addendum 2026 for IRP including the associated 2025-2034 forecast. • See Section 9 for a summary of the engagement on the results of economic evaluation and considerations to support alternative selection. See Appendix F, Economic Evaluation section, for a summary of the interpretation of DCF+ results. In-progress:

[37] EB-2024-0111, Exhibit N, Tab 1, Schedule 1, November 29, 2024, p.19-20,
[38] Decision on Threshold Question and Procedural Order No. 2, EB-2025-0333, March 24, 2026, p.2.

Priority	Activity	Status
		• See Section 2 for a summary of refinements to the ETEE model. Posterity Group has incorporated the TWG input received in 2024, and the final report will be available in Q2 2026. Learnings and findings from the SLH Pilot Project will be considered as they become available. • See Section 9 for a summary of the consultation on learnings from the economic evaluation results. These results will inform the IRP Framework review proceeding in 2026.
DCF+ Test	DCF+ Test consultation and methodology	Completed – See Section 9 for a summary of the consultation conducted. The positions of parties are well understood, and Enbridge Gas intends to bring forward its application of the DCF+ methodology with its first non-pilot IRP Plan.
IRP Pilot Project	Pilot project execution	In progress – See Section 4 for a summary on IRP Pilot Project implementation which will continue as a multi-year priority.
System Pruning	Develop its approach to system pruning in consultation with the IRP TWG by end of Q2 2025 and begin implementation of one or two pilots by end of Q1 2026.	In progress – See Section 4 for a summary of system pruning pilot project implementation which will continue as a multi-year priority.
Policy Proposals (for non-pilot IRP Plans)	Role of shareholder Incentives/ performance metrics for IRP, incrementality and use of IRP deferral accounts, treatment of risk, attribution between DSM and IRP.	Complete – IRP Incentive Mechanism application was filed on November 4, 2025 – the application currently remains in abeyance. In progress – the focus of the 2025 consultation prioritized the IRP Incentive Mechanism as opposed to a continuation of consultation on the additional IRP-related policy proposals. In relation to a broader IRP jurisdictional scan, the jurisdictional scan conducted by DNV for system pruning also included information related to non-pipe alternative programs and policies due to the infancy of system pruning activities. The approach for the policy proposals and additional jurisdictional review will be considered alongside the next steps in the IRP Framework Review proceeding.

Priority	Activity	Status
Framework Consultation	Engage in the Framework Review discussions led by OEB Staff during TWG meetings and participate in the Framework Review consultation	Completed – OEB staff engaged the TWG over the course of 2025. Enbridge Gas was a participant in the OEB consultation. The OEB issued a letter in April 2026 on the next steps for the IRP Framework, and has determined that Enbridge Gas should file an updated IRP Framework for adjudicative review by August 31,2026.

Appendix B: Integrated Resource Planning Alternatives

As per the IRP Decision, the IRP Annual Report is to include "a summary of the best available information on demand-side IRPAs, including the types of IRPAs, estimates of cost, peak demand savings, status in Ontario and learnings from pilot projects and other jurisdictions". Additionally, a summary of the best available information on supply-side IRPAs has been included below.

Demand Side IRP Alternatives

Enhanced Targeted Energy Efficiency ("ETEE")

IRPA Overview
Enhanced targeted energy efficiency ("ETEE") programs focus on achieving necessary reductions in a specific geographical area to reduce peak period system demands. ETEE programs could include enhancing existing broad-based Demand Side Management ("DSM") offerings through additional incentives and targeted marketing, or introducing new geo-targeted programs not offered through broad-based DSM. The mix of offerings and measures utilized in an ETEE program is dependent on the scope of the facility investment project under consideration, customer characteristics in the specific project services area, past DSM participation, etc. Broad-based DSM programs have been offered to natural gas customers across Ontario since 1993. On November 15, 2022, the OEB issued its Decision for the Company's 2023-2025 DSM Plan (EB-2021-0002) to guide ongoing broad-based DSM programming. As defined by the OEB in their DSM Letter, the objective of broad-based DSM is "assisting customers in making their homes and businesses more efficient in order to help better manage their energy bills". As ETEE programs focus on peak hour reductions, many ETEE measures would focus on enhancing existing broad-based DSM measures such as space heating equipment and building envelope upgrades. Enbridge Gas is undertaking the IRP Pilot Project (EB-2022-0335) to develop an understanding of how to design, deploy and evaluate ETEE programs and how ETEE programs impact peak hour demand within a geo-targeted area. The learnings from these IRP Pilots, as well as any non-pilot IRP Plans, will be incorporated into future iterations of the IRP Annual Report's Appendix B, "Demand Side Alternatives".
IRPA Peak Impacts
Forecast peak impacts will be estimated on a case-by-case basis depending on the ETEE program. Enbridge Gas worked with Posterity Group to build an end-use model of its service territory with the 2019 Achievable Potential Study ("APS") being the starting point for the IRP model. First, a mirror model of the APS was created and then several adjustments were made to better reflect Enbridge Gas's knowledge and experience of the Ontario DSM market, Enbridge Gas's current Technical Resource Manual (TRM) assumptions, and known changes to applicable standards.[39] Posterity Group then worked with Enbridge Gas to develop peak factors which were added to the IRP model so that enhanced targeted energy efficiency peak hour impact estimates could be developed for each region, sector, segment, and end use.[40] Posterity Group's IRP model is run through Posterity's

[39] Posterity Group report detailing the development and assumptions of the underlying mirror model (EB-2021-002, Exhibit E, Tab 4, Schedule 7, Attachment 1 – "Demand Side Management Planning Support Final Report Documenting Data Inputs, Assumptions and Method (April 2021)" - Link

[40] Posterity Group memo on peak modelling methodology and hours-use peak factor assumptions (filed as part of EB-2022-0157 (PREP) – Exhibit I.ED.7, Attachment 4) - Link. Posterity Group memo on calculation of peak reduction on an efficiency measure (July 2022) - Link

Navigator software, where the details in how the Navigator software works and how the model parameters interact with each other are available and documented.[41] Posterity Group and Enbridge Gas work to evolve this model by refining assumptions and assessment methodologies to refine and improve forecasting of peak hourly flow reduction potential. It is expected that the ETEE programs as part of the IRP Pilots will provide greater insight on the peak impacts of such programs.
IRPA Cost Details
Costs will be determined on a case-by-case basis depending on the ETEE program. The Posterity model described above also includes cost assumptions for ETEE programs, based largely on the APS, with adjustments made in an attempt to better reflect Enbridge Gas' knowledge and experience of the Ontario DSM market.[42] Posterity Group and Enbridge Gas evolve this model as required by refining assumptions and assessment methodologies so it can be used to assess project specific costs for an ETEE program. It is expected that the ETEE programs as part of the IRP Pilots will provide greater insight on the costs of such programs.
IRPA Deployment Strategy
The selection of energy efficiency measures for an ETEE program and the deployment strategy would be dependent upon the scope of the facility investment project under consideration, customer characteristics in the specific project service area, past DSM participation, etc. The IRP Pilots will provide insights that could guide the deployment strategy of future IRP ETEE programs. The pilots could also provide insights on the deployment strategy into the richness of customer ETEE incentive levels and the intensity of the ETEE program delivery approaches for various customer groups to drive the participation uptake levels necessary to meet peak demand reduction requirements.
IRPA Solution Timing
Timing on an ETEE IRPA solution is dependent upon the scope of the facility system need under consideration, the type of ETEE program(s) being considered, and the customer characteristics in the specific project service area. A high-level estimate of a 3-to-5-year minimum lead time would be required to support program implementation and deployment, and subsequent performance measurement to evaluate the impact to the system peak hour. ETEE can be deployed with supply-side IRPA(s) to defer the system need and ensure that Enbridge Gas can reliably meet peak hour system demand requirements while demand-side ETEE IRPA(s) are implemented.
IRPA Implementation Risks/Challenges
There are several operational risks related to ETEE: - Principle of universality (offering different DSM programing and incentives to different customers). - Undersubscription of ETEE programming to meet peak demand requirements to delay or avoid the facility system need. - Uncertainty on the reliability of peak reduction capabilities of ETEE measures to be delivered in a cost-effective manner for facility planning. - Coordination of timing between fully effective ETEE IRPAs and meeting the system needs.

[41] Posterity Group, Enbridge's Navigator End-Use Model Presentation: Posterity (Enbridge's Navigator End-Use Model) and "Navigator Energy and Emissions Simulation Suite – Functional Specification Document" (filed in EB-2022-0200 – Exhibit I.1.10-SEC-29, Attachment 1) - Link

[42] Posterity Group report detailing changes to reference case assumptions on DSM measures (EB-2021-002, Exhibit E, Tab 4, Schedule 7, Attachment 1, Appendix A) – "Demand Side Management Planning Support Final Report Documenting Data Inputs, Assumptions and Method (April 2021)" - Link

- Current lack of experience in implementing ETEE programming; DSM expertise in delivery programming has been broad-based.
- Variances in energy planning and the lack of coordinated energy planning between gas utilities, electric distributors and the IESO. Risk of insufficient electrical capacity to absorb electric measures as part of an ETEE program.

Learnings from Pilot Projects/Other Jurisdictions

Enbridge Gas filed a Geo-Target Demand Side Management Case Study in EB-2020-0091 at Exhibit C, Appendix A. The objectives of the case study were:

1. Assessment of the impacts of geo-targeted DSM programs on reducing peak hour demand.
2. Assessment of the costs of geo-targeted DSM program implementation.

The results from this case study only illustrate the impacts geo-targeted DSM had on the town of Ingleside and although informative and directional, the results cannot be generally applied due to the specific nature of customer composition.

In 2022, Enbridge Gas engaged Guidehouse to undertake a jurisdictional review of ETEE and DR natural gas pilots implemented for general service customers, where the pilots' objectives were to defer or avoid infrastructure.[43] Guidehouse focused on three jurisdictions, summarizing the pilot objectives, marketing activities, costs, findings, and challenges faced. Additionally, Guidehouse noted challenges in data availability in completing the jurisdictional review.

As part of the first-generation IRP Framework, the OEB determined that it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs. However, a limited number of electrification measures are included in the Southern Lake Huron pilot project and System Pruning pilot.

In 2023, Enbridge Gas undertook some jurisdictional research in-house to better understand how non-pipeline electric alternatives could be offered more broadly in the future, including attending industry webinars.44 High-level learnings include that the Colorado Public Utilities Commission includes beneficial electrification as a non-pipeline alternative to offset gas infrastructure investments in the long-term.[45] [46] The New York Public Commission encourages gas utilities in New York to offer building electrification as a non-pipeline alternative as part of a program to remove leaking or leak-prone gas infrastructure. In California, the California Public Utilities Commission considers electrification as a non-pipeline alternative to meet energy needs in utilities gas-planning activities, and one utility is offering a small electrification program to facilitate the retirement of gas assets.47 Additionally, the California Energy Commission is funding two building electrification and gas infrastructure decommissioning pilots.[48] Many of the utilities reviewed in other jurisdictions are dual-fuel utilities with ability to coordinate internally, whereas Enbridge Gas would require coordinated planning with the IESO and LDCs to consider similar electrification plans. Enbridge Gas intends to continue its jurisdictional research into non-pipeline electric alternatives as part of its IRP demand-side alternatives, and of jurisdictions seeking to electrify customers as a means to decommission natural gas distribution pipelines.

In 2025, DNV was engaged to conduct a jurisdictional scan to support the development of the System Pruning pilot approach.[49] The purpose of this study was to better understand and gain insights into how gas utilities among

[43] IRP ETEE-DR Pilot Review April 8, 2022 Guidehouse (IRP ETEE-DR Pilot Review)
[44] TWG Meeting #32 (December 12, 2023) (link)
[45] Strategen, Non-Pipeline Alternatives: A Regulatory Framework and a Case Study of Colorado, October 2023. (link)
[46] Berkley Lab, Not Just a Pipe Dream: Non-Pipeline Alternative Framework Analysis and Experiences. (link and recording)
[47] Strategen, Non-Pipeline Alternatives to Natural Gas Utility Infrastructure: An Examination of Existing Regulatory Approaches, November 2023. (link)
[48] California Energy Commission, Gas Research and Development Program Proposed Budget Plan for Fiscal Year 2023-2024, May 2023. CEC-500-2023-020.pdf (ca.gov)
[49] Engage with us, OEB (link)

North American and European jurisdictions are approaching pruning to their gas distribution pipelines, where informative to the Ontario context. The scan covered six utilities/jurisdictions – five were selected as they have planned or undertaken system pruning or non-pipeline activities, and one was selected because of their successful collaboration activities amongst the gas and electric utilities within that jurisdiction. Of the six studied jurisdictions, only two (California and New York) have completed actual system pruning projects. The study found that system pruning is a utility action in its infancy. Among the reviewed jurisdictions, the primary driver of system pruning or non-pipeline alternative activities is a policy framework centered around climate and equity. Although considerations about system cost represent a concern, it was not explicitly cited as the driver to policies that promote system pruning and NPAs.

Demand Response ("DR")

IRPA Overview
Natural gas demand response aims to reduce natural gas customers' demand during peak periods. For residential and commercial customers, this can commonly be seen in the form of gas demand reductions during DR program events via thermostat control or water heater temperature settings. For contract customers, this can be done through leveraging interruptible rates. Demand response would include: 1. Negotiable interruptible rate - as detailed in Section 9, the use of interruptible rates was reviewed as part of the IRP Framework Decision, and Enbridge Gas filed an Interruptible Rate Study that evaluated the use of demand response in the context of future IRP Plan Application where applicable. 2. Utilization of another alternative (i.e., onsite CNG) when a peak hour/day event is called. 3. Incentives to shift peak hourly demands to off-peak periods. Enbridge Gas is undertaking the IRP Pilot Project (EB-2022-0335) to develop an understanding of how to design, deploy and evaluate residential DR programs and how residential DR programs impacts peak hour demand within a geo-targeted area. The learnings from the IRP Pilot, as well as any non-pilot IRP Plans, will be incorporated into future iterations of the IRP Annual Report's Appendix B, "Demand Side Alternatives".
IRPA Peak Impacts
Peak impacts will be determined on a case-by-case basis depending on the DR service (e.g., program, rate design etc.). As a starting point for a residential space heating smart thermostat program, an estimated impact of 18.5% peak gas (m3/hr) reduction was developed based on the evaluation of SoCal's residential smart thermostat DR program[50] and adjusted for Ontario climate/buildings.[51] It is expected that the residential DR program as part of the IRP Pilot Projects will provide greater insight on the peak impacts of such a program.
IRPA Cost Details
DR IRPA costs will be determined on a case-by-case basis depending on the DR service (e.g., program, rate design etc.). It is expected that the residential DR program as part of the IRP Pilot Projects will provide greater insight on the actual costs to deploy such a program.

[50] https://www.calmac.org/publications/SoCalGas_2019_DR_Evaluation_Report_-_PUBLIC_FINAL.pdf
[51] Adjustment for Ontario climate/buildings provided on p.2 - Link

IRPA Deployment Strategy
The deployment strategy will be determined on a case-by-case basis depending on the customer mix and characteristics in the project area. The IRP Pilot residential DR program will provide insights that could guide the deployment strategy for future programming. For contract rate customers, as part of the IRP evaluation process, Enbridge Gas engages with all contract customers in the project area to assess whether those customers could reduce their peak demands, convert their firm demand service to interruptible service or leverage another fuel source.
IRPA Solution Timing
DR IRPAs are dependent upon the scope of the facility system need under consideration, the type of DR program being considered, and the customer characteristics in the specific project service area. The IRP Pilot residential DR program will provide insight on the time required to design a DR program and to deliver a DR program to reach participation levels required to inform future assessment for specific facility IRPAs. Engagement of contract rate customers will occur as part of the detailed technical assessment.
IRPA Implementation Risks/Challenges
There are several operational risks related to a residential DR program: • Principle of universality (offering DR programing/incentives to different geographically specific customers) • Undersubscription and lack of persistent participation of DR programming to meet peak demand requirements of the delay or avoidance of facility system need • Uncertainty on the reliability of cost-effective DR performance for facility planning • Coordination of timing between fully effective DR IRPAs and meeting the system needs • Current lack of experience in implementing DR programming; Enbridge Gas has not previously implemented a gas-DR program for general service customers.
Learnings from Pilot Projects/Other Jurisdictions
In 2022, Enbridge Gas engaged Guidehouse to undertake a jurisdictional review of ETEE and DR gas pilots implemented for general service customers, where the pilots' objectives were to defer or avoid infrastructure [52]. Guidehouse focused on three jurisdictions, summarizing the pilot objectives, marketing activities, costs, findings, and challenges faced. Additionally, Guidehouse noted challenges in data availability in completing the jurisdictional review.

[52] IRP ETEE-DR Pilot Review April 8, 2022 Guidehouse (IRP ETEE-DR Pilot Review)

Supply Side IRP Alternatives

Compressed Natural Gas ("CNG")

IRPA Overview
CNG is a mobile solution that can be used in place of traditional pipeline reinforcement to meet customer demands at peak hours on peak days. Natural gas is compressed into large tube trailers and moved by trucks from the compression station "hub" to a mobile decompression station "spoke" where the gas is delivered into the pipeline. This is an active control best utilized in long, single feed pipe networks with cold weather peaking loads. Hub stations are situated in relative proximity to spoke stations (within 200 kms) to minimize driving distance.
IRPA Peak Impacts
CNG targets peak hours on peak demand days, where the injection of gas back into the system at the spoke station would have an equivalent 1 for 1 offset of gas otherwise required to flow through the traditional pipeline bottleneck. Injecting near the low-pressure point on the system would magnify the benefit beyond 1 for 1 on a hydraulic basis. Although the trailered gas will need to be withdrawn from the system at the hub station, this can be done at off-peak times and locations and where capacity is available.
IRPA Cost Details
From a capital cost perspective: • Tube trailers typically have a capacity of 10,000 m^3 of natural gas (at standard conditions) and cost approximately $700,000 per trailer with a 15-year useful life. • Hub and spoke stations costs can vary based on capacity requirements, but typically cost approximately $300,000 and $3M per station, respectively, with a 20+ year useful life. Capital costs may be impacted by the procurement strategy of utilizing a third-party vendor or procurement of the asset by Enbridge Gas. From an operational cost perspective, the equipment requires regular maintenance and supervised operation. Drivers are also required to drive the trailers between the hub and spoke stations with highway tractors.
IRPA Deployment Strategy & Timing
The equipment is mobile and can be deployed in various locations throughout the province. CNG would be most ideal in areas where the gas demands are large enough to achieve economies of scale but small enough to be practical. For instance, the transmission pipeline scale is too large as it may require hundreds of trailers, but a few households would be too small as a single trailer will be underutilized. Additional consideration based on location would impact the suitability of CNG as a solution, such as urban versus rural and the number of trucks required. Depending on the system need and location, CNG can be a suitable bridging solution for ETEE implementation or for the deferral of baseline facility projects as system needs may evolve, inclusive of the energy transition landscape in Ontario. CNG can be deployed in a relatively short amount of time, and can be scalable by the addition of mobile compressor stations and trailers.
IRPA Implementation Risks/Challenges
The biggest risk associated with this solution is a potential disruption in the supply of trailers to the spoke station, for instance road closure due to weather or an accident while in transit. To mitigate this risk, extra trailers can be made available on-site at the spoke station and the associated additional costs would need to be considered when assessing the viability of this IRPA.

Market-Based Supply

IRPA Overview

Market-based supply-side IRP alternatives include incremental natural gas deliveries or pressure increases at specific interconnects between Enbridge Gas's system and other pipelines, such as the TC Energy Mainline and US based pipelines including Panhandle Eastern Pipeline Company and Vector. These alternatives are considered in the IRP assessment as governed by the IRP framework and are incremental to the options previously considered as part of gas supply planning, as governed by the Gas Supply Framework. Contracting for market-based supply-side alternatives into Enbridge Gas's franchise area, where applicable and available, can reduce, defer or mitigate traditional infrastructure by meeting incremental natural gas demands in a defined area through incremental deliveries or increased pressures.
IRPA Peak Impacts
Incremental deliveries or increased pressure must be delivered in the project area to impact peak hour demands. Therefore, market-based supply side alternative options are limited to interconnects with TC Energy along the mainline and Enbridge Gas's system or with interconnects with other pipelines that connect to Enbridge Gas's system such as Parkway, Ojibway and Dawn.
IRPA Cost Details
Market-based supply-side alternative costs are based on market dynamics at the time of contracting. Enbridge Gas cannot forecast the cost of market-based supply-side options on a long-term basis. The IRPA costs will be incremental to options previously considered under gas supply planning, as governed by the Gas Supply Framework.
IRPA Deployment Strategy and Timing
Enbridge Gas can contract and deploy market-based supply-side alternatives if the deliveries from a third party or pipeline are available. While U.S. interstate pipelines regulated by the Federal Energy Regulatory Commission are permitted to offer both short-term and long-term transportation services, access to incremental capacity at specific interconnects is subject to upstream capacity availability, tariff terms, and commercial negotiations. In practice, opportunities to secure market-based supply-side services from U.S. pipelines are market condition dependent, and may be limited in duration, and location. As many of Enbridge Gas's interconnects are with U.S. pipelines, these factors must be assessed on a case by case scenario to determine the extent to which market-based supply-side services can be relied upon as IRP alternatives.
IRPA Implementation Risks/Challenges
There are two primary operational risks with market-based supply-side alternatives: limited availability of incremental capacity and delivery risk. Market-based supply side alternatives rely on availability of incremental capacity at specific interconnects, which is contingent upon upstream pipeline conditions and competing market demand, particularly during peak periods. As a result, while market-based supply-side alternatives may be used to defer a facility project in the near term where capacity is available, their ability to fully mitigate a need over the planning horizon is uncertain. In instances, a market-based supply-side alternative could be used to defer a project in the short-term and then the need and IRP alternatives will need to be reassessed. While Enbridge Gas may have contracted for a market-based supply side alternative, if the capacity underpinning the service is not firm, then natural gas market dynamics may cause the supplier to fail on its delivery obligations. For example, without firm capacity underpinning the market-based service, during peak weather events upstream pipeline systems may become constrained and non-firm services can be curtailed. If the service provider is relying on non-firm services, it may be unable to supply natural gas to Enbridge Gas. While contract penalties and other contract language may limit most events like the example above from happening, it remains a legitimate and

material risk. If the contracted service was not delivered as planned, Enbridge Gas could have insufficient gas supply deliveries to meet its market demands; potentially resulting in a system outage during the coldest periods of the year. While Enbridge Gas would collect financial penalties, if applicable, after the event occurred, Enbridge Gas would still need to deal with the physical and customer impacts that resulted due to the failed delivery of the incremental gas on that day.

Appendix C: IRP Screening and Evaluation Results

This section includes the following summaries on the IRP screening and evaluation results:

- Investments that did not pass the initial screening stage are included in Table 1
- Investments that did not pass the binary screening stage are included in Table 2
- Investments that did not pass the technical screening stage are included in Table 3 [53]
- Investments that did not pass the technical evaluation stage are included in Table 4
- Investments that did not pass the economic evaluation stage are included in Table 5

Table 1 – Breakdown of Investments Screened out in Initial Screening of the 2025-2034 AMP for IRP

Category	2025-2034 Forecast (Includes overhead allocation)	# of Investments
Non-Gas Carrying	$1,048M	334
Grand Total	**$1,048 M**	**334**

Table 2 – Breakdown of Investments Screened out in Binary Screening of the 2025-2034 AMP for IRP

Category	2025-2034 Forecast (Includes overhead allocation)	# of Investments
Customer Connection – related projects are required to serve new customers connected in accordance with guidelines of EBO 188. The OEB concluded that as part of the first-generation IRP Framework it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs.	$1,231.7 M	112
Customer Specific Build - If an identified system constraint/need has been underpinned by a specific customer's (or group of customers') clear request for a facility option and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities, then it is not appropriate to conduct IRP analysis for those projects.	$127.1 M	8
Dollar Threshold - If a facility project is being advanced for replacement or relocation of a pipeline and the cost is less than the minimum project cost that would necessitate a Leave to Construct approval, then an IRP evaluation is not required.	$455.1 M	634
Economic Development - If a facility project has been driven by government legislation or policy with related funding explicitly	$7.8 M	2

[53] Appendix F, Table 1 outlines investment categories screened out for IRP at the technical screening stage and the associated rationale.

aimed at delivering natural gas into communities, then an IRP evaluation is not required		
Emergent Safety - If an identified system constraint/need is determined to require a facility project for Enbridge Gas to offer safe and reliable service or to meet an applicable law, an IRP evaluation is not required.	$13.8 M	6
Timing – If an identified system constraint/need must be met in under 3 years, an IRPA cannot be implemented and its ability to resolve the identified system constraint/need cannot be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need.	$0.01 M[54]	1
Grand Total	**$1,835.5 M**	**763**

Table 3 – Breakdown of Investments Technically Screened out of the 2025-2034 AMP for IRP

Category	2025-2034 Forecast (Includes overhead allocation)	# of Investments
NPS 2, cannot downsize or retire	$16.3 M	6
Compression Station related projects are required to maintain existing deliverability and throughput. This is necessary to maintain security of supply and stable natural gas pricing during supply disruptions.	$453.4 M	628
Storage Pools & Well related projects are required to maintain existing deliverability and throughput. This is necessary to maintain security of supply and stable natural gas pricing during supply disruptions.	$108.6 M	88
Hydrogen related projects are required as no IRPAs can replace the hydrogen feasibility assessments and hydrogen blending initiatives.	$7.96 M	1
Distribution station condition related, IRPA not applicable	$365.8 M	544
Additional Screening for Investment descriptions where IRPAs are not applicable[53]	$2,255.4 M	324
Project Status/Timing Related	$251.4 M	19
Grand Total	**$3,458.9 M**	**1610**

The category in Table 3 with the highest capital costs is “Additional Screening for Investment descriptions where IRPAs are not applicable” [53].

[54] Investment #103275 (ISD 2022, Growth asset class) was binary screened out for “Timing” in the 2023-2032 Asset Management Plan. The $0.01 M amount pertains to final project closeout costs.

Table 4 – Breakdown of Investments Technically Evaluated out of the 2025-2034 AMP for IRP

Category	2025-2034 Forecast (Includes overhead allocation)	# of Investments
Potential project scope could be replaced with NPS 2. IRPAs not applicable and scope to be confirmed when project enters the detailed design phase.	$152.2 M	55
IRPAs unable to defer, reduce or eliminate project scope.	$2.9 M	1
Grand Total	**$155.1 M**	**56**

Table 5 – Breakdown of Investments Economically Evaluated out of the 2025-2034 AMP for IRP

Category	2025-2034 Forecast (Includes overhead allocation)	# of Investments
Facility alternative is the optimal solution, and the project scope will be monitored. Annual review of the facility and IRP alternatives will be conducted to confirm optimal solution prior to alternative implementation.[55]	$30.1 M	20
Pilot Project	$0.3 M	1
Grand Total	**$30.4 M**	**21**

[55] The facility was the optimal solution at both the Ph1 and Ph1+2 level for the investments evaluated.
For the subset of investments applicable to supply-side alternatives, a cost reduction in the range of 85% to 150% would be required for the supply-side alternative to achieve parity with the facility alternative at Ph 1 and Ph 1+2. This outcome is driven by the need to construct a facility once the supply-side deferral period ends.

For the subset of investments applicable to demand-side alternatives, a cost reduction in the range of 100% to 150% was required for the demand-side alternative to achieve parity with the facility alternative at Ph 1 and a cost reduction in the range of 50% to 150% at Ph1+2. This outcome is driven by relatively higher demand-side implementation costs compared to the achievable cost savings.

Appendix D: IRP Screening Results for Facility Applications

This section provides a summary of any on-going facility applications or facility applications where an OEB Decision was provided in 2025.This section does not include LTC Exemption Applications.[56]

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
EB-2023-0343	East Gwillimbury Community Expansion Project			Fail	Enbridge Gas has applied the Binary Screening Criteria and determined this Project meets the definition of a community expansion project, as defined in the IRP Framework, as the Project has been approved by the government of Ontario as part of the Phase 2 NGEP, to provide access to natural gas services in the Town of East Gwillimbury. The IRP Framework Decision explains that "Given the goal of the Ontario Government's Access to Natural Gas legislation to extend gas service to designated communities, the OEB will not require Enbridge Gas to develop an IRP Plan or consider alternatives to the infrastructure facilities to meet this need.	Proceeding is currently in progress.
EB-2024-0187	Boblo Community Expansion Project			Fail	Enbridge Gas has applied the Binary Screening Criteria and determined this Project meets the definition of a community expansion project, as defined in the IRP Framework, as the Project has been approved by the government of Ontario as part of the Phase 2 NGEP, to provide access to natural gas services in the Town of East Gwillimbury. The IRP Framework Decision explains that "Given the goal of the Ontario Government's Access to Natural Gas legislation to extend gas service to designated	Proceeding is currently in progress.

[56] On September 24,2024, the OEB released new Filing Requirements applicable for exemption on hydrocarbon line projects that cost between $2M and $10M, where information on project need and alternatives are not required.

Filed: 2026-07-30, EB-2026-0108, Exhibit G, Tab 2, Schedule 1, Page 53 of 141

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
					communities, the OEB will not require Enbridge Gas to develop an IRP Plan or consider alternatives to the infrastructure facilities to meet this need.	
EB-2024-0200	St. Laurent Pipeline Replacement Project				As this is a pipeline integrity project, the IRP Analysis for this project was limited to whether the proposed pipeline size can be reduced, as neither a supply side or demand side alternative would adequately address the corrosion and third party damage risk. Enbridge Gas reviewed potential IRPA such as incremental gas supply, trucked CNG, ETEE and for contract customers to de-contract or convert existing firm service to an interruptible service. These alternatives were found to not be technically feasible or viable solutions.	OEB Decision dated March 18, 2025: The OEB grants Enbridge Gas's application for leave to construct the project. The OEB finds that the Project is in the public interest based on an examination of the Project need, alternatives, cost and economics, environmental impacts, land use requirements, and Indigenous consultation. The OEB finds that Enbridge Gas's consideration of alternatives, which included facility and non-facility alternatives, is sufficient to demonstrate that full replacement is the preferred option in this case.
EB-2024-0304	2025 Waubuno Well Drilling Project				Enbridge Gas has applied the Technical Screening Criteria and determined that the Project Need does not warrant further IRP consideration as this project is driven by the need to maintain deliverability and throughput.	On May 8, 2025, the OEB issued a report to the Minister of Natural Resources recommending the issuance of a well drilling license to Enbridge Gas for the well, subject to certain Conditions of License.
EB-2024-0322	Kimball-Colinville and Bickford MOP Increase Project				Enbridge Gas is undertaking this project to increase the storage capacity of the Kimball-Colinville and Bickford Storage Pools. Since the underground storage reefs are finite containers with defined boundaries, the only way to physically increase the storage capacity of the reefs is to increase the MOP, allowing more gas to be stored in the reef. Enbridge Gas stated that it is	OEB Decision dated May 13, 2025: The OEB grants Enbridge Gas approval to increase the MOP of the Kimball-Colinville and Bickford Storage Pools subject to certain conditions. The OEB accepts Enbridge Gas's assessment that there are no alternatives to increase the

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
					not aware of any alternative to increase the capacity (volume) in the reef.	storage capacity of the Storage Pools other than through an increase in the MOP.
EB-2025-0073	Mississauga Reinforcement Project	Fail			Enbridge Gas has applied the Binary Screening Criteria and determined that this Project meets the definition of a Customer-Specific Build, as defined in the IRP framework, Customer-Specific Builds Customer-Specific Builds – if an identified system need has been underpinned by a specific customer's (or group of customers) clear request for a facility project and either the choice to pay a Contribution in Aid of Construction or contract for long-term firm services delivered by such facilities, then an IRP evaluation is not required.	OEB Decision dated February 19, 2026: The OEB grants Enbridge Gas's application for the leave to construct the project. The OEB finds that the Project is in the public interest based on an examination of the Project need, alternatives, cost and economics, environmental impacts, land use requirements, and Indigenous consultation. The OEB finds that Enbridge Gas's consideration of alternatives, which included facility and non-facility alternatives, is sufficient to demonstrate that full replacement is the preferred option in this case.
EB-2025-0271	Washago Community Expansion Project			Fail	Enbridge Gas has applied the Binary Screening Criteria and determined this Project meets the definition of a community expansion project, as defined in the IRP Framework, as the Project has been approved by the government of Ontario as part of the Phase 2 NGEP, to provide access to natural gas services in the community of Washago and surrounding areas. The IRP Framework Decision explains that "Given the goal of the Ontario Government's Access to Natural Gas legislation to extend gas service to designated communities, the OEB will not require Enbridge Gas to develop an IRP Plan or consider alternatives to the infrastructure facilities to meet this need.	Proceeding is currently in progress.

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
EB-2025-0301	Port Colborne Reinforcement Project	Fail			Enbridge Gas applied the IRP Binary Screening Criteria and determined that this Project meets the definition of a Customer-Specific Build, as defined in the IRP Framework: Customer-Specific Builds – If an identified system need has been underpinned by a specific customer's (or group of customers') clear request for a facility project and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities, then an IRP evaluation is not required.	Proceeding is currently in progress.
EB-2025-0306	Lanark and Balderson Community Expansion Project			Fail	Enbridge Gas has applied the Binary Screening Criteria and determined that because the Project is a community expansion project driven by government legislation, an IRP evaluation is not required. In its Decision and Order on the IRP Framework, the OEB explains that "[g]iven the goal of the Ontario Government's Access to Natural Gas legislation to extend gas service to designated communities, the OEB will not require Enbridge Gas to develop an IRP Plan or consider alternatives to the infrastructure facilities to meet this need.	Proceeding is currently in progress.
EB-2025-0307	Waubuno Gathering System and Compressor Replacement Project				Enbridge Gas has applied the Technical Screening criteria and determined that the Project Need, does not warrant further IRP consideration. This project is required to maintain existing physical storage space capacity and capability.	Proceeding is currently in progress.
EB-2025-0293	2026 Kimball-Colinville Well Drilling Project				Enbridge Gas has applied the Technical Screening criteria and determined that the Project need does not warrant further IRP consideration as the Project is driven by the need to maintain existing injection and withdrawal capability and system	Proceeding is currently in progress.

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
					throughput. This is necessary to maintain security of supply and stable natural gas pricing during supply disruptions.	

Appendix E: Technical Working Group Report

Review of Enbridge Gas Inc. 2025 Integrated Resource Planning (IRP) Annual Report and Update on IRP Working Group Activities

From: Integrated Resource Planning Technical Working Group

May 29, 2026

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1. Introduction and Overview of IRP Working Group

The Ontario Energy Board (OEB) established a first-generation Integrated Resource Planning (IRP) Framework for Enbridge Gas through its July 22, 2021 Decision and Order (IRP Decision). The IRP Decision directed the OEB to establish an IRP Technical Working Group (Working Group) and required that a Working Group report be filed in the same proceeding as Enbridge Gas's annual IRP report. The Working Group was formed and announced in a letter issued by the OEB on December 6, 2021, and has been active since then.

This Working Group report provides:

- The Working Group's review of Enbridge Gas's Annual IRP Report and comments on Enbridge Gas's implementation of the IRP Framework in 2025 and priorities for 2026, including individual member comments or concerns. (**Chapter 2**)
- A summary of activities undertaken by the Working Group from mid-June 2025 to the end of 2025. Activities prior to this are covered in the previous Working Group report.[1] (**Chapter 3**)

The Working Group report was prepared by OEB staff with input from all current Working Group members and approved by them as an accurate summary of the Working Group's activities.[2] This report clearly indicates where opinions expressed in the report do not reflect the views of all members.

1.1. Overview and Membership of IRP Working Group

The Working Group was established with an objective to provide input on IRP issues that will be of value to both Enbridge Gas in implementing IRP and to the OEB in its oversight of the IRP Framework. Members of the Working Group were determined through a call for nomination process where the OEB selected non-utility members, representatives from the OEB and Enbridge Gas, and an observer from the Independent Electricity System Operator (IESO). Other Enbridge Gas representatives also attend Working Group meetings as required, depending on the topics under discussion. For example, Catherine McCowan leads the system pruning work

[1] Previous Working Group reports have included details of Working Group activities beyond the end of the calendar year until near the date of report issuance. In order to align with the time period covered by Enbridge Gas's annual IRP report, this year's Working Group report only includes activities up to the end of 2025 (and thus covers a shorter time period than previous reports).
[2] The Working Group includes an observer from the Independent Electricity System Operator. As noted in the Working Group's Terms of Reference, any materials authored by the IRP Working Group (including this report) should not be considered to represent the views of Working Group observers or their organizations.

for Enbridge Gas and Eric Buan leads the work on the Southern Lake Huron Pilot and attended Working Group meetings in these capacities in 2025.

There were no Working Group member changes over the past year:

Table 1: Current IRP Working Group Membership

Name	Role
Michael Parkes	OEB staff representative (Working Group chair)
Stephanie Cheng	OEB staff representative
Alison Moore	Enbridge Gas representative
Whitney Wong	Enbridge Gas representative
Helen Tong	Enbridge Gas representative
John Dikeos, ICF Consulting Canada Inc.	Non-utility member
Tamara Kuiken, DNV Inc.	Non-utility member
Cameron Leitch, Enwave Energy Corporation	Non-utility member
Chris Neme, Energy Futures Group	Non-utility member
Dwayne Quinn, DR Quinn & Associates Ltd.	Non-utility member
Jay Shepherd, Shepherd Rubenstein Professional Corporation	Non-utility member
Stuti Rungee, Independent Electricity System Operator	Observer

Meeting notes and materials for all IRP Working Group meetings are published on the OEB's website following meetings to document key discussion points and to allow stakeholders to follow the Working Group's progress.[3] These materials can be found at: https://engagewithus.oeb.ca/irp

[3] Meeting materials are typically posted online shortly after the meeting. Meeting notes are not typically posted until after the following meeting, to allow for members to review draft notes and identify any omissions or inaccuracies.

2. Review of Enbridge Gas's Annual IRP Report and Comments on IRP Framework Implementation

Per the IRP Decision, the Working Group is expected to review a draft of Enbridge Gas's annual IRP report. The review is coordinated by OEB staff.

Enbridge Gas is expected to provide the Working Group with a draft of its annual IRP report far enough in advance of its planned filing with the OEB to allow the Working Group adequate time to review and comment. The IRP Decision also stipulates that the Working Group report should include any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved within the Working Group.

Consistent with prior years, the Working Group's review took the following steps:

STEP 1:

Enbridge Gas

Provided a draft of its 2025 IRP annual report to the Working Group for review.

STEP 2:

Working Group Members

Provided suggested edits/ comments/ clarifying questions.

STEP 3:

Enbridge Gas

Revised and finalized its annual report.

- Enbridge Gas discussed member comments at the April 8, 2026 meeting.
- Enbridge Gas subsequently finalized its annual report, documenting how it addressed comments from Working Group members. Final determinations as to the contents of Enbridge Gas's IRP annual report were made by Enbridge Gas, not the Working Group.

Working Group Members

STEP 4:

Provided final individual comments on implementation of the IRP Framework for inclusion in the Working Group report.

Member comments are discussed further below in Section 2.1.

2.1. Working Group Comments on the Implementation of the IRP Framework and 2026 IRP Priorities

Working Group members reviewed Enbridge Gas's description of its IRP activities in its 2025 IRP annual report (sections 1-9 of the annual report, plus relevant appendices) and also the IRP work streams identified by Enbridge Gas for 2026 (section 10).

To categorize its 2026 IRP priorities, Enbridge Gas used the same work streams as in 2025:

- External Stakeholder Outreach
- Continued IRP Evaluation and Project Monitoring
- Discounted Cash Flow-Plus (DCF+) Test
- Pilot Projects
- System Pruning
- Policy Proposals
- Framework Consultation

Specific new activities identified by Enbridge Gas for 2026 include:

- Working with Posterity Group on updates to the IRP model to improve forecasting of peak hourly flow reduction potential and costs, and refining modeling assumptions based on learnings and findings from the pilot as they become available.
- Continued execution of the Southern Lake Huron IRP Pilot plan, including implementation, wind-down, and evaluation and reporting, and engaging the Working Group for input and review on these actions.

- Field implementation of the system pruning pilot, inclusive of updating and consulting with the Working Group on key elements as appropriate.
- Next steps in the IRP Framework Review, contingent on OEB direction.

Working Group members (except observers) were asked the following question:

> ***Having reviewed Enbridge Gas's description of its IRP activities in the previous year in its final 2025 IRP annual report and having also participated in the IRP Working Group, do you have any comments and/or concerns with the implementation of the IRP Framework in 2025? Do you have any comments or concerns regarding the priority IRP work streams Enbridge Gas has identified for 2026 (section 10 of the Enbridge Gas annual IRP report)?***

Working Group members generally viewed 2025 as a year of incremental but still insufficient progress on IRP implementation. Members were pleased with the much-awaited implementation of the Southern Lake Huron IRP pilot and the continued development of the system pruning pilot as important steps that are expected to yield useful learnings. However, members generally expressed ongoing frustration that IRP progress remains slower than originally contemplated, in that five years after the initial OEB-approved IRP Framework, IRP has not yet meaningfully displaced or deferred conventional gas infrastructure investment. Several members noted the persistent disagreement and lack of resolution (between Enbridge Gas and the Working Group) on core elements of the framework – particularly the DCF+ cost-effectiveness test and the overall IRP screening process – as key constraints on advancing IRP alternatives as a viable, scalable option for ratepayers.

Working Group members generally emphasized evaluation and synthesis of lessons learned from the pilots – especially the Southern Lake Huron pilot, alongside implementation and evaluation of the system pruning pilot – as the top near-term priority for 2026. Several members called for faster iteration and decision-making so learnings can translate into timely adjustments and scaling (including planning for subsequent pilots in parallel with evaluation). In addition, several members highlighted the need to address foundational analytical and policy issues that have slowed progress, including resolving or reforming the DCF+ test and examining why so few projects are meaningfully exposed to IRP evaluation. Suggested areas of focus included stronger sensitivity analysis in demand and cost modelling (to test conditions under which an

IRP alternative could be preferred and the value of deferral), greater transparency on actual facility project costs and realized demand relative to forecasts, and using the IRP Framework review to consider changes that improve regulatory certainty, accountability, and the overall speed and effectiveness of the Framework.

OEB staff will work with Enbridge Gas to develop a schedule/work plan for the Working Group based on 2026 priorities.

Comments provided by individual members can be found below in **Table 2**.
Comments from Enbridge Gas Working Group members follow in **Table 3**.

Table 2: Individual Comments of IRP Working Group Members

Working Group Member	Comments (optional)
John Dikeos (non-utility member)	It was encouraging to see movement on the long-delayed SLH pilot program in 2025. Enbridge also demonstrated progress towards the implementation of a system pruning pilot project. Although there has been a noticeable uptick in the pace of progress over the past couple years, I agree with most of the comments and concerns shared by other members of the TWG, and the pace of progress is still too slow for IRPAs to become a viable alternative that can be applied to a meaningful portion of gas infrastructure projects in the near future. In particular, the structure of the IRP framework has been hindering progress, so the ongoing review of the framework presents an important opportunity for improvement. I'm hopeful that it will be meaningly restructured to help enable success. As I noted in my feedback to Enbridge's 2024 IRP annual report, top priorities in the review of the IRP Framework should include a review of stated goals and objectives, support for the consistent and long-term valuation of GHG emissions benefits, and a requirement for Enbridge to consider stranded asset risks for new gas infrastructure projects. The IRP Framework review should also consider a nimbler process for any related pilots and projects to allow for quicker implementation and learnings and reduced risks in implementing IRPA projects. Finally, as other TWG members have stated, important changes to the DCF+ cost-effectiveness methodology for IRPA projects are needed and

	related updates to the IRP Framework could help expedite this process. Regarding the priority IRP work streams that Enbridge Gas has identified for 2026, the target sample for system pruning seems to be unnecessarily constrained, despite feedback on this point from myself and other TWG members. However, I'm hopeful that Enbridge will pivot as necessary to ensure that the system pruning pilot garners broader feedback on the potential for wider implementation. Given the extended timeline for pilot approvals and the ongoing need for learnings related to broader IRPA project implementation, I would also suggest that Enbridge start considering additional pilots, targeting potential gaps from ongoing initiatives.
Tamara Kuiken (non-utility member)	I am pleased that 2025 finally saw the implementation of an IRP pilot. While 2025 also saw extensive research into and planning for system pruning, I feel the overall timeline continues to be too slow to achieve the learnings necessary to protect ratepayers from unnecessary investments. For 2026, as mentioned by the OEB staff, I think evaluation of the IRP pilot should be of highest priority. I would also like to see changes to the process that encourage faster learnings, even at the cost of slightly increased risk, and faster implementation as new learnings come in. Specifically I'd like to see the following considered: • Changes to the framework to improve the speed of the entire process. The System Pruning scan found that regulatory uncertainty will result in delays and stakeholder opposition; I believe we're seeing that in action in Ontario. As we work to disrupt the way the natural gas industry does business, maybe we need to consider how the regulatory industry can change to more closely match the current rate of business. We are creating new processes and business models; iteration must happen faster. • Changes to the DCF+ test to make it internally consistent and logical. Cost effectiveness testing has been the number one disagreement between the TWG and EGI for the last five years. We have exhausted all paths to compromise. Per my previous bullet, changes need to be made to help resolve questions like this in a more timely manner.

	• Faster decision-making and action to quickly scale based on learnings. The initial feedback from the IRP pilot suggests success. Based on previous experience, it takes a long time (more than 1 year?) to design and plan implementation of such a pilot. I'd like to see processes in place that encourage immediate planning for the next pilot, paced to parallel the learnings received by the evaluation process as they come in. To be more specific, I'd like to see the TWG investigate and make recommendations to the OEB on how the regulatory and oversight process can be adjusted (on a pilot basis, if necessary) to allow greater innovation and faster iteration, which provides greater value for ratepayers.
Cameron Leitch (non-utility member)	I'm encouraged that the SLH IRP Pilot is progressing, but like other TWG members continue to be frustrated at the rate of progress. Most of the TWG members have been involved since inception more than 5 years ago, when direction was to identify and commence implementation of a pilot within a year. I think a majority would agree that if we could have foreseen the rate of progress 5 years out, "success" wouldn't be the first noun that comes to mind. This last sentence, like the following brief summary, mimics the same comments I'd made in the 2024 report and in years prior to that. We've spent a substantial amount of time debating the mechanisms of DCF+ with very little modification despite very little rationale for keeping things the same. But as it turns out, we needn't have spent so much time since so few investments (in this recent IRP Report, 20 of approximately 2,800) get an opportunity to be evaluated. And since Enbridge is resolved to argue the DCF+ mechanism that they have chosen when the first non-pilot IRP Alternative is brought forward (notably after it manages to "pass" the current DCF+ methodology), it will likely be some time before this debate is resolved. There have been thousands (perhaps tens of thousands) of investments in the AMPs over the past 5 years, and billions of dollars invested, all while not a single non-pilot IRP has been able to compete based on the current methodology. It seems unfathomable, but I believe there are opportunities to understand why this process has been so one-sided, and I think there is merit in the investigation of those opportunities in 2026.

	Although we have had insight into the modelling of demand, current market volatility (in particular a dramatic slowdown in new construction, considerable inflation in construction material and labour indices, and significant swings in commodity costs due to global factors and market mechanisms - particularly in the Ontario electricity market) should be reflected through the modelling of significant sensitivities. Those sensitivities should help us answer the questions "what would have to happen for an IRP Alternative to be preferred", and the corollary "what would have to happen for the Facility investment to fall out of favour". Especially with the recent uncertainty in growth, there must be a way to determine the value in deferring an investment decision. In addition to sensitizing inputs for forward-looking modelling and assessment, some insight into actual costs that Enbridge has encountered on projects (relative to budgeted costs) and what the actual incremental demand realized was compared to what was forecasted (and how close the Posterity model was to reality) based on recent investments, would give the TWG some familiarity with the level of certainty in the proposed requirements and forecasted cost for traditional facilities projects. We've spent significant time talking about IRPAs and their costs and value, but appreciably less questioning the other side, and I think that merits some investigation. Lastly, and it may be optimistic, but I hope to see a non-pilot IRPA be identified to proceed in 2026.
Chris Neme (non-utility member)	My comments on the IRP Working Group's efforts and progress in 2025 are similar to those I provided in 2024, and echo those of Jay Shepherd below. While the Working Group still does useful work, including providing input on the Lake Huron pilot and the new pruning pilot, the group has not succeeded in advancing non-pipe alternatives (NPAs) as a truly viable alternative to capital investment in Enbridge's distribution system. As Mr. Shepherd notes, five years after the Board's order in the IRP case, we have just two pilots underway while many billions of dollars have been invested in traditional infrastructure investments. I believe that this is a function of a flawed policy framework.

	That is not to say that the IRP Working Group has not provided value. I think it has. For example, some good work has been done in helping shape the Lake Huron pilot (even if it took much longer than it should have to get it launched). However, the Working Group's value is constrained by current policy. For example, despite, what I consider to be very compelling economic and policy arguments for changing key aspects of the cost-effectiveness test for NPAs (DCF+), progress on that issue has stalled and will stay that way absent new direction from the Board. I also want to observe that the sensitivity of the Company's forecast of necessary distribution system investments to changes in forecast levels of demand, which is discussed below, raises questions about whether the value of the Company's system-wide DSM programs in reducing or deferring capital investment is being adequately captured in avoided costs used to assess DSM cost-effectiveness. Given the debate that often occurs around the rate impacts of DSM, analysis of the relationship between the magnitude of projects in the AMP and load growth should be undertaken and used to estimate the value system-wide DSM provides in reducing distribution system investments and the related downward pressure on rates associated with such reductions. For 2026, the Working Group can continue to provide some value in reviewing results and synthesizing lessons learned from the two pilots and contributing to considerations of modifications to the current IRP policy framework.
Dwayne Quinn (non-utility member)	As noted in some submissions, when the Parry Sound pilot was deferred (appropriately), not only was this event a loss of one of only two pilots ordered by the Board, but also it eliminated a project that was supplied by a single source making it ideal to evaluate the system benefit of the IRP measures. It is unfortunate that in the over two years since EGI informed the TWG that the system need was deferred, there has been no advancement of a comparable pilot project. As commented on below in the Pilot project section, I believe there is a need to establish a solid initial baseline from which to evaluate the system need that is generated from a verified simulation. Once that system baseline is established, the utility can evaluate the base case, prudent facilities' investment to meet the system need. The cost of this facilities

	investment would be compared against IRPAs to support an informed decision on how to proceed.
Jay Shepherd (non-utility member)	My comments from the 2024 Report continue to be applicable today. After five years since the OEB mandate/direction, and many years of discussion before that, IRP has still not been used to delay or replace any gas infrastructure. During that period, something in the order of $10 billion or more of facilities projects have proceeded. The primary cause of this is an OEB-approved IRP methodology/framework in which each of the multiple steps is designed to screen out an IRP alternative. The result is that none remain viable; all are screened out. As long as that continues to be true, Enbridge will continue to successfully prevent, delay, and avoid the implementation of any alternatives to building conventional gas distribution rate base. The current IRP Framework Review will, I hope, allow for a broader discussion of other ways to move IRP forward, with the goal of making the energy services provided to Ontario residents more economic and sustainable for the long term. In the meantime, the impact of the Working Group, while still valuable, is somewhat limited. Of significant concern is that Enbridge Gas has consistently refused to provide Working Group members with access to the several models on which they rely heavily. This is surprising given that some Working Group members have considerable experience with these types of models. It appears to me to be inefficient to delay disclosure of those models until a formal regulatory proceeding with multiple parties, when they will likely be produced by order, and their review at that time will delay and complicate the proceeding. This refusal raises the possibility that these models may be poorly designed, biased, or otherwise embarrassing to Enbridge. It is noteworthy that Enbridge finally shared one of the models, the ETEE model, only after being called out for failing to do so in these comments. Since making my original comments, I have seen the Enbridge comments, which appear to be solely directed at seeking to rebut everything the non-utility members have said

	in their comments. Most striking is the statement that screening out all IRPAs should be considered a successful use of the IRP Framework. This reinforces my previously stated view that Enbridge will not implement any meaningful IRPAs until they suffer consequences for failure to do so, of which the most useful consequence would be to have some or all of the risk of stranded or underutilized facilities investments fall on the shareholders rather than the ratepayers.
Mike Parkes/ Stephanie Cheng (OEB staff representatives)	**Comments and/or concerns with the implementation of the IRP Framework in 2025**: • 2025 saw encouraging developments with the Southern Lake Huron IRP pilot coming to market, and the approach to a system pruning pilot being developed (for implementation in 2026). Both of these pilots should provide useful learnings regarding IRP. The Working Group played an important role in providing input on the design of both of these pilots. • The OEB released an OEB staff discussion paper in October 2025 assessing progress implementing the IRP Framework and proposing updates to the IRP Framework. Taken together, these proposals are intended to continue to drive the adoption of the most prudent infrastructure or IRP alternative to meet a given system need, while improving the IRP value-to-effort ratio and positioning the natural gas sector to quickly and effectively adapt to various potential future scenarios. Input from the Working Group in 2025 was helpful to OEB staff in refining the proposals in the discussion paper. OEB staff does not have any additional comments or specific concerns with the implementation of the IRP Framework in 2025. **Comments or concerns regarding the priority IRP work streams Enbridge Gas has identified for 2026 (section 10 of the Enbridge Gas annual IRP report)**: • Of the noted priority IRP work streams, continued work on implementing and evaluating the two pilots (Southern Lake Huron and system pruning) should be the highest operational priority, and is an area where input from the Working Group can add significant value. • In addition, the OEB's direction for Enbridge Gas to file an updated IRP Framework for adjudicative review will also impact the priority IRP work streams for 2026.

	Enbridge Gas had previously indicated plans to conduct an updated IRP jurisdictional scan, with a contributing role for the IRP Working Group (similar to the approach taken for the completed system pruning jurisdictional scan described in the IRP Annual Report). OEB staff believes this scan would be a valuable input for the IRP Framework adjudicative proceeding and encourages Enbridge Gas to proceed with it, including the proposed role for the Working Group. The updated IRP Framework will likely include requirements for Enbridge Gas to develop and file an Implementation Plan as a second phase of the IRP Framework proceeding. OEB staff expects that Enbridge Gas will seek input from the IRP Working Group on the draft Implementation Plan (particularly technical aspects of the plan) before it is reviewed by the OEB. • It is also expected that supporting IRP policy/guidance documents developed by Enbridge Gas would be filed as part of the Implementation Plan approval request. The IRP model and methodology developed by Posterity Group and used by Enbridge Gas to forecast peak hourly flow reduction potential and costs from IRP Alternatives (discussed in Section 10 of the Enbridge Gas annual IRP report) is one specific guidance document which OEB staff encourages Enbridge Gas to work with the IRP Working Group to review and refine before it is considered in the adjudicative proceeding.

Table 3: Comments of Enbridge Gas IRP Working Group Members

Working Group Member	Comments (optional)
Alison Moore/ Whitney Wong/ Helen Tong (Enbridge Gas representatives)	Pilot Projects Enbridge Gas agrees with member comments that implementation of the SLH Pilot Project and System Pruning Pilot is a high priority for 2026. TWG members expressed encouragement regarding the advancement of the Pilots, while also noting frustration with the delay for the SLH Pilot Project relative to the deployment timing in the IRP Framework. While the timing of the regulatory proceeding for the updated SLH Pilot Project Application was outside the

	Company's control, Enbridge Gas took proactive steps in advance of the OEB issuing its Decision to expedite implementation where possible. This included moving forward with incremental resourcing required for the pilot, initiating activities required to retain an evaluation contractor, and engaging larger commercial and industrial customers in the pilot area in a targeted effort to identify potential participants to expedite the implementation of individualized hourly metering. For the System Pruning Pilot, Enbridge Gas has met the milestone dates established in the Rebasing Phase 2 Settlement Agreement and conducted extensive consultation with the TWG. Enbridge Gas has, and will continue to, consult with the TWG for input as implementation and evaluation of the pilots progress. In response to a member's suggestion of establishing a solid initial baseline for the SLH Pilot Project, Enbridge Gas notes that the evaluation methodology considers detailed customer-level data, aggregated to establish an appropriate baseline, as outlined in the evaluation plan. This approach provides the information required to assess system level impacts of ETEE and DR on peak demand. System level data is not available or required to meet the pilot objectives, as previously discussed with the TWG. While the pilot is expected to provide insights that are applicable to similar customer segments across the Enbridge Gas system, application of these learnings to specific system constraints will be dependent on system characteristics and may require appropriate scaling. As such, the existence of a specific facility need or system constraint within the pilot area is not required to achieve the objectives of the Pilot Project. With respect to member comments on considering additional pilots more broadly, Enbridge Gas maintains its view that it is not efficient or appropriate to proceed with consideration of another IRP Pilot Project while the OEB's IRP Framework Review is underway. This position is consistent with OEB's Findings in the Motion to Review Decision, which varied the March 27,2025 Decision to remove the requirement for Enbridge Gas to consult with the TWG on a potential second IRP pilot as part of the SLH Pilot Project proceeding. The OEB found that it would not be efficient or cost-effective for Enbridge Gas and TWG members to begin discussions on a second pilot project in parallel with the IRP Framework

	Review and stated that matters related to any further IRP pilot projects are to be addressed through the Framework Review.[1] <u>IRP Framework Review</u> Multiple members commented on the structure of the IRP Framework and the opportunity to evolve it through the IRP Framework Review proceeding. Enbridge Gas agrees on the importance of ensuring clarity in IRP objectives and policies. However, consistent with its comments from 2024, Enbridge Gas does not agree that IRP success or progress should be assessed based on the implementation of non-pilot IRP alternatives, as this does not reflect whether the IRP evaluation process has been properly applied in accordance with the Framework. The purpose of the IRP Framework Review, and objective of IRP more broadly, is not to maximize the number of IRP alternatives implemented, but rather to ensure the most appropriate solution is identified to address system needs. The outcome of this process, where an IRP alternative is not selected as the preferred alternative, represents a finding as opposed to a failure in the IRP Framework or its implementation. In 2025, Enbridge Gas completed the IRP assessment of all investments in the AMP with a defined scope. Enbridge Gas considers the IRP Framework Review an opportunity to improve regulatory and operational efficiency, including a “fit-for-purpose” approach informed by experience gained through implementing the IRP assessment process. The IRP Framework Review will also provide the opportunity to ensure IRP is aligned with Ontario government policy, consistent with OEB direction (EB-2025-0125), which notes that Enbridge Gas’s updated IRP Framework application should consider relevant elements of Ontario’s Integrated Energy Plan.[2] Enbridge Gas does not agree with member comments that the updated IRP Framework should include long-term valuation of GHG emissions benefits or consideration of stranded asset risks and does not agree with member criticisms of the DCF+ cost-effectiveness methodology. However, Enbridge Gas considers these matters most appropriately addressed through the IRP Framework Review proceeding rather than through continued TWG consultation.

	With respect to stranded asset risk, demand forecasting sensitivities and forecast validation, Enbridge Gas considers the rebasing proceeding to be the appropriate forum to assess the demand forecasting methodology, capital planning and related assumptions. Addressing these issues across multiple proceedings would be inefficient and may result in inconsistent and/or incomplete considerations. Within the IRP economic evaluation process, Enbridge Gas has introduced a single-variable cost sensitivity analysis to support comparison of alternatives informed by input from the TWG in 2025. This analysis considers the degree to which the cost of alternatives would need to change to achieve parity with the preferred alternatives on a DCF+ Phase 1 net present value basis. Enbridge Gas is developing a template to support the economic evaluation of IRP alternatives, inclusive of this information, which will be shared with the TWG in 2026. Enbridge Gas also acknowledges comments regarding the anticipated development of an IRP Implementation Plan as a subsequent phase of the IRP Framework Review, including the opportunity for TWG input into the development and refinement of supporting elements of the plan. Enbridge Gas agrees that TWG engagement will be included in this process, recognizing that such engagement should not duplicate prior consultations. For example, extensive consultation has already occurred on the DCF+ test and Enbridge Gas has incorporated modifications that it has determined are appropriate. With respect to jurisdictional review, Enbridge Gas agrees that such information can be useful, provided it considers the proper context in relation to Ontario (such as differences in policy objectives, regulatory mandates, system characteristics, etc.). Given the infancy of system pruning activities, the system pruning jurisdictional scan prepared by DNV was broader in scope and incorporated relevant insights on non-pipe alternative programs, policies, and framework level considerations. However, in the context of IRP objectives and Ontario's public policy framework, the scan reported a key distinction: identified jurisdictions[3] that are considering, planning or implementing non-pipe alternatives are primarily driven by decarbonization and climate goals, which reflect policy contexts that differ from Ontario.

	Additional jurisdictional review will be considered alongside the next steps in the IRP Framework Review proceeding. <u>ETEE Model</u> Enbridge Gas does not agree with the characterization that it has consistently refused to provide TWG members with access to its models. During TWG Meeting #56 (in June 2025), Enbridge Gas provided a detailed overview of its internal ETEE model, including the methodology, key assumptions and formulas underpinning its application. Enbridge Gas subsequently provided a follow-up at TWG Meeting #59 confirming the consistency of the forecasting approach, the basis for the peak-to-annual savings factor, and the treatment of load diversification. Provision of the model was not discussed or requested during 2025 consultations. At TWG Meeting #63 (in April 2026), a TWG member requested access to the model. Enbridge Gas explained that its approach had reflected its objective to receive input on the methodology of the model and input on assumptions, recognizing that the model is an analytical tool requiring appropriate context and governance for use, including within Enbridge Gas. Enbridge Gas does not accept that its consultation approach reflects concerns with the model's design or application. At Meeting #63, Enbridge Gas committed to considering the request for a copy of the model. Following consideration of TWG feedback, Enbridge Gas provided the ETEE model to the TWG in May 2026. This reflects Enbridge Gas's continued commitment to transparency, responsiveness to TWG input, and meaningful engagement. [1] EB-2025-0333, Decision and Order - Motion to Review Decision on Integrated Resource Planning Pilot Project, May 14, 2026 [2] EB-2025-0125, Next Steps - Integrated Resource Planning Framework Review for Enbridge Gas, April 28, 2026 [3] The exceptions were Oklahoma at the "considering" phase with a primary economic driver associated with exploring a roadmap of creating a hydrogen economy and Denmark at the "implementing" phase with a primary driver on reducing reliance on Russian gas imports.

3. Description of Key Working Group Activities in 2025

Enbridge Gas's IRP priorities for 2025 were previously identified in its 2024 IRP annual report. These included:

- External Stakeholder Outreach
- Continued IRP Evaluation
- Discounted Cash Flow-Plus (DCF+) Test
- Pilot Projects
- System Pruning
- Policy Proposals (for non-pilot IRP Plans)
- Framework Consultation

Progress on each of these items was subsequently discussed in some form with the Working Group in 2025, with particular emphasis placed on the two pilots (Southern Lake Huron Pilot and System Pruning Pilot). Progress on these pilots (implementation and evaluation) had been identified by Working Group members in the 2024 IRP Working Group report as the top IRP priority for 2025. Working Group discussion to inform the OEB staff discussion paper on the IRP Framework review was also a focus. A high-level summary of key topics discussed by the IRP Working Group is provided in the subsections below. Readers can refer to the meeting folders on the OEB's Engage with Us IRP webpage[4] for meeting materials and meeting notes summarizing key discussion points and outcomes. Refer to Table 4 below for a summary of meeting dates and key topics discussed at each meeting.

Table 4: Summary of Working Group Meetings and Key Topics Discussed

Meeting Date	Key Topics Discussed
June 25, 2025	• System Pruning Pilot approach – addressing Working Group feedback • IRP incentives – review types of incentive mechanisms • IRP Assessment – presentation on input assumptions and methodology of the demand-side (Enhanced Targeted Energy Efficiency (ETEE) / Demand Response (DR)) IRPA Model

[4] https://engagewithus.oeb.ca/irp

July 30, 2025	• IRP Pilots Update (Southern Lake Huron and System Pruning) • System Pruning jurisdictional scan • IRP Evaluation (Status update, DCF+ results and interpretation, DCF+ update) • IRP Framework Review (Electrification)
September 3, 2025	• IRP Framework Review (Future Role of Working Group)
September 25, 2025	• IRP Shareholder Incentive Mechanism Proposal
October 29, 2025	• Southern Lake Huron Pilot Update (pilot offers, marketing, evaluation, stakeholder engagement, measurement update, evaluation, measurement & verification (EM&V) and data analysis) • IRP Jurisdictional Scan • Stakeholder Update
December 3, 2025	• System Pruning Pilot update

3.1. External Stakeholder Outreach

In November 2025, Enbridge Gas shared a draft of its Fall 2025 IRP Regional webinar slide deck with the Working Group, ahead of the public webinars scheduled for December 1 and December 11, 2025. Working Group members were invited to provide written feedback on the draft materials, which would be considered by Enbridge Gas in finalizing its stakeholder engagement tips and materials; however, no members provided comments, and Enbridge Gas subsequently finalized materials and held the public webinars.

3.2. IRP Evaluation Process

In 2025, Enbridge Gas continued discussions with the Working Group on refining aspects of its IRP evaluation process, and shared results of completed IRP evaluations for a subset of projects selected to illustrate the application of the DCF+ methodology with differing facility cost and demand growth characteristics. The Working Group provided input on two key topics:

- **Improving the methodology and documentation by which energy efficiency IRP alternatives (ETEE and DR measures) are assessed**. Enbridge Gas sought feedback from the Working Group on the methodology and input assumptions of an updated demand-side IRPA regional model, which forecasts IRP participation, costs, and peak demand savings, making use of forecasts and participation data for Enbridge Gas's existing demand-side management (DSM) programs. This model will be used as an input in both the technical evaluation and economic evaluation stages of IRP evaluation going forward. The

model was not shared with the Working Group, but members provided feedback on the inputs and assumptions for Enbridge Gas's consideration. Members raised questions about factors such as: the assumptions involved in forecasting IRP participation based on the previous level of participation in DSM programs, how to predict participation levels that would result from customer incentive levels higher than those previously used, how the accuracy of the model will be assessed and calibrated, and the exclusion of contract customers from the model. Enbridge Gas provided clarification and subsequently made several minor updates to its model based on Working Group input, including adjusting the scaling based on regional consumption and ETEE adoption rates. The issues raised by members have not been fully resolved; Enbridge Gas noted that the model is likely to be refined and improved based on actual IRP project results, including the Southern Lake Huron pilot.

The IRP regional model uses information from and complements the IRP model previously developed by the Posterity Group that has been used by Enbridge Gas at the technical evaluation stage to assess whether an IRP alternative is technically feasible. In response to previous discussions with the Working Group (covered in a previous report), Enbridge Gas has committed to work with the Posterity Group to update and publicly document the methodology for this IRP model. This is expected to provide other interested parties with a better understanding of the modeling approach used in technical potential evaluations.

- **Updated IRP evaluation results of projects in Enbridge Gas's Asset Management Plan (AMP) in 2026, factoring in newly available and relevant information, data, and insights including system reinforcement plan updates.** Summaries of updated evaluation results were shared with the Working Group for questions and comments. A Working Group member noted concerns with the sensitivity of the AMP to the growth forecast, and that many growth projects that were in the previous version of the AMP had been removed from the updated version, highlighting the significant uncertainty associated with the growth forecast. Enbridge Gas noted that changes in the growth forecasts and the associated investment project scopes are a result of many factors, such as updates to customer forecasts/demands/attachments and that projects are progressively refined as projects progress towards their in-service date. Enbridge Gas subsequently provided details on the specific changes to the growth forecast that led to the updated results. The larger issue of how the IRP Assessment process should account for a changing demand forecast remains a concern, and is noted in the OEB staff discussion paper on the IRP Framework review.

3.3. Discounted Cash Flow-Plus Test

In 2025, Enbridge Gas presented IRP economic evaluation (DCF+) results for four new projects to the Working Group. The analysis compared project cost, results of the individual phases, combined Phase 1 and Phase 2 Net Present Value, and relative bill impact between Facility Alternatives and IRP Alternatives. The analysis also looked at whether the demand driving the project need was expected to persist and the timing of the project need, which impacted whether a final decision (Facility Alternative or IRP Alternative) was needed or whether the need could continue to be monitored. The analysis indicated that a Facility Alternative was the preferred alternative for three of the projects, while a supply side IRP Alternative (compressed natural gas) was the preferred alternative for one project. The timing of this system need is not until 2029, so Enbridge Gas will not immediately implement the supply-side IRP Alternative. Enbridge Gas will continue to monitor the system need in the following year and reassess as required, to allow for the possibility of changes to the demand forecast that could impact the system need. Enbridge Gas subsequently noted that compressed natural gas solutions can be deployed in a relatively short timeframe (i.e. deployed within the same year as the required facility in-service date).

Enbridge Gas also used this discussion to provide an update on its perspective on the broader issues the Working Group had identified with the DCF+ test, including concerns regarding the exclusion of carbon costs and the methodology for capturing broader economic impacts through a GDP multiplier. Despite the Working Group's disagreement with the substance of if and how phase 3 societal impacts are captured and how its approach aligns with the OEB's orders, Enbridge Gas maintained that the DCF+ test appropriately reflects economic impacts within the OEB's mandate and that Working Group feedback has been considered.

The next step is for the OEB to review Enbridge Gas's updated DCF+ methodology as part of Enbridge Gas's first non-pilot IRP plan application, which will provide an opportunity for this question to be adjudicated.

3.4. Southern Lake Huron Pilot – Implementation and Evaluation

The 2021 IRP Framework required Enbridge Gas to develop and implement two IRP pilot projects. In July 2023, Enbridge Gas applied to the OEB for approval of two IRP pilot projects, but one of the pilots was later withdrawn. The other pilot, the Southern Lake Huron Pilot, was approved by the OEB on March 27, 2025, with certain modifications. While certain aspects of

the OEB decision have been appealed and are under review, Enbridge Gas has proceeded to implement most aspects of the approved pilot. The pilot was brought to market in 2025 under the name “Sarnia Saves”, offering enhanced customer incentives for energy efficiency measures that reduce peak demand, and a new demand response program for residential customers.

Enbridge Gas provided the Working Group with updates on the pilot for feedback. These updates covered the design and implementation of residential, commercial, and industrial pilot offerings (including lessons learned), evaluation, measurement, and verification of peak savings, marketing plan, and stakeholder engagement.

Progress related to the Pilot’s two primary objectives is summarized below:

Objective 1: Develop an understanding of how ETEE programs and DR programs impact peak hour flow/demand.

- Enbridge Gas selected Dunsky Energy and Climate Advisors as the external consultant to assist in assessing the peak demand impact of the pilot. A draft EM&V plan was expected to be shared with the Working Group for feedback in late 2025, but this was postponed to early 2026.
- Enbridge Gas shared its preliminary in-house hourly load regression analysis approach which will be used as an input to assess peak demand impacts (Dunsky Energy and Climate Advisors are also expected to assess and support the development of this internal tool). The Working Group reviewed and provided comments on Enbridge Gas’s preliminary approach, including which variables to track and suggestions on how to test the tool for reasonableness. The Working Group also recommended collecting and retaining as much data as possible, as it is easier to exclude unnecessary data later than to retroactively collect data related to previously excluded variables.
- Enbridge Gas will take the Working Group’s feedback into consideration in finalizing its approach to data collection and EM&V.

Objective 2: Develop an understanding of how to design, deploy, and evaluate ETEE and residential DR programs.

- Enbridge Gas provided an update on design and implementation of the Southern Lake Huron Pilot (“Sarnia Saves” program), which generally aligns with the project plan outlined in the 2025 IRP annual report but includes minor updates informed by Working

Group feedback. The Working Group provided additional input on marketing and stakeholdering activities and considerations for both residential and commercial pilot offers, as well as tips and considerations on the use of Brightlync meters for hourly data collection. A Working Group member noted concerns about whether an appropriate baseline can be established and whether the pilot's results will be transferable to other systems, given Southern Lake Huron's multi-feed network and limited flow data at the feed points which makes it challenging to quantify system-level benefits.

- Enbridge Gas reported stable and consistent engagement from both residential and commercial customer leads. Given the high interest and early success, Working Group members raised questions about exploring opportunities to expand customer participation, while recognizing the pilot's budget and scope constraints.
- A member of the Working Group served as a representative to review and provide feedback on draft customer survey and interview guides. These tools will then be finalized and used by the program evaluator to gain a better understanding of the experience of those involved in the Southern Lake Huron pilot. Baseline surveys were completed in September 2025. Initial Enbridge Gas staff interviews were conducted in July 2025, followed by delivery agent and energy advisor interviews in December 2025. Residential and commercial participant interviews are expected to take place in 2026.

It is expected that Enbridge Gas will continue to engage with the Working Group to review and provide input on project plan, implementation, and evaluation elements throughout the Southern Lake Huron Pilot.

3.5. System Pruning Pilot and Jurisdictional Scan

As part of the Settlement Agreement for Phase 2 of Enbridge Gas's rebasing application, Enbridge Gas committed to conducting a system pruning pilot (i.e., incenting customers to voluntarily exit the gas system as an alternative to replacing gas infrastructure), with the approach to be developed in consultation with the IRP Working Group. Implementation of one or two system pruning pilots was expected to begin by the end of Q1 of 2026.

Throughout 2025, Enbridge Gas worked closely with the Working Group (and a temporary system pruning subgroup of the Working Group) to refine a draft "approach" document for the system pruning pilot. This work was mostly undertaken in the first half of 2025 and was documented in last year's Working Group annual report.

In late June 2025, the approach document was finalized. It outlines key elements of the pilot including objectives, selection criteria for system renewal projects potentially suitable for system pruning, the customer engagement plan and offers, customer choice (i.e., how the pilot will address circumstances where customers do not want to disconnect from the natural gas system, or wish to reconnect after participation in the pilot), a stakeholder engagement plan, the approach to program delivery, an implementation plan, and evaluation strategy. Proposed revisions to the document were reviewed by the full Working Group in June 2025 with the intent of enabling Enbridge Gas to incorporate member feedback into the plan. While the Working Group did not formally approve the document, it supported proceeding with it as a reasonable initial approach, subject to ongoing review and further Working Group input as the pilot is executed and lessons are learnt. The system pruning approach document was filed by Enbridge Gas with the OEB on July 4, 2025.

To support the development of the system pruning pilot, DNV was engaged as an external consultant to conduct a jurisdictional scan on system pruning. In the first half of 2025, the system pruning subgroup provided extensive feedback to DNV to inform the development of this report. In July 2025, DNV provided the full Working Group with an update on revisions made to the draft jurisdictional scan report in response to member feedback. The report was published in August 2025.

Following the filing of the system pruning approach document, Enbridge Gas continued to bring the pilot closer to implementation, including identifying target project areas and selecting a contractor to deliver the pilot. In July 2025, the Working Group reviewed and provided feedback on a customer outreach pre-screen survey that would be used to gauge customer interest in participating in a system pruning project, including suggestions related to survey language and delivery methods. Enbridge Gas updated the pre-screen survey to incorporate feedback provided by the Working Group, and proceeded with the pre-screen phase of the pilot implementation to a subset of customers in target project areas that met the defined criteria. In December 2025, Enbridge Gas shared the survey results and discussed how the findings would inform field implementation. In response, the Working Group provided feedback on several aspects of the pilot design including customer outreach approach and interpretation of survey results (e.g., cautioning against interpreting non-response as lack of interest), the importance of targeting high-value opportunities (e.g., expanding outreach beyond the initial six interested customers to include one or two neighboring customers or small clusters in parallel with proceeding with the initial participants), consideration of commercial and mixed-use

opportunities, and the value of testing different marketing and outreach methods through multi-modal and repeated engagement. Members also emphasized that messaging should clearly originate from Enbridge Gas to enhance legitimacy and trust and should motivate customers by communicating potential bill impacts or savings, potentially supported by modest financial incentives to increase engagement. Enbridge Gas will proceed to next steps in pilot implementation with the six interested customers, which was supported by the Working Group. Enbridge Gas will also consider the Working Group's suggestions regarding conducting additional outreach, informed by the insights gained through engagement with the six targeted candidates. Working Group feedback noted considerations of increasing pilot participant numbers to improve the likelihood that the pilot will provide meaningful learnings.

3.6. Non-Pilot IRP Plan Policy Proposals – Incentive Mechanisms

In 2023, the Working Group discussed IRP policy proposals related to attribution of savings between Demand-Side Management programs and IRP Plans, shareholder incentives and performance metrics, IRP Deferral Accounts, and management of risk associated with IRP implementation. At the time, Enbridge Gas expected to consider perspectives of the Working Group and then file proposals on these topics for the OEB's consideration as part of Enbridge Gas's first non-pilot IRP plan. Enbridge Gas did not have a viable non-pilot IRP plan application to file with the OEB in 2024, and so other topics took priority and these policy discussions with the Working Group were put on hold in 2024. However, the Phase 2 rebasing settlement approved by the OEB in November 2024[5] established a new commitment for Enbridge Gas to file an application that includes a proposal and request for approval of an IRP incentive mechanism by the end of November 2025, resulting in the discussion on shareholder incentives resuming.

In June 2025, Enbridge Gas provided the Working Group with a recap of the incentive discussions that took place in 2023, highlighting the pros and cons of each of the types of incentive mechanism discussed. Enbridge Gas then shared its initial findings on how shareholder incentive mechanisms are used in other jurisdictions. The Working Group noted that the analysis to date may not sufficiently consider the level of incentive required to meaningfully motivate Enbridge Gas's shareholders to pursue IRP alternatives instead of traditional rate-base-eligible infrastructure. Acknowledging the conceptual goal of aligning shareholder interests with prudent IRP outcomes, some Working Group members expressed

[5] Decision on Settlement Proposal and Interim Rate Order, November 29, 2024, EB-2024-0111

skepticism that the OEB would ever approve an IRP incentive mechanism that provides returns comparable to those available through rate-basing capital investments.

In September 2025, Enbridge Gas brought the Working Group a specific incentive proposal for discussion. Under this proposal, Enbridge Gas would capitalize the O&M costs of an IRP Plan and incorporate a shared savings mechanism to retain some of the cost savings of the IRP Plan relative to the traditional facilities investment. A Working Group member noted that the choice of a shared savings mechanism is aligned with the IRP Framework's emphasis on cost-effectiveness testing and prioritizes cost savings from IRP. However, Working Group members noted several concerns with the specific incentive design, e.g., questioning the premise that the return to shareholders needs to be the same for an IRP Alternative as for a higher-cost Facility Alternative (i.e., a traditional infrastructure solution), noting that the percentage of savings retained by the utility is lower in some other jurisdictions that use a shared savings mechanism, and noting the risk that Enbridge Gas may overstate the expected cost of a traditional solution in order to be eligible for a larger incentive.

On November 4, 2025, Enbridge Gas filed its IRP incentive mechanism application (which was based on the incentive proposal discussed with the Working Group) but requested that the application be put in abeyance until the outcome of the IRP Framework Review proceeding is known. On December 22, 2025, the OEB granted the request, and the application remains in abeyance.[6]

3.7. IRP Framework Review

In March 2025, the OEB announced that it was initiating a consultation to review the IRP Framework. As part of the consultation, the OEB noted that it would consider several key items including:

- How the Framework would be best constituted to allow for broad, flexible implementation that can adapt at a pace that supports innovation,
- The OEB's expectations and approach to oversight of innovation-related IRP proposals,

[6] EB-2025-0292

- Expectations for natural gas distributors regarding electrification as an IRP alternative, including how electricity availability issues should be considered if electrification is being proposed as an IRP alternative, and
- Opportunities to improve the effectiveness and efficiency of the Framework.

OEB staff consulted with the Working Group to inform development of OEB staff's IRP Framework Review discussion paper. In the first half of 2025, the Working Group discussed the purpose and form of the IRP Framework, the approach to technical evaluation of the viability of IRP alternatives, and how the Framework should address innovation. In July and September 2025, the Working Group continued its IRP Framework Review discussions, focusing on the role of electrification, the proposal for a 3-year adjudicated IRP implementation plan, and how the role of the IRP Working Group would evolve with the framework.

Regarding electrification, Working Group members shared a variety of differing views on its appropriate role within IRP. Members generally envisioned electrification as one IRP alternative to be considered when seeking to address a system need. However, there was some concern with the idea of Enbridge Gas acting as the gatekeeper or delivery agent for electrification initiatives due to potential conflict of interest. Some members proposed the IESO or local electric utilities should lead electrification efforts with Enbridge Gas advancing gas infrastructure where electrical options are insufficient. Enbridge Gas emphasized that the IRP Framework is intended to be neutral and cautioned against perceived bias toward IRP alternatives over traditional gas infrastructure. Enbridge Gas noted there is a need for full comparisons of all ratepayer costs, as well as consideration of policy guidance in the Integrated Energy Plan on the future role of natural gas, while some members noted that existing cost analyses may understate select gas infrastructure-related costs such as costs associated with carbon emissions and stranded asset risk.

Regarding the proposal for an IRP implementation plan to be adjudicated every 3 years with annual informational updates, some Working Group members supported this approach as a way to create clearer accountability (through adjudicative oversight), while providing flexibility in the Plan approval for a more nimble approach to make program changes in the years between adjudication. Another member favored a more frequent rolling plan with some adjudicative oversight each year to enhance forward-looking transparency, cautioning that greater procedural flexibility must be balanced with safeguards to address ratepayer concerns and ensure front-end oversight rather than reliance on after-the-fact prudence reviews.

Discussion on the role of the IRP Working Group reflected Working Group member concerns about the Working Group's limited influence and impact under the current IRP Framework, underscoring the need for adjudicated processes to drive accountability. Various members observed that Enbridge Gas appears to determine its preferred IRP direction internally then seeks Working Group input selectively, which, while useful, falls short of a fully collaborative process. Some members noted that slow progress on IRP is driven more by the absence of clear and supportive policy direction that creates a strong business case or policy rationale for IRP, rather than by any shortcoming of the Working Group's role or processes.

In October 2025, OEB staff released a staff discussion paper with proposals for updating the IRP Framework, informed by the input previously provided by the Working Group.

Appendix F: IRP Assessment Screening and Evaluation Guidelines

IRP Assessment Screening and Evaluation Guidelines

Version Date: 2026

Introduction

This document outlines the IRP Assessment Screening Criteria and rationale used in the IRP Evaluation process and is updated on an annual basis to reflect process updates and learnings gained through the year. Previous versions were filed in past IRP Annual Reports, as well as at EB-2022-0200, JT 5.36 Attachment 2 and examples of the detailed technical evaluation form can be found at EB-2022-0220, JT 5.36 Attachment 3 and 4.

On an annual basis, Enbridge Gas files an Asset Management Plan ("AMP") or AMP Addendum. To ensure the most optimal facility alternative is included in the AMP, and prior to the IRP assessment process, Enbridge Gas routinely considers a wide range of traditional facility alternatives when conducting project scoping of facility needs, where applicable. Investments are subsequently reviewed as part of the Asset Investment Planning & Management ("AIPM") process for IRP alternatives ("IRPAs") which are assessed against the project scope where traditional facility alternatives have already been considered. This process can be iterative due to the dynamic nature of facility planning and changes to demand forecasts. Therefore, project scopes for both traditional and IRP alternatives may require reassessment to ensure the most up to date information is captured.[57]

The IRP Assessment Screening and Evaluation criteria described in this document are conducted using the direction and guiding principles provided by the OEB in its IRP Decision and Order (EB-2020-0091). The investments considered as part of this binary screening and technical screening and evaluation process include investments within the AMP and are limited to regulated Enbridge Gas investments. In future AMP investment assessments, Enbridge Gas will systematically apply these learnings to allow focus on the geographic areas and investment types that are most likely to yield an IRP Plan that is both technically and economically feasible.

IRP Assessment Process Overview

1. **Initial Screening**
   The evaluation process began with removing non-gas-carrying asset investments from the list of AMP Addendum 2026 investments that would proceed to the binary screening phase.

2. **Binary Screening**
   Investments are screened out as per Section 5.2 of the IRP Framework. Investments under the Asset Class of Customer Connections are also screened out as part of Binary Screening.

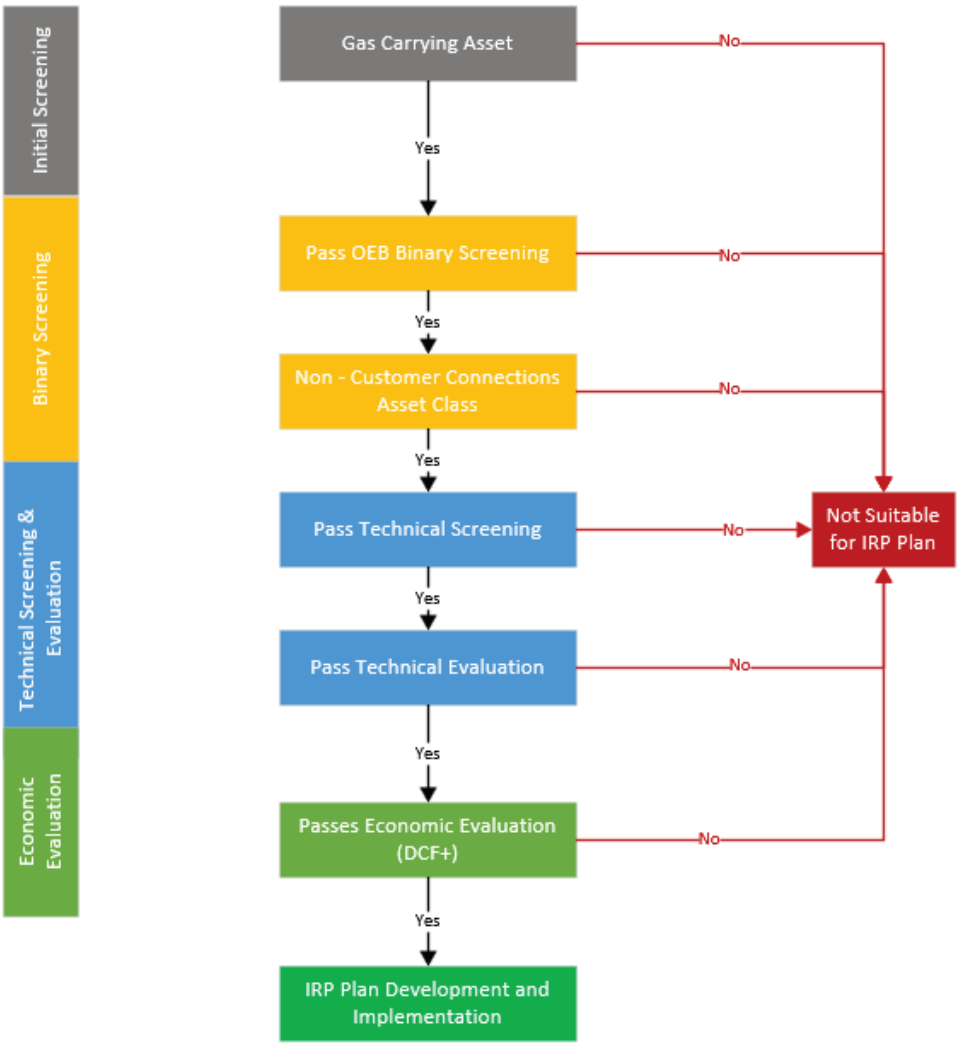
3. **Technical Screening & Evaluation**
   Investments undergo an initial technical screening to determine whether a detailed technical evaluation is required.

   Investments that have passed technical screening will be evaluated for whether an investment could have a technically feasible IRPA(s). To assess the technical potential of IRPAs to meet a system need, Enbridge Gas calculates the required demand reduction and/or incremental supply by determining the difference between the required and current system capacity. Where IRPAs have the technical potential to offset the required capacity through either a reduction in the design hour/day demand or incremental supply within the required timeframe to address the system constraint, and without compromising the safety and reliability of the system, these investments pass the technical evaluation.

4. **Economic Evaluation**
   Investments that have passed technical evaluation will be economically evaluated using the DCF+ test. The DCF+ test compares each technically feasible IRPA and the identified baseline facility project to a 'do nothing' scenario. The DCF+ results for the IRPAs and the baseline facility alternative are then compared to one another to determine the optimal alternative or combination of alternatives to meet the system need. If it is determined that the most optimal option includes one or more IRPAs, an IRPA Plan will be developed where applicable.

[57] IRP Annual Report, Section 7, Table 7.1 provides a "Summary of Facility and IRP Alternatives"

Figure 1 – IRP Assessment Flow Chart



Initial Screening

Ahead of the binary screening, investments in non-gas carrying assets were removed. These investments are in the "Real Estate & Workplace Services", "Fleet & Equipment", and "Technology & Information Services" asset classes.

Binary Screening

All remaining investments are subject to the binary screen criteria as provided by the OEB. Investments that satisfy the binary screening criteria were removed from further evaluation.

- ***Investments deemed Emergent Safety Issue***
  "If an identified system constraint/need is determined to require a facility project for Enbridge Gas to offer safe and reliable service or to meet an applicable law, an IRP evaluation is not required. An example of such a system constraint/need, and an emergent safety issue, would be if an existing pipeline sustained unanticipated damage and needed to be replaced as quickly as possible to ensure the safety of local communities and Enbridge Gas's broader transmission and distribution systems.

Longer-term safety related system constraints/needs may be appropriate for an IRP Plan and should be considered on a case-by-case basis".[58]

- ***Investments failing based on Timing***
  "If an identified system constraint/need must be met in under three years, an IRP Plan could not likely be implemented and its ability to resolve the identified system constraint could not be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need".[59]

- ***Investments failing based on Cost ($) Threshold***
  "If a facility project is being advanced for replacement or relocation of a pipeline and the cost is less than the minimum project cost that would necessitate a Leave to Construct approval, then an IRP evaluation is not required".[60] On September 24,2024, the OEB released new Filing Requirements applicable for exemption on hydrocarbon line projects that cost between $2M and $10M, where information on project need and alternatives are not required.[61] The new exemption requirements for facility projects with costs between $2M and $10M are considered a legislative change and thus, does not impact the Binary Screening cost threshold. Therefore, Enbridge Gas continues to apply a cost threshold of $2M to screen replacement or relocation projects out at this stage, as well as any associated main replacement/relocation programmatic spend.

- ***Customer-Specific Build***
  "If an identified system constraint/need has been underpinned by a specific customer's (or group of customers') clear request for a facility option and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities, then an IRP evaluation is not required".[62]

- ***Community Expansion & Economic Development:***
  "If a facility project has been driven by government legislation or policy with related funding explicitly aimed at delivering natural gas into communities, then an IRP evaluation is not required."[63] As noted in the AMP[64], Community Expansion and Economic Development projects are not included in the AMP and therefore no associated IRP evaluation is conducted.

Additionally, investments with the asset class of "Customer Connections" will be screened out at the Binary Screening stage. *Customer Connection-related projects are required to serve new customers connected in accordance with guidelines of EBO 188. The OEB concluded that as part of the first-generation IRP Framework it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs.*

The investments in the customer connections asset class are related to costs associated with serving new customers, including materials and installation of distribution mains, services and regulating equipment. Enbridge Gas determined that implementing an IRPA could not reduce the size of the assets, as these cannot be further downsized. In addition, there are no non-gas IRPAs available within the current IRP Framework that can be offered to avoid the customer connection service being requested. Therefore, investments under this category should be screened out through the binary screening phase, in advance of technical evaluations. It should be noted that any associated main reinforcement investments are still subject to the binary screening and technical evaluation process.

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[58] EB-2020-0091 Decision and Order, Integrated Resource Planning Proposal, July 22, 2021, p. 47
[59] EB-2020-0091 Decision and Order, Integrated Resource Planning Proposal, July 22, 2021, p. 48
[60] EB-2020-0091 Decision and Order, Integrated Resource Planning Proposal, July 22, 2021, p. 49
[61] EB-2024-0233 Correspondence, OEB Filing Requirements LTC Exemption Applications
[62] EB-2020-0091 Integrated Resource Planning Proposal, Decision and Order July 21, 2021, p. 44.
[63] EB-2020-0091 Integrated Resource Planning Proposal, Decision and Order July 21, 2021, p. 48.
[64] EB-2022-0200 Exhibit 2, Tab 6, Schedule 2, p. 282

Technical Screening and Evaluation

As per the OEB Decision, system needs progressing past the IRP binary screening will proceed through to a technical evaluation. The technical stage of the IRP Assessment Process is comprised of two components: technical screening and technical evaluation. This stage is intended to assess the technical viability of IRPAs to eliminate, reduce or defer the project scope.

As Enbridge Gas progressed to the Technical Evaluation stage of the IRP framework, it became evident that that not all investments passing Binary Screening required a detailed technical evaluation due to the nature of the project scope. A detailed technical evaluation involves network modelling of customer demands, demand reductions and/or incremental supply required to meet system needs. This is a rigorous and time-intensive process that would not be applicable to investment categories outlined in Table 1 below.

To reflect this distinction, the “Technical Evaluation” stage within the IRP Assessment Process has been updated to “Technical Screening and Evaluation,” as shown in Figure 1. Enbridge Gas has discussed and reviewed the Technical Screening and Evaluation Process with the TWG, incorporated the feedback received and will continue to engage with the TWG to support ongoing refinement of the IRP Assessment Process.

Enbridge Gas has undertaken detailed technical project review of these investments, including initial verification of the forecasted need(s), project cost(s) and project driver(s). Through this process, certain categories and investment types were identified in which IRPAs would not be considered effective. The categories and rationale are described below and in Table 1. These investments are systematically screened out during the initial IRP technical screening process and these categories will be refined and updated to reflect any changes in the screening and evaluation process.

Concurrently, in 2023, the Enhanced Distribution Integrity Management Program (“EDIMP”) was approved and established. As EDIMP pipelines undergo review and assessment, there may be changes to the scope and timing of the projects currently listed in the AMP, which in turn could affect the subsequent IRP analysis. These projects will be reviewed closely to ensure technical evaluation is completed on the updated scope.

Technical Screening

As noted above, Enbridge Gas identified categories of investments that do not have a technically feasible IRPA and subsequently screened them out at the technical screening stage. The categories of projects, their corresponding technical screening commentary and rationale are listed below.

Compressor Stations

- Technical Screening Comment: *Compression Station related projects are required to maintain existing capacity, deliverability and throughput. This is necessary to maintain security of supply and stable natural gas pricing during supply disruptions.*

The investments in the compression stations asset class related to the maintenance of the existing fleet of compressors include the periodic original equipment manufacturer (“OEM”) prescribed overhauls and replacement of components that are not performing as intended or are obsolete. These types of investments cannot be offset by IRPAs and therefore will be screened out during technical screening. However, any investments driven by growth would be subject to the detailed technical evaluation process.

Hydrogen Blending

- Technical Screening Comment: *Hydrogen related projects are required as no IRPAs can replace the hydrogen feasibility assessments and hydrogen blending initiatives.*

The investments in the hydrogen blending asset class/program are related to the use of hydrogen in the distribution system, studies on hydrogen blending and are focused on reducing the carbon footprint of the existing transmission and distribution system. These investments cannot be offset by IRPAs and therefore will be screened out during technical screening.

Storage Pools & Wells

- Technical Screening Comment: "*Storage Pools & Well related projects are required to maintain existing capacity, deliverability and throughput. This is necessary to maintain security of supply and stable natural gas pricing during supply disruptions."*

The investments in the storage pools and wells asset class are related to maintenance and compliance driven upgrades to allow for ongoing deliverability from the storage pools. This includes the drilling of observation wells for compliance reasons and work that arises annually from the Integrity Management Program. These investments cannot be offset by IRPAs and therefore will be screened out during technical screening.

Distribution Stations

- Technical Screening Comment: *Distribution Station condition related, IRPAs not applicable*

The investments in this category are related to distribution station projects driven by the condition and not by growth. These distribution station condition related projects are prioritized based on inspections that evaluate the condition of various components (regulators, valves, piping, etc.) and systems (heating, odourant, communications, etc.) at the stations. In some instances, the specific projects are time constrained and low in dollar value and would fail at the binary screening stage. For larger projects, an understanding of the impact on upstream and downstream facilities is required and "like for like" replacement is usually preferable – particularly if a full station replacement is not being planned. As such, all condition related station rebuilds, and replacements will be screened out during technical screening. However, any station investments that involve an element of growth would be subject to the detailed technical evaluation process.

CNG Facilities

- Technical Screening Comment: *See investment description – IRPAs not applicable for CNG*

These investments are related to the ongoing replacement and upgrade of CNG facilities to fuel Enbridge Gas's natural gas vehicles. These needs cannot be replaced through IRPAs, and therefore will be screened out during the technical screening.

Other

- Technical Screening Comment: *See investment description, IRPAs not applicable*

The investments in this category were determined that there would not be a technically feasible IRPA and are described below in Table 1.

Project Status/ Timing Related

Technical Screening Comments:

- *A Leave to construct regulatory process has received OEB decision for approval of proposed project scope.*
- *LTC regulatory process in progress*
- *N/A - Project in construction phase*
- *N/A - Investment Cancelled*
- *N/A - Project Completed*

Investments that fall within this category are those that are already under construction, already granted leave to construct by the OEB or are projects that have been cancelled. These investments will be screened out during technical screening.

Table 1 – Description of Investments Screened out at the IRP Technical Screening Stage

	Sub-category	Asset Class	Asset Program	Description
1	AMI Pilot	Utilization	UTIL-Monitoring Systems	The AMI Pilot will establish the technical and economic benefits related to the installation of AMI meters and associated infrastructure. No technically feasible IRPA's can replace this spend.
2	AMP Fitting	Distribution Pipe	DP-Service Relay	An AMP fitting is a mechanical fitting installed between 1969 and 1984, on below ground residential gas service lines, to transition from a plastic service line to a copper riser. Locations with an AMP Fitting are identified annually and prioritized based on risk.
3	Class Location	Distribution Pipe & Transmission Pipe & Underground Storage	DP-Class Location TPUS-Class Location	This is one of the Integrity Management Programs in which the spend is held in a Programmatic spend budget to cover specific projects that are identified each year. Class locations projects arise when a facility needs to be relocated because of increased development and associated population density around the facility. The programmatic spend cannot be assessed for IRPAs, however, any identified pipeline replacements will be included in the IRP Technical Evaluation.
4	Compression Stations	Compression Stations	All	See section above on Compression Stations
5	Corrosion	Distribution Pipe	DP-Corrosion	This programmatic spend covers the replacement of depleted anodes, work arising from bridge crossing inspections, and repairs to rectifier beds.
6	Depth of Cover Program	Transmission Pipe & Underground Storage	TPUS-Integrity	This programmatic spend budget is for facilities that are identified each year as exposed or shallow leading to an increased risk of 3rd party damage. Once identified the pipeline must be lowered, replaced, or otherwise protected to control risk. The programmatic budgeted here cannot be assessed for IRPAs, however, any identified pipeline replacements will be included in the IRP Technical Evaluation.
7	District Station	Distribution Stations	DS-Station Rebuilds & B & C Stations	These investments hold budget for specific station rebuild investments that have been identified through annual inspections and that have been prioritized for rebuild based on condition.
8	Farm Taps	Utilization	UTIL-Regulator Refit	This is programmatic spend that is budgeted to cover the costs of remediating situations in which there are problems with the first or second cut of the regulation at a customer's premise.

9	Facilities Integrity Management Program (FIMP)	Distribution Stations	DS-Integrity	This is programmatic spend that is budgeted to cover the costs of large station inspections that must be completed annually to scope the extent of work that is required at each large station investment identified in the AMP. The programmatic spend cannot be assessed for IRPAs, however, any identified facility replacements where growth is a project driver will be included in the IRP Technical Evaluation
10	Fire Suppression	Distribution Stations	DS-Gate, Feeder & A Stations	These investments relate to the installation of Fire Suppression at Distribution Stations with Odourant. Going forward all such Station programs that are driven by condition, end-of-life, and compliance will be removed from IRP Technical Evaluation.
11	Geohazard	Distribution Pipe	DP-Integrity	This integrity management programmatic spend is budgeted to cover the costs related to identifying pipelines that must be replaced because of risks related to geohazards. The programmatic spend cannot be assessed for IRPAs, however, any resulting pipeline replacements will be included in the IRP Technical Evaluation.
12	Independent Asset Integrity Review (IAIR)	Distribution Pipe & Transmission Pipe & Underground Storage	DP-Integrity, TPUS-Integrity	This is programmatic spend that is budgeted for work that results from the Independent Asset Integrity Review. The programmatic spend budgeted cannot be assessed for IRPAs, however, any identified pipeline replacements will be included in the IRP Technical Evaluation.
13	Integrity Digs	Distribution Pipe & Transmission Pipe & Underground Storage	DP-Integrity, TPUS-Integrity	This programmatic spend is budgeted to cover the costs related to repairs and replacements that are identified through in-line inspections. The programmatic spend cannot be assessed for IRPAs, however, any identified pipeline replacements will be included in the IRP Technical Evaluation
14	Integrity Retrofit	Distribution Pipe, Distribution Stations & Transmission Pipe & Underground Storage	DP-Integrity, DS-Integrity, TPUS-Integrity	This is programmatic spend that is budgeted for installing pig launchers and receivers, allowing annual in-line inspection to be accomplished more easily and the life of transmission pipelines to be potentially extended. This work takes place at stations and does not affect the distribution system itself.
15	Inside Room Regulators (IRR)	Distribution Stations	DS-Inside Regulator & ERR Program	This is programmatic spend that is budgeted for remediation of inside regulation sets based on risk.

16	Large stations	Distribution Stations	DS-Gate, Feeder & A Stations	These stations are identified through inspections and prioritized for rebuild based on condition. Each year, this programmatic spend is converted into specific projects. Any identified investments where growth is a project driver will be included in the IRP Technical Evaluation. It should be noted that there is also the possibility that reduced load will drive some investment in stations.
17	Liquified Natural Gas (LNG)	LNG	All	These investments relate to the maintenance of the Hagar LNG facility that is used to peak shave the load in the Sudbury area. Unless driven by Growth, all investments at the Hagar facility will be excluded from the Technical Evaluation moving forward.
18	Low Pressure Delivery Meter Sets (LPDMS)	Utilization	UTIL-Remediation	This is programmatic spend budgeted to cover the inspection and remediation of Low-Pressure Delivery Meter sets, which are usually at commercial customer locations.
19	Main & Service Repl - Leaking	Distribution Pipe	DP-Service Relay	Similar investments in the EGD Rate Zone were excluded at Binary Screening and going forward these too will be excluded at Binary Screening as Emergent Safety Issue. Aside from the safety concern, leaks must be addressed quickly to avoid GHG's.
20	Meter exchanges	Utilization	UTIL-Regulator Refit	This programmatic spend is budgeted to cover the costs of replacing meters through the Measurement Canada approved processes.
21	Maximum Operating Pressure (MOP) Verification	Distribution Pipe & Transmission Pipe & Underground Storage	DP-Replacements, TPUS-Replacements	This programmatic spend is budgeted to cover the replacement of pipelines where this may be required because of a review of records for pipeline systems operating above 30 per cent SMYS. Once the MOP has been identified and based on the associated risk, the pressure in these pipelines may need to be reduced until the pipeline can be replaced. The programmatic spend cannot be assessed for IRPAs, however, any identified pipeline replacements will be included in the IRP Technical Evaluation.
22	Odourant Program	Distribution Stations	DS-Gate, Feeder & A Stations	These investments are for the upgrade of odourant systems at stations.
23	Pressure Factoring Metering (PFM) Program	Stations	DS-Station Rebuilds & B and C Stations	This programmatic spend is budgeted to cover the costs of PFM stations that require a bypass.
25	Relocation Program	Distribution Pipe	DP-Relocations	This programmatic spend has been budgeted to cover the costs of projects that are identified annually in response to the requirements of municipalities and other agencies. The programmatic spend cannot

				be assessed for IRPAs, however, any identified pipeline replacements will be included in the IRP Technical Evaluation
26	Remote Terminal Units (RTU)	Distribution Stations	DS-Gate, Feeder & A Stations	These investments are for the replacement of Remote Terminal Units that are no longer supported by the manufacturer.
27	Storage Facility	Transmission Pipe & Underground Storage	TPUS-Improvements	As noted above, investments related to Storage Pools and Wells will be excluded from Technical Evaluation going forward unless they are driven by growth.
28	Telemetry	Distribution Stations	DS-Gate, Feeder & A Stations	These investments are for telemetry at distribution stations.
29	Vintage Steel Main (VSM)	Distribution Pipe	DP-Replacement	There is a programmatic spend budgeted for Vintage Steel Main projects that have not yet been identified. The programmatic spend cannot be assessed for IRPAs, however, any identified pipeline replacements will be included in the IRP Technical Evaluation.
30	Well Laterals	Transmission Pipe & Underground Storage	TPUS-Integrity	As noted above, investments in Storage Pools & Wells, and their associated Integrity Management Programs will be similarly excluded from Technical Evaluation.

Technical Evaluation

Investments that are not screened out through the technical screening, as noted above, proceed to a technical evaluation. Examples of the technical evaluation form can be found at EB-2022-0200, JT 5.36 Attachment 3 and 4.

During the technical evaluation, Enbridge Gas assesses the technical feasibility of the following IRP alternatives (IRPAs):

- Supply-side alternatives:
  - Compressed Natural Gas ("CNG"): Consideration of CNG injection volumes, the number of years of CNG, location of CNG injection, and the subsequent impact to project scope
  - Market-based supply: Consideration of the presence of a third-party source in the project area-of-benefit, the availability of higher pressure or increased capacity, and the subsequent impact to project scope
- Demand-side alternatives:
  - Enhanced Targeted Energy Efficiency ("ETEE"): Consideration of the level of peak demand reduction required, the level of peak demand achieved by ETEE, the number of years of ETEE, the amount of firm contracted demand on the system and potential reduction, and the subsequent impact to the project scope.
  - Demand Response ("DR"): Consideration of the level of peak demand that can be shifted through DR, and the subsequent impact to the project scope

The following are the types of technical evaluation commentary associated with investments with technically feasible IRPAs.

IRPA(s) applicable – IRPA(s) applicable could defer, reduce or eliminate project scope

These investments pass the technical evaluation as there are technically feasible supply or demand side IRPA(s) that could impact the project scope. These investments proceed with detailed system modelling for peak hour demands.

The following are the types of technical evaluation commentary associated with investments with no technical feasible IRPAs. These investments will be excluded from further detailed technical evaluation.

Scope is NPS 2, cannot downsize further or retire

The existing scope is already NPS 2 and thus cannot be further downsized. These investments were then reviewed to determine whether they could be retired. These scopes had services coming off the pipe that needed to be maintained and thus cannot be retired. Since the pipe size cannot be reduced beyond NPS 2 and cannot be eliminated, IRP has no impact on the project scope and therefore fails technical evaluation.

Potential to be downsized to NPS 2. Further assessment closer to ISD

During technical evaluation, it was determined that the project scope could potentially be replaced with NPS 2 prior to any IRP assessment. If the pipe size can be reduced, then IRP will not be applicable; the scope will be confirmed when the project enters the detailed design phase.

Timing – Market Based Supply Side not available

Some investments failed because they are required in the near term (1-3 years) and there is no technically feasible supply-side alternative that can meet the need.

Economic Evaluation

Investments that pass the technical evaluation proceed to the economic evaluation stage, where a three-phase DCF+ test is conducted to assess the cost effectiveness of IRP and facility alternatives. While there is a strong emphasis on the rate impact from the DCF+ Phase 1 test, additional factors are taken into consideration to determine the selection of the optimal alternative.

The key considerations to assess cost effectiveness includes:

- Phase 1 NPV results from the DCF+ (Relative Rate Perspective)
  - The Phase 1 DCF+ calculates the benefits and costs for existing ratepayers and reflects the utility perspective by assessing the impact on future utility rates

  Phase 1 + 2 NPV results from DCF+ (Total Customer Perspective)
  - The combined Phase 1 and Phase 2 DCF+ results reflect the total Enbridge Gas customer perspective, by assessing the impact to existing ratepayers and participants, reflecting the entire customer base's economic impacts.

- Combined Project Capital and O&M Cost
  - Alternatives are compared to determine the lowest cost alternative based on the combined project capital and O&M costs and the lowest relative bill impact.

- Persistence of Demand
  - The underlying demand profile driving the capacity constraint is reviewed to ensure the most cost-effective alternative is aligned with project needs. The demand forecast profiles typically fall within the following patterns:
    - Demand is forecast to continue increasing over the period
    - Demand is forecast to increase in the short term and then decline
    - Demand is forecast to increase in the short term and then stabilize

Enbridge Gas determines the preferred alternative by selecting the option with the highest Phase 1 NPV. This preferred alternative is further validated by comparing it with the combined Phase 1 + Phase 2 NPV results. In Enbridge Gas' experience, the preferred alternative is consistently supported by both Phase 1 and Phase 1 + Phase 2 results.

To inform decision thresholds and test robustness, single-variable cost sensitivity analyses on O&M and capital expenditures will be conducted. These analyses will determine the cost shift required for the other alternatives to achieve parity on Phase 1 NPV with the preferred alternative.

The final selection of the optimal alternative reflects a balance of considerations, including Phase 1 NPV results supplemented by consideration of the Phase 1+2 NPV results, the cost-effectiveness differential between alternatives, the forecasted demand profile, total project costs, relative customer bill impacts, while also taking into account the single-variable cost sensitivity analysis.

Following this determination, investments for which an IRP alternative is identified as the optimal solution will advance to the IRP Plan development[65] or implementation stage, or continue to be monitored and reviewed annually to confirm the IRP alternative remains the optimal solution, based on their respective lead times. Conversely, investments for which a facility alternative is deemed optimal will either proceed with the implementation of the facility alternative or continue to be monitored and reviewed annually to confirm the facility alternative remains the optimal solution.

[65] IRP Plan filing with OEB is only applicable for investments greater than $2M.

Appendix G: SLH Evaluation, Measurement and Verification Plan

Evaluation, Measurement, and Verification Plan

Southern Lake Huron (SLH) Integrated Resource Planning (IRP) Pilot

Prepared for:

Enbridge Inc.

April 2026

Submitted to:

Enbridge Inc.

Lauren Duggal
Engineer, Distribution Optimization Engineering
lauren.duggal@enbridge.com

Dunsky Project Number: 25096

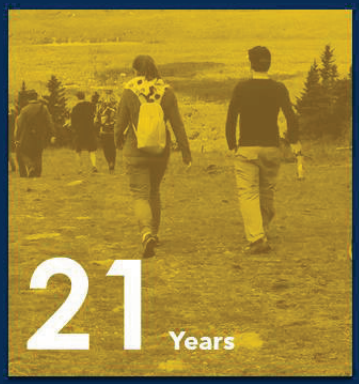
Prepared by:

Dunsky Energy + Climate Advisors
50 Ste-Catherine St. West, suite 420
Montreal, QC, H2X 3V4

www.dunsky.com | info@dunsky.com
+ 1 514 504 9030

With support from:
Alex Hill, Partner | alex.hill@dunsky.com

About Dunsky



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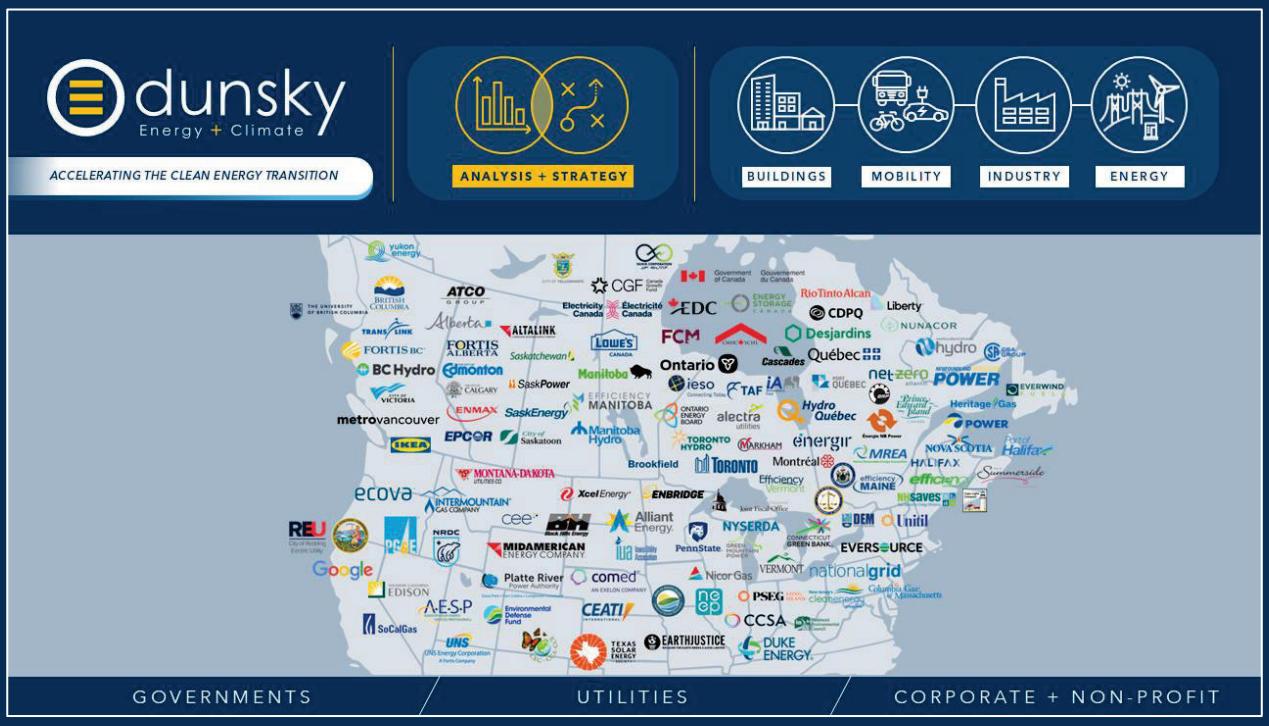
With deep expertise across the Buildings, Mobility, Industry and Energy sectors, we support our clients in two ways: through rigorous **Analysis** (of technical, economic and market opportunities) and by designing or assessing **Strategies** (plans, programs and policies) to achieve success.



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Executive Summary

The Southern Lake Huron (SLH) Integrated Resource Planning (IRP) Pilot is Enbridge Gas' first large-scale effort to measure whether demand-side Integrated Resource Planning Alternatives (IRPAs), specifically Enhanced Targeted Energy Efficiency (ETEE) and Demand Response (DR), can provide significant measurable reductions in peak hour natural gas demand and support system planning under the OEB's IRP Framework. With approximately 30,000 customers across a representative mix of residential, commercial, and industrial segments, the SLH region provides a strong test case for evaluating these alternatives.

This Evaluation, Measurement, and Verification (EM&V) Plan outlines the methods, data sources, analytical procedures, and reporting structure that will guide the independent evaluation of the SLH IRP Pilot. Developed to fulfill the OEB's direction and Enbridge's IRP Pilot commitments, the EM&V Plan provides a transparent, rigorous, and replicable framework to determine the extent to which ETEE and DR measures can reduce peak hour loads and contribute to system reliability under design-day conditions.

Evaluation Objectives

The evaluation focuses on enabling Enbridge to develop a clear understanding of how ETEE and DR programs impact system peak hour demand. Specifically, the evaluation will:

- Quantify actual peak-hour flow reductions (m^3/h) from ETEE and DR by comparing pre- and post-program load.
- Assess DR event performance, including the reliability, magnitude, and persistence of customer response.
- Identify factors that influence achieved impacts (weather, building characteristics, measure types).
- Extrapolate observed impacts to design-hour conditions using Enbridge's regression methods.

These findings will support future IRP Plans by improving assumptions, refining modeling techniques, and informing the feasibility of using demand-side IRPAs in lieu of traditional system reinforcement projects.

Evaluation Methodology

The evaluation applies a set of coordinated analytical approaches to estimate program impacts.

- Load-vs-temperature regression to measure normalized pre/post load changes and validate Enbridge's regression approach.
- Participant vs non-participant comparisons using hourly interval meter data.
- DR event analysis using smart thermostat telemetry matched to consumption records.
- Impact disaggregation by customer type and measure where statistically reliable.
- Load curve analysis to examine peak shifting, rebound effects, and system-level peak relief.

As part of this approach, customer demand extrapolation will be led by Enbridge, with Dunsky providing methodological review and collaboration. This collaborative approach enables the evaluation to leverage Enbridge's deep expertise in system design, demand

profiling, and historic Ontario design-day practice, while also incorporating Dunsky's experience in demand response, regression-based load modeling, and large dataset evaluation.

All analyses will incorporate rigorous data validation and transparency regarding uncertainty levels, underlying assumptions, and extrapolation techniques. The evaluation relies on hourly meter data, weather data (temperature, wind), smart thermostat event records, and program tracking datasets.

Evaluation Timeline and Deliverables

The evaluation is structured across two heating seasons. Key deliverables include:

- **Draft EM&V Plan** – January 2026.
- **Final EM&V Plan** – March 2026.
- **Interim Report** – Q3 2026, based on the first full winter of data and initial impact results.
- **Final Evaluation Report** – mid-2027, integrating both years of results and full system-level analysis.

Ongoing data requests, regression quality assurance, and periodic updates to Enbridge staff will ensure continuous alignment throughout the evaluation process.

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1. Pilot Background

Enbridge Inc. (Enbridge) has developed and is implementing an Integrated Resource Plan (IRP) pilot in the Southern Lake Huron (SLH) region to evaluate the impact of Integrated Resource Planning Alternatives (IRPA) on the local system peak hour. An IRPA is a potential solution other than a Facility Alternative considered in Enbridge Gas' IRP Assessment Process in response to a specific system need of Enbridge Gas[1].

investments or activities that provide utilities with an opportunity to reduce system costs, emissions, and customer risk by offering cost effective alternatives to infrastructure investment.

In July 2021, the Ontario Energy Board (OEB) issued the first Integrated Resource Planning (IRP) Framework to shape the process to compare and evaluate IRP alternatives for natural gas system needs. The Framework prescribes that IRPAs must be in the best interest of Enbridge Gas and its customers; thus, any alternative must align with the guiding principles of reliability, safety, cost-effectiveness, public policy, optimized scoping, and risk management.

The OEB has since provided approval for the SLH IRP Pilot Project, which Enbridge is implementing to understand and evaluate how IRPAs can potentially avoid, delay, or reduce facility projects.

As outlined in the pilot application to the OEB, the primary objectives of the SLH IRP Pilot project are twofold.

1. Develop an understanding of how Enhanced Targeted Energy Efficiency (ETEE), Demand Response (DR) programs, electrification measures, and advanced technologies impact peak hour flow/demand.
    a. Quantify actual peak hour flow reductions (m3/hr) resulting from ETEE and DR programming by customer type by comparing peak hour flow per customer prior to and after ETEE and DR programming is implemented.
    b. Evaluate DR event parameters on peak hour flow reductions and the adoption and persistence of customer participation in DR programming over time.
2. Evaluate and understand how to design, deploy, and evaluate ETEE and, residential DR programs, as well as other IRPA measures, that are targeted to specific, geographic areas.

The scope of this project is to support the achievement of objective 1. Outputs from this evaluation may serve as the input to future projects or initiatives.

The SLH distribution system supplies natural gas to approximately 30,000 customers located in the City of Sarnia and the Village of Point Edward in the County of Lambton. The market characteristics match well to Ontario as a whole, with a balanced mix of residential, commercial and industrial customers.

[1] IRP Framework for Enbridge Gas, July 22, 2021. pp 4.

Figure 1 - SLH Pilot Area

The SLH IRP Pilot operates within the same planning framework used to determine Enbridge Gas's system capacity requirements. Under the *Design Criteria and Design Demands Process* (EB-2022-0200), Enbridge defines system design criteria using the coldest observed day on record, expressed as Heating Degree Days adjusted for wind speed (HDDw). This "set-temperature" method reflects a no-failure reliability standard - ensuring that all infrastructure and operational plans can meet customer demand during the coldest historical conditions. The associated design-day (maximum daily) and design-hour (maximum hourly) demands form the basis for system sizing, reinforcement decisions, and assessment of Integrated Resource Planning Alternatives (IRPAs).

By evaluating how Enhanced Targeted Energy Efficiency (ETEE) and Demand Response (DR) affect peak-hour load under these design conditions, the pilot provides empirical evidence on whether demand-side resources can offset or defer capital investment while maintaining Enbridge's mandated reliability and safety standards.

The pilot focuses on residential and commercial programs, including[2]:

- enhanced residential whole home and single measure demand-side management (DSM).
- enhanced commercial/industrial custom, direct install (DI), and prescriptive DSM.
- electrification measures (ASHP, GSHP) with limited residential customer participation, including customers who have previously installed these, where known.
- residential demand response (DR) pilot, using a bring your own device (BYOD) strategy to target gas space heating.

Roughly 1600 participants are expected for residential ETEE pilot offers, 700 participants for residential DR, and 60 to 150 participants for Commercial ETEE Pilot Offers.

Enbridge has engaged Dunsky Energy + Climate Advisors (Dunsky) to evaluate its Southern Lake Huron (SLH) Integrated Resource Planning (IRP) pilot project. This evaluation plan document outlines and is intended to guide the evaluation process. It is a crucial first step to understand the SLH IRP pilot and surrounding factors, outline evaluation objectives, identify appropriate data and data sources, and describe the evaluation methods and schedule to

[2] Advanced technology measures have not yet been approved in the OEB Decision and Order, but are at issue in the OEB Motion to Review.

meet Enbridge's evaluation obligations as determined by the OEB. This document includes an overview of the SLH IRP pilot program, supported projects, evaluation objectives, key research questions, methodology, evaluation schedule, and how findings will be communicated.

2. Key Research Objectives

The objective of this work is to support Enbridge's pursuit of the first IRP Pilot Project objective in developing an understanding of how ETEE and DR offerings impact peak hour flow/demand throughout the duration of the IRP Pilot Project term through evaluation activities. The evaluation of this objective will assist Enbridge in the refinement of the approach and assumptions to be applied to the evaluation and implementation of these programs in relation to the IRP process and future IRP Plans.

Specifically, the evaluation aims to:

- Quantify actual peak hour flow reductions (m3/hr) resulting from ETEE and DR programming by customer type by comparing peak hour flow per customer prior to and after ETEE and DR programming is implemented.
- Evaluate DR event parameters on peak hour flow reductions and the adoption and persistence of customer participation in DR programming over time.
- Extrapolate evaluation findings to project design peak impacts using Enbridge's regression analysis approach.

3. Data Sources

3.1 ERT Data

3.1.1 ERT Data Description and Scope

ERT (Encoder Receiver Transmitter) data are hourly gas consumption readings collected from Enbridge's smart gas meters. These meters transmit interval data, providing time-stamped hourly usage records that can be used to assess load shape, seasonal patterns, and customer responses to demand-side measures.

In the SLH IRP Pilot, ERT data are the primary quantitative input for evaluating peak-hour demand impacts of Enhanced Targeted Energy Efficiency (ETEE) and Demand Response (DR) programs. The data allow for direct comparison of pre- and post-program peak usage (m^3/h) by customer type and region. The following table shows ERT customer counts for available hourly data in the SLH pilot region as of early 2025.

Customer Type	Hourly ERT Data	Total	% with Hourly ERT Data
Residential	18,976	26,597	71%
Commercial/ Industrial	1,505	2,170	69%
All Customers	20,481	28,767	71%

3.1.2 ERT Data Quality and Challenges

Review of hourly data has highlighted some gaps and challenges on some routes. ERT data quality is influenced by meter age, route configuration, and data transmission settings.

- **Completeness:** Vintage ERTs (prior to 2009) are not able to provide hourly data (represents approximately 30% of all customers). For the ERTs that are able to provide hourly data, over 70% of meters have been gathering data consistently (50% of total customers). Gaps are being closed through updated meter-reading contractor procedures that ensure hourly data collection is enabled for ERTs. It is expected that additional customers with ERTs will have adequate baseline hourly data prior to customer measures being implemented.
- **Temporal Alignment:** Each route's data are time-stamped and linked to corresponding hourly weather (temperature, wind) data for regression analysis by Enbridge. Multiple weather stations will be considered and analysed.
- **Spatial Coverage:** Routes in both urban Sarnia and Point Edward are read monthly, ensuring regular geographic sampling across mixed customer types. Intermittent route gaps and errors remain a variable that will need to be managed through ongoing data quality processes.
- **Data Validation:** Enbridge performs load-vs-weather regression analysis and is developing automated processes to handle the hundreds of millions of hourly ERT data points. Dunsky will be validating and replicating the processes and analysis in samples of data.

3.2 BrightLync Data

3.2.1 BrightLync Data Description and Scope

BrightLync modules are advanced telemetry devices installed on commercial and industrial (C/I) meters to record and transmit hourly natural gas consumption data. The technology is appropriate for the larger meter sizes these customers sometimes use.

In 2024-Q4, Enbridge reached out to large C/I customers in the SLH pilot area; over 90 customers showed interest in meter station upgrades, and Enbridge proceeded to order BrightLync modules. Meter station upgrades (swap or rebuild) are sometimes challenging, involving product procurement, scheduling, customer availability, and technical needs (e.g. bypass availability for duration of work, location of meter, etc.).

At the end of 2025, approximately 80 BrightLync devices will be installed, as well as hourly ERTs on smaller commercial sites interested in the SLH pilot. Additional devices will be installed on a customer interest basis from the program roll-out. Baseline data gathering begins with installation and proceeds until a customer implements an ETEE measure.

3.2.2 BrightLync Data Quality and Challenges

BrightLync installations deliver high-resolution, equipment-calibrated readings suitable for regression analysis ETEE measure impact verification, but several operational and data-integrity challenges remain.

- **Installation Constraints:** Winter conditions limit work at sites without bypass valves, delaying some installations until warmer weather. Meter swaps and rebuilds depend on customer availability and coordination with internal station crews, introducing variability in data start dates.
- **Baseline Duration:** Because BrightLync module installation began in early 2025, only limited pre-program data (one heating season or less) may be available before ETEE implementation begins.
- **Data Integration:** Enbridge is still integrating BrightLync feeds into its central hourly meter database to enable automated analytics.
- **Data Completeness:** Early datasets cover only a handful of customers; broader rollout through 2025 is ongoing to achieve statistically meaningful samples.
- **Measurement Verification:** Ongoing data-quality and calibration reviews are in place to ensure reliable readings as additional modules come online.

3.3 Weather Data

3.3.1 Weather Data Description and Scope

Weather data are used to assess gas consumption and load sensitivity to outdoor temperature and wind. In the SLH pilot area, Enbridge currently uses hourly temperature and wind data from regional Environment and Climate Change Canada (ECCC) weather stations near Sarnia and the Southern Lake Huron service area (London, Windsor), synchronized to hourly gas meter readings.

This data is used by Enbridge teams as part of their load-vs-weather regression models, which quantify how natural gas demand varies with weather (temperature and wind) and time of day for typical modeling activities.

Regression parameters derived from weather data (e.g., heating degree hours, temperature, wind) allow for comparison of participant and non-participant peak-hour demand, controlling for climatic variability.

For program evaluation purposes, weather data will be used to generate Heating Degree Hour (HDH) and wind-adjusted Heating Degree Day (HDDw) indicators, consistent with Enbridge's *Design Criteria and Design Demands* Process. The HDDw formulation accounts for the combined influence of temperature and wind speed on heating load and provides the linkage between the pilot's regression models and Enbridge's official design-day conditions. This will be applied in both baseline/non-participant normalization and participant impact models. Enbridge will also investigate the modeling accuracy results with different weather station locations (Windsor vs London). Other variables may be considered as described in 4.4.

3.3.2 Weather Data Quality and Challenges

While temperature data from ECCC and other public sources are generally reliable, several factors influence the quality and representativeness of weather inputs in the SLH pilot context.

- **Spatial Resolution:** The SLH region spans both urban and rural microclimates, and a single reference station (e.g., Sarnia Airport) may not perfectly reflect all local conditions, especially for coastal or industrial zones. This effect is likely to be minor or negligible and can be mitigated by using data from multiple nearby ECCC stations.
- **Temporal Alignment:** Precise timestamp synchronization between hourly temperature readings and ERT/BrightLync consumption records is required; even small-time offsets can introduce regression noise during peak-hour periods.
- **Missing or Noisy Data:** Occasional data gaps, rounding errors, or timestamp irregularities from ECCC feeds can reduce continuity in the hourly temperature series. These are typically corrected through interpolation or substitution from nearby stations. Depending on the type and volume of customer data or weather data that may be missing, Enbridge either removes the data for linear regression, or substitutes average customer sizes for day-to-day modeling. Substitution prior to regression is not completed since this is not for customer billing or any other purpose for monthly needs. For the SLH pilot, no substitution should take place on the upfront data gathering.

3.4 Smart Thermostat Data for Demand Response

3.4.1 Smart Thermostat Data Description and Scope

Smart thermostat data is a customer-level data source for evaluating Demand Response (DR) program performance. The data captures both thermostat operation and event participation metrics during scheduled DR events intended to reduce gas demand during system peak hours.

For participating residential customers, smart thermostats record:

- temperature setpoints (before, during, and after DR events).
- HVAC system runtime and cycling behaviour.
- event participation details (including opt-ins, opt-outs, and overrides).
- customer interaction data (such as manual adjustments during events or comfort complaints logged through apps).

This data is transmitted via the thermostat vendor's cloud-based platforms. Thermostat and consumption data must be linked before these records are anonymized and aggregated to provide useful inputs for integration into the DR evaluation dataset. Information will be anonymized between the DR Delivery Agent and Enbridge by using a unique customer identifier code rather than an account number, address, name, etc.

These datasets are used to quantify average hourly load reductions (m^3/h) during event windows relative to baseline hours (non-DR event hours during cold weather). It can also be used to assess event reliability, customer persistence, and rebound effects (post-event load increases). These data are paired with ERT hourly consumption data and weather variables to create complete regression-ready event records for impact analysis. In this analysis, ERT data

may be primary, with the vendor thermostat data providing details on customer opt-outs, quantities, etc.

3.4.2 Smart Thermostat Data Quality and Challenges

While smart thermostat telemetry provides rich, high-frequency behavioural data, several data quality and coverage challenges affect its use for rigorous DR impact evaluation:

- **Data Provision:** As of the date of issue of this EM&V Plan, there is a signed contract with a smart thermostat contractor for data provision, but discussion is ongoing regarding specific data and information to be provided. Exact details on provision and access to smart thermostat data will shape the extent to which DR measures can be evaluated.
- **Data Limitations:** Smart thermostats do not differentiate what equipment they control and only have runtime data. Thus, actual equipment consumption cannot be known from smart thermostat data alone.
- **Data Integration and Timing:** Smart thermostat event data and ERT gas consumption data are logged by separate systems, often at different timestamps or time zones. Aligning thermostat runtime data with hourly gas usage for the same household requires precise temporal synchronization to avoid misattribution of DR effects.
- **Limited Penetration:** Only a subset of ERT-equipped residential customers are expected to have enrolled in the DR program during the initial pilot window. This small sample size may limit statistical significance in aggregate DR savings estimates. This uptake will be determined during the course of the SLH pilot evaluation.
- **Opt-Outs and Overrides:** Customer comfort preferences may alter event outcomes. Opt-outs or manual adjustments during an event reduce measured savings and increase variability in results.
- **Temperature Rebound and Persistence Effects:** Post-event "catch-up" heating can create a new peak if mitigating strategies are not put in place. Detecting this requires multi-hour post-event tracking and accurate weather normalization. Depending on the number of enrolled customers and geographic locations, this post-event peak is likely acceptable if the overall system peak is reduced on the system of need. This may necessitate groupings of DR measures or limits on customer saturation of DR.

3.5 Other Data

3.5.1 Other Data Description and Scope

In addition to metered consumption and weather data, the SLH IRP Pilot draws on a suite of program-level, customer-level, and contextual datasets to support evaluation. These "other" data sources enable evaluators to understand who participated, what ETEE measures were installed, and DR event opt-in rates. Key datasets include the following.

- **Program Tracking Data:** Participation records from Enbridge's internal IRP and DSM systems, documenting customer enrollment dates, measure types (e.g., insulation, heat pumps, etc.), installation timelines, and incentive levels.
- **DSM / ETEE Program Records:** Legacy and pilot-specific DSM datasets identifying equipment characteristics, savings assumptions, and measure costs, used for cross-comparison with historical program performance.
- **Customer Characteristics:** Building type, age, size, heating system type; drawn from Enbridge's customer database and MPAC property records.

3.5.2 Other Data Quality and Challenges

While these datasets provide valuable context, they are administrative rather than instrumented data sources and thus carry their own limitations and consistency risks.

- **Data Completeness:** Program records may omit installation dates, or measure details.
- **Consistency Across Systems:** DSM, IRP, and customer information systems were developed separately; ensuring consistent identifiers (e.g., customer account number, premise ID) across systems is essential for clean joins with metered data.
- **Timeliness:** Updates to participation and installation records can lag behind actual implementation, creating potential misalignment between "program start date" and observed load impacts.
- **Data Accuracy:** Building and demographic data (e.g., MPAC) can contain outdated information on building size or system type, requiring validation against billing or field data.
- **Administrative Limitations:** MPAC data carries contractual limitations on storage, adding complications to data handling practices; accessibility of this data to be explored during evaluation activities.

4. Customer Load Extrapolation Methodology

4.1 Overview

The customer demand extrapolation will be led by Enbridge with collaboration from and methodology evaluation by Dunsky. This will allow the pilot results to draw on the expertise of Enbridge in system design, demand profiling, and historic design practice in Ontario, while allowing for Dunsky's experience in demand response, regression-based load modeling, and large dataset evaluation to be incorporated. In addition to validating the methodology and general evaluation approach, Dunsky will run analyses on data samples to verify the peak impact estimates.

This section contains an overview of Enbridge's proposed load extrapolation methodology and approach, which is under review by Dunsky as described in Section 5 of this EM&V Plan document. It is intended to contextualise the peak design methodology used by Enbridge and the pilot project, but does not constitute an evaluation methodology for the pilot project (the evaluation methodology for the pilot project is described in Section 5 and subsequent sections). This pilot project focuses on using actual consumption data to understand customer consumption patterns for the purposes of gas delivery network design. However, since these networks are designed to meet demand under extreme weather conditions it is important to estimate consumption at these conditions. The extreme weather condition is termed the Design Degree Day. Extrapolations must be used since these extreme weather conditions are infrequent, and have a low probability of occurrence during the 2-year pilot timeframe.

Several models will be developed to extrapolate the actual data to design conditions. Models will focus on isolating demand data for a specific time period (ex. demand on Wednesday at 7 AM during the winter) and assessing the sensitivity of demand against hourly weather data. This allows for linear regressions to be performed for each time period separately.

Statistical analysis will be performed to understand the strengths and weaknesses of the different models for different groups of customers. The Root Mean Square Error (RMSE) will be calculated to evaluate the strength of the various models. When comparing models a higher weight is given to model performance during the highest consumption hours, cold months, and extreme cold temperatures to bias the results towards accuracy under these conditions. The best performing model for the majority of customer demand will be selected by Enbridge to estimate design customer demand.

Coincident peak of all customers is considered to ensure results are appropriate for system design. The customer models will be combined into a system profile to determine when the coincident peak occurs at a Design Degree Day. Once the time of the coincident peak is determined the demand from each customer at this time will be considered their peak demand for system design. Once developed these models can be used on consumption history for different time periods to understand how ETEE and DR impact customer peak demand.

4.2 Data Validation and Filtering

Prior to regression modeling, all input datasets undergo systematic data validation and cleaning to ensure reliability and comparability. Where either consumption or weather data is missing the data is removed. Missing weather data is an infrequent occurrence, so estimating gaps is unnecessary. While in some cases there are substantial gaps in consumption data, the gaps are very long so filling them in would pose a large challenge. Additionally, since the model is meant to predict consumption (not estimate billing), this would create a feedback loop where estimates are used to model more estimates which would undermine the validity of the results.

Holidays and days where local time shifts due to DST adjustments will also be filtered out since habits during these days may be affected. The period from Christmas to New Years is also removed since many businesses shut down during this time frame, which could affect not only their demand, but residential demand since the workers schedules will also be affected.

Only winter data will be used for creating models to bias the results to cold temperatures during the heating season. Winter is defined as December through March inclusive. While shoulder seasons (spring and fall) could be utilized in regression, it can be difficult to predict if a customer's heating system is active, which can lead to difficulties in predicting consumption. Removing the shoulder seasons from the analysis eliminates this variable.

Interquartile analysis is performed on each customer's demand to detect outliers. The analysis must incorporate temperature since its exclusion can make it seem like customer demand at extreme temperatures are outliers, which would remove some of the most critical data.

4.3 Linear Regression by Hour

Data will be separated by hour such that 24 individual linear regressions can be performed. Customer consumption is regressed against heating degree hours. This allows for the heat sensitivity of customers to be understood while isolating for differing habits across the day. The constant variable from the regression represents the base demand present under all weather conditions for uses like water heating, cooking and process loads. The slope represents the temperature sensitivity of the customer per degree hour representing building heating.

Inputting a degree hour into 24 equations will yield a customer demand profile for the day. Demand surfaces can also be created by combining the profiles for all possible degree hours into a 3D graph.

4.4 Model Variations

Different versions of the model will be developed to ensure that system demand can be estimated as accurately as possible. Permutations of variations will be evaluated against each other to assess which is the most appropriate. Below is a preliminary list of variations that are expected to be tested.

Base Temperature

Enbridge uses a constant base temperature of 15°C when calculating degree days. While this is a standard average base temperature, it may not be appropriate for all customers. Additionally, due to variables such as building occupancy and thermostat setbacks, this value

may not be appropriate for a single customer under different time periods. Models will be developed allowing variation of base temperature between customers and times.

Recent Weather History

Buildings have thermal mass that may not react instantly to changes in outdoor temperatures. Models will be developed to determine whether averaging temperatures in recent hours reduces model error. Degree days will be compared with degree hours with and without wind speed adjustments. Alternate models with lagged variables will be explored.

Weekday Effects

Different days of the week will have different customer habits affecting consumption. Ideally models would seek to look at these effects independently, but this will limit the amount of data available for each regression. It will be investigated if there are significant differences between different days of the week, and if sufficient data is available to improve model performance.

4.5 Demand Response Analysis

Analyzing demand response (DR) events will be challenging since there will be fewer days of data that can be evaluated than for ETEE. This will be mitigated by intentionally selecting event days with a range of outdoor temperatures at which to observe trends.

DR analysis will use the same regression methodology as outlined in herein for ETEE but will only have event days included in the analysis to understand customer demand during events. Non-DR event days will be used to estimate what the demand likely would have been to measure against (expanded upon in Section 8).

4.6 Model Validation Approach

Since multiple analysis models will be developed, it is important to have a repeatable method of validating modeled results. The following methods will be used to ensure modeled results are appropriate for system design.

Segmenting Model Training and Test Data

Since multiple models will be developed there is a risk of overfitting models. This could occur if the selected model performs well on the historical meter reads collected, but when new meter reads are gathered the model performance drops. This could be due to some coincidental factor in the historical data that might not be present in future data.

To mitigate the chance of overfitting, data will be split into training data and test data. Training data will be used as an input to models linking external weather data with consumption patterns. Once the models are developed for all customers, the test data will be used to calculate composite RMSE values for evaluating model performance.

Composite RMSE

The primary statistic used for this evaluation will be the Root Mean Squared Error (RMSE). A composite value of RMSE for all customers evaluated will be created to generate a single number for comparison. RMSE was selected for evaluation over R-squared because it describes fit and overall error in a single number. By including overall error in the composite value, we ensure that the impact of larger customers is not lost. For example, if a composite R-

squared value was selected, all values would max out at 1, which would give the same weight to error in a small residential customer as a large industrial customer. For system design it is important that total load is calculated accurately, not that most customers have the least error.

First, a customer composite RMSE will be calculated. This will be a weighted average of the RMSE for all separate time periods regression was performed on focusing on time periods where system peaks are likely to occur. Since system peaks are the focus, only data from January and February will be included in test data. Holidays and days where local time shifts due to DST adjustments will be removed from training and test data. The outline below is a draft and may be updated if results show that peak time periods aren't as expected.

For hourly separations weights are as follows:

- 70% of weight will be given to peak hours (7-9 am)
- 20% of weight will be given to afternoon peak (5-7 pm)
- 10% of weight will be given to all other hours

For daily separations weights are as follows:

- 60% of weight will be given to midweek days (Tuesday to Thursday)
- 30% of weight will be given to weekend adjacent days (Monday and Friday)
- 10% of weight will be given to weekends (Saturday and Sunday)

Once the customer weighted RMSE is calculated, a system RMSE will be calculated. The system RMSE is an average of the customer RMSEs.

Visual Inspection of Results

Model performance may be very close between variations, so visualising results will assist in understanding performance across a range of conditions or customer groups. Graphics will be created to compare actual and modeled values for the following scenarios.

- System profile on selection of coldest / highest demand days.
- Estimated profile under design degree day conditions.
- Temperature/DD vs consumption graphs for selected customer groups.
- Additional graphics as required.

Enbridge Collaboration with Dunsky

Enbridge has over 100 years of experience in gas delivery system design. This makes Enbridge ideally suited to understand the historic practices around demand profiling to ensure that the pilot results can be implemented within the business. The demand extrapolation methodology will build on the company's experience with using historic gate station demand to estimate customer demand across their systems.

Dunsky will be involved in the final selection of the model so that their experience in demand response, regression-based load modeling, and large dataset evaluation can be applied as a 3rd party review.

5. Regression Analysis Model Evaluation

The first step in the analysis will focus on assessing Enbridge's peak load vs hourly weather regression analysis. This assessment will confirm that the methodology appropriately captures customer load sensitivity to weather factors, accurately extrapolates results to design-hour conditions, and provides a sound foundation for subsequent ETEE and DR impact analyses.

The general process to perform this assessment is outlined below. The approach is designed to remain flexible and may be refined as additional data or analytical insights become available over the course of the project.

Stage 1 – Technical Working Meetings

Participate in technical working meetings hosted by Enbridge to review the regression methodology and associated data workflows. These sessions will cover the following topics.

- Background on the hydraulic modeling methodology for design conditions
- Pilot data collection methods
- Visualization of individual, averaged, and grouped customer data
- Hourly estimation model development and validation
- Modeling objectives, data sources, and preparation
- Data analysis processes including a summary of raw data, missing data, and outlier detection processes
- Correlation analysis between gas consumption and weather variables
- Regression modeling approach for baseload and heat load
- Planned model enhancements
- Demonstration to Dunsky of Enbridge's internal Hourly Dashboard for visualizing data

These discussions will provide the technical foundation for understanding the analytical framework and identifying potential enhancements. They will also serve as a forum to ask questions on the current analysis methodologies.

Stage 2 – Sample Data Review

Dunsky will review representative treated data files for each primary data type (ERT, BrightLync, and smart thermostat) to gain familiarity with the datasets used in regression analysis. This review will include verification of: data completeness and timestamp consistency; alignment between consumption and weather variables; route-level and customer-level aggregation methods; and data cleaning and filtering processes.

The goal of this stage is to ensure that the regression inputs are properly structured, validated, and suitable for model estimation.

Stage 3 – Regression Algorithm Review

Review Enbridge's regression algorithm and compare it qualitatively to alternative methods and best practices. Dunsky will apply its expertise in demand response, regression-based load modeling, and large dataset evaluation to assess three key factors.

1. **Extrapolation Approach:** the method used to extend historic load and temperature data to the extreme conditions that define Enbridge's system design criteria (e.g., coldest observed HDH, HDDw).
2. **Customer Segmentation:** the approach used to capture differences among customer types, end uses, and other known drivers of peak demand.
3. **Hourly Dynamics:** the model's ability to represent intra-day load changes (particularly during peak periods) to support analysis of preheating, rebound, and heat pump control behaviour observed in the SLH IRP Pilot.

This review will identify potential enhancements that could improve model robustness and interpretability across customer classes.

To validate reproducibility and model sensitivity, Dunsky will request a **representative random customer sample** (residential and commercial/institutional customers, with stratified sampling to ensure good representation of larger customers) to independently re-run the regression model. This verification exercise will:

- validate model reproducibility and sensitivity;
- identify potential data or coding gaps; and
- support transparent benchmarking of Enbridge's regression process.

The results of the sample data set re-run will be summarized in a supporting workbook, including commentary on data quality and observed variance (if any) between Enbridge's and Dunsky's results.

Stage 4 – Error Evaluation

Identify and, where feasible, quantify individual and cumulative sources of variance inherent in the regression analysis. This assessment will help prioritize areas for methodological or data improvement and support understanding of the uncertainty introduced into subsequent pilot impact evaluations. Examples of potential error sources include:

- model specification bias;
- dependence of regression residuals; and
- regression extrapolation uncertainty under extreme temperature conditions.

Stage 5 – Data Enhancement Opportunities

Identify additional data sources that could strengthen regression accuracy and statistical power. These might include better hourly or other time-differentiated load data, both from a top-down system level (e.g., from Enbridge's operations meters) as well as from bottom-up customer and end-use levels, including real-time measured data (e.g. from hourly ERTs and smart thermostats within SLH) or from more generalized data (e.g. from hourly meter/thermostat data throughout Ontario or from load shapes borrowed from other applications and utilities).

Stage 6 – Summary and Reporting

Prepare a memo outlining our assessment of the regression analysis, the standard error that it may introduce into the forthcoming ETEE/DR Pilot impact evaluation, and its application to future evaluations. The memo will outline any data quality issues and propose potential remedies and include an accompanying workbook with sample data set re-run results.

6. Evaluation Statistical Methods

Section 6 presents an overview the evaluation approach for assessing the impacts of the SLH IRP pilot. Sections 7 and 8 then present detailed evaluation methods, with Section 7 focusing on the assessment of enhanced targeted energy efficiency (ETEE) impacts and Section 8 focusing on the assessment of demand response (DR) impacts. Together, these sections explain how pilot impacts will be calculated and interpreted.

6.1 Control Group Selection

Enhanced Targeted Energy Efficiency

For the ETEE offerings and electrification measures, we will use a combination of pre- and post-treatment data with control groups. Control Group 1 will be selected to include non-participants to DSM offerings inside of SLH region, matched to ETEE participants using known characteristics.

To limit self-selection bias, we will attempt to select a control group outside of the SLH treatment region (Group 2), which will be matched to participants based on known (observable) characteristics. Control Group 2 will apply for residential customers only, as hourly interval meter data is unavailable for commercial customers outside of the SLH pilot region.

For electrification measures, customers may or may not participate in other programs, including ETEE offerings. The appropriate control group is thus a mix of non-participants and participants to regular DSM programs, inside and outside of the SLH region (Control Group 1b and Control Group 2b, respectively).

Demand Response

For demand response (DR), control groups are not required, as each participant's baseline load curves will be used to establish the baseline for DR events. This assumes that a few time periods that would normally constitute an event are observed before the program deployment of DR events to create those baseline load curves under extreme weather conditions.

6.2 Control Group Summary

Table 1: Control Group Summary

Pilot Group	Control Group
Enhanced residential whole home DSM offering (1600 expected participants)	Non-participants to DSM offerings inside of SLH region (group 1). Participants to whole home DSM offering outside of SLH region with ERT (group 2).
Enhanced commercial/industrial custom, direct install (DI), and prescriptive DSM (60-150 expected participants)	Non-participants to DSM offerings inside of SLH region, matched to ETEE participants using known characteristics.
Electrification measures (ASHPs, GSHPs)	Gas customers (mix of non-participants and participants), inside and outside of SLH region (respectively group 1b and group 2b), matched to electrification participants using known characteristics.
Residential DR pilot (700 expected participants)	No control group needed.

6.3 Statistical Methods

Table 2: Evaluation Methods Summary

Pilot Group	Evaluation Method
Enhanced residential whole home DSM offering (1600 expected participants)	**Peak savings:** regression analysis of control groups vs treatment group hourly usage against weather conditions (outside temperature, wind) for participants with ERTs.
Enhanced commercial/industrial custom, direct install (DI), and prescriptive DSM (60-150 expected participants)	**Peak savings:** regression analysis of control groups vs treatment group hourly usage against weather data (outside temperature, wind) for participants with ERTs.
Electrification measures (ASHPs, GSHPs)	Identify control and treatment group from among participants and non-participants. Apply pre- and post-hourly load analysis to determine peak hour savings. **Peak savings:** regression analysis of pre-post hourly usage against weather data (outside temperature, wind) for participants with ERTs.
Residential DR pilot (700 expected participants)	Establish baseline peak curve and compare to DR response events.

* If any proposed evaluation method results are inconclusive, we will consider supplementing the analysis with engineering algorithms and modeling approaches where they may increase the robustness of the results. Alternate methods for evaluating peak savings involve applying algorithms to calculate peak savings from energy savings using load shapes developed from available meter data, smart thermostat data, available generic end use load curves, past evaluations, etc.

7. Enhanced Targeted Energy Efficiency (ETEE) Evaluation

7.1 Overview and Methodology

The Enhanced Targeted Energy Efficiency (ETEE) evaluation assesses how energy efficiency measures influence peak-hour and design temperature gas demand. The objective is, for the purposes of gas delivery system design, to quantify measurable load reductions (m^3/h) attributable to ETEE interventions while controlling for temperature, customer type, and market trends.

The regression analysis will include the following tasks.

- Clean and assemble billing data, metering data, and program tracking data for all ETEE participants.
- Estimate site-level peak demands for pre- and post-installation periods for participants.
- Identify and remove outliers and other ETEE participants with issues (missing data, inconsistent regression coefficient, etc.).
- Construct a comparison group (group 1 – DSM non-participants) to address non-DSM exogenous change, and a similar comparison group (group 2 – DSM participants) to address non-ETEE exogenous change.
- Determine the average peak savings and savings at design temperature per participant resulting from ETEE participation.

7.2 Statistical Methods

Table 3: ETEE Evaluation Methods

Pilot Group	Evaluation Method
Enhanced residential whole home DSM offering (1600 expected participants)	**Peak savings:** regression analysis of control groups vs treatment group hourly usage against weather conditions (outside temperature, wind) for participants with ERTs, incorporating additional key program data; incorporating smart thermostat data, if available; extrapolated to non-ERT customers based on known usage/building/customer characteristics. Peak hour gas use prior to and after implementation of ETEE measures will be compared to verify that they are statistically different, and the difference between the two curves will be extrapolated to design temperature.
Enhanced commercial/industrial custom, direct install (DI), and prescriptive DSM (60-150 expected participants)	**Peak savings:** regression analysis of control groups vs treatment group hourly usage against weather data (outside temperature, wind) for participants with ERTs, incorporating additional key program data; extrapolated to non-ERT customers based on known usage/building/customer characteristics. Peak hour impacts to be extrapolated to design temperature. • Homogenous group(s), 40-50 or more, identify best targets (segment, annual consumption, etc.). • Potentially collect additional hourly building and/or end use metering data for larger/custom projects. • Apply engineering algorithms to estimate net savings at peak for other customers/measures. • Total savings adjusted using pre/post impacts of control groups.
Electrification measures (ASHPs, GSHPs)	Identify control and treatment group from among participants and non-participants. Apply pre- and post-hourly load analysis to determine peak hour savings. **Peak savings:** regression analysis of pre-post hourly usage against weather data (outside temperature, wind) for participants with ERTs, incorporating additional key program data; extrapolated to design temperatures for peak day/hours; extrapolated to non-ERT customers based on known usage/building/customer characteristics.

7.3 Control Group Selection

For the ETEE offerings and electrification measures, we will use a combination of pre- and post-treatment data with control groups. The pre- and post-treatment data will estimate the impact of energy efficiency and electrification measures, while the control groups will factor in external effects such as energy prices and social trends on naturally occurring energy efficiency and electrification.

Control Group 1 will be selected to include non-participants to DSM offerings inside of SLH region, matched to ETEE participants using known characteristics such as size, vintage, etc.

One key consideration when designing the evaluation approach is the possibility of having a self-selection bias in the results. Program participants are self-selected (they choose to participate or not), and this choice may be correlated to building characteristics, consumption profiles, etc. In other words, the program participants may have different characteristics than those of the general population just because they chose to participate in the program.

To limit self-selection bias, we will attempt to select a control group outside of the SLH treatment region (Group 2), which will be matched to participants based on known (observable) characteristics and time of participation in DSM programs. The possibility of creating such a control group will be explored and the outcome may be determined by data availability and data quality. Control Group 2 will apply for residential customers only, as hourly interval meter data is unavailable for commercial customers outside of the SLH pilot region.

Both groups will be matched to pilot participants based on observable characteristics such as annual consumption, building type/segment, etc. This will help alleviate the self-selection bias, although unobservable characteristics may still differ between the control group and program participants.

For the ETEE portion, we will assess the peak hour impacts against two baselines: DSM participants, and non-participants. This will enable us to determine the absolute peak hour impact, as well as any incremental peak hour impact of ETEE when compared to standard DSM offerings. Control Group 1 will be selected among non-participants to assess the overall impact of DSM including the ETEE offering. An analysis of program uptake will complement the evaluation of savings per participant as ETEE can also have the effect of increasing the uptake. Control Group 2 (contingent on data availability) will thus be selected among participants to regular DSM programs to evaluate increased savings (deeper savings) from ETEE.

For electrification measures, customers may or may not participate in other programs, including ETEE offerings. The appropriate control group is thus a mix of non-participants and participants to regular DSM programs, inside and outside of the SLH region (Control Group 1b and Control Group 2b, respectively).

Table 4: ETEE Control Group Descriptions

Pilot Group	Control Group
Enhanced residential whole home DSM offering (1600 expected participants)	Non-participants to DSM offerings inside of SLH region, matched to ETEE participants using known characteristics (group 1). Participants to whole home DSM offering outside of SLH region with ERT, matched to ETEE participants using known characteristics (group 2). If possible, control group 2 will be selected in regions that have a similar climate to the pilot's territory.
Enhanced commercial/industrial custom, direct install (DI), and prescriptive DSM (60-150 expected participants)	Non-participants to DSM offerings inside of SLH region, matched to ETEE participants using known characteristics.
Electrification measures (ASHPs, GSHPs)	Gas customers (mix of non-participants and participants), inside and outside of SLH region (respectively group 1b and group 2b), matched to electrification participants using known characteristics. If possible, control group 2b will be selected in regions that have a similar climate to the pilot's territory.

7.4 Limitations and Intended Uses of Results

The evaluation produces empirical results based on observed pilot data; however, the scope, sample size, and data quality constraints inherent to a pilot setting introduce limitations. Thus, the results should be viewed as directional rather than definitive. This section identifies key limitations and clarifies how the results should be applied in future IRP planning.

Limitations

- **Pilot Scale and Duration:** The SLH IRP pilot covers a limited number of participants and a two-year evaluation window. This short timeframe restricts the ability to observe long-term persistence of energy savings or customer behavioural changes. In addition, seasonal variations (e.g., only one or two heating seasons per site) may introduce volatility in estimated savings. Small sample sizes for some customer segments or measures may limit statistical significance and ability to subsegment data.
- **Participant Self-Selection:** Program participants self-select into ETEE offerings, and while matching with control group customers based on known characteristics attempts to correct for this bias, participants may differ from the broader customer population on unobservable characteristics (e.g., building efficiency, equipment vintage, or energy-use behaviour).

- **Statistical Uncertainty:** Regression-based estimates include standard errors and confidence intervals that reflect data variability and model fit. These uncertainties will be reported and should be considered when interpreting numerical savings estimates.
- **Model extrapolation:** The model must be extrapolated outside of the range of observed outside temperatures to evaluate impacts at the system design temperature. Steps will be taken to control for possible bias (e.g. analysing residual errors with outside temperature, testing alternate non-linear models).

Intended Uses

The ETEE pilot evaluation is designed to inform planning. Its findings will guide how IRP Alternatives are valued and assessed with a better estimate of customer uptake, program costs, and peak hour effects. Appropriate uses include the following.

- **Gas Delivery System Design:** With a focus on extreme cold conditions.
- **IRP Assessment Process Learnings:** Providing empirical evidence on the feasibility and magnitude of efficiency-driven demand reduction for system-planning purposes.
- **Program Design Improvement:** Identifying effective measure types, participation drivers, and data-collection practices for future pilots or full-scale programs.
- **Methodological Learning:** Testing regression models, control-group selection methods, and data-integration processes for use in broader IRP applications.

7.5 ETEE Measures Available by Customer Type

Customer Type	Meter Type	ETEE Measures	Notes
Residential	ERT	Insulation (attic, basement, walls); draft-proofing (air sealing); windows, doors, skylights, sliding doors; heat pump water heaters; electric cold climate ASHPs (maximum 20); electric GSHPs (maximum 20); smart thermostats.	Up to $15,000 in upfront full cost coverage. Participants cannot receive an incentive for both a heat pump and home upgrades. It's one or the other.
Small Commercial	ERT	Direct install and prescriptive measures: air curtains; dock door seals; condensing make-up air units; ozone laundry; ventilation; destratification fans; demand-controlled kitchen ventilation; demand controlled (other) ventilation; heat recovery and energy recovery ventilators). Custom options: including but not limited to building automation systems; control upgrades; ventilation equipment; heat recovery.	Direct-install and prescriptive measures: up to $100,000 in full cost coverage. Custom incentive (less uptake for small commercial): $2/m^3 up to $250,000 for general commercial and up to $500,000 for industrial, agricultural, and institutional customers.
Large C/I	BrightLync	Same measures as for Small Commercial customers.	Same direct-install, prescriptive, and custom pathways as for Small Commercial Customers.

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7.6 Measurables and Data Evaluation

7.6.1 Residential (ERT)

Control Groups (Non-Participants): Customers outside or inside of the SLH region, matched to pilot participants on consumption and building characteristics. Two control groups will be selected amongst the following customers.

- Non-participants to whole home DSM of ETEE offering inside of SLH region, matched to ETEE participants using known characteristics (group 1).
- Participants to whole home DSM offering outside of SLH region, matched to ETEE participants using known characteristics (group 2).

Sample Group (Participants): Approximately 1600 participating homes are expected in the SLH region.

Measure Breakdowns: Where sufficient participation data exist, results will be disaggregated by measure type to highlight the relative contribution of key residential upgrades. If sample sizes are too small for measure-level analysis, results will be aggregated at the whole-home level with supporting qualitative insights from program tracking data.

The regression results and load-curve analysis will quantify the effects of ETEE in absolute terms (m^3/h) per customer and groupings of customers, forming the basis for system-level extrapolation of residential ETEE impacts.

7.6.2 Commercial (ERT & BrightLync)

Control Groups (Non-Participants): Customers inside of the SLH region, matched to pilot participants on consumption and building characteristics. The control group will be selected amongst the following customers, subject to data availability.

- Non-participants to custom, DI, and prescriptive DSM or ETEE inside of SLH region, matched to ETEE participants using known characteristics.

Sample Group (Participants): The C/I participant group is expected to include approximately 150 facilities located within the SLH region. These sites are enrolled in ETEE programs tailored to their sector and building type. Facilities are equipped with either ERT (for smaller commercial customers) or BrightLync (for larger commercial sites) hourly gas metering. Hourly data from these meters, as available, will be used to perform pre- and post-ETEE regression analyses that relate load to weather and operating conditions, allowing estimation of changes in peak-hour demand and overall energy use. These participant-level results will then be compared with matched control-group customers inside of the SLH region.

Measure Breakdowns

Where sufficient participation data are available, results will be analyzed by major measure type to identify which interventions yield the largest impact. Representative measure categories. If sample sizes for certain measure types are limited, measures may be aggregated by sector (e.g. office, retail, light manufacturing) for statistical reliability.

The regression results and load-curve analysis will quantify the effects of ETEE in absolute (m^3/h) terms per customer and groupings of customers, forming the basis for system-level extrapolation of commercial ETEE impacts.

7.6.3 System Level Impacts of ETEE

The system-level analysis translates customer-level savings into measurable impacts on the SLH regional gas distribution system. Results from the customer-level residential, small-commercial, and industrial regression models will be aggregated to estimate how ETEE participation affects overall system load during critical peak periods.

This aggregation combines:

- the number of participating customers by category;
- average per-customer reductions in peak-hour flow (m^3/h) by category.

Savings from ERT customers will be scaled up to include non-ERT customers. If ERT and non-ERT customers in any given segment differ materially on any observable characteristics (e.g. annual gas consumption, past participation level to DSM programs), then and adjustment factor may be applied to correct for these characteristics, where relevant.

From these data, Enbridge is poised to estimate total peak-hour demand reduction (m^3/h and percent of total load at peak conditions). These values can be compared with modeled system constraints in Enbridge distribution systems to assess whether ETEE measures could meaningfully defer or reduce future infrastructure investments.

7.6.4 Sources of Error

Several potential sources of error may influence the accuracy of ETEE impacts – outlined below.

- Metering gaps or communication losses for customers enabled for hourly interval metering data (ERT/BrightLync).
- Metering gaps for subset of customers within the SLH pilot region that are not enabled for hourly interval metering data.
- Inaccurate installation or participation records.
- Weather station representativeness.
- Regression-model specification errors (to be assessed under load regression evaluation).
- Self-selection bias and other biases.
- Others as determined as the evaluation process progresses.

7.7 ETEE Evaluation Conclusions

The ETEE evaluation will quantify incremental peak-hour reductions achieved through ETEE measures delivery in the SLH pilot region. Expected outcomes:

- quantified peak-hour gas reductions under extreme cold-weather conditions and extrapolated design temperature demand reductions.
- validation of ETEE targeting as a technically viable IRP Alternative by customer segment, measure, approach, or other characteristic.
- actionable insights for improving data collection, program design, and modeling approaches in future IRP assessment processes.

8. Demand Response (DR) Evaluation

8.1 Overview and Methodology

The Demand Response (DR) evaluation assesses how event-based programs influence hourly gas demand within the SLH pilot region. The objective is, for the purposes of gas delivery system design, to quantify measurable load reductions (m^3/h) achieved by participating customers during DR events, and load impacts right before and after events, to determine the reliability, magnitude, and persistence of these reductions under extreme weather conditions.

The DR contractor has agreement with thermostat providers, and event notification varies between providers through in-app notifications and/or emails. DR strategies are still being defined, and evaluation methodology will evolve as the pilot design is finalized.

Unlike ETEE, which compares participants to external control groups, the DR evaluation uses each participant's own pre-event (or non-event) load curve as the baseline (as described in Sections 4 and 6). Hourly ERT data and smart thermostat event data will be used to:

- establish baseline temperature–load relationships under system peak conditions;
- measure changes in gas demand during DR events; and
- assess rebound, persistence, and customer response patterns before and after events.

Regression and event-analysis techniques will be applied to estimate peak load reductions.

8.2 Statistical Methods

Table 5: DR Evaluation Method

Pilot Group	Evaluation Method
Residential DR pilot (700 expected participants)	Establish baseline peak curve and compare to DR response events (including before and after the event horizon to capture pre-heating, rebound and other effects). Design conditions to be extrapolated to understand the impact on system design.

8.3 Control Group Selection

For demand response (DR), control groups are not required, as each participant's baseline load curves will be used to establish the baseline for DR events. This assumes that a few time periods that would normally constitute an event are observed before the program deployment of DR events to create those baseline load curves under extreme weather conditions. We will use hourly data and building-level regression to calculate expected energy use during what would constitute peak events under the program's definition, compare that curve of expected energy use to real energy use for validation, and then use these results to calculate the baseline energy use during events. Modeled energy use (baseline) and real metered energy use (incorporating program impacts) will be compared at the aggregate level (all DR participants) on an hourly and event basis to evaluate peak savings and other program effects (e.g., pre-heating, rebound, etc.).

8.4 Limitations and Intended Uses of Results

The DR evaluation generates high-resolution insights into short-term load flexibility, but results should be interpreted within the constraints of a small pilot-scale program.

Limitations

- **Participant Self-Selection:** Customers opting into the DR pilot may differ from the broader population in thermostat usage, comfort tolerance and responsiveness to DR events. Results of a small pilot project may not be extrapolated to estimate the impacts of a larger program without some adjustments.
- **Baseline Accuracy:** Baselines derived from pre-event periods may not perfectly represent conditions during actual events, for example when occupancy differs.
- **Data Integration:** Synchronizing thermostat and ERT hourly data requires precise time alignment to avoid underestimating or overestimating savings.
- **Limited Persistence Data:** With only one to two DR seasons (dependent on smart thermostat data availability and timeliness), persistence and fatigue effects may not be quantifiable within the evaluation timeframe.

Intended Uses

The DR results will provide directional evidence of the peak-hour load relief achievable through short-duration thermostat control events. Appropriate uses include the following.

- **IRP Assessment Process Learnings:** Estimating the potential of DR to contribute to localized capacity increase deferral as an IRPA.
- **Program Design Improvement:** Identifying optimal event timing, duration, and control strategies for future DR expansions.
- **Behavioural Insights:** Understanding customer participation, comfort preferences, and rebound behaviour for demand-side planning.

8.5 DR Participation and Data Sources

Customer Type	Meter Type	DR Measures	Data Source(s)
Residential	ERT + Smart Thermostat	Event-based heating setback during peak hours via smart thermostats; baseline and event data used to measure load reductions.	ERT hourly consumption, thermostat cloud data.

8.6 Smart Thermostat Data

Smart thermostat data form the foundation of the DR evaluation. These data provide hourly (or sub-hourly, in some cases) data on temperature setpoints and system runtime. These data can be used to quantify DR event participation and customer response/setbacks during peak-hour. Smart thermostat data will be provided with all personally identifiable information (PII) removed.

Temperature Setpoint Data: Capture thermostat's target indoor temperature. Comparing event-hour setpoints to baseline conditions indicates temperature setback magnitude during a DR event. Setpoint recovery profiles following the event can be analyzed to assess customer comfort preferences and post-event rebound.

Integration with ERT Data: Smart thermostat data alignment with ERT hourly gas consumption data enables regression models to link thermostat behaviour directly to measured load changes. This provides supplemental contextual data to correspond smart thermostat setpoint reductions to metered consumption impacts.

DR Event Call Details: Alignment with event call details enables linking between DR event characteristics, customer/thermostat behaviour, and measured load changes. These details include: event hours and duration, event call execution method (i.e. automated, other methods), data capturing manual overrides.

8.7 Measurables and Data Evaluation

8.7.1 Residential (ERT & Smart Thermostats)

Baseline Group (Non-Event): Because the DR analysis relies on event-based comparisons, there is no external control group. Instead, participant baseline load curves will be developed from similar, non-event days with comparable temperature and occupancy conditions. These non-event days may consist of comparable days pre-DR participation and comparable days post-DR participation when a DR event is not called. This baseline represents the customer's expected heating load in the absence of a DR event. Baselines will be built using non-event regression models that relate hourly gas consumption to weather conditions (temperature, wind).

Sample Group (Participants): The participant group will include approximately 700 residential customers that are expected to enrol in the smart thermostat DR pilot. These customers are equipped with ERT hourly meters and internet-connected smart thermostats

capable of automated temperature setbacks during event hours. Hourly gas consumption data will be analyzed to determine weather-normalized changes in gas demand during DR events.

Event Breakdowns: Where sufficient data are available, results will be grouped by event characteristics to highlight factors that most influence consumption (e.g. event duration, event start time, setback magnitude, ambient temperature band, customer participation/opt-in/out/default enrolment). If sample sizes for some segments are limited, events may be grouped by characteristic groups where analytically appropriate.

Effects of DR: The expected effects of DR for the residential sector include the following.

- **Improved load flexibility:** demonstration of customers' ability to reduce or shift gas demand during system peaks.
- **Limited rebound load:** limited post-event heating load increases as thermostats return to normal setpoints or increase to restore space temperature; rebound magnitude and timing to be quantified.

Regression and event-impact analyses will express these effects in both absolute m^3/h per customer.

8.7.2 System Level Impacts of DR

Event-level savings from residential DR program participants will be aggregated to estimate total system-level impacts. This aggregation combines:

- the number of active DR participants;
- average per-customer reductions in peak-hour flow (m^3/h) by category.

From these data, Enbridge can estimate total peak-hour demand reduction (m^3/h) and equivalent capacity relief (m^3/h) for the SLH pilot region. Savings from ERT customers will be scaled up to include non-ERT customers. If ERT and non-ERT customers in any given segment differ materially on any observable characteristics (e.g. annual gas consumption, past participation level to DSM programs), then an adjustment factor may be applied to correct for these characteristics, where relevant.

Observed participation variability, including opt-outs, inactive participants, or partial response, will be incorporated into the system-level calculations to ensure that estimated aggregate impacts represent actual, realized performance rather than theoretical maximum participation. Participation trends will also be tracked over multiple events and up to two heating seasons (2026 and 2027) to assess persistence and program fatigue, subject to smart thermostat data availability and timeliness.

Where DR events do not coincide with design-day temperatures, results can be scaled to design-hour conditions using regression-based temperature sensitivity factors, estimated baseline heat-sensible gas load at design temperature and average gas use reduction. The evaluation will document assumptions and uncertainty associated with this extrapolation, and will also run a regression analysis on the drop of gas use compared to outside temperature using each hour of the DR events as data points to validate or refine this assumption.

8.7.3 Sources of Error

Several potential sources of error may influence the accuracy of DR impact estimates – outlined below.

- Limited number of participants and DR events (smaller data set).
- Missing or incomplete ERT or thermostat data (gaps, communication losses).
- Time misalignment between thermostat and meter readings.
- Weather station representativeness.
- Uncertainty from extrapolating observed impacts to design-hour conditions.
- Changes in hours of operation or process schedules during events that can mask or mimic DR effects.
- Overlap/program interactions of ETEE measures or other DSM activities with DR events.
- Regression model specification errors (to be assessed under load regression methodology evaluation).

8.8 DR Evaluation Conclusions

The DR evaluation will quantify short term, event-based reductions in residential gas demand achieved through smart thermostat control. Expected outcomes:

- Verified peak-hour demand reductions during cold weather events and extrapolated design temperature peak hour reductions.
- Assessment of rebound magnitude/significance and event consistency.
- Insight into customer behavioural response (overrides under varying conditions).

9. Expected Evaluation Timeline

The following high-level timeline and deliverables are expected for this project.

Task	2025				2026												2027						
	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
Task1: Project Management & Admin																							
Kick-Off Meeting & Workplan	M	D																					
Project Management																							
Enbridge & Dunsky Project Meetings	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M
Task 2: Evaluation Planning																							
Initial Data Request		D																					
Draft EM&V Plan					D																		
Final EM&V Plan							D																
Task 3: Regression Analysis Model Evaluation																							
Technical Working Meetings	M	M	M	M	M	M	M																
Sample Data Review																							
Regression Algorithm Review																							
Error Evaluation																							
Data Enhancement Opportunities																							
Summary and Reporting (Memo)									D														
Task 4a: Impact Analysis Round 1																							
Data Collection																							
RSME Evaluation																							
Visual Inspection of Results																							
Impact Analysis and Evaluation																							
Interim Report													D										
Task 4b: Impact Analysis Round 2																							
Data Collection																							
RSME Evaluation																							
Visual Inspection of Results																							
Impact Analysis and Evaluation																							
Draft Report																					D		
Final Report																						D	
Final Presentation																						D	

M = Meeting D = Deliverable

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10. Reporting

Reporting will summarize findings from the evaluation activities carried out under the SLH IRP Pilot. Each report will include quantitative results, methodological updates, and qualitative insights to inform future Integrated Resource Planning (IRP) applications.

10.1 Interim Report

The Interim Report will provide the first-year impact assessment and evaluation results from the SLH IRP Pilot. It is intended to:

1) present early findings on ETEE and DR program performance;
2) summarize data quality, participation levels, and baseline regression model results;
3) identify preliminary peak-hour load reduction estimates;
4) document lessons learned from data handling, measurement, and evaluation processes.

The Interim Report will be produced after the first full heating season of pilot operation (Q3-2026).

10.2 Final Report

The Final Report will present the complete findings and conclusions from the SLH IRP Pilot once data collection and evaluation activities are complete. This report will serve as the definitive documentation of pilot performance, providing actionable insights for potential scaling of IRPAs. This report will also include the second-year impact assessment and evaluation results from the Pilot.

Contents

- Summary of pilot design, participation, and implementation.
- Final regression model results and validated impact estimates for ETEE and DR measures.
- Discussion of Pilot successes, challenges, and recommendations for future IRP deployment.

The Final Report will be completed in mid-2027, following the conclusion of two full evaluation years and incorporating results from both rounds of analysis (Spring 2026 and Spring 2027).

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This report was prepared by Dunsky Energy + Climate Advisors, an independent firm focused on the clean energy transition and committed to quality, integrity and unbiased analysis and counsel. Our findings and recommendations are based on the best information available at the time the work was conducted as well as our experts' professional judgment.
Dunsky is proud to stand by our work.

Indigenous Working Group Report

May 29, 2026

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Appendix A - Enbridge Gas Inc. Indigenous Working Group Meeting Minutes

1. Introduction

As set out in the complete settlement on Item 4 of the Settlement Agreement and accepted by the Ontario Energy Board (OEB) in its Decision on the 2024 Rebasing Phase 1 Settlement Agreement, Enbridge Gas Inc. (Enbridge Gas) established an Indigenous Working Group (IWG)[1] to inform and enhance its ongoing consideration of the unique rights and concerns of Indigenous customers and rightsholders with respect to Enbridge Gas rates and services and has undertaken a number of activities in relation to the IWG. One of the required activities is for Enbridge Gas to work with the members of the IWG to draft an annual report (IWG Report) summarizing the activities of the IWG and initiatives planned or implemented, including minutes of the IWG meetings. This IWG Report is to be filed as part of Enbridge Gas's annual deferral and variance account (DVA) proceeding. This is the second annual IWG Report.

2. IWG Members

The IWG initially consisted of Ginoogaming First Nation (GFN) and the Three Fires Group (TFG), which groups were intervenors in the 2024 Rate Rebasing proceeding. The Settlement Agreement allows for any other First Nation community or reserve to join the IWG provided they or their distribution companies are Enbridge Gas customers. Additional communities (and distribution companies) that have joined the IWG are Minogi Corp, representing Mississaugas of Scugog Island First Nation (Minogi), Chippewas of the Thames First Nation (COTTFN), and Six Nations Natural Gas (together with GFN and TFG, referred to as the Indigenous Parties).

3. IWG Meetings & Minutes

The IWG held meetings on the following dates since the previous annual IWG Report (in-person and virtual):

1.	May 14, 2025	In-person
2.	July 15, 2025	Virtual
3.	September 23, 2025	In-person
4.	November 26, 2025	Virtual
5.	March 25, 2026	In-person

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule1, August 17, 2023, pp.16-20.

Please refer to Appendix A to this IWG Report for copies of the minutes of each meeting.

4. Summary of Discussions

The meetings are managed in accordance with a collaborative approach of determining agenda items and taking turns chairing. Representatives of Enbridge Gas and the Indigenous Parties have attended meetings, shared information and delivered presentations. Overall, the group looks for opportunities to expand on the discussions to provide more information for the OEB and others.

Discussions at meetings are reflected in the minutes appended to this report and included the following topics:

- Leave to Construct (LTC) Environmental Assessment Process
- Responses to The Brattle Group recommendations regarding theenergy transition
- Reconciliation principles
- Heat Pump Strategy Update
- IWG Reporting and Budgeting
- Indigenous Supply Chain Management (SCM) Update
- Engagement Opportunities/Timelines - 2029 Rebasing Filing and Enbridge Projects
- Updated LTC Environmental Assessment (EA) Process
- Integrated Resource Planning (IRP) Process
- Sustainability and Nature-Related Disclosures
- Archaeology firms contracted, and IWG recommendations respecting same
- Relationship with TC Energy
- Bill 5
- 2027 + Demand Side Management (DSM) Plan
- 2029 Rebasing Customer Engagement
- Gas Supply Plan Update

- 2029 Rebasing Indigenous Engagement and IWG Expert Recommendations regarding same
- Methane Measurement related to Enbridge Gas' Assets
- Environmental Report (ER) terminology, including for Archaeological Studies,
- Use of LiDAR for Archaeological Studies and Cumulative Effects Assessments

5. Summary of Presentations to the Group

Meetings include presentations from IWG members and Enbridge Gas subject matter specialists to facilitate informed discussion of a topic. The IWG has received the following presentations and resources in relation to Enbridge Gas:

- May 14, 2025 - LTC Environmental Assessment (EA Process), presented by Enbridge Gas, Kelsey Mills – Supervisor, Environment Projects, who sought feedback from the IWG on opportunities for improvement relating to Indigenous engagement undertaken by Enbridge Gas and explained current initiatives being incorporated into future engagement.
- May 14, 2025 - Response to The Brattle Group recommendations regarding the energy transition, presented by Enbridge Gas, Brent Bullough – Strategist, Community and Indigenous Engagement. The IWG expressed that the responses could be improved and Lisa DeMarco – Resilient LLP, representing TFG and Minogi, provided a list of issues that she would like to see further discussion on, including equity participation, definition of impacts, community specific plans, Brattle misalignment of expectations, and accountability metrics for Enbridge Gas. The IWG suggested continuing the discussion at a future meeting.
- May 14, 2025 - Reconciliation Principles presented by Enbridge Gas, Kim Brenneis – Director, Community and Indigenous Engagement, who provided an update on the status of reconciliation commitments made by Enbridge Inc. since the release of the updated Indigenous Reconciliation Action Plan (IRAP) in April 2025. Following the presentation, discussion ensued around the Indigenous Advisory Group's perspectives surrounding the IRAP.

- May 14, 2025 - Heat Pump Strategy Update, presented by Enbridge Gas, Craig Fernades – Manager, Residential Energy Conservation, who discussed how the strategy has changed since the elimination of the federal carbon surcharge. It was acknowledged there was a need to revisit the topic with COTTFN. Following the update, the IWG expressed interest in getting a third-party to look at cost implications in various scenarios.
- May 14, 2025 - Indigenous SCM Update, presented by Enbridge Gas, Richard Brant – Supply Chain Analyst, Indigenous Engagement, who presented on Indigenous spend statistics and the Enbridge Gas Socio-Economic Requirement of Contractions (SERC) process. Themes of the discussion that followed included potential areas of improvement within the process so that Indigenous businesses could better take advantage of opportunities offered through the SERC process.
- July 16, 2025 - Engagement Opportunities/Timelines – 2029 Rebasing Filing and Enbridge Projects, presented by Enbridge Gas, Vanessa Innis – Director Strategic Regulatory Applications – Rebasing, who sought feedback on Nation participation in the context of the 2029 rebasing consultation. IWG members stressed the importance of customer engagement frameworks and the perspectives of Indigenous Communities in the Regional Scenario Analysis (RSA). Kate Kempton, of Woodward and Company, representing GFN, identified issues and the IWG suggested forming a subcommittee to be involved in consultation. Enbridge Gas advised of upcoming technical sessions and invited IWG members to attend.
- July 15, 2025 - Updated LTC EA Process presented by Enbridge Gas, Kelsey Mills – Supervisor, Environment Projects, who provided an update on the EA process, including the Archaeology Assessment process. Topics included terminology, requirements of archaeologists and LiDAR.
- July 15, 2025 - IRP Process, presented by Enbridge Gas, Alison Moore – Manager, IRP, who sought feedback on the best way to engage the IWG going forward as it relates to the IRP and what the initial focus of the engagement should be. Topics of discussion included the Southern Lake Huron Pilot and the

importance of treaty-based engagement. The IWG suggested organizing a smaller group to discuss.

- July 15, 2025 - Sustainability and Nature-Related Disclosures, presented by Enbridge Inc., Gina Jordan – Manager, Sustainability & ESG Policy, who clarified Enbridge Gas's performance and provided an overview of the Sustainability Report. Gina Jordan discussed ways Enbridge Inc. is working to better understand impacts and dependencies, including continuing to evaluate the disclosure recommendations and guidance set out in the Taskforce on Nature-related Financial Disclosures (TNFD).
- September 23, 2025 - Archaeology firms contracted, and IWG recommendations respecting same, presented by Nicholas Daube – Woodward and Company, representing GFN, who provided an overview of IWG Participant preferred archaeology firms for Enbridge Gas to consider. Enbridge Gas agreed to investigate the list and how suggestions could be incorporated into existing procedures.
- September 23, 2025 - Relationship with TC Energy, presented by IWG, Kate Kempton – Woodward and Company, representing GFN, who expressed disappointment with TC Energy's relationships with GFN. Kate Kempton requested Enbridge Inc. meet with TC Energy to encourage improvement of engagement with Indigenous Communities. Diana Audino, Managing Legal Counsel, for Enbridge Inc. confirmed she would reach out to TC Energy.
- September 23, 2025 - Bill 5, presented by Enbridge Gas, Jessica Maga – Manager, Government Affairs, who attended to answer questions on Bill 5.
- November 26, 2025 - 2027 + DSM Plan, presented by Enbridge Inc., Erin Lindsay – Supervisor, Energy Conservation Business Planning, who provided an update on the approved 2026 DSM Plan and the upcoming 2027+ application, detailing program continuity, budget allocations, and anticipated procedural steps. In addition, the Home Winterproofing Program (HWP), engagement done with First Nations, and attempts to overcome barriers to bringing the HWP to First Nation communities were discussed. Daniel Vollmer – Resilient LLP,

representing TFG and Minogi, requested data on the HWP's uptake in First Nations.

- November 26, 2025 - 2029 Rebasing Customer Engagement, presented by Enbridge Gas Gesiena Antuma – Supervisor, Customer and Market Insights, who sought input on the best way to conduct engagement with Indigenous customers. The IWG requested retaining an expert to help channel First Nations' perspectives, needs, and opportunities.
- March 25, 2026 - Gas Supply Plan Update, presented by Enbridge Gas, Echo Xu – Specialist II, Gas Supply Business Management, who provided an overview of the Gas Supply Plan, including the OEB framework and Enbridge's Gas's supply planning process, inputs to Enbridge's gas supply plan, and Enbridge's 2025/26 Gas Supply Plan and annual update. Topics of discussion included opportunities for First Nations to provide input, Enbridge Gas's relationship with TC Energy and sourcing decisions relating to same, and potential ways to enhance transparency, including reporting on discussions at the IWG.
- March 25, 2026, 2025 - 2029 Rebasing Indigenous Engagement and IWG Expert Recommendations regarding same, presented by Oakview Advisory, Sarah Welch who provided recommendations for future engagement on rebasing. IWG members identified the best method of contact for the Nations they represent. Topics of discussion included current challenges and different ways to facilitate engagement including interviews and Nations reaching out to their members. Nicholas Daube emphasized this as a priority for the IWG.
- March 25, 2026 - Methane Measurement, presented by Enbridge Gas, Luna Munro – Specialist, Carbon Strategy, who discussed the Oil and Gas Methane Partnership (OGMP) 2.0 (including OGMP 2.0 self-assessment), pilot satellite study from 2024, and the Fugitive Emissions Measurement Plan (FEMP), which was included in the rebasing and deferral applications submitted to the OEB. Topics of discussion included OGMP 2.0 self-assessment and methane measurement technologies,
- March 25, 2026 - ER terminology, including for Archaeological Studies presented by Enbridge Gas, Kelsey Mills – Supervisor, Environment Projects, who provided

responses to outstanding IWG items. Enbridge Gas, Stephanie Muller – Advisor, Environment, summarized the archaeology process. Themes of the discussion included appropriate term for 'archaeological resources' when referring to found objects and concluded to go to each community for preferred terminology. This discussion was held on March 25, 2026.

6. Additional, Ongoing, IWG Initiatives

A smaller group within the IWG created a subcommittee to consider Indigenous communities' perspectives on the RSA. A meeting of this subcommittee was held on September 3, 2025.

As noted above, the IWG retained Oakview Advisory to analyze the previous rebasing engagement and recommend ways that future rebasing engagement could be improved. Oakview Advisory met with the IWG and presented their analysis and recommendations on March 25, 2026. There is a reasonable likelihood that they may be further engagement on the basis of those initial recommendations.

In addition, the IWG has retained BDR North America to analyze rates for Indigenous and non-Indigenous customers. This work is ongoing and the IWG expects the analysis and recommendations to be presented at a future IWG meeting.

7. IWG Capacity Funding for 2027

Under the OEB-approved Settlement Agreement, Enbridge Gas is required to provide capacity funding for the reasonable costs of each of the Indigenous Parties for their preparation for and participation in the IWG meetings, which includes reasonable technical expert and legal assistance necessary to engage meaningfully on the topics the IWG addresses, as well as to establish a budget reflecting estimated capacity funding for the following year. Actual capacity funding costs incurred are recorded in Enbridge Gas's IWG deferral account and will be subject to review and clearance in the applicable DVA proceeding.

The IWG is presenting the 2027 estimated budget for review by the OEB as part of the DVA proceeding. The Indigenous Parties propose an estimated budget for capacity funding for the calendar year 2027 of $640,000, described as follows:

1. There is a desire to increase Indigenous community membership on the IWG, and in particular those communities which Enbridge Gas services. As membership increases, we expect there to be increased representation and coordination costs.
2. There is an expectation that 2027 will continue to see a need for legal and technical expert assistance, especially in light of the work being undertaking for the 2029 rate rebasing application expected to be filed in 2027, as well as the priorities that the participating First Nations and Enbridge Gas continue to advance as areas of focus for the IWG.
3. The requested capacity funding costs for the IWG for 2027 are:
    i. $242,000 for legal support;
    ii. $202,000 for consultants and First Nation representatives; and
    iii. $196,000 for experts.

Enbridge Gas will pay the capacity funding based on actual reasonable costs incurred and appropriately invoiced by the Indigenous Parties to participate in the IWG.

8. Additional Perspectives from the Indigenous Parties

The IWG recognizes the importance of reflecting the perspectives of the Indigenous Parties in the context of a summary of the IWG's activities.

Accordingly, the Indigenous Parties and Enbridge Gas have collaboratively developed the following new section of the Annual Report. The purpose of this section is to provide additional context regarding the IWG's activities, including matters of particular importance to the represented First Nations as Treaty and section 35 rightsholders, as well as opportunities for continued advancement of the IWG's objectives.

The Indigenous Parties view the inclusion of this section as an important step toward ensuring that their perspectives form part of the Annual Report. The Indigenous Parties and Enbridge Gas are committed to continuing to work together through the IWG to

further refine and enhance this section in future annual reports so that it continues to meaningfully include the perspectives of the Indigenous Parties.

The Indigenous Parties continue to view the IWG as an important forum for engagement, recognizing that, like any forum, there is always an opportunity for continuous improvement and development over time. They view the IWG as an important forum to express their priorities, to exchange ideas and information and engage in substantive discussions with Enbridge Gas (often with the benefit of company or external experts), and ideally to make meaningful progress on energy-related issues of importance to the represented First Nations and their members.

The Indigenous Parties believe that there will be continued opportunities that will present themselves to fully realize the IWG's potential. To this end, they would like to see Enbridge Gas continue to build on its existing support and investment in relation to the issues of highest priority to the Indigenous Parties and reconciliation more generally.

For example, one area of particular interest for many or all of the Indigenous Parties is continuing meaningful conversations on measures that would meaningfully contribute to economic reconciliation. These conversations should reflect the fact that Enbridge Gas's operations and infrastructure exist within territories of the represented First Nations, and that appropriate Project mitigations and any additional accommodation that may be required should be considered in this context.

The Indigenous Parties believe that the IWG has served as an important forum for discussions and information exchanges on other issues of importance, as detailed throughout this report. They believe that will continue to be the case over the coming year, with an anticipated focus on the following issues of importance to each of the Indigenous Parties, among others to be identified over the course of the year:

- Enbridge Gas rates as they relate to Indigenous customers;
- Enhancements to Enbridge Gas's customer engagement practices relating to Indigenous customers to continually improve responsiveness to their priorities and interests;
- Integrated Resource Planning and related Enbridge Gas programs;

- Enbridge Gas's archaeological practices as they relate to Indigenous peoples, their lands and cultural heritage and patrimony;
- Enbridge Gas's practices in relation to the employment of Indigenous peoples and its engagement of Indigenous businesses;
- Environmental, climate, and nature-related issues of consequence to the Indigenous Parties as they relate to Enbridge Gas's business;
- To the extent it relates to Enbridge Gas's business, energy transition consequences for Indigenous peoples and ways the impact of energy transition on Indigenous customers can be mitigated; and
- Reconciliation and economic reconciliation in relation to Enbridge Gas's business.

Enbridge Gas Inc. Indigenous Working Group Minutes

Minutes of a meeting of the Indigenous Work Group (IWG) held on **May 14, 2025,** at 10:00 a.m. at Enbridge Gas Inc., 500 Consumers Road, North York, Ontario M2J 1P8.

PRESENT

Lisa DeMarco	Resilient LLP, Three Fires Group, Minogi Corp
Daniel Vollmer	Resilient LLP, Three Fires Group, Minogi Corp
Rob Lukacs	Minogi Corp.
Todd Jardine	Three Fires Group
Nicholas Daube	Woodward and Company, Ginoogaming First Nation
Tracy Skye	Six Nations Natural Gas
Bruce Tsuchida	The Brattle Group
Peter Fraser	The Brattle Group
Richard Brant	Enbridge Gas Inc.
Henry Ren	Enbridge Gas Inc.
Kris Geekie	Enbridge Gas Inc.
Diana Audino	Enbridge Gas Inc.
Kim Brenneis	Enbridge Gas Inc.
Lauren Whitwham	Enbridge Gas Inc.
Tania Persad	Enbridge Gas Inc.
Arend Wakeford	Enbridge Gas Inc.
Brent Bullough	Enbridge Gas Inc.
Jennifer Cittadini	Enbridge Gas Inc.
Craig Fernandes	Enbridge Gas Inc.
Gabby Lapalme	Enbridge Gas Inc.
Erin Nolan	Enbridge Gas Inc.
Kelsey Mills	Enbridge Gas Inc.

Note on usage of “Enbridge Inc” and “Enbridge Gas Inc”: Policies and plans, such as the Indigenous Reconciliation Action Plan are Enbridge Inc. documents that apply to the whole company including Enbridge Gas Inc. For the purposes of IWG meetings, Enbridge staff are representing Enbridge Gas Inc.

MATTERS FOR DISCUSSION

1. Review of the Agenda for today (attached at Appendix A) and Logistics
   - Lauren Whitwham chaired the meeting, consensus to continue to rotate the facilitator/chair of each IWG meeting.
   - Gabby Lapalme provided a safety moment.
   - IWG agreed to take approval of March 4, 2025 minutes back and provide written comments.
   - Brent Bullough outlined the agenda for the meeting.
     - Enbridge Gas Inc. is seeking comments from the IWG on the Engagement Template and Lifecycle guidelines.

2. Enbridge LTC Environmental Assessment Process
   - Kelsey Mills presented on Enbridge Gas Inc's Environmental Assessment (EA) Process, highlighting Indigenous Engagement as a key element for project development, planning, and review.
   - Kelsey Mills sought feedback from the IWG on opportunities for improvement throughout the process and potential areas of focus for the presentation.
   - Lisa DeMarco asked if Kelsey Mills could provide slides and Kelsey Mills advised that the presentation is in early stages and the idea would be to create a more targeted presentation for the next meeting based on feedback from the IWG.
   - Rob Lukacs stated that Mississaugas of Scugog Island First Nation (MSIFN) are treated like stakeholders opposed to rights holders throughout the EA process and that Enbridge Gas Inc. treats the Ontario Energy Board (OEB) requirements as a be all end all. Rob Lukacs stated that Enbridge Gas Inc. is not limited by OEB requirements and that they should be more receptive to feedback. Rob Lukacs indicated that the Mississaugas of Scugog Island First Nation (MSIFN) is prepared to share feedback with Enbridge Gas Inc. but it is difficult when they are not offered the opportunity to attend field studies during the EA.
   - Kelsey Mills advised that participation during field verification (windshield) surveys was historically not a practice. Going forward, Enbridge Gas Inc. will invite Indigenous communities to participate and provide traditional knowledge during field verification surveys and archaeology field visits, to encourage early engagement. Additionally, after the Notice of Commencement (NOC) is distributed, Enbridge Gas Inc. will provide an environmental screening memo to Nations indicating what exists in the area through an initial desktop review of available materials.
   - Rob Lukacs advised that it would be meaningful to have most of the information available during the NOC (transparent communication), going beyond the Crown requirement. For example, the impacts on certain species. He further emphasized Enbridge Gas Inc. not recognizing First Nations as working partners. A commitment from Enbridge Gas Inc. is needed with regards to capacity funding, timelines, and the work being done.
   - Lauren Whitwham confirmed that Enbridge Gas Inc. offers capacity funding on all projects and asks the Nations to advise on the amount they require to engage.
   - Lisa DeMarco asked that timelines consider Nations' need to gather capacity.
   - Kelsey Mills agreed that there are opportunities to investigate the timelines and to potentially provide more time for early engagement preparation. With regards to opportunities, there needs to be an ongoing dialogue with Nations.
   - Diana Audino emphasized that it is helpful for Nations to provide quotes for capacity funding.
   - Nicholas Daube advised that it would be helpful to see the points in the process where experts (archaeological, environmental, etc.) are included.
     - Lauren Whitwham suggested that this could also include proposed dates and the documents that need to be reviewed. For example, in the form of a Gantt chart included in the NOC.
   - The IWG is interested in seeing the opportunities for Indigenous employment.
   - Rob Lukacs advised that a Principles of Ownership agreement is being worked on by MSIFN and can be shared with Enbridge Gas Inc.
     - Diana Audino advised that Enbridge Gas Inc. can also enter into data protection agreements extending to consultants with Nations.

- Kelsey Mills confirmed she would add information about the archeology and built cultural heritage process to the next presentation along with opportunities for monitors. Kelsey Mills also spoke on how Nation histories can be included in Stage 1 reports.
- Rob Lukacs brought up Bill 5 and is seeking to understand Enbridge Gas Inc.'s engagement expectations in special economic zones and proposed discussing it at the next IWG meeting. Rob Lukacs is also wondering if Enbridge Gas Inc. is lobbying the government to become a trusted proponent and if this would change engagement priorities. Rob Lukacs advised that Bill 5 would have lots of impact on treaty rights and processes.
    - Kelsey Mills advised that it would be on the proponent (Enbridge Gas Inc.) to work ethically and responsibly, specifically with respect to impacts on Species at Risk.
- Lisa DeMarco brought up the Taskforce on Nature-related Financial Disclosures (TNFD) and asked what Enbridge Gas Inc.'s oversight is for governance around nature related dependencies and impacts on nature. Specifically, how these dependencies feed up the organization and what Enbridge Gas Inc. has committed publicly.
- Rob Lukacs emphasized that MSIFN has been bringing this up since 2023.
- Lisa DeMarco referenced where TNFD is addressed in Enbridge Gas Inc.'s Sustainability Report
- Todd Jardine advised that getting things in early stages would be helpful to be aware of what is going on with projects.

3. Enbridge Response to The Brattle Group Recommendations
    - Brent Bullough provided an update on Enbridge Gas Inc.'s response to The Brattle Group's (Brattle) recommendations.
    - Brent Bullough advised that Enbridge Gas Inc. does not intend to update the pathways to net zero studies at this time. The Regional Scenario Analysis (RSA) is to feed into future filings.
    - Lisa DeMarco advised that clients feel the responses are inadequate and delayed and do not take accountability. For example, the response to the energy transition is inadequate. They advised that going forward, it would be good for Brattle and the First Nations to speak to the RSA team.
    - Bruce Tsuchida emphasized that the recommendation to provide a timeline of a project and opportunities for local inclusion was requested and the response was inadequate, and the overall responses were underwhelming.
        - Lauren Whitwham offered to provide a generic schedule of the engagement process.
    - Lisa DeMarco advised that the next filing is scheduled for 2029, but engagement should start in 2025.
        - Nicholas Daube agreed with this and recommended that the second paragraph from EGI's responses to the Brattle recommendations should start now, being EGI's commitment to "review and discuss with the IWG how best to include ETP potential impacts on indigenous communities (i.e. on community-level and/or daily lives)....".
            - Brent Bullough confirmed that participation would start soon, and the team is putting together timelines.
    - Lisa DeMarco requested the specific breakdown of the process to the 2029 filing and advised that energy related risk is related to nature related risk and dependencies for energy transition.
        - Lauren Whitwham confirmed that the timeline isn't finalized yet.
        - Nicholas Daube confirmed that whatever is available in the next month would be good.
    - Nicholas Daube brought up the second recommendation related to equity participation and advised that it is helpful to keep this on the agenda.
        - Kim Brenneis confirmed that many partnerships have been completed and are ongoing.

- Lisa DeMarco provided a list of key discrepancies and confirmed to follow up with them in an email:
    - Commitment to equity
        - The recommendation was clear, and the response referred to the Indigenous Reconciliation Action Plan (IRAP)
        - Crystalizing actionable items is important (i.e. co-signing a consultation framework with the IWG)
        - Equity partner targets in Ontario
        - Independent oversight (Indigenous led oversight to review report on reconciliation and resurgence efforts – accountability to Nations)
        - Fair compensation
    - Recognizing what falls under impact
        - First Nation vulnerabilities
        - In-person meetings
        - Early engagement
        - Process structure
        - Recommendation for engagement protocol
        - Developing a protocol mandating project meetings impacting traditional territories
        - Go beyond environmental assessment
        - The IWG hoped to provide feedback on the IRAP
    - Community specific plans
    - Brattle misalignment of expectations
        - IWG is seeking more action
    - Accountability metrics for Enbridge Gas Inc.
        - What is tracking and reporting on engagement for Enbridge Gas Inc.
        - Showcasing results (i.e. Online dashboard, where we are, what can we do better, etc.)
        - Proactive updates
        - Accountability metrics
        - Impacts, co-development (combining expertise and knowledge)
        - Be creative with media to share historical knowledge and experiences, cultural sensitivities
- Kim Brenneis emphasized from the last meeting that Enbridge Gas Inc. does not pay historical compensation for land use and Enbridge Gas Inc. sees equity as a commercial opportunity.
- Lisa DeMarco clarified that they meant framework as opposed to formula.
- Nicholas Daube advised they would take this discussion back to Kate Kempton for comments.

4. Enbridge Reconciliation Principles
    - Kim Brenneis provided an update on Enbridge Gas Inc.'s Reconciliation Principles since the release of the IRAP refresh in April 2025.
    - Enbridge Gas Inc. has achieved 12 of the 22 commitments. Five of those were integrated into Enbridge's corporate DNA and are no longer in the IRAP Refresh, and seven were achieved and remain in the Refresh. Twenty new or refreshed commitments comprise the IRAP Refresh for the next 3 years, with the progress to be reported on in the Sustainability Report (the IRAP as a living document)
    - Enbridge Gas Inc. is seeking to build the Lifecycle approach into processes.

- Kim Brenneis advised that the Indigenous Advisory Group (IAG) continues to provide perspectives and advice to senior management and is not representative of a specific Nation or group.
- Nicholas Daube asked what the IAG was most excited for and what they continue to push for.
    - Kim Brenneis said the IAG was most excited by the implementation of the IRAP and the progress made. They advised that the IAG continues to press for procurement and employment especially in a North American context. They also want to see a better reflection of the communities Enbridge Gas Inc. works in.
- Lisa DeMarco asked about the IAG members
    - Kim Brenneis explained that historically they have not shared names of members as per their request. The IAG feels they are best able to provide perspective without the members being publicized. IAG members respectfully decline meeting with the IWG.
    - Lisa DeMarco asked if the IWG can see the IAG meeting presentations/ notes.
    - Kim Brenneis advised that IAG members are not speaking on behalf of a rights bearing group just their individual experiences and perspectives.
    - Lisa DeMarco advised that Senior management and the Board of Directors are acting on behalf of the IAG so it would be helpful to gather more transparency.
    - Tracy Skye asked how someone becomes a member of the IAG.
        - Kim Brenneis advised that Enbridge Inc. worked with a consultant to identify leaders in different spheres (i.e. academic, business, etc.). Enbridge Inc. was then provided a list of people across North America and then there was a selection process.

5. Filing of OEB Report on IWG and 2026 IWG Budget
    - Lauren Whitwham reviewed the current version of the OEB report.
    - Rob Lukacs suggested switching language of Indigenous Way of Life and Stewardess to Inherent Responsibilities of the Land.
        - Lauren Whitwham confirmed that the original language was from Kodi Deleary and the IWG agreed to keep it how it is, and Lauren Whitwham confirmed to capitalize the title.
    - Lauren Whitwham confirmed to send out the report to the IWG for feedback on budget, amount changes and rationales.
    - Section 6. IWG Capacity Funding
        - Nicholas Daube suggested and the IWG agreed that it would be helpful to give everyone the full context of the number and reproduce some text from the Settlement Agreement.
    - With regards to the high legal fees, Lauren Whitwham explained Resilient LLP's role and the Brattle Report.
    - Lauren Whitwham confirmed to send an email including the Report for review and comment and confirmation of March meeting minutes
        - Regulatory is giving until May 24, 2025 for the Report
    - Nicholas Daube asked if the presentations could be included in the minutes.
        - Tania Parsad said there should not be a concern with this, but they would need to confirm with other parties (i.e. Brattle).
6. Heat Pump Strategy Update
    - Craig Fernandes provided an update on the heat pump strategy since the federal carbon surcharge is now zero. They have to circle back with Chippewas of the Thames First Nation (COTTFN) to discuss further.

- Nicholas Daube advised that it is important for people to understand what they are getting into and there is a lot of dispute in OEB proceedings regarding the range of cost implications of the technology.
- Nicholas Daube asked if it is possible to get a third-party expert to look at cost implications in various scenarios.
    - This topic would need to be revisited with COTTFN
    - Enbridge Gas Inc. and IWG to look to see if there is someone/ organization to do this
    - Craig Fernandes thought it would be possible and beneficial. They also confirmed they would be transparent.
    - Rob Lukacs also agreed to an independent review.
    - Rob Lukacs advised that there is no carbon charge scenario and asked if the incentives were linked to policy included in the analysis.
        - Craig Fernandes confirmed that they were referring to operational cost for the pilot and not the cost to participants.

7. Enbridge Indigenous Supply Chain Management (SCM) Update
    - Richard Brant provided an update on Indigenous SCM.
    - Richard Brant provided Indigenous spend statistics from 2017-2025 and noted that 2025 spend is low so far because construction starts in the summer. Richard Brant discussed the Socio-economic Requirement of Contractors (SERC) and broke down the types of businesses and services they look for. They also noted that in Ontario there are not as many projects being planned. To work directly for Enbridge, businesses go through ISN (ISNetworld) safety assessments to be given a green, yellow, or red status. Green and yellow can work for Enbridge Gas Inc. and they are working on developing a feedback mechanism for Indigenous businesses.
    - Nicholas Daube noted that the third bullet on the Important Considerations slide is an area for opportunity. They advised that one issue is that any contract from Enbridge Gas Inc. would not be completely sufficient for operations for an Indigenous business.
    - Richard Brant explained that there are two parts: What Enbridge Gas Inc. needs and what a Nation business can provide. There are also two types of opportunities: smaller jobs for existing businesses and bigger jobs that businesses would need to build toward to be considered.
    - Kim Brenneis reinforced that Enbridge Gas Inc. is open to how Nations see themselves economically on their journey.
    - Nicholas Daube discussed an opportunity to improve information deficits and understanding for Nations to capitalize.
    - Richard Brant emphasized the importance of having the right person at the community with the knowledge to best situate their businesses. They further emphasized that engagement can begin 1-2 years in advance because Enbridge Gas Inc. can foresee work that will need to be done.
    - Nicholas Daube asked if anything similar has been done in other provinces and Richard Brant confirmed there has been.
    - Tania Persad advised there is lots of publicly available information about planned activity and opportunities for development.
8. Action Items
    - Item 1: Enbridge Gas Inc. to provide meeting minutes from IWG meeting on March 4, 2025, with the IWG for comments and approval.
    - Item 2: Enbridge Gas Inc. to provide the IWG Report with March's meeting minutes (seeking feedback specifically on budget, amount changes and rationale). Enbridge to capitalize the title of

the OEB Report, include language from the Settlement Agreement in the updated budget, and confirm if power point slides from the March 2025 meeting can be included in the minutes.

- Item 3: Enbridge Gas Inc. to add the archaeology process into the next Environmental Assessment Process PowerPoint.
- Item 4: Rob Lukacs to share Principles of Ownership agreement being developed by MSIFN with Enbridge Gas Inc.
- Item 5: Enbridge Gas Inc. to include Bill 5 on the next IWG meeting agenda.
- Item 6: Enbridge Gas Inc. to provide information about the company's oversight for governance around nature-related dependencies and impacts on nature, related to TNFD and how these dependencies feed up the organization and what Enbridge Gas Inc. has committed to publicly.
- Item 7: Enbridge Gas Inc. to provide a generic schedule of the engagement process.
- Item 8: Enbridge Gas Inc. to provide the timeline for the 2029 filing when it becomes available.
- Item 9: Lisa DeMarco to follow up with an email outlining the key discrepancies between the Brattle Recommendations and Enbridge Gas Inc.'s initial responses discussed at the meeting to be included in the minutes.
- Item 10: Enbridge Gas Inc. to see if they can provide the IAG meeting presentations/ notes to the IWG.
- Item 11: Enbridge Gas Inc. to revisit heat pump discussion with COTTFN.
- Item 12: Enbridge Gas Inc. and IWG to see if there is someone that could do an independent review of cost implications for different scenarios with regards to heat pumps.

NEXT MEETING

Next meeting of the IWG is tentatively set to take place virtually in July/August and the date to be canvased by email.

APPENDIX A – AGENDA FOR MEETING OF IWG ON MAY 14, 2025

Time	Matter	Participants
10:00-10:15 am	Safety moment, introductions, administrative matters, status of action items, approval of minutes	Lauren Whitwham and Group
10:15-10:30 am	Enbridge LTC Environmental Assessment Process	Kelsey Mills and Erin Nolan
10:30-11:45 am	Enbridge Response to The Brattle Group Recommendations	Enbridge and Group
11:45-12:15	Enbridge Reconciliation Principles	Kim Brenneis
12:15-1:00 pm	Lunch	
1:00-1:45 pm	Filing of OEB Report on IWG and 2026 IWG Budget	Lauren Whitwham and Group
1:45-2:00 pm	Heat Pump Strategy Update	Jennifer Cittadini and Craig Fernandes
2:00-2:30 pm	Enbridge Indigenous SCM Update	Richard Brant
2:30 pm	Wrap-up/Adjourn	Group

Enbridge Gas Inc. Indigenous Working Group Minutes

Minutes of a meeting of the Indigenous Work Group (IWG) held virtually on **July 15, 2025,** at 9:00 a.m.

PRESENT

Lisa DeMarco	Resilient LLP, Three Fires Group, Minogi Corp
Daniel Vollmer	Resilient LLP, Three Fires Group, Minogi Corp
Rob Lukacs	Minogi Corp.
Todd Jardine	Three Fires Group
Rick Peters	Three Fires Group
Kate Kempton	Woodward and Company, Ginoogaming First Nation
Nicholas Daube	Woodward and Company, Ginoogaming First Nation
Shelly Rahme	Ginoogaming First Nation
Kodi Chrisjohn-Deleary	Chippewas of the Thames First Nation
Peter Fraser	The Brattle Group
Diana Audino	Enbridge Gas Inc.
Richard Brant	Enbridge Gas Inc.
Jennifer Murphy	Enbridge Gas Inc.
Lauren Whitwham	Enbridge Gas Inc.
Tania Persad	Enbridge Gas Inc.
Arend Wakeford	Enbridge Gas Inc.
Brent Bullough	Enbridge Gas Inc.
Richard Lanni	Enbridge Gas Inc.
Gesiena Antuma	Enbridge Gas Inc.
Vanessa Innis	Enbridge Gas Inc.
Cara-Lynne Wade	Enbridge Gas Inc.
Gabby Lapalme	Enbridge Gas Inc.
Henry Ren	Enbridge Gas Inc.
Kelsey Mills	Enbridge Gas Inc.
Levi Gordian	Enbridge Gas Inc.
Heidi Steinberg Laxton	Enbridge Gas Inc.

Note on usage of "Enbridge Inc" and "Enbridge Gas Inc": Policies and plans, such as the Indigenous Reconciliation Action Plan are Enbridge Inc. documents that apply to the whole company including Enbridge Gas Inc. For the purposes of IWG meetings, Enbridge staff are representing Enbridge Gas Inc.

MATTERS FOR DISCUSSION

1. Review of the Agenda for today (attached at Appendix A) and Logistics
   - Brent Bullough chaired the meeting.
   - Gabby Lapalme provided a safety moment.
   - Approval of May meeting minutes
     - Kodi Chrisjohn-Deleary indicated support of the Ontario Energy Board (OEB) Report presentation name change suggested by Rob Lukacs from Indigenous Way of Life and Stewardess to Inherent Responsibilities of the Land.
     - Kodi Chrisjohn-Deleary mentioned that Chippewas of the Thames (COTTFN)'s perspective on heat pumps has changed and Lauren Whitwham suggested setting up a separate meeting to discuss this.
       - Lisa DeMarco requested that the heat pump discussion be extended to the rest of the IWG.
     - Lisa DeMarco advised that updates to the May minutes would be provided in an email.
     - Enbridge Gas Inc. and the IWG agreed to take the approval of the May 14, 2025 minutes back until additional edits were incorporated
   - Status of May meeting's Action Items
     - Item 5: Enbridge Gas Inc. to include Bill 5 on the next IWG meeting agenda.
       - Brent Bullough confirmed to put a discussion on Bill 5 on the September meeting's agenda.
       - Rob Lukacs asked if Enbridge Gas Inc. is going to request to be a trusted proponent in special economic zones.
       - Lisa DeMarco asked for a summary of any lobbying activity surrounding Bill 5.
         - Brent Bullough confirmed that a statement on the Economic Zones Act was filed, and they would see if it could be shared with the IWG along with lobbying activity.
       - Kate Kempton advised that they had filed an application to strike out Bill 5 and key aspects of Bill C-5.
         - Kate Kempton advised that companies that stand behind Bill 5 would lose Nation support.
         - Kate Kempton discussed how the Endangered Species Act authorizes the permanent wiping out of species. They advised that Bill 5 is going back to when there was no engagement. They clarified that they are not against economic opportunities but want First Nations at the table.
           - Kate Kempton confirmed to circulate the Notice of Application to Enbridge Gas Inc. and the IWG.
     - Item 9: Lisa DeMarco to follow up with an email outlining the key discrepancies discussed at the meeting to be included in the minutes.
       - Lisa DeMarco confirmed they are working on this.
     - Item 10: Enbridge Gas Inc. To see if they can provide the IAG meeting presentations/ notes to the IWG.

- Lauren Whitwham confirmed they are working on this.

2. Engagement Opportunities/Timelines - 2029 Filing and Projects
   - Vanessa Innis presented on 2029 Rebasing.
   - Lisa DeMarco asked about the approach to consultation and what data is available.
     - Vanessa Innis clarified that they are looking for specific feedback on where Nations would like to be involved (e.g. Depreciation study).
     - Lisa DeMarco advised that Nations would be interested in all aspects of the rate case, specifically capital growth models and rate base.
     - Vanessa Innis advised that they do not have data yet about forecast underpinnings and indicated that the proposal would be going through the forecast process in 2027.
   - Gesiena Antuma advised that they are working through a plan for customer engagement and are looking to understand the best way for engagement.
     - Lisa DeMarco requested the general customer engagement framework and rights holder engagement framework.
   - Jennifer Murphy presented on the First Nation Engagement Approach and the Regional Scenario Analysis (RSA).
     - Jennifer Murphy proposed a discussion-based session in mid- to late-August with the IWG and Indigenous communities that are served by EGI to seek input that could be incorporated into the RSA.
       - Lisa DeMarco asked for clarification about what the meeting would be.
         - Jennifer Murphy confirmed that this would be the consultation.
       - Lisa DeMarco advised that the nature of the consultation itself would be highly contingent on the development of content and what is in the proposal.
         - Lisa DeMarco emphasized the importance of requests from First Nations reflected in the RSA proposal.
         - Rob Lukacs and Todd Jardine agreed.
       - Kate Kempton identified two issues;
         - Climate change and the need to get off GHG emissions needs to be addressed in the RSA and the IWG needs to be included.
         - Revenue sharing between Nations whose lands are being used.
         - Jennifer Murphy advised that this is not necessarily part of the RSA which would focus on creating a forecast of demand and would then look to make plans and incorporate First Nation input into this.
           - Looking at what kind of information the Nations could contribute.
           - Kate Kempton advised that demand is partly constructed by the company (i.e. Lobbying efforts impact demand).
           - Lisa DeMarco proposed forming a subcommittee of the IWG to work on skeleton elements of the RSA.
             - Cara-Lynne Wade suggested that a next step could be to work with one or two people on the IWG.
               - Cara-Lynne Wade clarified that the initial piece of work is not looking at the likelihood of scenarios but about which scenarios they could model to understand the impact on demand, customer

count, etc., and looking to ensure that they are modeling ones that are valuable.
- Lisa DeMarco advised that a number of IWG members have experience creating scenarios and could contribute.
    - Cara-Lynne Wade asked who they should consult on the IWG and Lisa DeMarco volunteered.

- Jennifer Murphy asked what other nations not represented on the IWG that Enbridge serves would want to be involved.
    - Lisa DeMarco suggested Peter Fraser (Brattle Group).
- Jennifer Murphy also advised that technical sessions with external parties are being planned to provide an overview of RSA scenarios.
    - Jennifer Murphy asked if anyone is interested in participating in the technical session on July 30.
        - Lisa DeMarco and Nicholas Daube confirmed they would like to attend.

3. Enbridge Updated LTC Environmental Assessment (EA) Process

- Kelsey Mills presented on the Environmental Assessment Process.
    - Rob Lukacs advised that First Nations need to be working with Enbridge to come up with preferred routes.
        - Kelsey Mills advised that this is part of the Notice of Upcoming Project where Enbridge Gas Inc. seeks input on routes. Kelsey Mills also advised that the process is being modified to better work with communities. Recently and going forward Nations are invited to field verification surveys.
- Lisa DeMarco suggested changing the language of 'confirmation of preferred route' to 'determination of preferred route'.
    - Rob Lukacs further advised that they take issue with language of 'Incorporation of Treaty Rights and Indigenous Knowledge' and requested it be changed to 'Weave Treaty Rights and Indigenous Knowledge into Mitigation Measure Development'.
        - Kelsey Mills confirmed to investigate changing this.
- Archaeology Assessment (AA)
    - Lisa DeMarco emphasized the importance of having adequate monitors to participate in field work.
        - Kelsey Mills advised that Enbridge Gas Inc. recognizes this and offers opportunities to be involved and provides capacity funding for this.
        - Rob Lukacs asked what level of information informs the cumulative effects assessment in respect to archaeological resources.
            - Kelsey Mills confirmed to take this back to the team.
        - Nicholas Daube asked if there is a requirement for people doing the assessment to have experience with First Nations, and further, if there is an opportunity for First Nations to have a say in the selection of people performing the studies.
            - Kelsey Mills advised that the standard for assessments and consultation with First Nations by archaeologists is set by the Ministry.
                - Rob Lukacs responded to Nicholas Daube indicating that Enbridge should have an internal policy including one that contains the

requirements including processes of identification of artifacts and it should be dedicated to requirements at each stage of the process. Rob Lukacs advised that Nations should be able to help develop this internal policy.
        - Kelsey Mills advised that they would see if an internal policy could be shared with the IWG.
            - Nicholas Daube advised that this is part of a bigger discussion on internal policies.
            - Lauren Whitwham confirmed that archaeology work is done by licensed archologists.
    - Lisa DeMarco asked to what extent LiDAR is being used along the full preferred route.
        - Kelsey Mills advised that they typically don't get to a Stage 3 or 4 as the priority is to put the pipe into previously disturbed corridors. Enbridge Gas Inc. doesn't want to be limited to just looking for burials.
            - Lisa DeMarco suggested Enbridge Gas Inc. work with archeologists to create a cost benefit analysis of LiDAR along the full preferred route.
        - Daniel Vollmer asked what the ministry standard is for what an expert archaeologist needs to know when it comes to cultural significant matters.
            - Kelsey Mills confirmed that Enbridge Gas Inc. does try to go beyond what is required by the ministry.
                - Nick Daube advised that ensuring adequate attention to both documented records and community knowledge is a challenge. He asks how Enbridge Gas Inc. ensures that the experts have the resources available to address areas of greatest consequence to First Nations and in a way that they are not just relying on the Nations to fill in the gaps. Nick Daube suggested further discussion.
                    - Kodi Chrisjohn-Deleary noted that Nations have preferred archaeology firms.
                        - Kelsey Mills advised that they would be interested in knowing what these firms are and agreed that additional discussion on archaeological expert knowledge and expertise would be beneficial
                - Shelley Rahme noted the language of ‘resources’ in the presentation should be changed to ‘assets’.
                    - Kelsey Mills advised they would investigate changing this.
        - Nicholas Daube asked Rob Lukacs if there was anything else being done by other proponents that could be proposed to Enbridge.
        - Rob Lukacs agreed that these questions are worth pursuing but understanding Enbridge Gas Inc’s stance on Bill 5 would be useful.

4. Integrated Resource Planning Discussion
    - Alison Moore discussed Integrated Resource Planning (IRP) and asked what the best way to engage the IWG is going forward and feedback on initial focus for engagement.
    - Daniel Vollmer suggested setting up a smaller group to continue to discuss. The IWG and Enbridge Gas Inc. agreed.

- Kodi Chrisjohn-Deleary asked what Nations were engaged for the Southern Lake Huron Pilot (SLHP) project.
    - Lauren Whitwham confirmed that Chippewas of Kettle and Stoney Point First Nation (CKSPFN) and Aamjiwnaang First Nation (AFN) were engaged. Lauren Whitwham confirmed that they would provide the information provided to date.
- Kodi Chrisjohn-Deleary asked about the SLHP's objective.
    - Alison Moore advised that it was to look at how enhanced targeted energy efficiency and demand response programs impact peak hour flow and demand, and how to best design, deploy and evaluate these programs going forward. The learnings from the pilot would be used to inform the evaluation of non-pipelines alternatives.
- Kodi Chrisjohn-Deleary emphasized the importance of treaty-based engagement.
    - Alison Moore offered to provide the SLHP application that was filed with the OEB.

5. Sustainability and Nature-related Disclosures at Enbridge
    - Gina Jordan presented on Sustainability and Nature-related Disclosures at Enbridge.
    - Rob Lukacs asked what is meant by 'monitoring impacts to wildlife'.
        - Gina Jordan advised that Enbridge Gas Inc. continually monitors performance and does internal audits on protection programs and looks to enhance performance. Gina Jordan confirmed that programs include air and land monitoring.
    - Lisa DeMarco asked about materiality assessments and definitions of nature.
        - Gina Jordan confirmed that Enbridge Gas Inc. performs a materiality assessment on a regular basis and it is in the Sustainability Report. Enbridge Gas Inc. focuses on the global risk to nature loss and its effect on business and society.
        - Gina Jordan also confirmed that they are looking at the Taskforce on Nature-related Financial Disclosures (TNFD) and working to better understand impacts and dependencies. Enbridge Gas Inc. has also started working with Tandem Global to consider this.
    - Lisa DeMarco asked for Tandem Global's Terms of Reference
    - Gina Jorden advised that in terms of TNFD, it is still early days.
        - Lisa DeMarco clarified the point of assessing material risk in terms of impact and dependencies is important to Nations.
    - Lisa DeMarco asked to be provided any materials shared with the Indigenous Advisory Group (IAG) around nature related dependencies and impacts.
    - Gina Jordan advised that they would share the pages in the Sustainability Report that address Lisa DeMarco's questions.
    - Shelley Rahme advised of an opportunity to support grassland birds and habitat similarly to how Enbridge has deployed sheep in Sarnia.
        - Gina confirmed they could look into this once Tandem Global finishes their report.
6. Brattle Recommendations Follow-Up
    - Brent Bullough summarized some of the Brattle Recommendation categories.
    - Related to the RSA, Enbridge Gas Inc. is seeking clarification on several points, which will be confirmed with the IWG via email before the next meeting
    - how the IWG sees the lifecycle impacts being addressed.
        - what scenarios the IWG is interested in.
        - if it was the pathways report versus the RSA.
        - what was meant by upstream and downstream environmental and economic impacts.

- Brent Bullough discussed the recommendation for Enbridge Gas Inc. to increase support for First Nation communities to be self-sufficient and advised that the general response from Enbridge Gas Inc. is that they feel they are doing this through things like capacity funding.
- Brent Bullough discussed how one of the recommendations was to engage Indigenous groups to co-develop impact assessments and publish a timeline for these engagements, but Enbridge Gas Inc. is seeking clarification on what the impact assessments would be on.
- Enbridge Gas Inc. and IWG agreed to discuss further over email.
- Brent Bullough advised that Enbridge Gas Inc. is committed to engaging on energy transition plans and the 2029 submission and sought clarification on what 'major projects' refer to in the recommendations and asked if it is specific to energy transition or projects which is beyond the scope of what Brattle was looking at.
- The IWG agreed to respond to questions over email afterward.

7. Action Items

- Item 1: Enbridge Gas Inc. COTTFN, and IWG to set up a meeting to discuss heat pumps.
- Item 2: Enbridge Gas Inc. to confirm that the final March's minutes were shared with the IWG.
- Item 3: Enbridge Gas Inc. to include Bill 5 on the September IWG meeting agenda.
- Item 4: Enbridge Gas Inc. to inquire about circulating Enbridge Gas Inc's statement on Special Economic Zones Act and Bill 5 with the IWG.
- Item 5: Enbridge Gas Inc. to inquire about circulating a document of Enbridge's lobbying activity regarding Bill 5 with the IWG.
- Item 6: Kate Kempton to circulate the Notice of Application on Bill 5 and the Endangered Species Act to Enbridge Gas Inc. and the IWG.
- Item 7: Lisa DeMarco to follow up with an email outlining the key discrepancies discussed at the meeting to be included in the May minutes. (Item 9 outstanding from May meeting).
- Item 8: Enbridge Gas Inc. to see if they can provide the IAG meeting presentations/ notes to the IWG. (Item 10 outstanding from May meeting).
- Item 9: Enbridge Gas Inc. to provide IWG customer engagement framework for rebasing.
- Item 10: Enbridge Gas Inc. to provide IWG rights holder engagement framework for rebasing.
- Item 11: Enbridge Gas Inc. and IWG to create a sub-committee for RSA discussion.
- Item 12: Enbridge Gas Inc. to provide the invite to Lisa DeMarco and Nicholas Daube for the July 30 RSA technical session.
- Item 13: Enbridge Gas Inc. to investigate changing EA language from 'confirmation of preferred route' to 'determination of preferred route' and from 'Incorporation of Treaty Rights and Indigenous Knowledge' to 'Weave Treaty Rights and Indigenous Knowledge into Mitigation Measure Development'.
- Item 14: Enbridge Gas Inc. to gather information on what level of information goes into a cumulative effects assessment in regards to archaeological assessments.
- Item 15: Enbridge Gas Inc. to inquire about sharing internal archaeology assessment policies with the IWG.
- Item 16: Enbridge Gas Inc. to consider IWG request to work with archeologists to create a cost benefit analysis of LiDAR along the full preferred route.
- Item 17: IWG to provide list of preferred archeology firms.

- Item 18: IWG and Enbridge Gas Inc. to discuss having a focused discussion on archaeological expertise related to community knowledge.
- Item 19: Enbridge Gas Inc. to inquire if language of 'resources' in the Environmental process presentation could be changed to 'assets' when speaking to archaeological resources.
- Item 20: Enbridge Gas Inc. and IWG to create a smaller group to discuss IRP and triangulate topics to discuss.
- Item 21: Enbridge Gas Inc. to share the information shared with CKSPFN and AFN about the SLHP project.
- Item 22: Enbridge Gas Inc. to provide the SLHP application that was filed with the OEB to the IWG.
- Item 23: Enbridge Gas Inc. to provide key pages in the Sustainability Report that discuss impacts and dependencies.
- Item 24: Enbridge Gas Inc. and IWG to further discuss the Brattle Recommendations over email.
- Item 25: Enbridge Gas Inc. to provide the slides from today's meeting.

NEXT MEETING

Next meeting of the IWG is set to take place at the Enbridge Gas Inc. office at 500 Consumers Road North York, Ontario M2J 1P8 on September 23, 2025. Team to canvas for an Agenda closer to the date.

APPENDIX A – AGENDA FOR MEETING OF IWG ON JULY 15, 2025

Time	Matter	Participants
9:00-9:10 am	Safety moment, introductions, administrative matters, status of action items, approval of minutes	Lauren Whitwham and Group
9:10-9:35 am	Engagement Opportunities/ Timelines – 2029 Filing and Projects	Vanessa Innis and Group
9:35-10:00 am	Regional Scenario Analysis – Engagement Approach	Cara-Lynne Wade and Group
10:00-10:45 am	Enbridge Updated LTC Environmental Assessment Process	Kelsey Mills and Group
10:45-11:15 am	Brattle Recommendations Follow-Up	Brent Bullough and Group
11:15-11:30 am	Integrated Resource Planning Discussion	Alison Moore and Group
11:30-12:00 am	Sustainability and Nature-Related Disclosures at Enbridge	Gina Jordan and Group
12:00 pm	Wrap-up/ Adjourn	Group

Enbridge Gas Inc. Indigenous Working Group Minutes

Minutes of a meeting of the Indigenous Work Group (IWG) held on **September 23, 2025,** at 10:00 a.m. at Enbridge Gas Inc., 500 Consumers Road, North York, Ontario M2J 1P8.

PRESENT

Daniel Vollmer	Resilient LLP, Three Fires Group, Minogi Corp
Rob Lukacs	Minogi Corp.
Todd Jardine	Three Fires Group
Rick Peters	Three Fires Group
Kate Kempton	Woodward and Company, Ginoogaming First Nation
Nicholas Daube	Woodward and Company, Ginoogaming First Nation
Shelly Rahme	Ginoogaming First Nation
Kodi Chrisjohn-Deleary	Chippewas of the Thames First Nation
Jennifer Mills	Chippewas of the Thames First Nation
Peter Fraser	The Brattle Group
Diana Audino	Enbridge Gas Inc.
Richard Brant	Enbridge Gas Inc.
Jennifer Murphy	Enbridge Gas Inc.
Lauren Whitwham	Enbridge Gas Inc.
Tania Persad	Enbridge Gas Inc.
Brent Bullough	Enbridge Gas Inc.
Gabby Lapalme	Enbridge Gas Inc.
Kelsey Mills	Enbridge Gas Inc.
Matthew Webster	Enbridge Gas Inc.
Kris Geekie	Enbridge Gas Inc.
Jessica Maga	Enbridge Gas Inc.

Note on usage of "Enbridge Inc" and "Enbridge Gas Inc": Policies and plans, such as the Indigenous Reconciliation Action Plan are Enbridge Inc. documents that apply to the whole company including Enbridge Gas Inc. For the purposes of IWG meetings, Enbridge Inc. (and its affiliates) staff are representing Enbridge Gas Inc.

MATTERS FOR DISCUSSION

1. Review of the Agenda for today (attached at Appendix A) and Logistics
   - Brent Bullough chaired the meeting.
   - Lauren Whitwham provided a safety moment.
   - IWG approved May meeting minutes.
   - IWG approved July meeting minutes.
   - Status of July meeting action items:
     - Item 1: Brent Bullough confirmed Enbridge Gas Inc. would set up a meeting to discuss heat pumps with Chippewas of the Thames First Nation (COTTFN) and IWG.
     - Item 2: Brent Bullough confirmed the final March meeting minutes were distributed and redistributed them on September 22, 2025.
     - Item 3: Brent Bullough advised that Jessica Maga would be attending to discuss Bill 5.
     - Item 4 & 5: Brent Bullough circulated Enbridge Gas Inc.'s statement on Special Economic Zones Act and Bill 5 along with information of Enbridge Gas Inc.'s lobbying activity with the IWG on August 7, 2025, and advised that Jessica Maga could also speak to this.
     - Item 6: Kate Kempton and Nicholas Daube provided the Notice of Application on Bill 5 and the Endangered Species Act to Enbridge Gas Inc. and the IWG on July 15, 2025.
     - Item 7: IWG approved May meeting minutes.
     - Item 8: Brent Bullough advised that Enbridge Gas Inc. is unable to share Indigenous Advisory Group (IAG) meeting presentations/ notes.
     - Item 9: Brent Bullough provided the Customer Engagement Framework for rebasing on September 23, 2025.
     - Item 10: Brent Bullough advised that Enbridge Gas Inc. generally includes the Indigenous Peoples Policy (IPP) as part of the application and Enbridge Gas Inc. but will consider whether a Rights-Holder Engagement Framework for rebasing would be beneficial after receiving and reviewing comments from the IWG on the Customer Engagement Framework.
     - Item 11: Brent Bullough confirmed a Regional Scenario Analysis (RSA) sub-committee was created and a meeting took place on September 3, 2025, with IWG members in attendance.
     - Item 12: Brent Bullough provided the RSA technical session invitation to Lisa DeMarco and Nicholas Daube.
     - Items 13, 14, 15, 16, 18, and 19: Deferred until next meeting.
     - Item 17: Nicholas Daube provided a list of archaeology firms and one was added during discussion. There is no consensus at this time on the firms. Further discussion needed by IWG members on recommended firms and Enbridge Gas Inc. to consider how recommended firms can be integrated into its policies and procedures.
     - Item 20: Brent Bullough advised that Enbridge Gas Inc. sought interest on discussing IRP on August 15, 2025, requesting input by September 29, 2025.
     - Items 21 & 22: Brent Bullough shared the Southern Lake Huron Pilot project information and application filed with the Ontario Energy Board (OEB) on August 15, 2025.

    - Item 23: Brent Bullough confirmed key pages in the Sustainability Report were provided and would confirm the date.
    - Item 24: Brent Bullough advised that Enbridge Gas Inc. hadn't received anything regarding the Brattle Recommendations via email. Rob Lukacs to provide IWG responses.
    - Item 25: Brent Bullough provided July meeting slides and the IAG organization chart on September 22, 2025.

2. IWG Suggested Archaeology Firms
   - Nicholas Daube presented potential archaeology firms, emphasizing that group consensus needs to be obtained and part of a broader conversation.
     - Potential firms:
       - White Spruce Archaeology
       - Tamarack
       - TMHC Inc.
       - Archaeological Research Associates (ARA)
   - Rob Lukacs advised that Mississaugas of Scugog Island First Nation (MSIFN) would also like to add Northeastern Archaeological Associates as a firm to consider.
   - Lauren Whitwham advised that Enbridge Gas Inc. works with TMHC Inc. already.
   - Jennifer Mills advised that she likes the fact that contracts for archaeological work have been with Enbridge Gas Inc. instead of the actual firms as it alleviates some of the administrative work.
   - Nicholas Daube suggested setting up a process to discuss any constructive feedback a participant may have about a firm.
     - Nicholas Daube advised that any endorsement from First Nations should include how they would like to see firms integrated into the process.
   - Nicholas Daube asked Enbridge Gas Inc. how they could use the list.
   - Rob Lukacs emphasized support for the list Nicholas Daube provided and noted that it would be good to hear from Enbridge Gas Inc. on its thoughts on the list.
   - Daniel Vollmer agreed and emphasized that the list is not necessarily a consensus among IWG members.
   - Daniel Vollmer advised that it is important to ask the Nations that are impacted their thoughts on the firms.
   - Kodi Chrisjohn-Deleary advised that the firms put forward by First Nations are based on relationships that are valued, which is related to Bill 5 and Special Economic Zones.
     - Kate Kempton agreed.
   - Nicholas Daube summarized the discussion and suggested continuing the conversation at the next meeting.
   - Kelsey Mills agreed that Enbridge Gas Inc. could investigate the list and how the suggestions could be incorporated into existing policies and procedures.
3. EGI Relationship with TC Energy
   - Kate Kempton discussed her client's relationships with TC Energy, as well as a claim that has been filed by Ginoogaming First Nation (GFN) against TC Energy. Her comments included:
     - Advised that they are not involved in an Indigenous working group with TC Energy and have been trying to get them to change this fact.
       - Launched a lawsuit in 2017 regarding integrity digs that is still ongoing.

    - Advised that TC Energy pays Crown governments and suggested that they pay First Nation governments similar payments (i.e., in the form of a property tax).
    - Suggested Enbridge Gas Inc. and the IWG go to the Canada Energy Regulator (CER) together to include this in the rate base as TC Energy has refused.
    - Noted that TC Energy was also asked to participate in the tolls taskforce and TC Energy also declined.
    - Emphasized the importance of First Nations being at the table to create a process of equity.
    - Advised that they were informing Enbridge Gas Inc. of this because they do business with TC Energy.
    - Asked Enbridge Gas Inc. to meet with TC Energy to persuade them to open the tolls taskforce.
    - Would like TC Energy to negotiate with First Nations the way they had offered to.
    - Appealed to Enbridge Gas Inc.'s corporate sense through the IWG to discuss with TC Energy and report back on the discussions.
- Diana Audino confirmed her understanding of Kate Kempton's position and emphasized that Enbridge Gas Inc. and TC Energy are different companies. Diana Audino advised that she would follow-up with her contact at TC Energy to explore.
    - Diana Audino advised that there are challenges on the property tax side, and Kate Kempton clarified that it didn't have to be a property tax specifically, but just a payment for using the land.
        - Shelly Rahme asked how Enbridge Gas Inc. would do this.
            - Diana Audino advised that they she would reach out to see who Enbridge could talk to at TC Energy about the matter.
            - Kate Kempton emphasized that they want Enbridge Gas Inc. to pressure TC Energy on the premise that what's being done for the Crown government should be for First Nations.
- Nicholas Daube advised that one point of dispute is the ongoing impact of TC Energy's operations.
- Nicholas Daube raised concerns about what Enbridge Gas Inc. is doing to ensure their business partners are acting appropriately
- Nicholas Daube suggested that First Nations would like to be meaningfully consulted about the issues that form the basis of EGI's applications. They would like these consultations also to take place in a timely manner. He suggested that consultations could take place in a way that allows the IWG to flag concerns and opportunities, suggesting it would be constructive to find a way to do this. He also acknowledged that EGI and the IWG would likely need to find a way to ensure that the integrity of EGI's litigation process and the integrity of OEB's process is appropriately respected, but he was suggesting that the IWG should be able to find a way to navigate these various priorities.

4. Enbridge and Bill 5
    - Jessica Maga attended to answer questions on Bill 5.
    - Kate Kempton discussed her position on how Bill 5 and C5 constitute erasure of First Nations and the work done towards reconciliation. Kate Kempton advised that her client wants Enbridge Gas Inc. to stand with the First Nations against these bills. Kate Kempton made these additional comments:
        - Defined reconciliation as the coexistence of two or more systems or worldviews so that they are mutually respectful. Reconciliation is to enable respectful space for First Nations to

govern, have worldviews, conduct ways of life, societies, that isn't forced to conform to or be subjected to other ways.
    - Emphasized that these bills are not a reaction to the United States and are based on Henry VIII regime of cabinet privilege.
    - Stated that the bills are fundamentally wrong and severe harm is being done.
- Nicholas Daube asked if Enbridge Gas Inc. had engaged on any questions relating to Bill 5 and C5 affecting First Nations.
    - With regards to Bill 5 specifically, Jessica Maga advised that Enbridge Gas Inc. did submit consultation vis a vis the public Environmental Registry of Ontario and there were conversations in terms of procurement, an ongoing concern about cost to ratepayers, and making sure the rate base is getting good value.
    - Nicholas Daube observed that Enbridge Gas Inc. did not address in its submissions in any significant way the question of how the legislation impacted First Nations.
        - Jessica Maga advised that the thrust of Enbridge Gas Inc.'s consultation had been that if the government is interested in developing economic zones, energy must be a part of the conversation.
        - Jessica Maga advised that Enbridge Gas Inc. also commented on the idea of one project, one permit and that engaging Indigenous communities is important.
        - Jessica Maga advised that the questions from the Bill 5 public engagement were not specific to what Enbridge Gas Inc. thinks about Indigenous communities. Enbridge Gas Inc. also discussed integrated planning and the importance of Indigenous engagement in the integrated energy plan.
        - Nicholas Daube, on behalf of GFN, advised that they were available as resources for Bill 5 and C5 if Enbridge Gas Inc. is looking for additional considerations.
- Nicholas Daube discussed the two aspects of Bill 5:
    - Special Economic Zones
        - Scary to First Nations who want to see protection continue and want to see the ability to share in decision making processes.
    - Concerns with specific legislation
        - Ontario is legislating away oversight, monitoring and ongoing protection.
        - Legal question on whether this is honorable or dishonorable conduct.
        - Whether Ontario is concerned with increasing the likelihood of Indigenous participation or if they have given up.
- Rob Lukacs sought clarification on what Nicholas Daube had advised that GFN requested.
    - Nicholas Daube advised that GFN would like to see perspectives captured in how Enbridge Gas Inc. thinks about Bill 5 and suggested the IWG be used as a resource at earlier stages.
- Rob Lukacs asked for clarification on the point Nicholas Daube had made about the cost of capital.
    - Nicholas Daube advised that the difference between how the BC regulator and the Ontario regulator approach cost of capital is the BC regulator thinks about risk (i.e. What is the risk of Indigenous opposition)
- Rob Lukacs asked if Enbridge Gas Inc. covers Indigenous consultation and accommodation expenses through its cost of capital filings at the OEB.
    - Tania Parsad confirmed that for LTC, the capacity and funding are involved in the project budget (not cost of capital, but capital expense)

- Rob Lukacs asked if Enbridge Gas Inc. would support explicitly recognizing accommodation costs as recuperable capital costs, not just as operating costs.
    - Tania Parsad advised that if it's related to a capital project, it's a capital expense, and if it's an operating type of activity, it's an operating expense.
    - Rob Lukacs sought clarification on when Enbridge Gas Inc. would apply the explicit recognition of accommodation costs as recoverable capital costs through a filing to the OEB.
        - Tania Parsad advised that the costs would be part of the capital cost of the project.
        - Lauren Whitwham advised that for LTC projects, capacity funding is in the project budget.
- Rob Lukacs advised that this is related to Bill 5 and the streamlining of approvals and would ideally like to see this embedded in submissions to the OEB to have accommodations covered when determining cost of capital so First Nations could be guaranteed accommodations coming out of capital projects.
    - Tania Parsad advised that Enbridge Gas Inc. does itemize this and is transparent about what the costs are, and this information is provided in filings.
        - Rob Lukacs advised that they are seeking to have the accommodation costs still covered.
        - Lauren Whitwham responded that in engagement, Enbridge Gas Inc. could still work with First Nations regarding mitigation measures, accommodation, and would still provide capacity funding.
            - Rob Lukacs asked if the permitting is removed through Bill 5, how would that be taken into account through the filing with the OEB.
            - Tania Parsad suggested this be a meeting takeaway.
            - Nicholas Daube offered to talk to Rob Lukacs offline.
- Jennifer Mills asked if there is a document that Enbridge Gas Inc. uses to determine the parameters of accommodation.
    - Lauren Whitwham responded that the Hydrocarbon Pipeline guidelines direct mitigation measures.
    - Diana Audino advised that Indigenous consultation requirements are also in the guidelines.
- Rob Lukacs advised that those costs only consider accommodations identified through the consultation period.
    - Diana Audino responded that it then turns into an ongoing operation expense.
        - Tania Parsad advised that Enbridge Gas Inc. follows accounting rules on whether it is a capital or operating cost.
            - Rob Lukacs asked where these rules are.
                - Tania Parsad answered that they are the Generally Accepted Accounting Principles (GAAP) or International Financial Reporting Standards (IFRS).

5. Brattle Recommendations – IWG Clarification
    - Rob Lukacs advised that they were still working through the recommendations.
6. Regional Scenario Analysis Update – Engagement Outcomes
    - Jennifer Murphy provided an update on the RSA session on September 3, 2025, and advised that Enbridge Gas Inc. is working on putting together a summary of the feedback.

7. Wrap-up
   - Nicholas Daube offered a summary of the meetings action items.
   - Nicholas Daube advised that GFN are anticipating that they would say that there should be earlier engagement with the IWG and First Nations regarding a 5-year plan.
     - Lauren Whitwham suggested this is an opportunity to tell the OEB that this should happen and GFN should include this in their reply.
     - Nick Daube asked if there was a way to get feedback to the OEB soon.
       - Lauren Whitwham replied that Enbridge Gas Inc. is moving in this direction.
       - Nicholas Daube suggested they keep talking about the 5-year plan.
       - Tania Parsad further suggested starting by following the OEB guidelines and agreed that it was worth revisiting.

Action Items

1. Enbridge Gas Inc., COTTFN, and IWG to set up a meeting to discuss heat pumps.
2. Rob Lukacs to provide IWG responses to Enbridge Gas Inc. questions on the Brattle recommendations.
3. (deferred item 13): Enbridge Gas Inc. to investigate changing environmental assessment (EA) language from 'confirmation of preferred route' to 'determination of preferred route' and from 'Incorporation of Treaty Rights and Indigenous Knowledge' to 'Weave Treaty Rights and Indigenous Knowledge into Mitigation Measure Development'. (Item 13 outstanding from July meeting).
4. (deferred item 14): Enbridge Gas Inc. to gather information on what level of information goes into a cumulative effects assessment regarding archaeological assessments. (Item 14 outstanding from July meeting).
5. (deferred item 15): Enbridge Gas Inc. to inquire about sharing internal archaeology assessment policies with the IWG. (Item 15 outstanding from July meeting).
6. (deferred item 16): Enbridge Gas Inc. to consider IWG request to work with archeologists to create a cost benefit analysis of LiDAR along the full preferred route. (Item 16 outstanding from July meeting).
7. (deferred item 19): Enbridge Gas Inc. to inquire if language of 'resources' in the Environmental process presentation could be changed to 'assets' when speaking to archaeological resources. (Item 19 outstanding from July meeting).
8. IWG to provide input on IRP. (Item 20 outstanding from July meeting).
9. Enbridge Gas Inc. to confirm the date the Sustainability Report key pages were provided to the IWG.
10. (deferred item 18): Enbridge Gas Inc. and IWG to continue archaeology firm discussion at the next meeting.
11. (deferred item 18): Enbridge Gas Inc. to investigate provided archaeology firms and see how they could be incorporated into policies and procedures.
12. Enbridge Gas Inc. to reach out to TC Energy to see if anything can be done to resolve challenges and report back to the IWG.
13. Enbridge Gas Inc. to consider how accommodation costs would be considered if permitting is removed through Bill 5.
14. Enbridge Gas Inc. to circulate dates for November meeting.

NEXT MEETING

Next meeting of the IWG is tentatively set to take place at the Enbridge Gas Inc. office at 500 Consumers Road North York, Ontario M2J 1P8 in November. Team to canvas for an Agenda closer to the date.

APPENDIX A – AGENDA FOR MEETING OF IWG ON SEPTEMBER 23, 2025

Time	Matter	Participants
10:00-10:20 am	Safety moment, introductions, administrative matters, status of action items, approval of minutes	Lauren Whitwham and Group
10:20-10:50 am	EGI Relationship with TC Energy	Kate Kempton and Group
10:50-11:10	IWG Suggested Archaeology Firms	Nicholas Daube and Group
11:10-11:25	Enbridge and Bill 5	Jessica Maga and Group
11:25-11:45	Brattle Recommendations – IWG Clarification	IWG and Group
11:45-12:30	Lunch	
12:30-1:00	Regional Scenario Analysis Update – Engagement Outcomes	Cara-Lynne Wade and Group
1:00-1:15 am	Wrap-up/Adjourn	Group

Enbridge Gas Inc. Indigenous Working Group Minutes

Minutes of a meeting of the Indigenous Work Group (IWG) held virtually on **November 26, 2025**, at 9:00 a.m.

PRESENT

Daniel Vollmer	Resilient LLP, Three Fires Group, Minogi Corp
Rob Lukacs	Minogi Corp.
Todd Jardine	Three Fires Group
Rick Peters	Three Fires Group
Tracy Skye	Six Nations Natural Gas
Nicholas Daube	Woodward and Company, Ginoogaming First Nation (GFN)
Diana Audino	Enbridge Gas Inc.
Tania Persad	Enbridge Gas Inc.
Lauren Whitwham	Enbridge Gas Inc.
Arend Wakeford	Enbridge Gas Inc.
Brent Bullough	Enbridge Gas Inc.
Gesiena Antuma	Enbridge Gas Inc.
Alvaro Atencio	Enbridge Gas Inc.
Jessica Maga	Enbridge Gas Inc.
Gabby Lapalme	Enbridge Gas Inc.
Henry Ren	Enbridge Gas Inc.
Kelsey Mills	Enbridge Gas Inc.
Erin Lindsay	Enbridge Gas Inc.
Matthew Webster	Enbridge Gas Inc.

Note on usage of "Enbridge Inc." and "Enbridge Gas Inc.": Policies and plans, such as the Indigenous Reconciliation Action Plan are Enbridge Inc. documents that apply to the whole company including Enbridge Gas Inc. For the purposes of IWG meetings, Enbridge staff are representing Enbridge Gas Inc.

MATTERS FOR DISCUSSION

1. Review of the Agenda for today (attached at Appendix A) and Logistics
   - Brent Bullough chaired the meeting and provided a safety moment.
   - Brent Bullough requested invoices for work completed relating to IWG be submitted by December 7, 2025.
   - Enbridge Gas Inc. and the IWG tentatively approved minutes from the September 2025 meeting, subject to confirmation from Nicholas Daube that his submitted edits were captured correctly.
   - Brent Bullough suggested removing the Integrated Resource Plan (IRP) as a standing agenda item and would request them to join if needed in the future. The IWG agreed.
   - Rob Lukacs requested Enbridge Gas Inc.'s self-assessed Oil and Gas Methane Partnership 2.0 (OGMP) maturity level for venting, fugitive emissions, flaring and stationary combustion be added as an agenda topic to a future meeting. He further requested a discussion be held at a future meeting to develop a plan to communicate rate harmonizations to Indigenous nations.
     - These items will be on an early 2026 meeting agenda.
   - Brent Bullough advised that the IWG would discuss preferred archaeology firms for archaeology work for Enbridge Gas Inc. projects at a 2026 meeting.
   - Brent Bullough advised that the gas supply team for Enbridge Gas Inc. would be presenting at the first IWG meeting in 2026.
     - Nicholas Daube asked if this was the gas supply team's annual update.
       - Lauren Whitwham advised that Enbridge Gas Inc. had committed to presenting an annual update.
   - Rob Lukacs advised that the Brattle recommendation discussion would take place at an early 2026 meeting.
   - Nicholas Daube asked to add a discussion about meeting location and experts to today's meeting agenda.
   - Status of IWG September 2025 meeting action items:
     - Item 1 and 2: Brent Bullough confirmed that the IWG had discussed it earlier in the meeting.
     - Items 3-7: Enbridge Gas Inc. and IWG agreed to defer environmental items to a future meeting.
     - Item 8: Brent Bullough confirmed that the IWG had discussed it earlier in the meeting.
     - Item 9: Brent Bullough to confirm the date the Sustainability Report key pages were provided to the IWG.
     - Item 10 and 11: Enbridge Gas Inc. and IWG agreed to defer archaeology items to a future meeting.
2. IWG Relationship with TC Energy
   - Diana Audino provided an update on her discussion with TC Energy (Item 12 from September meeting) and answers to Kate Kempton's questions.
     - Would the tolls task force be open to First Nations?
       - First Nations cannot be on the tolls task force because they are not shippers on TC Energy's system, which is a requirement to be part of the tolls task force.

- Whether TC Energy would negotiate an Indigenous property tax/ some sort of mechanism.
  - Advised that this is a confidential TC Energy matter.
- Nicholas Daube didn't identify specific questions but noted that this is a serious issue for GFN and one that is not going away.
  - Nicholas Daube advised he would take this back to GFN and noted it is important for Enbridge Gas Inc. to know that GFN is increasingly looking for help in the matter.

3. 2027 + Demand Side Management Plan (DSM Plan)

- Erin Lindsay provided a comprehensive update on the approved 2026 DSM Plan and the upcoming 2027+ application, detailing program continuity, budget allocations, and anticipated procedural steps.
- The 2026 Plan has been approved as proposed.
- The OEB requested Enbridge Gas Inc. provide an update on what they anticipate happening with the multi-year DSM Plan and when that would be submitted. Enbridge Gas Inc. anticipates filing a 2027+ DSM Plan by the end of this year.
- Engagement when developing a DSM Plan (specifically Indigenous engagement):
  - From a delivery model perspective and how to tailor outreach in a collaborative format, Enbridge Gas Inc. relied on First Nation Engineering Services Ltd. (FNESL), industry organizations, and Enbridge Gas Inc.'s Community and Indigenous Engagement (CIE) team for suggestions and feedback.
  - There is flexibility to introduce measures, change incentives, and change the delivery model within the construct of a DSM Plan.
  - Have had success with Indigenous communities, including hosting community events.
  - From the technical measures to offer, Enbridge Gas Inc. relied on FNESL, delivery agents and contractors looking to understand best practices, potential opportunities, etc.
- Programs targeting First Nation customers or where we would expect First Nation customers to participate are the Home Winterproofing Program (HWP) and/or the Residential Home Renovation Savings (HRS) Program.
- Home Winterproofing Program (HWP)
  - Most relevant program to First Nation customers; preferred path for those households that qualify.
  - Involves providing home insulation, among other items, at no cost to customers, and includes a budget to help overcome challenges that might prevent participation.
  - Nicholas Daube requested elaboration on the consultation done with First Nations.
    - Lauren Whitwham confirmed engagement with Chippewas of Kettle and Stony Point (CKSPFN) and Mohawks of the Bay of Quinte (MBQ).
    - It was noted though that there have been some barriers to bringing the HWP to First Nation communities. There is a team member who is Indigenous who is advancing the program in First Nations' communities. Enbridge Gas Inc. is also working with an organization out of the Chippewas of Rama First Nation (CRFN) to determine whether any improvements could be made to make it more feasible for Indigenous communities' participation. Enbridge Gas Inc. had reached out to four nations to advance the program; Saugeen First Nation, CKSPFN, MBQ and Couchiching First

Nation. The program has been going on for years and Enbridge Gas Inc. has worked with almost every nation that's involved in gas distribution. Enbridge Gas Inc. has tried to bring it to GFN and Nipissing First Nation (NFN) but have had challenges with uptake. Enbridge Gas Inc. had a community event at MBQ to discuss the program and have people sign up to try and move it forward.

- Nicholas Daube noted his client is interested in learning what GFN can be advocating for in proceedings and what generally has worked for the community.
- Lauren Whitwham advised that the program is only available to Enbridge Gas Inc. customers in the community due to the funding structure.
    - This is a challenge because Enbridge Gas Inc. may only service some homes in a community and therefore only these homes would be eligible.
- Erin Lindsay advised that they are targeting at least four nations per year and rely on FNESL to reach out to the Band Council.
    - Lauren Whitwham advised that the CIE team is also included in this initial engagement with FNESL.
- Erin Lindsay emphasized that Enbridge Gas Inc. is looking for any opportunity to build awareness among Indigenous communities.

- Residential HRS Program
    - This is the jointly delivered program between Enbridge Gas and the IESO.
    - Launched January 2025, it is open to residential consumers across Ontario providing access to all available rebates/incentives available for energy efficiency by either Enbridge Gas or the IESO.
    - Enbridge Gas is the natural gas component of the program and Enbridge Gas customers would be eligible for natural gas DSM incentives.
    - Enbridge Gas will be proposing continuation of this program, expected to be filed by the end of the year.
- Daniel Vollmer asked if there were Indigenous participants in the stakeholder advisory group.
    - Erin Linday advised that the OEB decided on who would be part of the advisory group and none were Indigenous.
    - Daniel Vollmer asked if intervenor groups that were involved in the consultation were Indigenous.
        - Erin Lindsay responded that invitations were based on the last proceeding and Anwaatin Inc. was invited but she didn't think they attended.
    - Daniel Vollmer asked if there was a possibility for the IWG to continue to be updated on programs and included in the process.
        - Erin Lindsay responded that they participated in the IWG to seek feedback and can continue to do so since there is flexibility in the plan's execution.
        - Lauren Whitwham advised that once they receive feedback, the HWP team discussed presenting to the IWG.
    - Daniel Vollmer asked if there is data on the HWP's uptake in First Nations.
        - Lauren Whitwham answered that there is basic data that they could get from the team and noted the program experienced less uptake than hoped.
- Nicholas Daube sought clarification on the barriers to program uptake noting he heard the following factors:
    - Knowledge in the community.

- General community buy-in.
- Suitability of buildings.
  - Lauren Whitwham clarified that "barriers" may not be the right word and added that the following may limit participation:
    - Proof of income is needed from the resident, so Enbridge Gas is trying to remove this requirement.
    - Factor of trust/ education of the program needed.
    - Some homes don't qualify because they need improvements to be eligible.
- Nicholas Daube asked if approvals are needed to remove the income question.
  - Erin Lindsay advised that in the past they've submitted a letter to the OEB (there are options).
- Nicholas Daube asked if there is a way to document how initiatives effect First Nations, wondering why there is no discussion about implications for First Nations, even indicating that it seemed Enbridge Gas would like to do more but there are barriers standing in the way.
    - What sort of policy support might make it easier for Enbridge Gas to advance DSM programming in First Nation communities.
    - Whether Enbridge Gas is anticipating a discussion in future DSM submissions and how they relate to First Nations.
  - Lauren Whitwham suggested that another factor is that Nations have a lot of other engagement going on.
    - Need to work with communities to lessen administrative burden and find ways to support communities.
  - Nicholas Daube advised that GFN would support a general discussion as a standard practice about implications for First Nations and an elaboration on barriers to doing more.
  - Erin Lindsay noted there's discussion about activities impacting First Nations in the annual report.
  - Nicholas Daube suggested the energy sector treats relationships with First Nations as being limited to the DTC being satisfied. GFN's position is that this is at odds with reconciliation and the Ontario government's statements about First Nation partnerships.

- Rob Lukacs asked how Enbridge Gas is measuring and reporting on supply chain within the DSM program (i.e. specific indicators to demonstrate real market transformation rather than just program delivery).
  - Erin Lindsay advised that there aren't specific metrics related to the number of contractors or changes in equipment. There are currently no separate market transformation metrics because it's seen as embedded in the process (e.g., upgrades in homes are fully customized) - no specific metrics or KPI on this.
- Rob Lukacs asked if there are supply chain bottle necks (e.g., workforce, contractor capacity, product availability) slowing down adoption so Enbridge Gas can go beyond just issuing rebates.
  - Lauren Whitwham advised that they don't track metrics but have FNESL in the community working to implement the program.
    - Erin Lindsay added that it depends on the program, but supply chain is not an issue with the HWP delivered to Nations.

- Rob Lukacs asked for elaboration on the tools used to influence peak management to reduce/ reshape natural gas demand. He was seeking to understand what's being done to further DSM.
    - Erin Lindsay advised that they define DSM as energy efficiency and are not looking at peak management.
    - Rob Lukacs asked why only downstream efficiencies are being considered while Enbridge Gas Inc. has upstream efficiencies that could have improvements.
        - Erin Lindsay advised there are programs doing similar things such as the IRP Sarnia pilot.
        - Lauren Whitwham added Enbridge Gas also works with large industrial partners to try and reduce their use of natural gas; however, Erin Lindsay and her team work on efficiency improvements.
        - Lauren Whitwham also clarified that Enbridge Gas transports natural gas and has no upstream activities in Ontario to consider.
- Rob Lukacs asked if the IWG could speak to someone from DSM to better understand how Enbridge Gas is working with its municipal and industrial partners to maximize efficiencies on DSM.
    - Erin Lindsay advised that depending on the sector, there are various programs, including retrofit and new construction. Enbridge Gas's full DSM portfolio is described in its DSM Annual Reports and filed DSM Plans.

4. 2029 Rebasing Engagement
    - Gesiena Antuma presented on 2029 rebasing and engagement with customers which is currently in the planning process.
    - Multiple stakeholder sessions are planned with the first one on December 4, 2025.
    - Enbridge Gas is seeking input from the IWG on the best way to conduct engagement with Indigenous customers.
        - Nicholas Daube asked why 2029 and Gesiena Antuma responded that the rates start for the plan in 2029, pointing out that the last rebasing was for 2024, but engagement commenced in 2021 and 2022. The goal is to submit the application in September 2027.
        - Nicholas Daube indicated that from the perspective of some of the Nations represented on the IWG, the last rebasing application didn't do enough to address concerns.
    - Nicholas Daube continued that IWG members had offline discussion and determined the need for an expert to help channel First Nations perspectives, needs, and opportunities into a professional framework that the OEB requires. The IWG requests the following:
        - Retain an expert to deliver a slide deck that would be presented to the IWG and serve as a basis for discussion.
        - Timing is good in terms of where Enbridge Gas is in the process and the IWG is hopeful to have the expert early in the new year.
        - IWG could provide preliminary ideas, but further comment would come in the form of a professional presentation and hearing from the Nations themselves.
            - Gesiena Antuma asked if the presentation would be for ideas on how to conduct the engagement or if it would cover customer needs and preferences.
                - Nicholas Daube clarified that the expert would focus on the process. Previous customer engagement survey was limited to a question about

Indigenous self-identification and didn't go into what potential concerns were.
- Under this proposal, specific concerns would come from the First Nations themselves.

- Rick Peters asked if the survey was the primary form of engagement previously and what else could be done.
  - Gesiena Antuma confirmed and advised that more can be done for customer engagement.
  - Nicholas Daube referred to a previous point made by Kodi Deleary that the new community energy representative would have information that a survey wouldn't be able to collect.
  - Rick Peters advised that they are also looking to revise their community energy plan and input gathered through that process could also contribute to DSM discussions.
- Rick Peters and Nicholas Daube are to connect on this matter.

- Jessica Maga asked if the expert would be for the whole rebasing process or just the engagement piece?
  - Nicholas Daube advised they hadn't drafted the scope of work but would focus on aspects connected to the IWG's purpose.
  - Gesiena Antuma noted that the goal is to have all the customer engagement completed by November 2026 so timing is important.
    - Nicholas Daube acknowledged the timing and noted the need to retain the expert soon.

5. Update on Experts
   - Nicholas Daube provided an update on retaining an expert to present on possible different rates for Indigenous and non-Indigenous customers.
     - Similar approach as with Brattle by providing the IWG with a PowerPoint report.
   - Nicholas Daube invited any questions/ input from IWG members.
6. Potential Meeting Locations
   - IWG agreed to have the next meeting in person at the Enbridge Gas London office in mid to late February 2026.

Action Items

1. Enbridge Gas Inc. to confirm the date the Sustainability Report key pages were provided to the IWG.
2. Enbridge Gas Inc. to get data on uptake of HWP.
3. IWG to provide a proposal to retain expert to present engagement recommendations to Enbridge Gas and IWG and another to present on Indigenous rates.

NEXT MEETING

Next meeting of the IWG is set to take place at the Enbridge Gas Inc. office at 109 Commissioners Road London, Ontario N6J 1X7 in February 2026. Team to canvas for an Agenda closer to the date and include previously suggested items.

APPENDIX A – AGENDA FOR VIRTUAL MEETING OF IWG ON NOVEMBER 26, 2025

Time	Matter	Participants
9:00-9:20 am	Safety moment, introductions, administrative matters, status of action items, approval of minutes	Brent Bullough and Group
9:20-9:30 am	IWG Relationship with TC Energy	Diana Audino and Group
9:30-10:15 am	2027+ DSM Plan	Erin Lindsay and Group
10:15-11:00	2029 Rebasing Engagement	Gesiena Antuma and Group
11:00-11:15 pm	Wrap-up/Adjourn	Group

Enbridge Gas Inc. Indigenous Working Group Minutes

Minutes of a meeting of the Indigenous Work Group (IWG) held on **March 25, 2026**, at 9:00 a.m. at Enbridge Gas Inc., 109 Commissioners Rd, London, Ontario N6J 1X7.

PRESENT

Daniel Vollmer	Resilient LLP, Three Fires Group, Minogi Corp
Rob Lukacs	Minogi Corp.
Emily Ferguson	Minogi Corp.
Todd Jardine	Three Fires Group
Rick Peters	Three Fires Group
Nicholas Daube	Woodward and Company, counsel for Ginoogaming First Nation (GFN)
Zack Hamm	GFN
Jennifer Mills	Chippewas of the Thames
Erna LeClaire	Chippewas of the Thames
Peter Fraser	The Brattle Group
Sarah Welch	Oakview Advisory
Steve Dantzer	Enbridge Gas Inc.
Amy Mikhaila	Enbridge Gas Inc.
Diana Audino	Enbridge Gas Inc.
Tania Persad	Enbridge Gas Inc.
Lauren Whitwham	Enbridge Gas Inc.
Arend Wakeford	Enbridge Gas Inc.
Brent Bullough	Enbridge Gas Inc.
Gesiena Antuma	Enbridge Gas Inc.
Jessica Maga	Enbridge Gas Inc.
Gabby Lapalme	Enbridge Gas Inc.
Kelsey Mills	Enbridge Gas Inc.
Richard Lanni	Enbridge Gas Inc.
Matthew Webster	Enbridge Gas Inc.
Adam Stiers	Enbridge Gas Inc.
Echo Xu	Enbridge Gas Inc.
Richard Wathy	Enbridge Gas Inc.
Johanna Sanchez-Gomez	Enbridge Gas Inc.
Laura Sheehan	Enbridge Gas Inc.
Stephanie Muller	Enbridge Gas Inc.

Tami Showers	Enbridge Gas Inc.
Luna Munro	Enbridge Gas Inc.
Peter Mussio	Enbridge Gas Inc.

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MATTERS FOR DISCUSSION

1. Review of the Agenda for today (attached at Appendix A) and Logistics
   - Brent Bullough chaired the meeting.
   - Tami Showers provided a safety moment.
   - Enbridge Gas Inc. and the IWG approved minutes from the November 2025 meeting.
   - Status of IWG November 2025 meeting action items:
     - Item 2: Brent Bullough advised that an update on the HWP had been moved to the next meeting.
     - Item 3: Brent Bullough advised that a discussion on rate harmonization had been moved to the next meeting.

2. Gas Supply Plan Update
   - Echo Xu presented an overview of Enbridge Gas Inc.'s Gas Supply Plan (the Plan), including in the context of its planning processes and the Ontario Energy Board's Framework.
   - Echo Xu noted that Enbridge Gas Inc.'s first annual update to the five-year Plan was filed on March 3, 2026, which informed the presentation.
   - Nicholas Daube advised that his client GFN believed that GFN's interests could be better accounted for in the Plan, including by way of a better mechanism to incorporate GFN's input. He also raised concerns with TC Energy's operations (which provide gas to Enbridge Gas Inc.) within GFN's Territory.
     - Adam Stiers advised that they see the IWG helping support engagement long term.
     - Enbridge Gas Inc. advised that the IWG provides an opportunity for the First Nation participants to provide input into the Plan going forward and confirmed that we are waiting for the OEB's decision on the public policy considerations of the Plan.
   - Amy Mikhaila advised that regarding TC Energy, there are very few alternatives (if any) for Enbridge Gas Inc. to contract with.
   - Nicholas Daube noted GFN would like different supply scenarios contemplated in an application for the Plan.
   - Nicholas Daube explained that GFN would like to better understand potential impacts on GFN's territories as a result of the Plan (e.g. impact on maintenance activities).
   - Amy Mikhaila acknowledged GFN had a concern with TC Energy and maintenance elements and asked whether there might be other concerns.
   - Nicholas Daube advised that a main interest of GFN is the impact of supply decisions regarding TC Energy's activities and operations on GFN's Territory (e.g. environmental risks, integrity digs) and GFN are interested in learning about opportunities for the First Nation participants to provide input

into the Plan. Nicholas Daube advised then that GFN desires more information and discussion around Enbridge Gas Inc.'s supply choice decisions, and more specifically, its decisions to source from TC Energy.

- Amy Mikhaila agreed that Enbridge Gas Inc. would reach out to TC Energy to share concerns, but recognized TC Energy is not obligated to share information given the commercial nature of the relationship.
- Amy Mikhaila noted that another takeaway could be outlining what other alternatives may be available to source gas instead of from TC Energy, if any.
    - Nicholas Daube agreed this would be useful information.
- Jennifer Mills asked how the planning cycle within the Plan ties into infrastructure planning.
    - Adam Stiers advised that planning is driven primarily by demand and emphasized that the gas supply planning team is distinct from other project focused teams.
    - Adam Stiers explained that the Plan team receives annual and design day demand forecasts and run simulations trying to determine whether the current infrastructure and supply is optimally sufficient to serve the demands identified, and if not, what action could be taken to adjust Enbridge Gas Inc.'s portfolio. The function and plan itself is a commercially focused procurement plan.
    - Adam Stiers advised that regarding the infrastructure portion, the determination of whether or not existing infrastructure is sufficient for future demands happens outside of the gas supply plan group.
- Daniel Vollmer asked if Enbridge Gas Inc. is open to describing the discussion held with the IWG about gas supply in the updated Plan to enhance transparency and accountability.
    - Diana Audino noted that the IWG meeting minutes are provided to the OEB and filed in the annual report and as such, would be on the record.
    - Amy Mikhaila confirmed Enbridge Gas Inc. would inquire whether these minutes could be included in the next Plan update.

3. IWG Expert Presentation on 2029 Rebasing Indigenous Engagement
    - Sarah Welch, an expert retained by the First Nation participants on the IWG, advised that she was asked to look at Enbridge Gas Inc.'s past customer engagement to see how future engagement with Indigenous Communities can be strengthened in rebasing.
    - Sarah Welch presented an overview of the report she had prepared including her recommendations, organized into 6 themes: Rights Holder Lens, Differentiated Engagement, Integration of Ongoing Engagement, Accountability & Trust, Upstream Participation, and Economic Reconciliation.
    - Sarah Welch's oral presentation generally tracked the details set out in her PowerPoint document entitled "Engagement Evaluation – From customer to rights holder", which is appended to these minutes.
    - Lauren Whitwham asked about the study methodology including who Sarah Welch met with to prepare the presentation.
        - Sarah Welch advised that she had met with the IWG representatives.
    - Gesiena Antuma sought, in response to Recommendation 3, any suggestions for how to conduct early engagements.
        - Sarah Welch suggested discussing directly with the Nations and continuing conversations within the IWG.

    - Rob Lukacs added that for MSIFN, this would be something consultation staff at MSIFN would like to facilitate internally and with the community and report back to Enbridge Gas Inc. and that capacity funding would be needed if this approach is taken.
    - Nicholas Daube offered that the first point of contact at GFN would be Zack Hamm.
    - Jennifer Mills advised that the contact at COTTFN would be the consultation department. The Housing department is also interested.
    - Rick Peters advised that CKSPFN could do data collection for their customers/potential customers on reserve to better inform the discussions.
- Gesiena Antuma asked if Enbridge Gas Inc. should try multiple ways of getting feedback or if there were concerns with this.
    - Rick Peters advised that there could be fatigue due to over surveying but believes doing one-on-one interviews would be successful.
    - Rob Lukacs confirmed that over surveying is an issue.
    - Sarah Welch offered that it would be important to know how each Nation would like to be engaged.
    - Lauren Whitwham also acknowledged Nation members living off-reserve who could be targeted with a survey and asked Sarah Welch for any suggestions. Sarah Welch offered to connect with David Coletto seeking ways to encourage off-reserve members to self-identify/ target them in engagement.
    - Diana Audino also suggested going to the Nations directly to reach out to their membership.
    - Nicholas Daube noted that the recommendations are a package to help better address questions.
    - Gesiena Antuma advised that parallel tracks are used for engagement with other groups.
- Gesiena Antuma sought clarification on the process for gathering feedback and asked if it was specific to Indigenous communities or broader engagement. Gesiena Antuma noted that the previous round of engagement gave respondents the option to receive a follow-up or not.
    - Sarah Welch confirmed this was specific to Indigenous communities and it would be their choice on how they wanted to be followed up with.
    - Rob Lukacs suggested it would be a record of consultation.
- For context, Lauren Whitwham noted that 20 communities are being served with natural gas from Enbridge Gas Inc.
- Lauren Whitwham and Gesiena Antuma agreed to have the teams work together to inquire and gauge interest.
- Nicholas Daube emphasized this should be a priority for the IWG.

4. Methane Measurement
    - Luna Munro presented the oil and gas methane partnership (OGMP) 2.0 self-assessment.
    - Luna Munro provided an overview of the OGMP 2.0 framework, maturity level, and challenges.
    - In the 2024 CSR, we give an overview of the work we have done to evaluate the OGMP 2.0 framework, including the pilot satellite study, which included Gas Transmission and Midstream (GTM) and Gas Distribution and Storage (GDS) participated. GDS is the applicable business unit to Enbridge Gas Inc.

- The Fugitive Emissions Measurement Plan (FEMP) was discussed in the Rebasing application and the Utility Earnings and Disposition of Deferrals Account Balances application (deferral application) submitted to the OEB.
- In 2023, Enbridge Gas Inc. filed a partial settlement with the OEB which required Enbridge Gas Inc. to develop a robust investigation plan on how to accurately measure fugitive emissions for specific Enbridge Gas Inc. assets (the Fugitive Emissions Measurement Plan - FEMP).
- Enbridge Gas Inc. retained Highwood Emissions Management to support FEMP and they developed the Highwood Report with recommendations.
- Peter Mussio advised that the Highwood Report looked at different technologies and found that satellite technology is not developed to the point where it can accurately detect the low level of emissions typically found on a distribution system. Vehicle mounted technology showed some promise.
- FEMP was submitted to the OEB as part of the deferral application, however the OEB did not believe FEMP would be a cost-effective activity and therefore did not approve the new deferral account that was requested for same. Based on the OEB's decision, Enbridge decided not to move forward.
- Luna Munro discussed opportunities to support measurement of fugitive emissions, including the amended federal Methane regulations.
- Luna Munro discussed Veritas, a standardized, science-based, technology-neutral, measurement-informed approach to calculating and reporting methane emissions.
- Emily Ferguson asked what the size of each grid square was for the pilot satellite study measurement and what the emissions intensity being looked for (would there be a certain level that would go undetected by satellite).
    - Peter Mussio confirmed to follow up with the answer.
- Emily Ferguson asked if the raw data of the pilot satellite study was available to be shared.
    - Peter Mussio to confirm.
- Rob Lukacs asked with regard to technology, if Enbridge Gas Inc. had consulted with Carbon Management Canada regarding methane detection and quantification testing.
    - Peter Mussio advised that there had been discussions with METEC to provide information in terms of quantification capabilities of various technologies.
    - Rob Lukacs asked if Enbridge Gas Inc. was looking at METEC's protocols with regards to established best practices for quantification.
        - Peter Mussio advised that they were looking at the Veritas protocol.
- Rob Lukacs requested more information on Veritas, why Enbridge Gas Inc. is funding the Veritas initiative and if Veritas offers auditing.
    - Peter Mussio advised that Enbridge Gas Inc. hadn't implemented Veritas methodology but could share an overview of the various protocols, which includes measurement and reconciliation. Peter clarified that Veritas doesn't perform the audits.
- Rob Lukacs sought confirmation if Enbridge Gas Inc. self-assesses maturity levels are stated in the Sustainability Report.
    - Peter Mussio confirmed that the OGMP 2.0 self-assessment included in CSR includes Enbridge Gas Inc.
- Rob Lukacs asked why Enbridge Gas Inc. doesn't externally audit the self-assessment.
    - Peter Mussio advised that there is no requirement to externally audit the self-assessment and the self-assessment was done to determine Enbridge Gas Inc.'s maturity level with the OGMP requirements.

    - Rob Lukacs advised that it would be important that Enbridge Gas Inc. communicate to stakeholders to be clear they aren't externally auditing these reports.
- Jennifer Mills asked what technology Enbridge Gas Inc. is using for continuously monitoring systems and the type of infrastructure it's appropriate for.
    - Luna Munro advised that they hadn't looked at all the technology options for the federal methane regulation Part 2 yet but are looking at technologies like electrochemical analyzers and lasers.
- Erna LeClaire asked if drones were used. Luna Munro responded that they had, but the technology reviewed to date will not work due to logistical issues.

5. Requested Changes to Environmental Report Terminology, Use of LiDAR for Archaeological Studies and Cumulative Effects Assessments
    - Kelsey Mills provided an overview responses to that were also provided by email on March 23 (See Attachment 4 – Requested changes to ER terminology):
    - Item 1. No questions from IWG.
    - Item 2. Jennifer Mills noted that the term mitigate could mean avoiding or extracting.
        - Kelsey Mills advised that Enbridge Gas Inc. first tries to avoid but if it comes to a point where there is an archaeology resource found, there is also the option to avoid further disturbance by rerouting the pipeline.
        - Rob Lukacs asked when rerouting would be given serious consideration.
            - Kelsey Mills advised that it depends on what the findings are; Enbridge Gas Inc. would try to limit disturbance to more significant finds such as burial sites, but that this does not happen frequently. Lauren Whitwham noted an example of this occurring before in the past.
            - Johanna Sanchez-Gomez advised that the licensed archaeologists also provide suggestions on how to manage situations.
    - Item 3. Stephanie Muller provided a summary of Enbridge Gas Inc.'s archaeology process.
        - Rob Lukacs asked how archaeology potential is determined for non-leave-to-construct (LTC) processes.
            - Kelsey Mills advised that a checklist for non-archaeologists, developed by the Ministry of Citizenship and Multiculturalism (MCM), is used. The checklist provides preliminary screening guidance and triggers for when an archaeologist should be retained to do a Stage 1 and/or 2 archaeological assessment (AA) if needed.
            - Rob Lukacs asked at what point would First Nations would be contacted for non-LTC process.
                - Lauren Whitwham advised that First Nations are invited to some Stage 2 AAs when in proximity to communities and areas of cultural significance and briefly outlined the process.
                    - Rob Lukacs advised that MSIFN would welcome the AA reports.
                - Enbridge Gas Inc. and MSIFN to discuss what level of information they would like to receive.
        - Jennifer Mills asked if there was anything within the checklists that explicitly discuss when a site would be avoided or excavated.

        - Kelsey Mills advised that Nations would have the opportunity to review the findings from the Stage 1 AA and voice opinions in the route determination process (for LTC process).
        - For non-LTC process, it would depend on the finding and Enbridge Gas Inc.
        - Johanna Sanchez-Gomez noted that the licensed archaeologist would also help identify next steps.
    - Rick Peters asked if the general archaeology process overview could be shared. Kelsey Mills confirmed it could. Rick Peters mentioned that workshops with the community are coming up and Enbridge Gas Inc. could possibly present this information.
    - Rob Lukacs asked if internal policies are going to change as a result of the new Ontario regulations.
        - Kelsey Mills advised that the documents are on a review cycle and would be updated to meet requirements of an updated Ontario Heritage Act.
- Item 4. No questions from IWG.
- Item 5. Jennifer Mills asked if the wording change from 'assets' to 'resources' was just for the presentation. Kelsey Mills advised it was but would also bring it to the archaeological consultants for consideration in archaeological assessment reports.
    - Zack Hamm noted that Indigenous communities are using 'ancestral belongings' or 'ancestral possessions' as the term.
        - Zack Hamm suggested looking to the communities for their preferred terminologies.
        - Lauren Whitwham asked what term would be used to describe tools. Zack Hamm advised that communities often refer to them as 'ancestral belongings'.
        - Jennifer Mills supported going to the communities for preferred terminology.
        - Kelsey Mills confirmed to take this discussion back to the archaeologists and discuss with communities.
        - Zack Hamm suggested including updated terminology in a terms of reference in reports.
- Item 6. Rob Lukacs advised that they would follow up on preferred archaeologist discussion. Lauren Whitwham noted that one of the IWG identified preferred archaeology firms was consulted for this response document.
    - Jennifer Mills expressed interest in receiving reports before they are added to the ER. Kelsey Mills advised that this could be done when the reports are available. Kelsey Mills noted that communities are also invited to attend the work that informs these reports. Kelsey Mills advised that these early opportunities to discuss are part of the updated process.
- Item 7. No questions from the IWG.

6. Next Meeting
    - Lauren Whitwham encouraged the IWG to attend in person and submit invoices.
    - Brent Bullough summarized outstanding agenda items, including rate harmonization, Brattle recommendations, winterization program, and an RSA update.

Action Items

1. Enbridge Gas Inc. to connect with TC Energy regarding concerns raised by Nations about their operations.
2. Enbridge Gas Inc. to present potential alternatives or scenarios for contracting with TC Energy for pipeline capacity.
3. Enbridge Gas Inc. to investigate including IWG minutes in future gas supply plan filing.
4. Oakview Advisory to inquire about suggestions for encouraging self-identification of off-reserve members on engagement surveys.
5. Enbridge Gas Inc. to gauge Nations' interest in rebasing discussions.
6. Enbridge Gas Inc. to provide the size of each grid square for the methane emissions satellite measurement and what the emissions intensity was being looked for.
7. Enbridge Gas Inc. to determine if the raw data from the pilot satellite emissions study can be shared.
8. Enbridge Gas Inc. and MSIFN to discuss the level of information/ reports to be shared with MSIFN for non-LTC work.
9. Enbridge Gas Inc. to share its general archaeology process overview with IWG.
10. Enbridge Gas Inc. to determine whether terminology used with archaeologists and communities can be refined to better align with Indigenous communities' expectations.
11. Enbridge Gas Inc. to circulate presentations that were provided during this meeting.

NEXT MEETING

Next meeting of the IWG is set to take place at the Enbridge Gas Inc. office at 500 Consumers Road North York, Ontario M2J 1P8 the first week of June, 2026. Team to canvas for an Agenda closer to the date and include previously suggested items.

APPENDIX A – AGENDA FOR MEETING OF IWG ON MARCH 23, 2026

Time	Matter	Participants
9:00-9:20 am	Safety moment, introductions, administrative matters, status of action items, approval of minutes	Brent Bullough and Group
9:20-10:20 am	Gas Supply Plan Update	Echo Xu and Adam Stiers

10:20-12:20 pm	IWG Expert Presentation on 2029 Rebasing Indigenous Engagement	Nicholas Daube and Gesiena Group
12:20-1:00 pm	LUNCH	
1:00-2:00 pm	Methane Measurement	Luna Munro and Peter Mussio
2:00-3:00 pm	Requested Changes to Environmental Report Terminology, Use of LiDAR for Archaeological Studies and Cumulative Effects Assessments	Kelsey Mills
3:00-3:15 pm	Wrap-up/Adjourn	Group

Distribution Integrity Management Program (DIMP) and Enhanced Distribution Integrity Management Program (EDIMP)

Report on Activities - 2025

ENBRIDGE
Life Takes Energy

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1. Overview

On August 17, 2023, the Ontario Energy Board (OEB) released its Decision on the 2024 Rebasing Phase 1 Settlement Agreement, in which the OEB approved the establishment of a new variance account for Distribution Integrity Management Program (DIMP) and Enhanced Distribution Integrity Management Program (EDIMP) costs.[1]

As part of the Decision, Enbridge Gas must provide annual reporting on actual DIMP/EDIMP spending, setting out the work done (and associated costs), listing the projects/facilities where work was done, describing what facilities work was deferred or avoided or otherwise impacted as a result and discussing the cost/benefit analysis of the DIMP/EDIMP work done during the past year.[2]

The actual DIMP/EDIMP spending in 2025 amounted to $13.189 million. This report describes the activities and work that comprised this spend. A breakdown of actual expenditures is shown in Table 1. This report also describes the long-term mitigation plans and actions arising from the quantitative risk assessments completed on the 2024 EDIMP inspected pipelines.[3]

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.31.
[2] Ibid, p.56.
[3] EB-2025-0155, Exhibit G, Tab 4, Schedule 1.

Table 1

2025 DIMP/EDIMP Actuals Breakdown

Line No.	Description	2025 Actuals ($ millions)
	DIMP	
1	Admin	1.561
2	Investigations & Assessments	0.579
3	Pipe Inspections	0.271
4	Station Inspections	0.106
5	Regulator Set Inspections	0.870
6	DIMP Carryovers	0.007
7	Total DIMP	3.394
	EDIMP	
8	Admin	0.946
9	In-line Inspection (ILI)	7.818
10	Corrosion Survey	0.380
11	Digs (Validation)	0.423
12	Assessments & Consulting	0.233
13	EDIMP Carryovers	(0.004)
14	Total EDIMP	9.795
15	Total DIMP and EDIMP	13.189

2. DIMP and EDIMP Administration

The total costs to administer the DIMP and EDIMP portfolios amounted to $2.506 million. These costs primarily included Full Time Equivalent (FTE) positions, contractor positions, and employee expenses such as travel & accommodations (T&A), training/conferences and professional dues to support the DIMP and EDIMP portfolios.

3. DIMP Projects

DIMP Projects consist of five distinct work categories: Investigations & Assessments; Pipe Inspections; Station Inspections; Regulator Set Inspections; and DIMP Carryovers. The actual spend for these work categories in 2025 was $1.833 million.

3.1 Investigations & Assessments

a) Unscheduled Inspections: Eight unscheduled inspections and assessments were performed in 2025. The unscheduled inspections and assessments were completed across multiple assets, including:

- Assessing the condition of cased steel piping in Kenora;
- Completing a mainline valve records review to identify the make and type of valves to improve valve reliability models and analysis;
- Completing a steam line risk assessment to identify all steam line systems in Ontario. This assessment followed the National Transportation Safety Board (NTSB) findings on the 2023 West Reading, PA incident[4] involving a cracked Aldyl-A punch tee that resulted in fatalities and injuries;
- Completing a soil corrosivity assessment to determine the cause of a corroded and leaking steel gas main;
- Conducting a soil temperature survey in London to measure the temperature profile in the proximity of steam lines. The results were used to validate a model to assess the risk of steel gas mains in the vicinity of steam line systems;
- Performing aerial crossing inspections at 168 aerial crossing sites in Ontario to develop appropriate risk-informed mitigation plans for each location;
- Conducting Non-Destructive Examination (NDE) tests on a gas service to support the root cause analysis of a leak investigation; and
- Conducting inspections on exceptional services to determine and verify their status. Exceptional services are service pipe that have been disconnected from the gas meter, but are still energized with natural gas (i.e., inactive services). This work followed the release of the NTSB findings on the 2024 Youngstown, OH incident[5] that resulted in a fatality and multiple injuries.

[4] National Transportation Safety Board, "UGI Corporation Natural Gas-Fueled Explosion and Fire," Washington, 2025.
[5] National Transportation Safety Board, "Enbridge Inc. Natural Gas-Fueled Building Explosion," Washington, 2025.

b) Special Leak Surveys: There were five targeted special leak surveys completed in 2025 for the purposes of managing and controlling risk.
   - Suspect saddle fusions: Annual leak survey to monitor suspect saddle fusions as a method of risk control. There are approximately 430 active saddle fusions that are considered suspect because they were installed by a particular gas fitter that had one joint fail prematurely, indicating a potential prevalent procedural flaw during installation.
   - Aldyl-A pipe systems: Twice annual leak survey in each of Erin and Campbellford, as both communities have experienced historical crack failures on their Aldyl-A pipe systems.

c) DriscoPipe M7000/8000 Plastic Pipe Assessment: This work involved the performance testing of DriscoPipe M7000/8000 segments removed from the Ontario distribution system to better understand material behaviour and long-term performance, as Enbridge Gas continues to operate a population of this pipe material within the system. The pipe has a defect where the glycerol used in the manufacturing process can cause the outer layers of the pipe to laminate and peel when subjected to heat, thereby reducing the safe operating pressure of the pipeline system. The results of the performance testing will be used to develop a mechanical model to assess the remaining service life of existing assets and support quantitative risk assessments for this material.

d) Heavier Hydrocarbon Contamination on PE Pipe: Hydrocarbon contamination is a condition seen primarily in Southwestern Ontario where pock-marks are formed at joints on PE pipe during the fusion joining process. When this occurs, it is a code requirement that mechanical fittings are used in place of conventional or electrofusion fittings. This work aims to understand the impact of the formation of pock-marks on the integrity of fused fittings to determine if adjustments to the procedure when hydrocarbon contamination is identified can be made, which could influence future code revisions. The investigation includes field sampling combined

with a series of mechanical testing and optical microscopy.

e) Plastic Pipe Records Review: This work involved reviewing over 120,000 as-laid drawings and field notes associated with approximately 54,000 gas main assets installed prior to 1987 to capture plastic material types that were not previously recorded in the work and asset management system (WAMS). This work was necessary to verify the inventory of Aldyl-A polyethylene (PE) pipe in Ontario following the recent increase in industry incidents related to Aldyl-A PE pipeline systems. Having greater certainty on inventory will inform the broader strategy for managing the risks associated with Aldyl-A PE pipelines, which are known to be susceptible to brittle-like cracking.

3.2 Pipe Inspections

a) Isolated Steel Service & Risers: This inspection plan focused on steel service lines and risers that have the potential to be electrically isolated from a cathodically protected steel pipeline system. In the absence of cathodic protection, a higher likelihood of leaks from corrosion exists for steel pipe. The inspection verified if the service lines were electrically isolated and also validated the riser type, improving certainty on riser type inventories. The information obtained from the inspections will support mitigation plans for identified electrically isolated steel services and risers. A total of 7,150 isolated steel services and risers were inspected in 2025.

3.3 Station Inspections

a) Distribution Stations: This inspection plan focused on identifying potential hazards at distribution stations beyond those identified during routine operational and maintenance inspections. The condition of each station was assessed with a focus on the cathodic protection of below ground piping at the station. Other hazards were identified including: frost heave, flooding, vegetation interference, lack of barriers, and unauthorized third-party interference. This inspection information is used to provide a comprehensive assessment for inspected stations that support risk-

informed plans and prioritization. A total of 1,988 distribution stations were inspected in 2025.

3.4 Regulator Set Inspections

a) *Service Extensions*: This inspection plan was performed to validate the inventory of service extensions, perform a visual assessment of the above ground piping condition and perform a pipe-to-soil measurement to determine if the below ground piping was adequately cathodically protected. A total of 1,088 service extension inspections were completed in 2025.

b) Local and Remote First Cut Reg Sets: This inspection plan was performed to validate the inventory of this type of regulator set, identify potential hazards, perform a visual assessment of the above ground components for atmospheric corrosion, and perform a pipe-to-soil measurement to determine if the below ground piping was adequately cathodically protected. A total of 5,076 local and remote first cut regulator set inspections were completed in 2025.

c) >400 Series Regulator Sets: This inspection plan was performed to validate the inventory of this type of regulator set, identify potential hazards, perform a visual assessment of the above ground components for atmospheric corrosion, and perform a pipe-to-soil measurement to determine if the below ground piping was adequately cathodically protected. A total of 6,000 >400 series regulator set inspections were completed in 2025.

d) 200 & 400 Series Regulator Sets: This inspection plan was performed to validate the inventory of this type of regulator set, identify potential hazards, perform a visual assessment of the above ground components for atmospheric corrosion, and perform a pipe-to-soil measurement to determine if the below ground piping was adequately cathodically protected. A total of 5,718 inspections were completed in 2025 on 200 & 400 series regulator sets.

e) Bulk Meters: This survey was completed to identify potential bulk meter sites and to collect condition and compliance information. Historically, bulk meters may have been installed to facilitate preferred customer rates for multi-unit customers, however the transfer of asset ownership was not well documented, creating potential uncertainty on responsibility for maintenance activities, such as leak surveys and cathodic protection surveys. The results will be used to clarify asset ownership between Enbridge Gas and associated customers, as well as developing a risk mitigation plan for assets that require remediation. A total of 18 bulk meter inspections were completed in 2025.

3.5 DIMP Carryovers

DIMP carryover costs are residual costs for DIMP projects commenced in 2024 but not charged until 2025.

4. 2025 EDIMP Projects

EDIMP Projects consists of five distinct work categories: In-line inspection (ILI); Corrosion Survey; Digs (Validation); Assessments & Consulting; and EDIMP Carryovers. The actual spend for these work categories in 2025 was $8.849 million.

4.1 ILI & Digs (Validation)

Five pipelines within the EDIMP portfolio were selected for in-line inspection in 2025:

- NPS 20 Winston Churchill (Mississauga)
- NPS 20 Queensway (Mississauga)
- NPS 10 Sarnia North (Southwestern Ontario)
- NPS 10 Dawn West (Southwestern Ontario)
- NPS 12 Fisher Ave. (Ottawa)

In-line inspections were conducted using crawler tool technology. The total inspected length for each pipeline was determined by a combination of several factors including, but not limited to, pipeline length, pipeline sections, environmental conditions, number of corrosion areas, previous corrosion survey results, accessibility, and the selected ILI

tool. A summary of the 2025 EDIMP ILI results are shown in Table 2.

Table 2
2025 EDIMP ILI Results

Pipeline Name	NPS	Major Vintage	Length (km)	ILI Runs	Length Inspected (km)	% Inspected	Phase 1 Anomalies Identified(1)
Winston Churchill	20	1958	10.7	6	3.33	~31%	0
Queensway	20	1955	17.5	7	4.07	~23%	5
Sarnia North	10	1936	19.2	10	5.27	~27%	57
Dawn West	10	1941	10.6	6	2.81	~27%	0
Fisher Ave.	12	1958	6.1	5	2.51	~41%	1

Notes:
(1) Phase 1 anomalies are: Metal Loss (ML) ≥ 70% wall thickness (wt), ML failure pressure ratio < 1.15, dent >2% with stress concentrator, dent with ML >40% wt.

16 out of the 63 Phase 1 anomalies that were identified through in-line inspections across the five inspected pipelines were mitigated in 2025. The remediation of these Phase 1 anomalies was completed through integrity digs and subsequent repairs. The remaining 47 Phase 1 anomalies will be remediated in 2026 as part of a partial pipeline replacement project on the Sarnia North pipeline. A summary of the mitigation activities for each pipeline is described below.

- NPS 20 Winston Churchill: No Phase 1 anomalies were identified, and no integrity digs were issued for this pipeline. Tool validation was completed in conjunction with the NPS 20 Queensway integrity dig non-destructive examination (NDE) results.
- NPS 20 Queensway: A total of five integrity digs were executed in 2025 to remediate five Phase 1 anomalies. Only two of the integrity digs were charged to the EDIMP Program for the purposes of tool validation. Once tool performance was confirmed, the remaining three integrity digs were capitalized.

- NPS 10 Sarnia North: Overall, a total of six integrity digs were executed to remediate ten Phase 1 anomalies, with all integrity digs executed in 2025. The integrity digs were all capitalized, as tool validation had been previously completed for this pipe size.

  Due to the quantity and close proximity of the other 47 Phase 1 anomalies, an approximately 1.7 km NPS 10 steel gas main replacement project was initiated in 2025, with an expected completion date in 2026. The exact replacement length will be determined once suitable tie-in points are confirmed. The initial estimated capital cost of the replacement project is $5.6 million, pending confirmation of tie-in locations. The partial replacement project will be executed within the capital budget of the 2026 Asset Management Plan, and will not contribute any O&M spend to the 2025 DIMP Variance Account.

- NPS 10 Dawn West: No Phase 1 anomalies were identified, and no integrity digs were issued for this pipeline. Tool validation was previously completed for this pipe size.

- NPS 12 Fisher Ave.: One integrity dig was executed in 2025 to remediate the identified Phase 1 anomaly. The integrity dig was capitalized, as tool validation had been previously completed for this pipe size.

The number of ILI runs executed for each pipeline ensures that sufficient data was collected to support an evaluation of risk against established risk targets, considering for remaining uncertainty in the uninspected segments. The number of integrity digs executed captures additional NDE data to validate ILI crawler tool performance and support quantitative risk assessments (QRA) for each pipeline as required.

A QRA is being completed for each pipeline and evaluated against risk criteria to support a determination on whether each pipeline is fit-for-service (FFS) in the long-term. If it is determined that the existing pipelines are not FFS, temporary mitigation efforts are considered to bring the risk as low as reasonably practicable (ALARP) in the

short-term while alternatives to bring the pipeline(s) back into tolerable risk thresholds are evaluated. Long-term permanent mitigation strategies to bring a pipeline back into acceptable risk thresholds may include, among other options:

1. Risk mitigation activities such as increased operational patrols, pipe protection (e.g., concrete slabbing), pressure restrictions, increased signage, public outreach, etc.
2. Implementing an “inspect and repair” program for the entire pipeline
3. Completing a partial replacement of the pipeline based on unique strata with intolerable risk levels and practical considerations
4. Completing a full replacement of the entire pipeline
5. Combination of any of the above or additional situational alternatives

The feasibility of any potential alternative will be determined by confirming that the post-mitigation risk is within acceptable levels and the practical considerations of implementing the solution. Any potential feasible alternative will then be evaluated and compared on factors, such as:

- Public safety and residual risk
- Public disruption and nuisance
- Uncertainty in long-term outcomes
- Net Present Value (NPV) analysis
- Other considerations (potential for alternative fuels, longevity of asset, future unplanned work and associated hazards/risks, property damage, reputational risk, etc.)

The QRA and evaluation of any potential required alternatives is expected to be completed, on a prioritized basis, for each 2025 EDIMP inspected pipeline by the end of 2026. The work required to implement long-term mitigations is planned to begin in 2027. Once the evaluation of potential required alternatives is completed, Enbridge Gas will be able to better quantify the cost/benefit analysis of the 2025 EDIMP work and what

facilities work was deferred or avoided.

An update on the QRAs and resultant long-term mitigation recommendations for the 2024 EDIMP inspected pipelines are described in Section 5 of this report.

4.2 Corrosion Survey

This work category is for above ground surveys such as Cathodic Protection (CP) system surveys and non-intrusive pipeline assessments (NIPA).

The CP surveys were performed on high priority EDIMP pipelines considered for potential in-line inspection in 2026. These surveys are utilized in the planning phase of each ILI project to identify areas of potential concern. These surveys can also be used to obtain deeper insight into the CP system health on each pipeline and will likely be used, when possible, to support future risk assessment work.

CP surveys also provide depth of cover (DOC) information along the pipeline. This data is used to plan the ILI execution and can also be used as an input to the risk assessment.

CP surveys were performed on the following pipelines in 2025:

- NPS 12 Effingham St. (Niagara Region)
- NPS 12 Third Concession Rd. (Niagara Region)
- NPS 10 Bentpath Line (Southwestern Ontario)
- NPS 20 Sydenham Rd. (Hamilton)

NIPA is a new method of pipeline assessment using Direct Current Voltage Gradient (DCVG), Close Interval Potential Survey (CIPS), DOC, and Long Stand-off Magnetometry (LSM) in combination with machine learning algorithms that utilize a large database of ILI results for similar pipelines. NIPA was used for the first time in EDIMP for the following pipelines:

- NPS 20 Winston Churchill
- NPS 10 Dawn West

4.3 Assessments & Consulting

The Investigations and Assessments work category was focused on high priority EDIMP pipelines. A consultant was hired to perform a desktop study to produce an inventory of geotechnical and hydrotechnical areas of concern for the following pipelines.

- NPS 6 Dryden
- NPS 10 Bentpath Line
- NPS 12 Effingham St.
- NPS 12 Third Concession Rd.
- NPS 20 Sydenham Rd.
- NPS 4, 6, 8 & 10 Atikokan
- NPS 36 Mississauga Southern Link
- NPS 10 English River Lateral

The purpose of this work is to obtain knowledge and insight into the geohazards associated with each EDIMP priority pipeline and utilize the information in the Hazard Assessment completed for each individual pipeline. The Hazard Assessment is a crucial component of each individual Integrity Plan which assesses the condition of a pipeline to determine if it is fit-for-service in both the short- and long-term.

In addition to the pipelines mentioned above, the consultant also refined the results for five previously identified sites to support further risk assessment and decision-making processes.

This work category also included investigation into the QRA model and like-in-kind approach improvements utilized for EDIMP pipelines.

4.4 EDIMP Carryovers

EDIMP carryover costs are residual costs for EDIMP projects commenced in 2024 but not concluded until 2025.

5. Update on 2024 EDIMP Inspected Pipelines

When the 2024 DIMP and EDIMP Report on Activities was published, the QRAs for each 2024 EDIMP inspected pipeline had not been completed. The purpose of this section is to provide an update on the QRA results, describe any long-term mitigation plans, and quantify the cost/benefit analysis completed for each pipeline where applicable.

Five pipelines within the EDIMP portfolio were selected for in-line inspection in 2024. A summary of the QRA results, long-term mitigation strategy, and cost/benefit analysis for each pipeline is shown below:

- NPS 12 Wilson Ave.: The QRA identified the predominant threat to be corrosion risk. After accounting for the repairs made to remediate the Phase 1 anomalies, 7.2 km (~63%) of the pipeline was identified as high-risk in its current condition.

  Two comprehensive, plausible, and feasible solutions were identified that would effectively mitigate the high-risks of the pipeline to acceptable levels.The alternatives evaluated included either:

  1. A full replacement of the existing pipe (11.4 km of NPS 12 steel high pressure (HP)); or
  2. The implementation of an inspect & repair campaign on a 15-year frequency for the entire pipeline. This option also included a potential replacement project of approximately 500m of NPS 12 steel HP east of Allen Rd, the full extent of which would be confirmed by an ILI in 2027.

  The benefits and limitations of each option, including an NPV analysis, were assessed to determine the optimal long-term mitigation strategy. The recommendation following the evaluation of potential long-term mitigation

strategies was to proceed with the inspect & repair option, as this was the lowest cost option that met Enbridge's risk thresholds.

The NPV of the inspect & repair option ($31.9 million) was significantly lower than the NPV of the replacement option ($109.0 million). The incremental O&M required for the inspect & repair option will be recorded in the Asset Life Extension (ALE) deferral account for later recovery.

As the inspect & repair mitigation strategy defers or eliminates a potential capital replacement project in the Asset Management Plan, the resulting cost savings from ALE activities will be recorded on the OEB scorecard. For the NPS 12 Wilson Ave. pipeline, these savings are calculated as the difference in NPV between the inspect & repair option and the replacement option. This difference is $77.1 million, and will be recorded in the 2026 ALE scorecard metric.

- NPS 12 Martin Grove: The QRA identified the predominant threat to be corrosion risk. After accounting for the repairs made to remediate the Phase 1 anomalies, 3.0 km (~39%) of the pipeline was identified as high-risk in its current condition.

  Two comprehensive, plausible, and feasible solutions were identified that would effectively mitigate the high-risks of the pipeline to acceptable levels. The alternatives evaluated included either:

  1. Replacing ~5.1 km[6] of the existing 7.77 km of NPS 12 steel HP pipeline; or
  2. Implementing an inspect & repair campaign on a 15-year frequency for ~5.9 km[7] (~76%) of the pipeline

  The benefits and limitations of each option, including an NPV analysis, were assessed to determine the optimal long-term mitigation strategy. The

[6] Replacement scope includes all pipe installed prior to 2002.
[7] Inspect & repair scope includes all pipe installed prior to 2022.

recommendation following the evaluation of potential long-term mitigation strategies was to proceed with the inspect & repair option, as this was the lowest cost option that met Enbridge's risk thresholds.

The NPV of the inspect & repair option ($9.9 million) was significantly lower than the NPV of the replacement option ($44.2 million). The incremental O&M required for the inspect & repair option will be recorded in the ALE deferral account for later recovery.

As the inspect & repair mitigation strategy defers or eliminates a potential capital replacement project in the Asset Management Plan, the resulting cost savings from ALE activities will be recorded on the OEB scorecard. For the NPS 12 Martin Grove pipeline, these savings are calculated as the difference in NPV between the inspect & repair option and the replacement option. This difference is $34.3 million and will be recorded in the 2026 ALE scorecard metric.

- NPS 10 Sarnia South: A QRA was conducted to evaluate the reliability and risk of the NPS 10 Sarnia South pipeline considering corrosion and third-party damage threats to its pipeline integrity. However, insufficient data was available to accurately assess the risk of compression couplings and aerial crossings along the pipeline. Therefore, it was recommended that additional analysis be performed on these features to assess their risks before any risk-informed mitigation strategies are fully developed and implemented. These additional studies are expected to be completed in 2026, at which point an updated QRA will be performed for the Sarnia South pipeline. Following the updated QRA, potential long-term mitigation strategies will be evaluated, and Enbridge Gas will then be able to better quantify the cost/benefit analysis for this pipeline.

- NPS 8 Port Stanley: A QRA was conducted to evaluate the reliability and risk of the NPS 8 Port Stanley pipeline considering corrosion and third-party damage threats to its pipeline integrity. However, insufficient data was available to

accurately assess the risk of compression couplings and aerial crossings along the pipeline. Therefore, it was recommended that additional analysis be performed on these features to assess their risks before any risk-informed mitigation strategies are fully developed and implemented. These additional studies are expected to be completed in 2026, at which point an updated QRA will be performed for the Port Stanley pipeline. Following the updated QRA, potential long-term mitigation strategies will be evaluated, and Enbridge Gas will then be able to better quantify the cost/benefit analysis for this pipeline.

- NPS 8 St. Thomas: A QRA was conducted to evaluate the reliability and risk of the NPS 8 St. Thomas pipeline considering corrosion and third-party damage threats to its pipeline integrity. The entire St. Thomas pipeline was assessed as meeting acceptable risk thresholds, and was therefore deemed as fit-for-service. No further mitigative action is required for this pipeline.

  As this assessment eliminated a potential capital replacement project from the Asset Management Plan, it qualifies as an ALE activity eligible for recording on the OEB scorecard. The associated ALE cost savings will be recorded as the avoided direct capital costs that would otherwise have been incurred to fully replace the St. Thomas pipeline (4.41 km of NPS 8). These replacement costs were estimated at $5.4 million and will be included in the 2026 ALE scorecard metric.

Supplemental Storage and Load Balancing Information Report

2025 Annual Report

ENBRIDGE
Life Takes Energy

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1. Introduction

1. This report supports the commitment(s) to report annually on inventory related to non-utility storage operations, on required deliverability each year and on decisions and actions taken by Enbridge Gas to meet in-franchise deliverability requirements above the base level of 4.0 PJ,[1] and on market-based storage (MBS) and load balancing costs.[2]

2. Non-Utility Storage Balances for 2025

2. In Union's 2013 Cost of Service Decision, the OEB directed Union to file a report similar to that ordered in the 2010 Earnings Sharing & Disposition of Deferral Accounts and Other Balances proceeding, to monitor the inventory related to non-utility storage operations. Appendix 1 shows the non-utility inventory balances for October and November of 2025.

3. During the 2025 injection season, the non-utility storage balance peaked on October 20, 2025, at 97.4% full, with a balance of 129.8 PJ compared to available space of 133.2 PJ. On October 31, 2025, the date to which the Company manages its storage balance, the non-utility balance was 93.8% of available space. The balance stayed below the total non-utility available space of 100% for the rest of 2025.

3.In-franchise Deliverability Requirements

4. In the 2024 Rebasing Phase 2 Settlement Agreement, Enbridge Gas agreed to report on required in-franchise deliverability each year, and on the decisions and actions taken by Enbridge Gas to meet in-franchise deliverability requirements that exceed in-franchise entitlements (maximum of 4 PJ)[3]. In 2025, in-franchise deliverability requirements did not exceed in-franchise deliverability entitlements and no action was required. Appendix 2 shows the actual in-franchise deliverability relative to entitlements.

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[1] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, p. 24.
[2] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, pp. 23-24.
[3] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, p. 24.

4. Load Balancing Reporting

5. As part of the Company's OEB-approved 2024 Rebasing Phase 2 Settlement Agreement, Enbridge Gas committed to report annually on its MBS[4] and load balancing costs. The 2024 Rebasing Phase 2 Settlement Agreement goes on to explain that starting with the Company's 2024 annual deferral and variance account disposition proceeding:

> …Parties can review and propose changes to the load balancing costs … even where such costs were previously disposed of through the PGVA, and Enbridge Gas will record any changes approved by the OEB accordingly.[5]

6. Load balancing is the practice of meeting seasonal changes in customer demand throughout the year. Enbridge Gas generally plans to meet load balancing requirements for sales service and bundled direct purchase (DP) customers through a combination of withdrawals from and injections into storage (cost-based and MBS) and purchases of gas supply.

7. The Union rate zones have sufficient cost-based storage to meet annual load balancing requirements on a stand-alone basis. In the Union South rate zone, bundled DP customers are responsible for managing their incremental load balancing requirements through their obligation to meet checkpoint balances at key winter and fall operational dates,[6] and semi-unbundled DP customers are responsible for managing the entirety of their load balancing requirements through their contracted allocation of storage services. The EGD rate zone does not have sufficient cost-based storage to meet annual load balancing requirements. Accordingly, Enbridge Gas uses a combination of storage deliverability (from cost-based and MBS), winter supply purchases, and third-party peaking services, to meet load balancing requirements for the EGD rate zone.

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[4] See Exhibit D, Tab 1, Schedule 1.
[5] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, pp. 26-27.
[6] Enbridge Gas manages incremental load balancing requirements beyond the checkpoint balancing obligations for bundled DP customers in the Union South rate zone.

8. In the 2024 Rebasing Phase 3 Application,[7] Enbridge Gas requested approval of a Rate Harmonization Plan to harmonize rate zones, including certain rate design methodologies for the determination and recovery of storage and load balancing costs. As part of the 2024 Rebasing Phase 3 Settlement Agreement,[8] parties agreed, and the OEB accepted, to harmonize rates and services and to establish one rate zone for distribution costs and three rate zones for gas supply, storage and transportation costs. Enbridge Gas expects to implement the harmonized rates and services sometime in 2027 and will file an implementation plan as part of the 2027 Rates application. Until that time, Enbridge Gas continues to apply the rate design methodologies and practices for the determination of storage and load balancing related deferral and variance account balances in accordance with the approved rate setting frameworks in place since the amalgamation of EGD and Union in 2019.

4.1 Load Balancing Supply Purchases

9. In addition to storage, Enbridge Gas also relies on the flexibility inherent in its procurement processes and policy related to Dawn supply purchases as well as third-party peaking services to meet load balancing requirements for the EGD rate zone.[9] While the primary function of the gas supply purchases Enbridge Gas makes is for consumption by sales service customers and for use in the Company's operations, the timing of the supply purchases also assists with load balancing needs due to seasonal changes in bundled in-franchise customer's demand.

10. On a planned basis, supply purchased upstream of the franchise area is transported and delivered ratably throughout the year to the Company.[10] To manage load balancing requirements, planned Dawn supply purchases vary by month, with the largest planned monthly purchases occurring during the winter season. In addition,

[7] The proposed harmonized methodology for the derivation of load balancing costs is provided at EB-2025-0064, Exhibit 4, Tab 2, Schedule 2, Attachment 3.
[8] EB-2025-0064, OEB Decision on Settlement Proposal and Rate Order (March 26, 2026).
[9] Enbridge Gas can adjust the timing of planned Dawn purchases and make unplanned short-term Dawn purchases to adjust for variation to forecast or market volatility.
[10] Except for planned unutilized capacity.

unplanned load balancing requirements are largely met through unplanned short-term Dawn supply purchases.

11. On a planned basis as needed, Enbridge Gas may also plan for the purchase of third-party peaking services to manage load balancing requirements during near-peak and peak day conditions.[11] Peaking services often have low fixed demand costs, however, they can be extremely expensive in the event supply is called upon since their commodity costs are often tied to the price at market locations that trade at a significant premium to Dawn. Enbridge Gas prefers to limit peaking services to a maximum limit of 2% of design day demand for each delivery area.[12]

12. On an actual basis, load balancing requirements may be higher/lower than planned due to customer demand being above/below normal. Enbridge Gas manages unplanned load balancing requirements for all bundled in-franchise customers in the EGD rate zone.

13. As provided in Table 1, 2025 planned Dawn supply purchases for the EGD rate zone were 38.9 PJ,[13] whereas actual Dawn supply purchases were 61.4 PJ.[14]

[11] Peaking services are a third-party service arrangement that typically provide Enbridge Gas with the ability to call on the delivery of supply to a delivery area up to the contracted quantity for a maximum of 10 days per year.
[12] EB-2026-0092, 2026 Annual Gas Supply Plan Update, Section 3.6.
[13] Planned Dawn supply purchases for 2025 are from the 2024/25 gas supply plan (January to October) and 2025/26 gas supply plan (November and December).
[14] Enbridge Gas did not call on supply under contracted peaking services in 2025.

Table 1
2025 Dawn Supply Purchases

Line No.	Particulars (TJ)	EGD Rate Zone Planned	EGD Rate Zone Actual
		(a)	(b)
1	January	21,700	21,700
2	February	2,637	16,968
3	March	-	-
4	April	-	-
5	May	4,030	-
6	June	678	-
7	July	-	2,061
8	August	-	-
9	September	3,900	-
10	October	4,030	2,113
11	November	-	-
12	December	1,963	18,569
13	Total	38,938	61,411

14. Actual Dawn supply purchases were more than planned in 2025 due to colder than normal weather experienced. Enbridge Gas mitigated the impacts of colder than normal weather by making incremental un-planned supply purchases at Dawn to ensure it was able to meet storage inventory target(s).

15. The total cost associated with the Dawn supply purchases of 61.4 PJ was $310.2 million. Actual third-party peaking service demand costs were $0.04 million.

4.2 Load Balancing Costs

16. Load balancing costs of the EGD rate zone are recovered from customers through load balancing charges in base rates and the load balancing component of the Purchased Gas Variance Account (PGVA).

Load Balancing Charges

17. Prior to the amalgamation of EGD and Union, EGD rates were set through a Custom Incentive Rate-setting (IR) application. On an annual basis through the Custom IR rate setting mechanism, EGD updated costs and forecast volumes used to set base rates as well as updated gas supply costs to reflect the most recent gas supply plan. Upon amalgamation of EGD and Union, the approved rate-setting mechanism for the 2019 to 2023 period for the EGD rate zone changed to a Price Cap IR. Accordingly, the gas supply plan underpinning base rates was no longer updated on an annual basis.

18. As part of Enbridge Gas's 2024 Rebasing Application, base rates were updated to reflect updated forecasts, planning assumptions and revenue requirement impacts starting in 2024. In accordance with the Phase 1 Settlement Agreement,[15] Enbridge Gas did not make a base rate adjustment for the 2024 gas supply plan and any variances in gas costs have been recovered in gas supply deferral and variance accounts. As part of Phase 3 of the 2024 Rebasing Application, parties agreed to harmonized rates that include an update to gas costs based on the 2024 gas supply plan.[16] Enbridge Gas expects to implement the harmonized rates sometime in 2027 and will file an implementation plan as part of the 2027 Rates application. Until that time, the gas supply plan in base rates for the EGD rate zone continues to reflect the gas supply plan and methodologies as approved in the 2019 Rates Application.[17]

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[15] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, pp.40-41. Parties agreed with Enbridge Gas's proposal for implementation of the 2024 Gas Supply Plan after the OEB's decision on relevant matters was issued, and for reflecting cost variances in gas supply deferral and variance accounts.
[16] EB-2025-0064, Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, January 21, 2026, p. 13-14.
[17] EB-2018-0305.

19. The classification of costs as Load Balancing in the cost study for the EGD rate zone includes third-party peaking services,[18] Dawn supplies, and upstream transportation costs to meet the load balancing needs of sales service and bundled DP customers. For purposes of this report, Enbridge Gas will focus on the commodity costs included in base rates (i.e., peaking services and Dawn supplies).

20. Forecast commodity purchase costs are updated in base rates each quarter with the Quarterly Rate Adjustment Mechanism (QRAM) application to reflect future market prices over a 21-day period as per the OEB-approved methodology with variances recorded in the PGVA. Forecast commodity purchase costs updated with the QRAM are used to derive gas supply charges each quarter based on the approved forecast volumes underpinning 2025 rates. Forecast commodity purchase costs include Dawn supply volumes of 2,649,848 10^3m^3 (102.1 PJ) and peaking supply volumes of 6,902 10^3m^3 (0.3 PJ) based on the gas supply plan in base rates.[19]

21. For 2025, forecast Dawn supply purchase costs were classified between system commodity costs, transportation, and load balancing costs (split between peaking and seasonal). The Empress reference price, inclusive of fuel, is applied to forecast Dawn and peaking supply purchase volumes to classify a proportion of these purchase costs as system commodity supply. Any forecast price premium for gas supply purchases at Dawn over the Empress reference price is attributed to the transportation and load balancing (peak and seasonal) classification in the same proportion as the amount included in rates (20% deemed transportation, 71% load balancing - seasonal, and 9% load balancing - peak).[20] Peaking services are classified 100% as load balancing - peak. The forecast load balancing costs are recovered from sales service and bundled DP customers through the load balancing charges. The allocation of load balancing costs to each customer class reflects cost

[18] EB-2017-0086, Exhibit G2, Tab 6, Schedule 2, p. 1.
[19] EB-2018-0305, Exhibit E, Tab 4, Schedule 3, pp. 1-2.
[20] Per the approved cost allocation methodology underpinning the 2025 QRAM applications.

causality and is based on load balancing needs of each customer class based on the gas supply plan in base rates.[21]

22. Table 2 provides the total load balancing costs updated each quarter with the QRAM including the forecast of Dawn and peaking supply purchase costs classified as load balancing.

[21] Per the approved cost allocation methodology underpinning the 2025 QRAM applications.

Table 2
2025 Load Balancing Costs in Rates – EGD Rate Zone

Line No.	Particulars ($000s)	2025 (1) Jan QRAM	April QRAM	July QRAM	Oct QRAM
		(a)	(b)	(c)	(d)
1	Forecast Dawn supply purchases (10^3m^3)	2,649,848	2,649,848	2,649,848	2,649,848
2	Forecast peaking supply purchases (10^3m^3)	6,902	6,902	6,902	6,902
3	Empress reference price ($/$10^3m^3$)	90.620	106.330	128.405	120.872
4	Dawn forecast price ($/$10^3m^3$)	151.659	206.912	196.895	179.401
	Dawn Supply Purchases Classification				
5	System commodity supply (line 1 x line 3)	240,130	281,758	340,254	320,292
6	Transportation (2)	32,355	53,316	36,304	31,025
7	Load balancing - seasonal (2)	115,013	189,521	129,051	110,283
8	Load balancing - peak (2)	14,377	23,690	16,131	13,785
9	Total (line 1 x line 4)	401,874	548,285	521,741	475,386
	Peaking Services Classification				
10	Load balancing - peak (3)	3,242	3,183	2,921	2,973
	Load Balancing Costs in Rates				
11	Total load balancing commodity costs (lines 7 + 8 + 10)	132,632	216,395	148,104	127,042
12	Other load balancing costs (4)	45,961	44,578	45,657	45,945
13	Total load balancing costs in rates (5)	178,592	260,972	193,761	172,987

Notes:

(1) January 2025 QRAM (EB-2024-0326), April 2025 QRAM (EB-2025-0078), July 2025 QRAM (EB-2025-0165), and October 2025 QRAM (EB-2025-0244).
(2) Classification calculated as line 9 minus line 5 multiplied by 20% for transportation, 71% for load balancing - seasonal, and 9% for load balancing - peak.
(3) The forecast cost of peaking services includes commodity costs plus demand costs.
(4) Other load balancing costs includes costs indirectly related to the commodity supply purchases such as transportation demand costs and gas in storage carrying costs.
(5) Total load balancing costs taken from QRAM evidence at Exhibit C, Tab 4, Schedule 4, p. 2. See Note 1 for the docket numbers of each QRAM application.

23. The determination of the changes in gas costs, including load balancing costs, through the QRAM process is mechanistic where Enbridge Gas updates the gas cost prices for the current QRAM and compares the total costs with the previous QRAM with the base rates adjusted for the difference. Enbridge Gas records the variance between actual and forecast gas supply purchase costs, including Dawn supply purchases, for past periods in the PGVA.

PGVA

24. There is no approved methodology for the EGD rate zone to determine a classification split of actual Dawn and peaking supply purchases. Supply purchases variances are recorded as commodity and load balancing variances within the PGVA components.

25. The volume variance between the actual gas supply purchases and the forecast gas supply purchases to serve EGD sales service customers is recognized as a commodity variance in the PGVA. Commodity variance costs are allocated to sales service customers only per the approved QRAM methodology.

26. The variance between the forecast and actual price differential of Empress supply and Dawn supply is applied to actual Dawn supply purchases each month plus the variance between forecast and actual peak costs and load balancing fees is recognized as the load balancing variance in the PGVA. Actual load balancing variance costs for 2025 was a debit to ratepayers of $40.1 million as provided at Appendix 3.[22] Load balancing variance costs are allocated to each customer class in the same manner as the allocation of load balancing costs in rates.

[22] The calculation of monthly variances can be found in QRAM evidence in Exhibit C, Tab 1, Schedule 2, pp. 3-4.

Appendix 1

Enbridge Gas Inc.

Summary of Non-Utility Storage Balances

Date	Entitlement (PJ)	Balance (PJ)	% Full (%)	Date	Entitlement (PJ)	Balance (PJ)	% Full (%)
1-Oct-25	133.2	119.8	90.0%	1-Nov-25	133.2	125.6	94.3%
2-Oct-25	133.2	120.9	90.7%	2-Nov-25	133.2	126.3	94.8%
3-Oct-25	133.2	122.0	91.6%	3-Nov-25	133.2	126.7	95.1%
4-Oct-25	133.2	123.3	92.5%	4-Nov-25	133.2	127.4	95.6%
5-Oct-25	133.2	124.4	93.4%	5-Nov-25	133.2	127.9	96.0%
6-Oct-25	133.2	124.9	93.7%	6-Nov-25	133.2	127.9	96.0%
7-Oct-25	133.2	125.3	94.0%	7-Nov-25	133.2	128.3	96.3%
8-Oct-25	133.2	125.7	94.3%	8-Nov-25	133.2	128.6	96.5%
9-Oct-25	133.2	126.0	94.6%	9-Nov-25	133.2	128.7	96.6%
10-Oct-25	133.2	126.6	95.0%	10-Nov-25	133.2	127.9	96.0%
11-Oct-25	133.2	127.4	95.6%	11-Nov-25	133.2	127.5	95.7%
12-Oct-25	133.2	128.0	96.1%	12-Nov-25	133.2	127.0	95.3%
13-Oct-25	133.2	128.0	96.1%	13-Nov-25	133.2	126.8	95.2%
14-Oct-25	133.2	127.8	96.0%	14-Nov-25	133.2	127.3	95.5%
15-Oct-25	133.2	127.7	95.9%	15-Nov-25	133.2	128.4	96.4%
16-Oct-25	133.2	127.8	95.9%	16-Nov-25	133.2	128.7	96.6%
17-Oct-25	133.2	128.1	96.1%	17-Nov-25	133.2	128.7	96.6%
18-Oct-25	133.2	128.8	96.7%	18-Nov-25	133.2	127.9	96.0%
19-Oct-25	133.2	129.4	97.1%	19-Nov-25	133.2	127.2	95.4%
20-Oct-25	133.2	129.8	97.4%	20-Nov-25	133.2	126.8	95.1%
21-Oct-25	133.2	129.6	97.3%	21-Nov-25	133.2	127.1	95.4%
22-Oct-25	133.2	129.1	96.9%	22-Nov-25	133.2	127.9	96.0%
23-Oct-25	133.2	128.4	96.4%	23-Nov-25	133.2	128.6	96.5%
24-Oct-25	133.2	127.6	95.8%	24-Nov-25	133.2	129.1	96.9%
25-Oct-25	133.2	127.4	95.6%	25-Nov-25	133.2	129.9	97.5%
26-Oct-25	133.2	127.1	95.4%	26-Nov-25	133.2	130.6	98.0%
27-Oct-25	133.2	126.9	95.2%	27-Nov-25	133.2	130.8	98.2%
28-Oct-25	133.2	126.4	94.9%	28-Nov-25	133.2	130.7	98.1%
29-Oct-25	133.2	125.8	94.4%	29-Nov-25	133.2	130.6	98.1%
30-Oct-25	133.2	125.1	93.9%	30-Nov-25	133.2	130.4	97.9%
31-Oct-25	133.2	124.9	93.8%				

Appendix 2
Actual In-franchise Deliverability Relative to Entitlements

Line No.	Date	Actual In-Franchise Deliverability (TJ) (a)	Entitlement (b)	Remaining Deliverability (c)=b-a
1	1-Nov-25	249	4,000	3,751
2	2-Nov-25	132	4,000	3,868
3	3-Nov-25	399	4,000	3,601
4	4-Nov-25	163	4,000	3,837
5	5-Nov-25	637	4,000	3,363
6	6-Nov-25	502	4,000	3,498
7	7-Nov-25	539	4,000	3,461
8	8-Nov-25	648	4,000	3,352
9	9-Nov-25	1,656	4,000	2,344
10	10-Nov-25	1,423	4,000	2,577
11	11-Nov-25	1,284	4,000	2,716
12	12-Nov-25	518	4,000	3,482
13	13-Nov-25	995	4,000	3,005
14	14-Nov-25	868	4,000	3,132
15	15-Nov-25	904	4,000	3,096
16	16-Nov-25	1,173	4,000	2,827
17	17-Nov-25	1,502	4,000	2,498
18	18-Nov-25	1,481	4,000	2,519
19	19-Nov-25	1,375	4,000	2,625
20	20-Nov-25	817	4,000	3,183
21	21-Nov-25	712	4,000	3,288
22	22-Nov-25	908	4,000	3,092
23	23-Nov-25	769	4,000	3,231
24	24-Nov-25	728	4,000	3,272
25	25-Nov-25	764	4,000	3,236
26	26-Nov-25	971	4,000	3,029
27	27-Nov-25	1,551	4,000	2,449
28	28-Nov-25	1,787	4,000	2,213
29	29-Nov-25	1,386	4,000	2,614
30	30-Nov-25	1,978	4,000	2,022
31	1-Dec-25	1,753	4,000	2,247
32	2-Dec-25	1,508	4,000	2,492
33	3-Dec-25	1,659	4,000	2,341
34	4-Dec-25	1,936	4,000	2,064
35	5-Dec-25	1,327	4,000	2,673
36	6-Dec-25	1,020	4,000	2,980
37	7-Dec-25	1,595	4,000	2,405
38	8-Dec-25	1,927	4,000	2,073
39	9-Dec-25	1,499	4,000	2,501
40	10-Dec-25	1,291	4,000	2,709
41	11-Dec-25	1,643	4,000	2,357
42	12-Dec-25	894	4,000	3,106
43	13-Dec-25	1,472	4,000	2,528
44	14-Dec-25	1,997	4,000	2,003
45	15-Dec-25	1,606	4,000	2,394
46	16-Dec-25	747	4,000	3,253
47	17-Dec-25	270	4,000	3,730
48	18-Dec-25	-	4,000	4,000
49	19-Dec-25	697	4,000	3,303
50	20-Dec-25	277	4,000	3,723
51	21-Dec-25	710	4,000	3,290
52	22-Dec-25	218	4,000	3,782
53	23-Dec-25	-	4,000	4,000
54	24-Dec-25	-	4,000	4,000
55	25-Dec-25	410	4,000	3,590
56	26-Dec-25	1,034	4,000	2,966
57	27-Dec-25	885	4,000	3,115
58	28-Dec-25	174	4,000	3,826
59	29-Dec-25	1,091	4,000	2,909
60	30-Dec-25	1,088	4,000	2,912
61	31-Dec-25	1,224	4,000	2,776

Appendix 3
Derivation of Load Balancing Costs Variance for 2025 - EGD Rate Zone

Line No.	Particulars	2025 Actual Ontario Delivered Supplies (10^3m^3)	Forecasted Average Prices Empress (1) ($/$10^3m^3$)	Actual Average Prices Empress (2) ($/$10^3m^3$)	Average Price Variance Empress ($/$10^3m^3$)	Commodity Cost Variance (3) ($000s)	Forecasted Average Prices Ontario Delivered (4) ($/$10^3m^3$)	Actual Average Prices Ontario Delivered (5) ($/$10^3m^3$)	Average Price Variance Ontario Delivered ($/$10^3m^3$)	Forecasted vs Actual Price Variance Ontario Delivered (6) ($000s)	Load Balancing Price Variance ($000s)	Other Load Balancing Costs (7) ($000s)	Total Load Balancing Price Variance (8) ($000s)	Forecasted Peaking Costs (9) ($000s)	Actual Peaking Costs (9) ($000s)	Peaking Costs Variance (10) ($000s)	Total Load Balancing & Peaking Costs Variance (11) ($000s)
		(a)	(b)	(c)	(d) = (c)-(d)	(e) = (d)*(a)	(f)	(g)	(h) = (f)-(g)	(i) = (h)*(a)	(j) = (i)-(e)	(k)	(l) = (j)+(k)	(m)	(n)	(o) = (n)-(m)	(p) = (l)+(o)
1	Jan	555,275.2	89.043	104.842	15.799	$8,773.0	148.486	175.427	26.941	$14,959.9	$6,186.9	$46.9	$6,233.9	$296.5	$9.7	($286.9)	$5,947.0
2	Feb	434,173.7	95.617	104.941	9.325	$4,048.5	145.180	202.507	57.327	$24,890.1	$20,841.6	$9.4	$20,850.9	$296.1	$9.8	($286.3)	$20,564.6
3	Mar	4.5	82.062	96.603	14.541	$0.1	138.488	0.000	(138.488)	$0.0	($0.1)	$48.8	$48.7	$295.9	$9.7	($286.2)	($237.5)
4	Apr	4.7	85.465	107.698	22.233	$0.1	0.000	0.000	0.000	$0.0	($0.1)	$277.3	$277.2	$0.0	$9.7	$9.7	$286.9
5	May	2.0	79.753	99.940	20.188	$0.0	182.785	0.000	(182.785)	$0.0	($0.0)	($213.0)	($213.0)	$0.0	$0.0	$0.0	($213.0)
6	Jun	0.8	82.445	77.596	(4.850)	($0.0)	183.619	0.000	(183.619)	$0.0	$0.0	$58.4	$58.4	$0.0	$0.0	$0.0	$58.4
7	Jul	52,725.9	87.120	65.503	(21.617)	($1,139.8)	163.940	137.748	(26.191)	($1,381.0)	($241.2)	$111.1	($130.1)	$0.0	$0.0	$0.0	($130.1)
8	Aug	0.2	88.569	47.179	(41.391)	($0.0)	167.132	0.000	(167.132)	$0.0	($0.0)	($43.8)	($43.8)	$0.0	$0.0	$0.0	($43.8)
9	Sep	0.3	91.792	50.697	(41.095)	($0.0)	161.410	0.000	(161.410)	$0.0	$0.0	$25.0	$25.0	$0.0	$0.0	$0.0	$25.0
10	Oct	54,078.3	65.879	63.044	(2.835)	($153.3)	134.634	156.766	22.132	$1,196.9	$1,350.2	$74.8	$1,425.0	$0.0	$0.0	$0.0	$1,425.0
11	Nov	2.3	119.567	124.366	4.800	$0.0	160.848	0.000	(160.848)	$0.0	($0.0)	$19.2	$19.2	$0.0	$0.0	$0.0	$19.2
12	Dec	475,154.5	137.138	155.197	18.059	$8,580.6	187.035	231.285	44.250	$21,025.8	$12,445.2	$288.7	$12,733.9	$292.1	$0.0	($292.1)	$12,441.8
		1,571,422.4				$20,109.2				$60,691.7	$40,582.5	$702.8	$41,285.3	$1,180.6	$38.9	($1,141.8)	$40,143.5

Note
(1) Forecasted average prices at Empress = Forecasted Empress supplies costs / Forecasted Empress supplies volumes. EGD uses the Empress reference price to set the commodity rates
(2) Actual average prices at Empress = Actual Empress supplies costs / Actual Empress supplies volumes
(3) Commodity cost variance related to the actual Dawn purchases
(4) Forecasted average prices at Ontario Delivered = Forecasted Ontario Delivered supplies costs / Forecasted Ontario Delivered supplies volumes
(5) Actual average prices at Ontario Delivered = Actual Ontario Delivered supplies costs / Actual Ontario Delivered supplies volumes
(6) Purchase price variances for Dawn supplies recorded in the PGVA
(7) Other load balancing costs include un-forecasted LBA fees paid to the gas suppliers (e.g. TC Energy)
(8) Load Balancing Price Variance are the load balancing components that are disposed of the PGVA. Refer to the EGD QRAM schedule, Exhibit C, Tab 1, Schedule 2, page 2.
(9) Peaking demand costs
(10) Peaking costs variance are the load balancing components that are disposed of the PGVA. Refer to the EGD QRAM schedule, Exhibit C, Tab 1, Schedule 2, page 2.
(11) Total load balancing costs variance are recovered or refunded from both system and direct purchase customers through the load balancing rate riders included in the QRAM

ENBRIDGE SUSTAIN BRAND CLARITY STUDY

1. Study Purpose and Context

1. As part of the 2024 Rebasing Phase 2 settlement proposal Enbridge Gas agreed to take reasonable steps in the next two years to study whether customers are confused between the utility and the competitive Enbridge Sustain affiliate, and what steps, if any, are appropriate to minimize or eliminate that confusion[1]. In relation to this commitment, the Parties do not agree about what jurisdiction, if any, the OEB has to address this matter but do agree that any such jurisdiction questions can be addressed, if necessary, after the report is filed [2].

2. This evidence discusses the "Brand Clarity" study (Study) undertaken by Enbridge Gas to fulfil the aforementioned commitment in the Phase 2 settlement proposal. The Study was undertaken to assess potential customer confusion between the utility and Enbridge Sustain. The Study can be found at Attachment 1 to this Exhibit.

3. Enbridge Gas contracted Ipsos LP, an independent third-party research firm, to conduct the Study. The Study was conducted using an online survey, with 2001 adult residents of Ontario from Ipsos' online panel. 47% of the sample self-identified as Enbridge Gas customers. The survey was fielded from October 14 to 16, 2025, with results weighted by age, gender, education, and region based on the latest census data to accurately reflect the adult population of Ontario.

2. Summary of Findings

4. The Study demonstrates that awareness of the Enbridge Sustain brand is very low among Ontario residents, including Enbridge Gas customers, and that the potential for brand confusion is correspondingly limited in scale.

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[1] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1 Schedule 1, November 29, 2024, p.37.
[2] Ibid

5. Study results indicate that awareness of the Enbridge Sustain brand is low among Enbridge Gas customers and non-customers, at 6% and 5%, respectively. The absence of any meaningful difference between the two groups indicates that Enbridge Gas customers are not more likely to be aware of the Enbridge Sustain brand by virtue of being utility customers or being familiar with Enbridge Gas. These results can be found at Exhibit G, Tab 5, Schedule 1, Attachment 1, page 6.

6. Awareness and familiarity are closely connected, suggesting that recognition goes beyond awareness of the name, and extends to a sense of familiarity. Of the 6% of Enbridge Gas customers who are aware of the Enbridge Sustain brand, just over two-thirds (69%) report being at least somewhat familiar with the Enbridge Sustain brand. Among 5% of non-customers that reported awareness, fewer are familiar, at 43%. In absolute terms, these results represent a very small proportion overall. These results can be found at Exhibit G, Tab 5, Schedule 1, Attachment 1, page 8.

7. Though some respondents report familiarity with the Enbridge Sustain brand, awareness of the products and services actually offered by Enbridge Sustain is limited, and the levels of “don’t know” responses are high. This suggests that stated familiarity likely overstates actual knowledge of the Enbridge Sustain brand and its offering. Among Enbridge Gas customers, awareness of Enbridge Sustain’s products and services ranges from 17% to 20%. These results can be found at Exhibit G, Tab 5, Schedule 1, Attachment 1, page 11.

<u>3. Conclusion</u>

8. The Study shows that some brand confusion is observed between Enbridge Gas and Enbridge Sustain; however, given the low awareness, limited functional understanding of the Enbridge Sustain brand, and very small number of customers that are both aware and familiar with the Enbridge Sustain brand, any brand confusion is very limited in scale.

BRAND CLARITY SURVEY

ENBRIDGE

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Ipsos#25-042789-01

Ipsos

Objectives & Methodology

Objectives

The primary goal of this research study was to assess potential brand confusion between Enbridge Gas, a regulated utility, and its affiliate, Enbridge Sustain, an unregulated energy-as-a-service business in Ontario. This survey explored the awareness of Enbridge Sustain among Ontario residents, including a group of individuals who self-identify as Enbridge Gas customers.

Methodology

Ipsos conducted an online survey with 2001 adult residents of Ontario utilizing the Ipsos pre-recruited iSay online panel. The survey was conducted between October 14th to 16th , 2025.

Results are weighted by age, gender, education, and region based on the latest census data to accurately reflect the adult population of Ontario.

Key Considerations

When interpreting this brand clarity survey, readers should be aware of several potential biases inherent to survey samples and brand association research, including:

- False-recognition bias: Respondents may claim familiarity with brands they have not actually encountered. This survey included two hypothetical brand names ("Enbridge Solutions" and "Enbridge Maintain") as controls. Awareness levels for these controls (17% and 6% vs. Enbridge Sustain's 6%) suggest that some reported awareness may reflect guessing or perceived familiarity with the "Enbridge" name rather than genuine recognition.
- Social desirability bias: Some participants may feel compelled to demonstrate knowledge rather than select "don't know" or "none of the above," which can influence how they respond to awareness questions.

Executive Summary

Brand Awareness

Awareness of Enbridge Sustain is very low at 6% among adult Ontarians and equally low among Enbridge Gas customers. By contrast, Enbridge Gas awareness is strong (71% overall; 89% among self-identified customers). Awareness of hypothetical brand names is on par with or higher than Enbridge Sustain, indicating a potential for false-recognition bias. **This indicates that current Enbridge Sustain awareness is almost non-existent.**

Familiarity with Enbridge Sustain

Among those who are aware of Enbridge Sustain, six in ten (61%) indicate that they are familiar with the brand. Familiarity increases slightly to seven in ten (69%) among Enbridge Gas customers, while less than half (43%) of non-customers who are aware of Sustain are also familiar with the brand. Given that only 6% of Ontarians and 5% of Enbridge Gas customers are aware of Enbridge Sustain, **the share of those who are both aware and familiar of the Enbridge Sustain brand is very small in absolute terms.**

Awareness of Products and Services

Results indicate low customer awareness of Enbridge Sustain offerings. Fewer than one in five customers correctly identify an Enbridge Sustain product or service, including home heating and cooling or water heater equipment and financing. **This suggests limited functional understanding of the Enbridge Sustain brand.**

KEY FINDINGS

Brand Awareness

- Only 6% of Ontario residents indicate that they are aware of the Enbridge Sustain brand. Awareness is equally low among Enbridge Gas customers (6%) and non-customers (5%).
- Two hypothetical brand names ('red herrings') were included in the survey to measure and compare awareness levels with brands that currently exist in the market. The findings show that awareness of these hypothetical brand names are on par or higher than the Enbridge Sustain brand, indicating that 'true' awareness is extremely low.
- Furthermore, those who are aware of the Enbridge Sustain brand also tend to be highly aware of the other hypothetical brand names, including Enbridge Solutions (77%) and Enbridge Maintain (61%), indicating the potential for false-recognition bias.

Brand Awareness by Enbridge Gas Customer Status

		Customers (n=1010)	Non-customers (n=843)
Hydro One	82%	85%	82%
Enbridge Gas	71%	▲ 89%	55%
Toronto Hydro	54%	57%	52%
Enercare	45%	▲ 55%	35%
Ontario Power Generation	45%	▲ 52%	41%
Hypothetical brand names Enbridge Solutions	17%	19%	16%
Enbridge Sustain	6%	6%	5%
Hypothetical brand names Enbridge Maintain	6%	6%	6%
None of the Above	6%	▼ 0%	9%

Base: All respondents (n= 2001)

Q1. Which of the following brands have you heard of? (Select all that apply)

*Note: The brand awareness question was asked prior to asking respondents if they are Enbridge Gas customers, to avoid biasing awareness responses.

Legend: ▲ upward green arrow = score is significantly higher than the comparative groups
▼ downward red arrow = score is significantly lower than the comparative groups

Comparing Awareness of Enbridge Gas and Enbridge Sustain by Demographics

- Both Enbridge Gas and Enbridge Sustain brands achieve the highest recognition in Central Ontario, yet other demographic patterns do emerge. Specifically, while Enbridge Sustain awareness persists at low levels across all subgroups, it is relatively higher among younger individuals aged 18-34 (9%), those with a higher education level (8%), and households with higher income levels (7%). In comparison, Enbridge Gas awareness is least among the younger demographic (48%), individuals with lower educational attainment (44%), and lower-income households (55%).

Awareness	Age			Gender		Region						Education				Household Income			
	18-34	35-54	55+	Male	Female	SW ON	East ON	Central ON	North ON	GTA 905	GTA 416	<HS	HS	Post Sec	Univ Grad	<$40K	$40K - <$60K	$60K - <$100K	$100K+
Aware of Enbridge Sustain (6%)	9%	6%	3%	▲ 7%	4%	5%	5%	▲ 10%	4%	5%	6%	-	5%	5%	▲ 8%	5%	▼ 3%	7%	7%
Aware of Enbridge Gas (71%)	▼ 48%	76%	83%	71%	71%	73%	68%	▲ 81%	60%	78%	66%	▼ 44%	69%	74%	75%	▼ 55%	72%	80%	80%

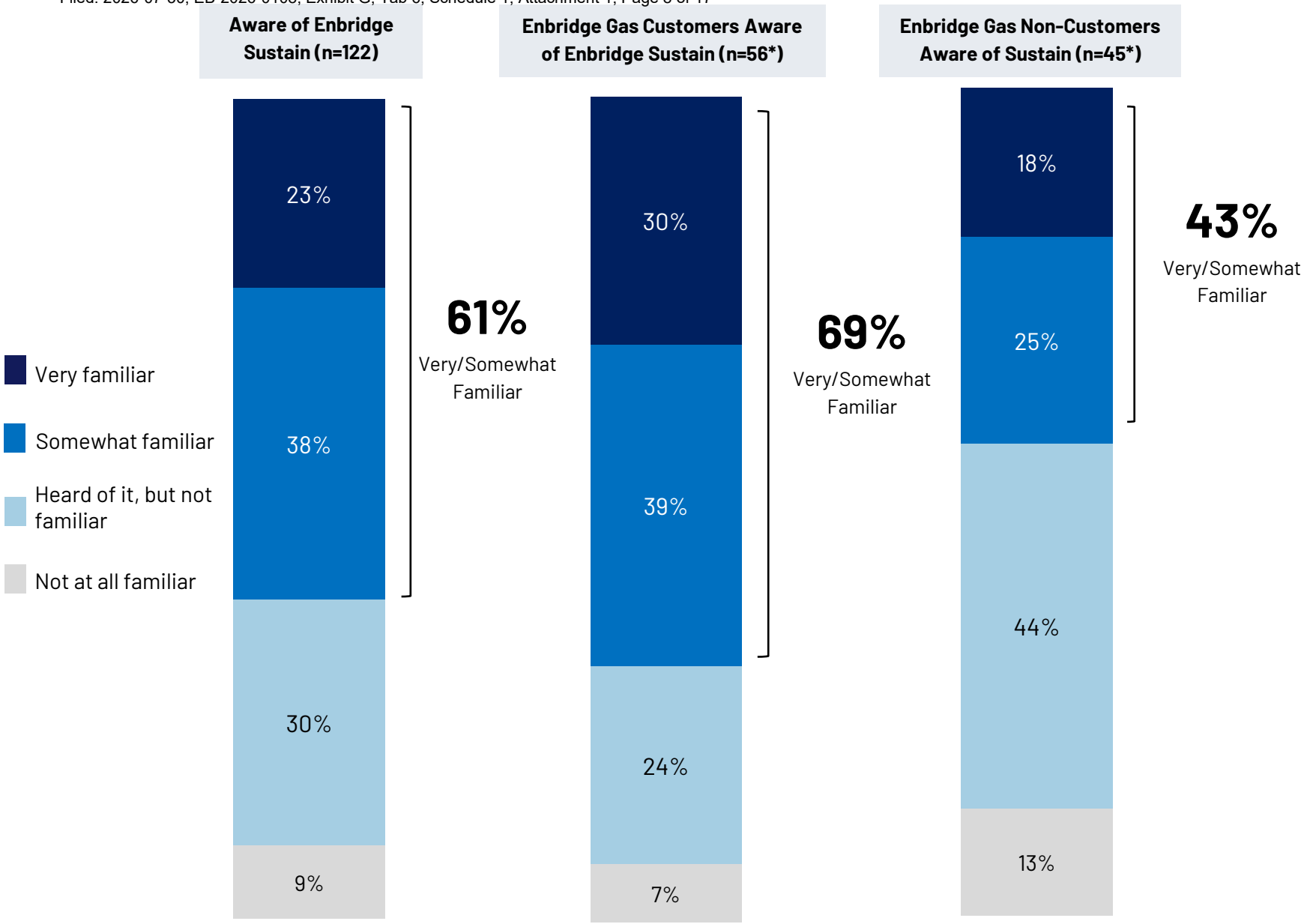
Base: All respondents (n=2001)
Q1. Which of the following brands have you heard of?
Number of respondents aware of each brand: Enbridge Sustain (122), Enbridge Gas (418).

Legend: ▲ upward green arrow = score is significantly higher than the comparative groups
▼ downward red arrow = score is significantly lower than the comparative groups

For region: higher or lower than 2 or more comparative groups

Familiarity with Enbridge Sustain

- While awareness of Enbridge Sustain is low at 6%, six in ten (61%) of those who are aware of Enbridge Sustain report being familiar with the brand, including 23% who are 'very familiar' and 38% who are 'somewhat familiar'.
- Among Enbridge Gas customers who are aware of Enbridge Sustain, seven in ten report familiarity, including 30% who are 'very familiar' and 39% who are 'somewhat familiar'. Note that the base size for this group is very small (n=56 respondents); thus, these findings should be treated with caution.
- Among those respondents who are not Enbridge Gas customers and who are aware of Enbridge Sustain, familiarity is slightly lower, although four in ten (43%) indicate that they are 'very familiar' or 'somewhat familiar' with Enbridge Sustain. Caution should be used when interpreting these results due to small base sizes.

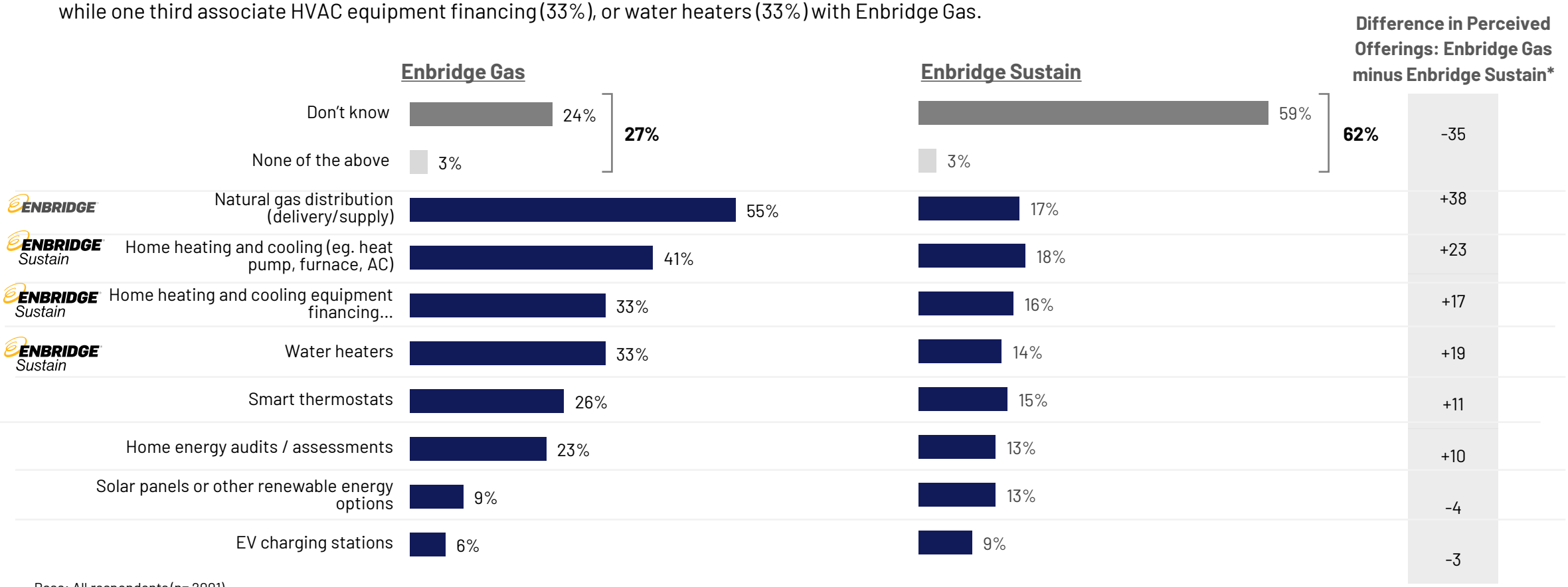


Base: n= 2001

Q2.How familiar are you with Enbridge Sustain? *Small base size, results should be interpreted with caution.

Awareness of Products and Services Offered by Enbridge Gas and Enbridge Sustain

- The majority (62%) of Ontarians do not know which programs and services are provided by Enbridge Sustain; among those who can identify a program or service, all options are mentioned equally. Some Ontarians attribute certain Enbridge Sustain offerings to Enbridge Gas - including 41% who associate home heating and cooling, while one third associate HVAC equipment financing (33%), or water heaters (33%) with Enbridge Gas.

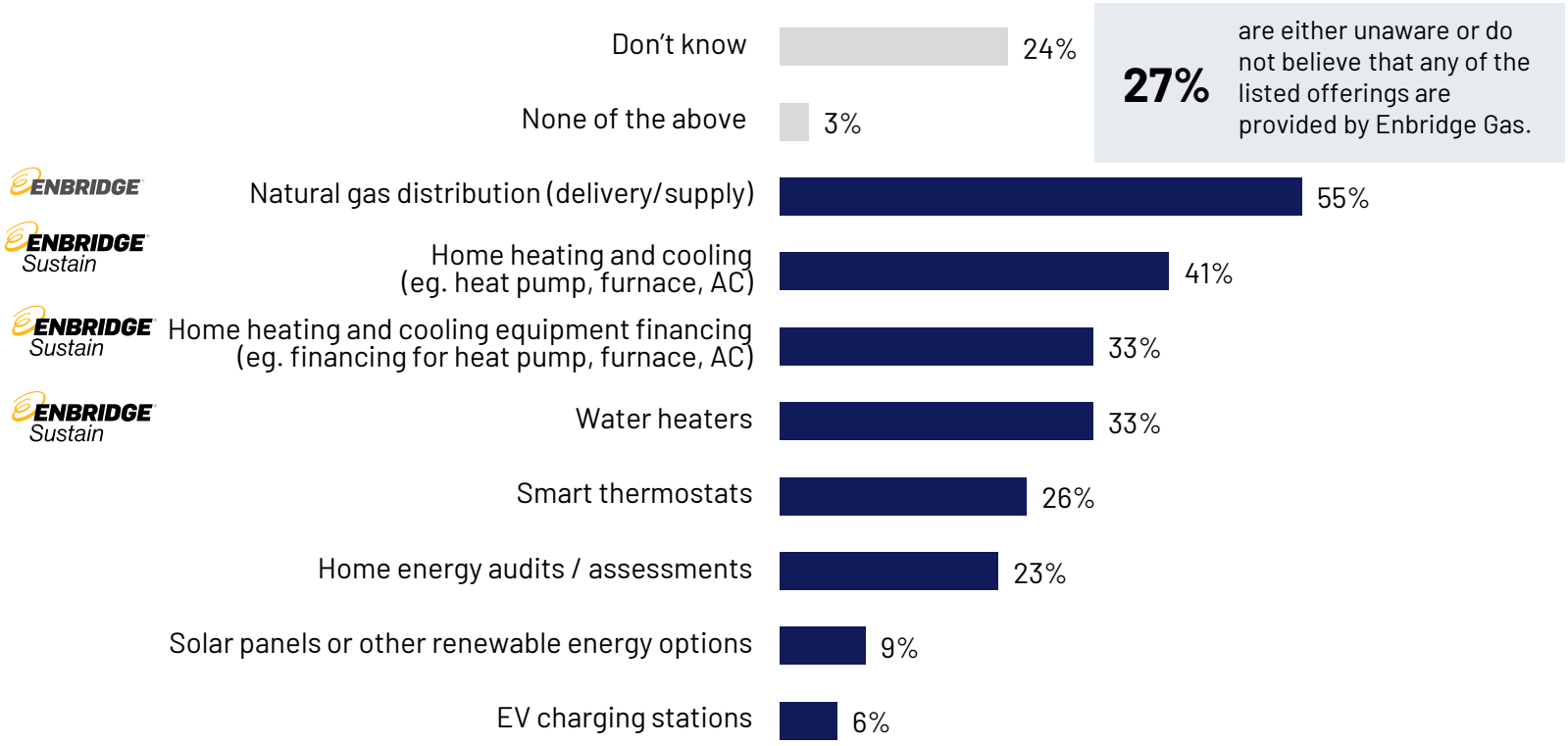


Base: All respondents (n= 2001)
Q3. Which, if any, of the following products and/or services does Enbridge Sustain offer? (Select all that apply) / Q4. Which, if any, of the following products and/or services does Enbridge Gas offer? (Select all that apply)
*Note: Positive values in column on right side of page indicates perceived association with Enbridge Gas exceeds that of Enbridge Sustain, negative values indicate perceived association of Enbridge Sustain exceeds that of Enbridge Gas.

Awareness of products and services offered by Enbridge Gas

- Just over half of Ontarians (55%) correctly identify Natural Gas distribution as an Enbridge Gas service, a proportion that increases to 70% among Enbridge Gas customers, suggesting these customers have a clearer understanding of its primary offering.
- However, there is considerable confusion, with many incorrectly associating Enbridge Sustain services, such as Home heating and cooling (41%) and their financing (33%), and Water heaters (33%), with Enbridge Gas, suggesting a potential default to the better-known brand of Enbridge Gas. Further, this misattribution is somewhat more prevalent among Enbridge Gas customers (51%, 41% and 43% respectively). Even among those who are aware or familiar with the Enbridge Sustain brand, there is still misattribution of Sustain programs and services to Enbridge Gas, suggesting potential ongoing confusion between the two brands.

Products and services ENBRIDGE



Enbridge Gas Customer	Awareness of Enbridge Sustain	Familiar with Enbridge Sustain
70%	76%	53%
51%	54%	41%
41%	50%	42%
43%	42%	36%
37%	35%	31%
29%	38%	30%
12%	28%	20%
8%	19%	15%

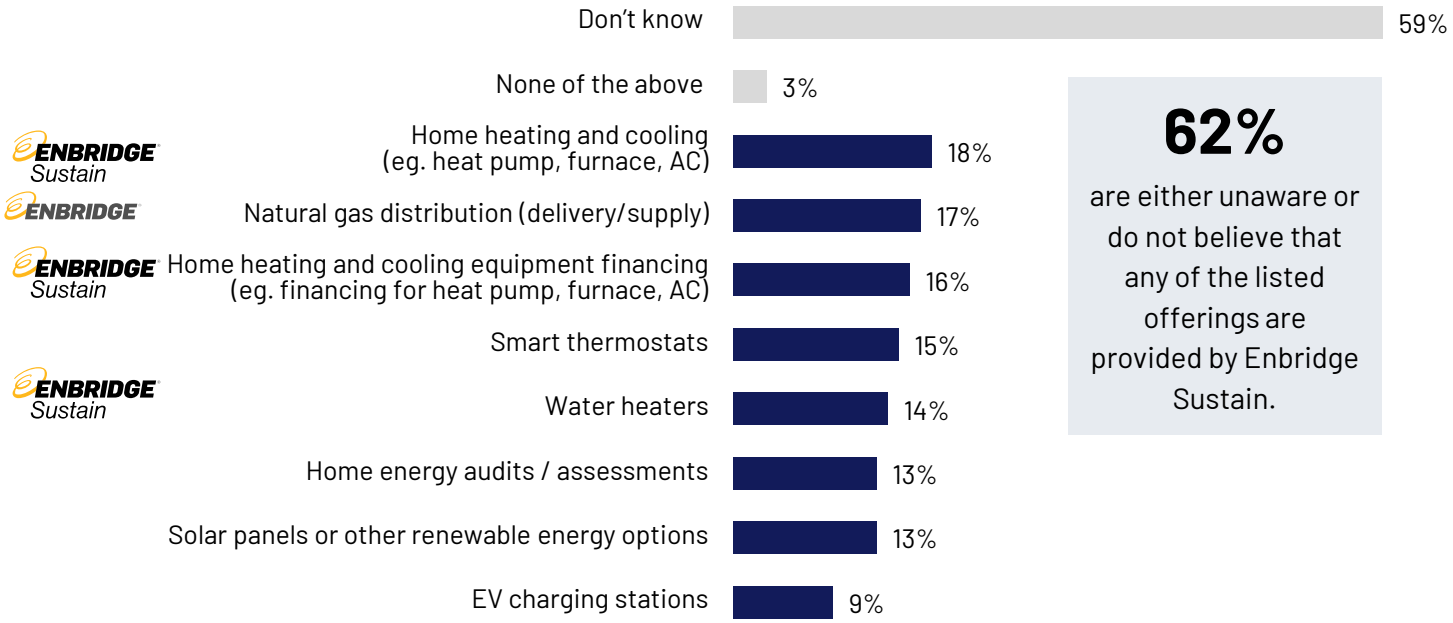
Base: n=2001

Q4. Which, if any, of the following products and/or services does Enbridge Gas offer? (Select all that apply)

Awareness of products and services offered by Enbridge Sustain

- Most Ontarians are unsure about the products and services provided by Enbridge Sustain. Fewer than 20% correctly identify an Enbridge Sustain product or service, although given that awareness of the brand is so low and association with all programs and services is constantly low, this indicates a low level of actual knowledge about what the Enbridge Sustain brand offers. Furthermore, 20% of Enbridge customers believe Enbridge Sustain provides natural gas distribution, which can also be interpreted as confusion with the Sustain brand.
- Attribution is higher among those who are aware or familiar with the Sustain brand; however, those programs or services actually offered by Enbridge Sustain do not stand out strongly in a significant way. Similarly, Enbridge Gas customers attribute Sustain programs and services at levels comparable to the general population.

Products and services ENBRIDGE Sustain



62% are either unaware or do not believe that any of the listed offerings are provided by Enbridge Sustain.

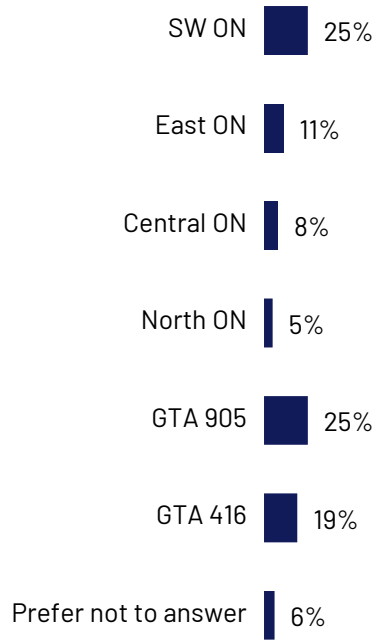
Enbridge Gas Customer	Awareness of Enbridge Sustain	Familiar with Enbridge Sustain
20%	42%	43%
20%	34%	37%
19%	45%	42%
18%	42%	30%
17%	32%	36%
17%	33%	29%
17%	36%	29%
11%	32%	23%

Base: All respondents (n= 2001)
Q3. Which, if any, of the following products and/or services does Enbridge Sustain offer? (Select all that apply)

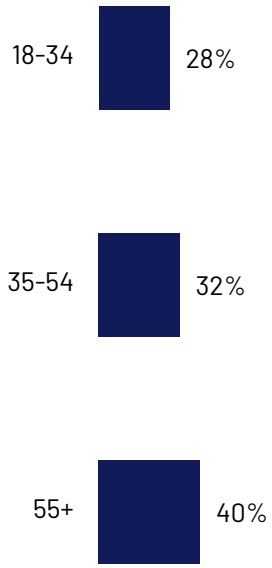
DEMOGRAPHICS

Demographics (1/3)

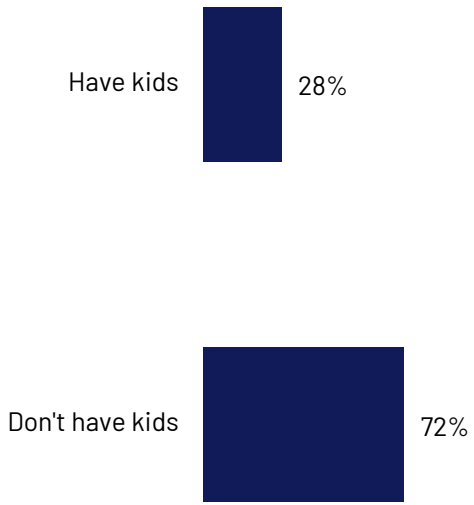
Region



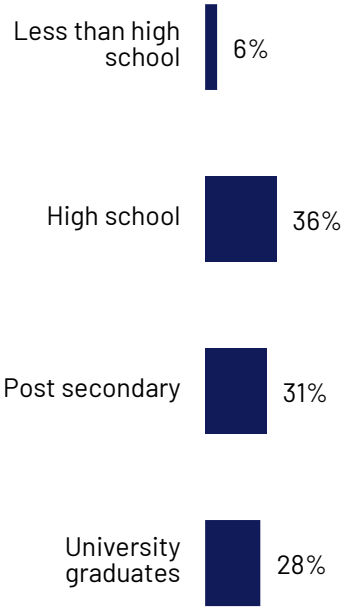
Age



Household composition



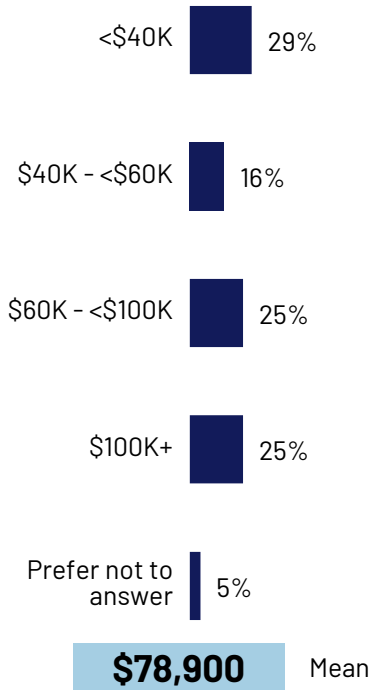
Education



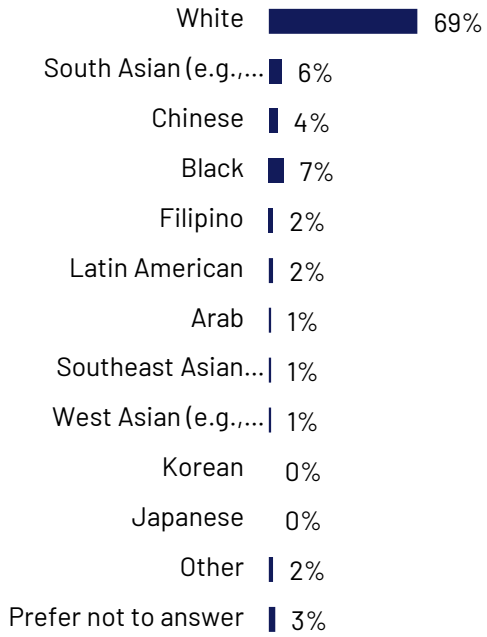
Base: All respondents (n= 2001)

Demographics (2/3)

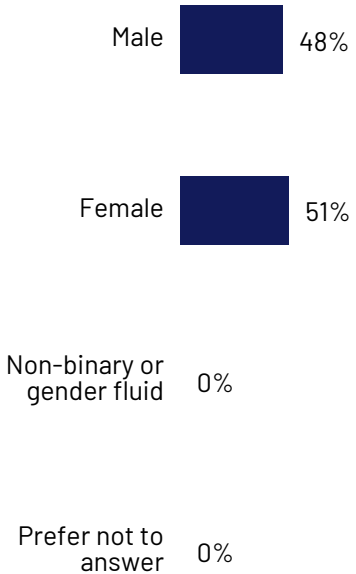
Income



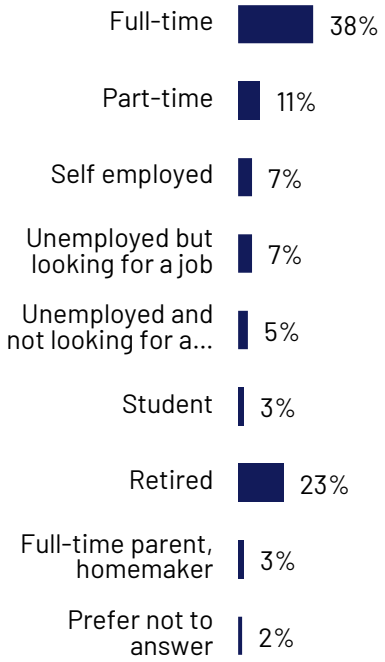
Ethnicity



Gender Identity



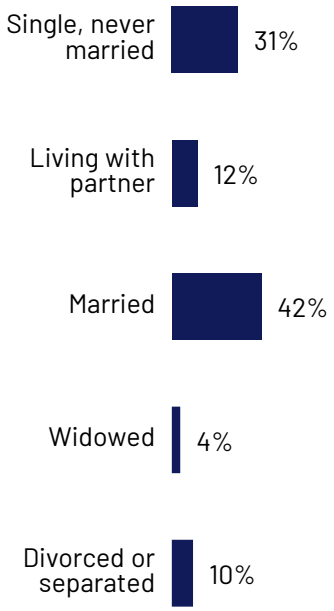
Employment Status



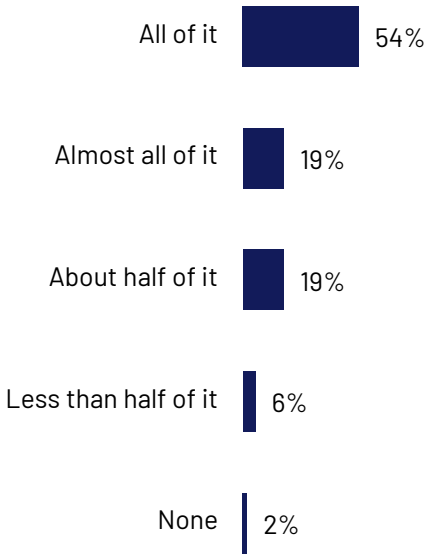
Base: All respondents (n=2001)

Demographics (3/3)

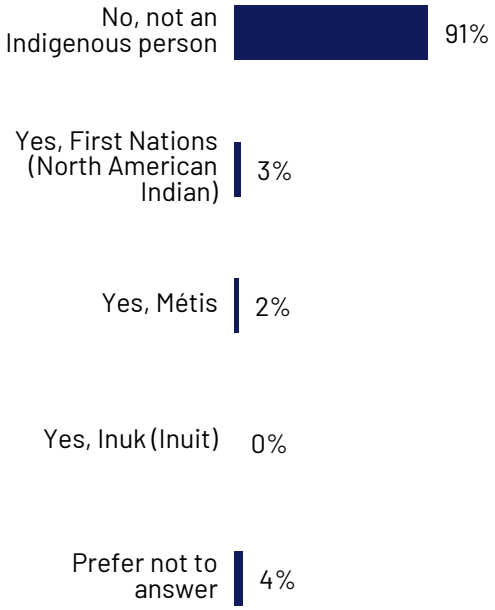
Marital Status



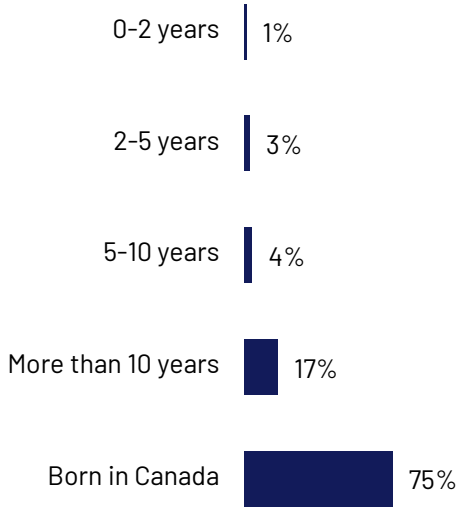
Household grocery shopping



Indigenous Identity



Length of Time in Canada

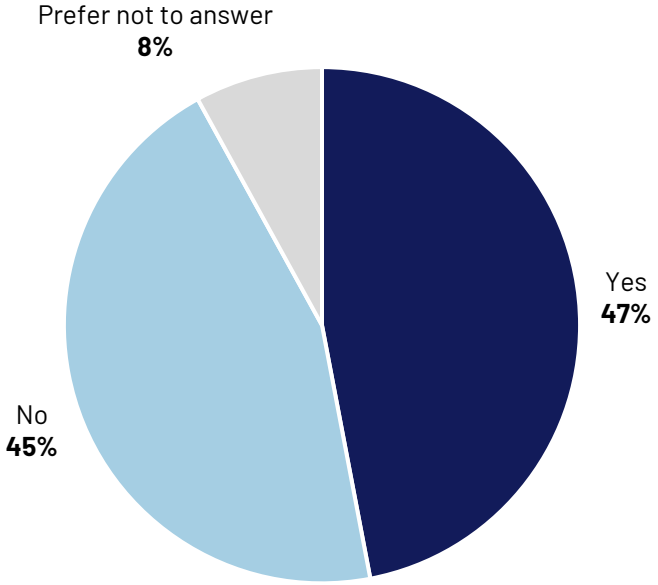


Base: All respondents (n= 2001)

Enbridge Gas Customers

Approximately half (47%) of those interviewed identify as Enbridge Gas customers.

Current Enbridge Gas Customers



Base: All respondents (n=2001)
Q5. Are you currently an Enbridge Gas customer?

THANK YOU

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October 2025

ONTARIO ENERGY BOARD

NOTICE OF A HEARING

Enbridge Gas Inc. has applied to dispose of the balances of certain deferral and variance accounts

Enbridge Gas Inc. (Enbridge Gas) has applied to dispose of the balances in certain deferral and variance accounts, including accounts related to earnings sharing, pensions and other post-employment benefits, taxes, disposition of property, the Low-income Energy Assistance Program Emergency Financial Assistance, the Ontario Energy Board (OEB) cost assessment and Integrated Resource Planning system pruning. For a complete list, refer to the application.

If the application is approved as filed, a typical residential customer and a typical general service customer of Enbridge Gas would see the following billing adjustments, effective July 1, 2027:

EGD Rate Zone (former Enbridge Gas Distribution Inc. customers)

- **Residential Rate 1 Sales Service and Direct Purchase** customers will see a one-time billing credit of $18.94

Union Rate Zones (former Union Gas Limited customers)

- **Union South Residential Rate M1 Sales Service** customers will see a one-time billing charge of $7.76
- **Union South Residential Rate M1 Direct Purchase** customers will see a one-time billing charge of $0.42
- **Union North-West Residential Rate 01 Sales Service and Direct Purchase** customers will see a one-time billing credit of $22.10
- **Union North-East Residential Rate 01 Sales Service and Direct Purchase** customers will see a one-time billing credit of $7.28

Other customers, including businesses, may also be affected. It is important to review the application carefully to determine whether you may be affected by the proposed changes.

This hearing will be held under section 36 of the ***Ontario Energy Board Act, 1998***, S.O. 1998, c.15, Schedule B.

Ce document est aussi disponible en français.

Ontario

Ontario Energy Board

YOU SHOULD KNOW

THE ONTARIO ENERGY BOARD WILL HOLD A PUBLIC HEARING

There are three types of OEB Hearings: oral, electronic and written. The applicant has applied for a written hearing. If you think a different hearing type is needed, you can write to us to explain why. During this hearing, we will question the applicant about its case. We will also hear questions and arguments from participants that have registered as Intervenors. After reviewing all the evidence, we will decide whether to approve this application.

HAVE YOUR SAY

You have the right to information about this application and to participate in the process. Visit www.oeb.ca/notice and use file number **EB-2026-0108** to:

- Review the application
- Apply to become an intervenor
- File a letter with your comments

IMPORTANT DATES

You must engage with the OEB on or before **September 8, 2026** to:

- Provide input on the hearing type (oral, electronic or written)
- Apply to be an intervenor

If you do not, the hearing will move forward without you, and you will not receive any further notice of the proceeding.

PRIVACY

If you write a letter of comment, your name and the content of your letter will be put on the public record and the OEB website. If you are a business or if you apply to become an intervenor, all the information you file will be on the OEB website.

LEARN MORE

Ontario Energy Board

1 877-632-2727 TTY: 1-877-632-2727

Monday - Friday 8:30 AM - 5:00 PM

oeb.ca/notice

Enbridge Gas Inc.

1-866-362-7434

Monday - Friday 8:00 AM - 6:00 PM

enbridgegas.com

This hearing will be held under section 36 of the ***Ontario Energy Board Act, 1998***, S.O. 1998, c.15, Schedule B.

Ce document est aussi disponible en français.

Ontario

Ontario Energy Board

Grand River Conservation Authority

Summary of the General Membership Meeting – July 27, 2026

To GRCA/GRCF Boards and Grand River watershed municipalities - Please share as appropriate.

Action Items

The Board approved the resolutions in the following reports as presented in the agenda:

- GM-08-26-83 - CAO, Chair, Vice-Chair, and Board Evaluation Timing for 2026
- GM-08-26-84 - Environmental Registry Posting 026-0740: Improving Ontario's Conservation Authority System
- GM-08-26-81 - 2027 International River Symposium in Toronto
- GM-08-26-76 - Financial Summary
- GM-08-26-82 - Request for Proposal Award – La Fortune Communication Tower Decommissioning and Disposal, Haldimand County
- GM-08-26-C19 - Disposition of Property - Town of Erin (Closed agenda)
- GM-08-26-C20 - New SCADA Support Specialist Position — GRCA Data Collection Network (Closed agenda)
- GM-08-26-C21 – Authorization for comment period for Niska parcel – City of Guelph (Closed agenda)

Information Items

The Board received the following reports as information:

- GM-08-24-85 - Chair's Report
- GM-08-26-77 - Cash & Investment Status
- GM-08-26-75 - Permits Issued under Ontario Regulation 41/24
- GM-08-26-73 - Update of the Grand River Water Management Plan – Progress Report
- GM-08-26-74 - Update on Water Quality in the Grand River watershed
- GM-08-26-78 - Water Control Structures Major Maintenance Forecast 2027 to 2031
- GM-08-26-79 - Funding of Water Infrastructure Major Capital Projects
- GM-08-26-80 – Current Watershed Conditions

Delegations

- Hugh Whiteley - Potential disposition of southeast Niska land parcel
- Mike Nagy - Concerns regarding Niska lands

Correspondence

The Board received the following correspondence:

- John Kemp - Giant Hogweed
- City of Guelph - Potential disposition of southeast Niska land parcel
- Regarding the potential disposition of southeast Niska land parcel from: Marie Carroll, Cameron Shelley, Dakota Cherry, Susan Watson, Hugh Whiteley, Joan Pollari, Laura Murr, Norah Chaloner, Kathy White

Source Protection Authority Correspondence & Action Items

The General Membership of the GRCA also acts as the Source Protection Authority Board.

- SPA-08-26-05 - Regulatory Amendments Under the Clean Water Act
- SPA-08-26-06 - Submission of the Section 36 Update to the Long Point Region

For full agendas and reports, and past minutes, please refer to our Board meeting calendar. The minutes of this meeting will be posted on following approval at the next meeting of the General Membership.

You are receiving this email as a GRCA board member, GRCF board member, or a Grand River watershed participating municipality. If you do not wish to receive this monthly summary, please respond to this email with the word 'unsubscribe'.

Grand River Conservation Authority

Summary of the General Membership Meeting – August 28, 2026

To GRCA/GRCF Boards and Grand River watershed municipalities - Please share as appropriate.

Action Items

The Board approved the resolutions in the following reports as presented in the agenda:

- GM-08-26-83 - CAO, Chair, Vice-Chair, and Board Evaluation Timing for 2026
- GM-08-26-84 - Environmental Registry Posting 026-0740: Improving Ontario's Conservation Authority System
- GM-08-26-81 - 2027 International River Symposium in Toronto
- GM-08-26-76 - Financial Summary
- GM-08-26-82 - Request for Proposal Award – La Fortune Communication Tower Decommissioning and Disposal, Haldimand County
- GM-08-26-C19 - Disposition of Property - Town of Erin (Closed agenda)
- GM-08-26-C20 - New SCADA Support Specialist Position — GRCA Data Collection Network (Closed agenda)
- GM-08-26-C21 – Authorization for comment period for Niska parcel – City of Guelph (Closed agenda)

Information Items

The Board received the following reports as information:

- GM-08-24-85 - Chair's Report
- GM-08-26-77 - Cash & Investment Status
- GM-08-26-75 - Permits Issued under Ontario Regulation 41/24
- GM-08-26-73 - Update of the Grand River Water Management Plan – Progress Report
- GM-08-26-74 - Update on Water Quality in the Grand River watershed
- GM-08-26-78 - Water Control Structures Major Maintenance Forecast 2027 to 2031
- GM-08-26-79 - Funding of Water Infrastructure Major Capital Projects
- GM-08-26-80 – Current Watershed Conditions

Correspondence

The Board received the following correspondence:

- Mike Nagy, Water Watchers - Concerns Regarding the July 27, 2026 Vote on the Niska Lands
- Town of Halton Hills - Support request for Modernizing Ontario's Invasive Plants Rules

Source Protection Authority Correspondence & Action Items

The General Membership of the GRCA also acts as the Source Protection Authority Board.

- SPA-08-26-05 - Regulatory Amendments Under the Clean Water Act
- SPA-08-26-06 - Submission of the Section 36 Update to the Long Point Region

For full agendas and reports, and past minutes, please refer to our Board meeting calendar. The minutes of this meeting will be posted on following approval at the next meeting of the General Membership.

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P.O. Box 129, 110 Main Street, Sundridge, Ontario, P0A 1Z0

Telephone (705) 384-5316
Fax (705) 384-7874
Email: admin@sundridge.ca

Village of Sundridge Council Resolution
August 19, 2026
Item (9.8)

Clearview Township – Resolution re Public Sector Salary Disclosure Inflation Adjustments
(originally appeared as Item 7 (E.3))

Resolution #2026-196
Moved By: Fraser Williamson
Seconded By: Sharon Smith

THAT The Council for the Corporation of the Village of Sundridge receive the Resolution from the Council for the Corporation of the Township of Clearview regarding Public Sector Salary Disclosure Inflation Adjustments;

AND THAT The Council for the Corporation of the Village of Sundridge supports the Corporation of the Township of Clearview in their request that the Public Sector Salary Disclosure Act be amended to reflect the impact of inflation on the $100,000 salary threshold for reporting, by either adding wording to reflect annual adjustments related to the consumer price index (CPI) or providing an adjusted salary of $150,000;

AND THAT the threshold continue to be amended annually based on the consumer price index;

AND THAT this resolution be sent to the Hon. Doug Ford, Premier; Ministry of Municipal Affairs and Housing; all MPP's; the Association of Municipalities of Ontario and all Ontario Municipalities.

Recorded Vote	**For**	**Against**	**Abstain**
Preston, Luke	**x**		
Smith, Sharon	**x**		
Whitmell, Vicki	**x**		
Williamson, Fraser	**x**		
Jackson, Shawn	**x**		
CARRIED			

www.sundridge.ca

RECEIVED
AUG 24 2026
Township of Puslinch

Hamilton

Office of the City Clerk
71 Main Street West, Hamilton ON L8P 4Y5
Phone: 905-546-2424 Fax: 905-546-2095
www.hamilton.ca

NOTICE OF ADOPTION OF A COMMUNITY IMPROVEMENT PLAN BY-LAW ('THE REVITALIZING HAMILTON'S COMMERCIAL DISTRICTS COMMUNITY IMPROVEMENT PLAN (2026)')

TAKE NOTICE that the City of Hamilton Council adopted The Revitalizing Hamilton's Commercial Districts Community Improvement Plan (2026) By-law No. 26-136 on the 5th of August 2026 under Section 28 of the *Planning Act*, R.S.O. 1990, c. P.13, as amended.

AND TAKE NOTICE THAT the **purpose and effect of this By-law** is to establish an updated Community Improvement Plan for the provision of financial incentive programs intended to support and stimulate private sector investment within the Revitalizing Hamilton's Commercial Districts Community Improvement Project Area (By-law No. 26-135).

AND TAKE NOTICE THAT this Community Improvement Plan is exempt from approval by the Minister of Municipal Affairs and Housing and as such the decision by City of Hamilton Council is final if a notice of appeal is not received on or before the last day for filing a notice of appeal.

AND TAKE NOTICE THAT any person or agency who objects to this Community Improvement Plan may appeal the decision of City of Hamilton Council to the Ontario Land Tribunal by filing with the City Clerk, not later than **4:30pm on the 8th day of September, 2026**:

- a completed notice of appeal form setting out the reasons for the appeal of the Community Improvement Plan is required to be accompanied with the Ontario Land Tribunal fee (appeal forms are available at: https://olt.gov.on.ca/)
- a certified cheque or money order in the amount of $1,100.00, payable to the Minister of Finance, Province of Ontario.

Appeal Procedure:

Only Individuals, Corporations and Public Bodies may appeal the Community Improvement Plan to the Ontario Land Tribunal. A notice of appeal may not be filed by an unincorporated association or group. However, a notice of appeal may be filed in the name of an individual who is a member of the association or group on its behalf.

No person or public body shall be added as a party to the hearing of the appeal unless, before the by-laws were passed, the person or public body made oral submissions at a public meeting or written submissions to the council or, in the opinion of the Ontario Land Tribunal, there are reasonable grounds to add the person or public body as a party.

For questions respecting appeals please contact:

Tamara Bates, Legislative Coordinator, at 905-546-2424 ext. 4102

Appeals should be submitted:

1. Electronically through the Ontario Land Tribunal's e-file Portal: https://olt.gov.on.ca/e-file-service/ (Or to: Clerk@hamilton.ca if the Portal is down); OR
2. In-person or by mail/courier to the City of Hamilton: City Clerk, City of Hamilton, 71 Main Street West, 1st floor, Hamilton, Ontario, L8P 4Y5.

Additional Information:

A hard copy of the adopted The Revitalizing Hamilton's Commercial Districts Community Improvement Plan (2026) By-law 26-136 is available from 8:30am to 4:30pm, Monday through Friday, at the Office of the City Clerk located at:

Hamilton City Hall
71 Main Street West, 1st floor
Hamilton, Ontario, L8P 4Y5

To access a digital version of the By-law visit:
https://www.hamilton.ca/city-council/by-laws-enforcement/search-by-laws

Questions respecting the purpose, effect or content of the By-law, please contact: Johnpaul Loiacono, RPP MCIP, Senior Project Manager, at johnpaul.loiacono@hamilton.ca or 905-546-2424 ext. 5134.

DATED at the City of Hamilton
This 19th day of August, 2026

M. Trennum, City Clerk
Hamilton, Ontario

THE PUSLINCH PROFILE FEATURES: Dean Manton - Remax Real Estate Centre

mail@deanmanton.com | deanmanton.com | 519-821-4000

For more than 25 years, Dean Manton has been helping buyers and sellers confidently navigate the local real estate market. As a trusted Realtor and Broker with RE/MAX Real Estate Centre, Dean proudly serves Guelph, Puslinch, Guelph/Eramosa, and surrounding Wellington County communities.

Specializing in residential homes, condominiums, rural properties, vacant land, and luxury real estate, Dean is known for his honest advice, responsive communication, and in-depth knowledge of the local market. Since 1998, Dean has built a reputation for delivering personalized service and strategic marketing tailored to each client's needs. Whether buying a first home, downsizing, relocating, or selling a country property, he is committed to helping clients achieve their real estate goals.

DEAN MANTON REALTOR® Your Unfair Advantage

As a local business, Dean understands the importance of supporting the community. Shopping local helps keep dollars circulating within the local economy, supporting local jobs, services, and community organizations while strengthening the places we all call home. Dean is proud to be part of that commitment by providing trusted local expertise and helping families put down roots in the communities he serves.

Dufferin Aggregates
2300 Steeles Ave W, 4th Floor
Concord, ON L4K 5X6
Canada

September 03, 2026

RECEIVED
SEP 08 2026
Township of Puslinch

Luke Rapus
Aggregates Technical Specialist
Ministry of Natural Resources and Forestry
Guelph District
1 Stone Road West
Guelph, Ontario
N1G 4Y2

Attention: Mr. Rapus

Re: Monthly Monitoring Report – August 2026
Mill Creek Pit, License #5738
Township of Puslinch, Wellington County

Please find enclosed the required monitoring data for the month of August 2026.

The head difference between BH92-27 and DP2 exceeded the threshold value on August 24th. It is suspected that drive point DP2 is compromised and, as such, the groundwater level measured at DP2 on August 24 may be erroneous. A replacement drive point (DP2R) was installed adjacent to DP2 on August 31, and weekly water levels will be measured at both drive points to confirm whether DP2 is compromised. It is noted that the head difference between BH92-27 and DP2 on September 3rd, 2026 (0.45 m) complied with the threshold value.

If you have any questions, please do not hesitate to call.

Sincerely,

[redacted]

Matthew Erdmann
Site Superintendent

CC: Township of Puslinch
Sonja Strynatka (GRCA)
Kevin Mitchell (Dufferin Aggregates)
University of Guelph

Dufferin Aggregates

Monthly Reporting
Mill Creek Aggregates Pit
August 2026

Date	DP21 (mASL)	Threshold Value (mASL)	Exceedance
6-Aug-26	305.82	305.49	NO
12-Aug-26	305.80	305.49	NO
18-Aug-26	305.79	305.49	NO
24-Aug-26	305.87	305.49	NO

Date	BH13 (mASL)	DP21 (mASL)	Head Difference (m)	Threshold Value (m)	Exceedance
6-Aug-26	306.15	305.82	0.33	0.10	NO
12-Aug-26	306.15	305.80	0.35	0.10	NO
18-Aug-26	306.14	305.79	0.35	0.10	NO
24-Aug-26	306.20	305.87	0.33	0.10	NO

Date	DP17 (mASL)	Threshold Value (mASL)	Exceedance
6-Aug-26	305.28	305.17	NO
12-Aug-26	305.28	305.17	NO
18-Aug-26	305.26	305.17	NO
24-Aug-26	305.34	305.17	NO

Date	BH92-12 (mASL)	DP17 (mASL)	Head Difference (m)	Threshold Value (m)	Exceedance
6-Aug-26	305.92	305.28	0.64	0.06	NO
12-Aug-26	305.94	305.28	0.66	0.06	NO
18-Aug-26	305.89	305.26	0.63	0.06	NO
24-Aug-26	305.91	305.34	0.57	0.06	NO

Date	DP3 (mASL)	Threshold Value (mASL)	Exceedance
6-Aug-26	304.74	304.54	NO
12-Aug-26	304.73	304.54	NO
18-Aug-26	304.72	304.54	NO
24-Aug-26	304.88	304.54	NO

Date	DP6 (mASL)	DP3 (mASL)	Head Difference (m)	Threshold Value (m)	Exceedance
6-Aug-26	306.00	304.74	1.26	0.58	NO
12-Aug-26	305.98	304.73	1.25	0.58	NO
18-Aug-26	305.96	304.72	1.24	0.58	NO
24-Aug-26	306.04	304.88	1.16	0.58	NO

Date	DP2 (mASL)	Threshold Value (mASL)	Exceedance
6-Aug-26	304.29	303.50	NO
12-Aug-26	304.29	303.50	NO
18-Aug-26	304.31	303.50	NO
24-Aug-26	304.45	303.50	NO

Date	BH92-27 (mASL)	DP2 (mASL)	Head Difference (m)	Threshold Value (m)	Exceedance
6-Aug-26	304.72	304.29	0.43	0.32	NO
12-Aug-26	304.69	304.29	0.40	0.32	NO
18-Aug-26	304.68	304.31	0.37	0.32	NO
24-Aug-26	304.74	304.45	0.29	0.32	YES

Date	DP1 (mASL)	Threshold Value (mASL)	Exceedance
6-Aug-26	304.32	303.91	NO
12-Aug-26	304.31	303.91	NO
18-Aug-26	304.31	303.91	NO
24-Aug-26	304.39	303.91	NO

Date	BH92-29 (mASL)	DP1 (mASL)	Head Difference (m)	Threshold Value (m)	Exceedance
6-Aug-26	304.90	304.32	0.58	0.23	NO
12-Aug-26	304.88	304.31	0.57	0.23	NO
18-Aug-26	304.87	304.31	0.56	0.23	NO
24-Aug-26	304.89	304.39	0.50	0.23	NO

Date	DP5CR (mASL)	Threshold Value (mASL)	Exceedance
6-Aug-26	303.27	302.79	NO
12-Aug-26	303.28	302.79	NO
18-Aug-26	303.28	302.79	NO
24-Aug-26	303.37	302.79	NO

Date	OW5-84 (mASL)	DP5CR (mASL)	Head Difference (m)	Threshold Value (m)	Exceedance
6-Aug-26	303.53	303.27	0.26	0.15	NO
12-Aug-26	303.53	303.28	0.25	0.15	NO
18-Aug-26	303.50	303.28	0.22	0.15	NO
24-Aug-26	303.62	303.37	0.25	0.15	NO

The head difference between BH92-27 and DP2 exceeded the threshold value on August 24. It is suspected that drive point DP2 is compromised and, as such, the groundwater level measured at DP2 on August 24 may be erroneous. A replacement drive point (DP2R) was installed adjacent to DP2 on August 31, and weekly water levels will be measured at both drive points to confirm whether DP2 is compromised. It is noted that the head difference between BH92-27 and DP2 on September 3 (0.45 m) complied with the threshold value.

Note: A beaver dam has been observed on private property upstream of DP5CR, which is likely to impact the water levels at DP5CR. Similar to what has occurred in the recent past at this location, the beaver dam may potentially cause action threshold exceedances. It is recommended that the appropriate authority arrange to have the beaver dam removed.

Monthly Reporting
Mill Creek Aggregates Pit
August 2026

Total Monthly Precipitation (mm):	81.9	Kitchener/Waterloo (Actual)
Total Monthly Normal Precipitation (mm):	88.2	Waterloo-Wellington A (30-year Normal)

Max. Allowable as per PTTW - Main Pond		
(Imperial Gallons)		(Litres)
2,500	per minute	11,365
1,800,000	per day	8,183,000

Max. Allowable as per PTTW - Silt Pond		
(Imperial Gallons)		(Litres)
2,597	per minute	11,806
3,739,477	per day	17,000,000

Date	Below Water Table Extraction SP4	Below Water Table Extraction Phase 2	Water Pumped from Main Pond (gals)	Water Pumped from Active Silt Pond (gals)	Main Pond Level (mASL)	Exceedance Y/N (BELOW 305.5 mASL)	Phase 2 Pond Level (mASL)	Exceedance Y/N (BELOW 305.0 mASL)	Phase 3 Pond Level (mASL)	Exceedance Y/N (BELOW 303.85 mASL)	Phase 4 Pond Level (mASL)	Exceedance Y/N (BELOW 304.5 mASL)
1-Aug-26	-	-	-	-	-	-	-	-	-	-	-	-
2-Aug-26	-	-	-	-	-	-	-	-	-	-	-	-
3-Aug-26	-	-	-	-	-	-	-	-	-	-	-	-
4-Aug-26	-	-	-	-	306.38	N	306.00	N	305.04	N	306.09	N
5-Aug-26	-	-	-	-	306.38	N	306.00	N	305.03	N	306.09	N
6-Aug-26	-	-	-	-	306.38	N	305.99	N	305.04	N	306.09	N
7-Aug-26	-	-	-	-	306.38	N	306.01	N	305.04	N	306.09	N
8-Aug-26	-	-	-	-	-	-	-	-	-	-	-	-
9-Aug-26	-	-	-	-	-	-	-	-	-	-	-	-
10-Aug-26	-	-	-	-	306.38	N	306.00	N	305.02	N	306.09	N
11-Aug-26	-	-	-	-	306.38	N	305.99	N	305.02	N	306.09	N
12-Aug-26	-	-	-	-	306.38	N	305.99	N	305.01	N	306.09	N
13-Aug-26	-	-	-	-	306.37	N	305.99	N	305.01	N	306.08	N
14-Aug-26	-	-	-	-	306.36	N	305.98	N	305.00	N	306.08	N
15-Aug-26	-	-	-	-	-	-	-	-	-	-	-	-
16-Aug-26	-	-	-	-	-	-	-	-	-	-	-	-
17-Aug-26	-	-	-	-	306.36	N	305.97	N	305.00	N	306.07	N
18-Aug-26	-	-	-	-	306.35	N	305.97	N	304.99	N	306.06	N
19-Aug-26	-	-	-	-	306.35	N	305.97	N	304.99	N	306.05	N
20-Aug-26	-	-	-	-	306.35	N	305.97	N	304.98	N	306.03	N
21-Aug-26	-	-	-	-	306.34	N	305.96	N	304.99	N	306.03	N
22-Aug-26	-	-	-	-	-	-	-	-	-	-	-	-
23-Aug-26	-	-	-	-	-	-	-	-	-	-	-	-
24-Aug-26	-	-	-	-	306.34	N	305.97	N	305.00	N	306.04	N
25-Aug-26	-	-	-	-	306.34	N	305.97	N	304.99	N	306.04	N
26-Aug-26	-	-	-	-	306.33	N	305.96	N	304.98	N	306.04	N
27-Aug-26	-	-	-	-	306.33	N	305.97	N	304.99	N	306.03	N
28-Aug-26	-	-	-	-	306.32	N	305.97	N	304.99	N	306.03	N
29-Aug-26	-	-	-	-	-	-	-	-	-	-	-	-
30-Aug-26	-	-	-	-	-	-	-	-	-	-	-	-
31-Aug-26	-	-	-	-	306.32	N	305.95	N	304.98	N	306.02	N
Total	0	0	0	0								

Notes:
No exceedances to report for the month of August.
No water taken from the site for the month of August.

Ontario

Ontario Provincial Conservation Agency | **l'Agence ontarienne de protection de la nature**

September 9, 2026

Dear Conservation Authority CAOs and GMs:

We have received several inquiries regarding CA board governance in light of the upcoming municipal election and would like to provide clarification. Specifically, we have heard concerns related to a potential "lame duck" status of municipal council members during the election period and resulting impacts for CA board responsibilities including the approval of 2027 budgets.

These concerns appear to stem from Section 275 of the *Municipal Act, 2001*, which establishes that if less than three quarters of the members of an outgoing council are returning, the outgoing council is restricted from specific actions, including making expenditures or incurring liabilities.

It is important to note that CAs are independent organizations and for that reason, this provision of the Act does not apply to CA's budgets or expenditures. In addition, Section 14(4.2) of the *Conservation Authorities Act* sets out that a municipal council member remains a member until they are replaced. This means that existing board members continue to hold their responsibilities as members of the conservation authority board, including participating in the budget process.

For these reasons, the municipal election this October will not affect the current composition or operation of CA boards. Existing board members will remain in their positions throughout the fall and until consolidation in February 2027.

To be clear, whether a current board member chooses not to seek re-election or is unsuccessful in their re-election, does not affect the CA board prior to consolidation. Current board membership remains unchanged until that time.

We hope this clarification is helpful and addresses any questions that may have arisen. We would also like to take this opportunity to thank you for your ongoing support and collaboration as we continue our transition planning.

Sincerely,

Hassaan Basit
CEO
Ontario Provincial Conservation Agency

Justine Brotherston

From: Township of Puslinch <services@puslinch.ca>
Sent: September 14, 2026 12:02 PM
To: Justine Brotherston
Subject: New Entry: Delegate Request

Follow Up Flag: Follow up
Flag Status: Flagged

Warning! This message was sent from outside your organization and we were unable to verify the sender.

Block sender | Report

Type of Meeting

Council

Meeting Date

September 16, 2026

How many delegates are requesting to make this presentation?

One (1)

Type of Delegation

This is a request to delegate on a topic on the upcoming agenda

Identify which agenda item you are requesting to delegate on?

10.5 Notice Permit to Take Water 101 Brock Rd. S - White Wolf Property Management Inc.

Type of Delegation

This request is to present a verbal delegation

Type of Attendance for verbal delegation

Via Zoom

Name of Delegate

Ilham Abdulkadir

Mailing Address of Delegate

[redacted]

Phone Number of Delegate

[redacted]

Email Address of Delegate

[redacted]

Purpose of delegation (please describe the conern/position taken on issue, if applicable)

We'd like to present our opposition to the permit to take water being sought by White Wolf. We will present our concerns and ask council to consider them when making a decision on whether to support this permit or not.

A formal presentation is being submitted to accompany the delegation

No

The delegation will require the use of audio-visual equipment (power point presentation)

No

Acknowledgement

I (we) have read, understand and acknowledge the Rules and Procedures relating to Delegations as prescribed by the Procedural By-law 2022-046.

Sent from Township of Puslinch

REPORT FIR-2026-004

TO: Mayor and Members of Council

PREPARED BY: Michael Chant, Fire Chief

PRESENTED BY: Michael Chant, Fire Chief

MEETING DATE: September 16, 2026

SUBJECT: Puslinch Fire and Rescue Service 2026 Q2 Report

RECOMMENDATION

That Report FIR-2026-004 entitled Puslinch Fire and Rescue Service 2026 Q2 Report be received for information.

Purpose

To formally inform Council of the 2026 Q2 Emergency Responses, Public Education Events, and other significant events attended by Puslinch Fire and Rescue Services.

Background

The continued practice of reporting to Council is vital for maintaining transparency and ensuring that Council is informed about the operations and constraints of the Fire Department. As directed by Council, reporting will take place quarterly rather than annually going forward.

Training:

- Focus for training is based on the July 1st, 2026, deadline for mandatory certification in the province of Ontario for specific certifications. In Q2 2026 staff completed a total of 586 hours of weekly training that takes place every Wednesday nights from 7:00pm to 9:00pm (with the occasional weekend).
- Additionally, eight auxiliary recruits completed 100 hours of county recruit training, working alongside other departments in Wellington County. The program is now complete with the final exams written. We are looking forward to adding 5 new personnel to our roster soon. Also, all members of the department are now certified in FF1, FF2 and NFPA 1072 (HAZMAT).

Public Education:

- In Q2 of 2026 staff attended 6 public events ranging from station tours, camp day, bike rodeo, open house and many other community events. 275 hours of public engagement by staff

resulted in Puslinch Fire Rescue Service speaking to approximately 850 members of the public about fire safety. A total of $4700 was raised for Sunrise Equestrian Centre as a result of the Open House.

Fire Prevention:

- Fire prevention staff has been concentrating on the recommendations outlined in the
- Community Risk Assessment report. Fire Prevention also completed 20 inspections, 4 Fire Safety Plan reviews, 3 fire investigations and 2 inspections of vulnerable occupancies.

Social media:

- 650 followers, an increase of 19% year to date.

Emergency Incidents:

- Puslinch Fire Rescue Services responded to a total of 86 Incidents in Q2, this is a 21% decrease year over year. The highest call for service was Motor Vehicle Accidents with 33 calls. 818 staff responded with 389 staff making the first truck to the emergency responses in Q2. YTD fire losses remain at a total of $4,675,000.00.
- As Council is aware, the Township partnered with Fire Marque to recover certain costs through private insurance plans. $8400.00 was recovered in Q2, totalling $11,900 YTD. Another $3000 has been submitted for reimbursement.

Fire Master Plan Update:

The Township is providing this update to Council and the public regarding the status of the Fire Master Plan and the anticipated next steps toward completion.

The Fire Master Plan has not yet been presented to Council because a completed, Council-ready document has not been received. Drafts provided to date require further work to ensure the information is accurate, appropriately supported and clearly presented. The Township has communicated its expectation that the Plan be a concise, accessible and visually engaging strategic document that clearly identifies service needs, priorities, recommendations, implementation timelines, and the associated capital and operating requirements to support informed decision-making, financial planning and ongoing monitoring and accountability.

Staff are continuing to work on the document and will bring the completed Fire Master Plan forward to Council for consideration once it is suitable for Council review and public release. The Township recognizes the community's interest in the Plan and will continue to provide updates as the document progresses.

<u>Financial Implications</u>

None

<u>Strategic Plan Alignment and Implications</u>

Strategic Priority #3: Connected, Safe, and Accessible Communities

This initiative directly supports Strategic Priority #3 by fostering connected, safe, and accessible communities by providing transparency, strengthening public awareness, and demonstrating the Township's ongoing commitment to community safety and engagement. Regular reporting also highlights opportunities for volunteerism, civic participation, and collaboration between residents, Council, and emergency services to help ensure all members of the community feel informed, supported, and connected.

Objective 3.1 Enhance Community Participation
The report enhances community participation by keeping residents informed, promoting fire prevention and emergency preparedness, encouraging volunteerism, and fostering a shared responsibility for community safety and well-being.

Action 3.1(b & d): Township consideration of Zoning By-law Amendments
This initiative aligns with Actions 3.1(b & d) by increasing awareness of fire prevention initiatives, public education efforts, and emergency preparedness activities, while strengthening engagement and collaboration between the Township, emergency services, and the community.

Applicable Legislation and Requirements
Municipal Act, 2001
Fire Protection and Prevention Act, 1997, S.O. 1997, c. 4

Engagement Opportunities
None

Attachments
Puslinch Fire Rescue Service OFM Incident Reports, Q2 2026

Respectfully submitted,	**Reviewed by:**
Michael Chant, **Fire Chief**	**Courtenay Hoytfox,** **CAO**

INCIDENTS: DAYS & TIMES

Puslinch Fire & Rescue Service | Last Refresh: 8/13/2026 8:00 PM

86	0	203	256	-53	-21%
Incidents Filtered	Not Reviewed	Incidents YTD	Prior YTD	Δ over PYTD	% over PYTD

SLICERS

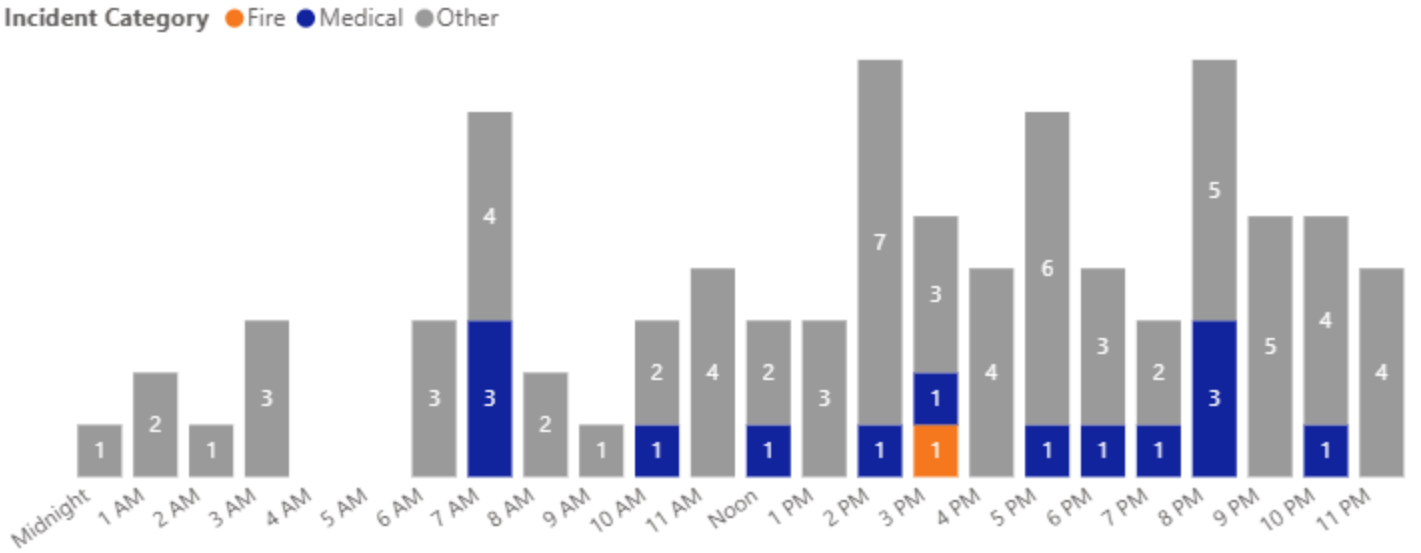
DETAILS

PAGES

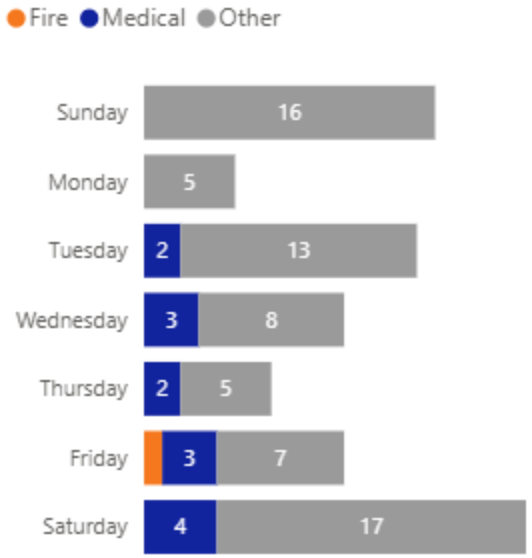
RESET

REVIEWED ONLY

of Incidents by Hour of the Day

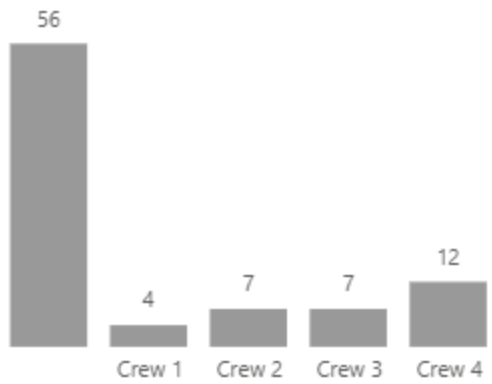


of Incidents by Weekday and Incident Category

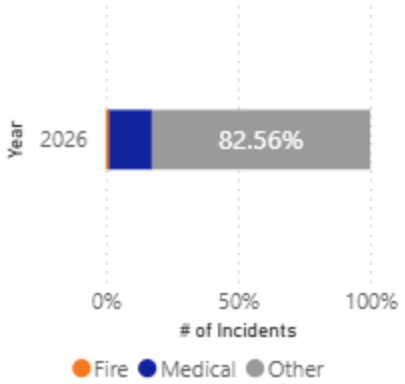


Top Stations by # of Incidents

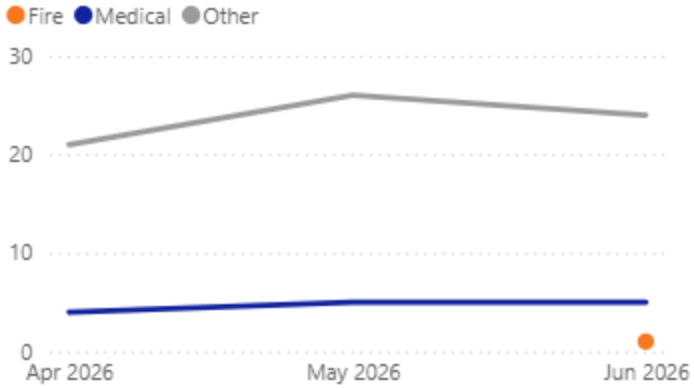
of Incidents by Shift



of Incidents by Category



of Incidents over Time



Puslinch Fire & Rescue Service

Puslinch, ON

This report was generated on 8/14/2026 8:46:28 AM

OFM Incident Report for Date Range for Incident Type

Incident Type(s): All Incident Types | Start Date: 04/01/2026 | End Date: 06/30/2026

LOCATION CODE	INCIDENT NUMBER	INCIDENT Date/Time	LOCATION	PROPERTY CLASS	ALARM SOURCE	TIME ON SCENE	RESPONSE TYPE	EST. LOSS	Pt	Pe	Re	In	Fa	CIn	CFa
P_PUS_3	2026-69	Apr 01 2026 11:06:00	[redacted]		From Police Services	00:37:19	Vehicle Collision	$0	7	4	0	0	0	0	0
P_PUS_6	2026-70	Apr 04 2026 14:45:20	[redacted]		911	00:07:02	Other False Fire Call	$0	7	5	0	0	0	0	0
P_PUS_1	2026-71	Apr 06 2026 15:46:21	[redacted]		From Police Services	00:09:43	Vehicle Collision	$0	8	5	0	0	0	0	0
P_PUS_2	2026-72	Apr 07 2026 09:47:01	[redacted]		From Ambulance	00:00:02	Call cancelled on route	$0	6	2	0	0	0	0	0
	2026-73	Apr 10 2026 18:03:04	[redacted]		From Ambulance	00:01:26	Medical/resuscitator call no action required	$0	5	3	0	0	0	0	0
P_PUS_6	2026-74	Apr 11 2026 15:48:49	[redacted]		911	01:28:11	Vehicle Collision	$0	10	4	0	0	0	0	0
P_PUS_6	2026-75	Apr 11 2026 23:32:07	[redacted]		911	00:23:25	CO false alarm - equipment malfunction (no CO present)	$0	8	4	0	0	0	0	0
P_PUS_2	2026-76	Apr 14 2026 17:17:55	[redacted]		From Ambulance	00:01:25	Other Medical/Resuscitator Call	$0	13	4	0	0	0	0	0
P_PUS_2	2026-77	Apr 14 2026 17:43:51	[redacted]		911	00:30:26	Alarm System Equipment - Malfunction	$0	12	4	0	0	0	0	0
P_PUS_2	2026-78	Apr 14 2026 18:59:51	[redacted]		From Police Services	00:01:04	Call cancelled on route	$0	9	1	0	0	0	0	0

Reviewed Incidents only. Pt = Total Personnel, Pe = Personnel on 1st Unit, Re = Rescued, In = Firefighter Injuries, Fa = Firefighter Fatalities, CIn = Civilian Injuries, CFa = Civilian Fatalities.

P_PUS_3	2026-79	Apr 15 2026 16:15:54	[redacted]	From Police Services	00:37:08	Vehicle Collision	$0	14	6	0	0	0	0	0
P_PUS_3	2026-80	Apr 15 2026 18:30:05	[redacted]	From Ambulance	00:38:05	Vehicle Collision	$0	20	4	0	0	0	0	0
P_PUS_5	2026-81	Apr 17 2026 17:55:17	[redacted]	From Ambulance	00:50:00	Vehicle Collision	$0	14	5	0	0	0	0	0
P_PUS_6	2026-82	Apr 18 2026 01:36:37	[redacted]	911	00:09:45	Other False Fire Call	$0	7	5	0	0	0	0	0
P_PUS_1	2026-83	Apr 19 2026 21:15:55	[redacted]	911	00:15:29	CO false alarm - equipment malfunction (no CO present)	$0	11	4	0	0	0	0	0
P_PUS_3	2026-84	Apr 22 2026 07:00:48	[redacted]	911	00:10:00	Other Medical/Resuscitator Call	$0	8	3	0	0	0	0	0
P_PUS_3	2026-85	Apr 22 2026 19:17:14	[redacted]	From Ambulance	00:18:08	Other Medical/Resuscitator Call	$0	4	4	0	0	0	0	0
P_PUS_3	2026-86	Apr 22 2026 20:58:41	[redacted]	911	00:04:58	Other False Fire Call	$0	12	3	0	0	0	0	0
P_PUS_4	2026-87	Apr 23 2026 06:05:53	[redacted]	From Ambulance	00:07:52	Assistance to Other Agencies (exc 921 and 922)	$0	10	5	0	0	0	0	0
P_PUS_1	2026-88	Apr 24 2026 20:39:15	[redacted]	From Ambulance	00:33:47	Vehicle Collision	$0	12	6	0	0	0	0	0
P_PUS_1	2026-89	Apr 25 2026 14:41:57	[redacted]	From Police Services	00:01:00	Vehicle Collision	$0	13	4	0	0	0	0	0
P_PUS_1	2026-90	Apr 27 2026 06:43:54	[redacted]	From Ambulance	01:03:38	Vehicle Collision	$0	8	4	0	0	0	0	0
P_PUS_1	2026-91	Apr 27 2026 16:36:23	[redacted]	911	01:26:53	Vehicle Collision	$0	7	3	0	0	0	0	0
P_PUS_3	2026-92	Apr 30 2026 01:37:36	[redacted]	From Ambulance	00:00:27	Call cancelled on route	$0	8	1	0	0	0	0	0

Reviewed Incidents only. Pt = Total Personnel, Pe = Personnel on 1st Unit, Re = Rescued, In = Firefighter Injuries, Fa = Firefighter Fatalities, CIn = Civilian Injuries, CFa = Civilian Fatalities.

P_PUS_4	2026-93	Apr 30 2026 13:54:31	[redacted]	911	01:24:23	Spill - Gasoline or Fuel	$0	10	4	0	0	0	0	0
P_PUS_6	2026-94	May 02 2026 22:08:36	[redacted]	From Ambulance	00:17:49	Vehicle Collision	$0	10	4	0	0	0	0	0
P_PUS_6	2026-95	May 02 2026 22:18:27	[redacted]	911	00:08:57	Alarm System Equipment - Malfunction	$0	10	5	0	0	0	0	0
P_PUS_4	2026-96	May 03 2026 11:15:47	[redacted]	911	00:04:57	Alarm System Equipment - Accidental activation (exc. code 35)	None	8	5	0	0	0	0	0
P_PUS_2	2026-97	May 05 2026 19:08:56	[redacted]	911	00:56:38	CO incident, CO present (exc false alarms)	$0	10	4	0	0	0	0	0
P_PUS_6	2026-98	May 09 2026 11:09:29	[redacted]	From Ambulance	00:06:36	Call cancelled on route	$0	7	5	0	0	0	0	0
P_PUS_2	2026-99	May 09 2026 20:18:32	[redacted]	From Ambulance	00:01:55	Medical Aid Not Required on Arrival	$0	10	5	0	0	0	0	0
P_PUS_2	2026-100	May 10 2026 03:55:21	[redacted]	From Ambulance	00:39:17	Vehicle Collision	$0	9	6	0	0	0	0	0
P_PUS_2	2026-101	May 10 2026 17:43:35	[redacted]	911	00:42:20	Vehicle Collision	$0	15	6	0	0	0	0	0
P_PUS_1	2026-102	May 10 2026 23:14:48	[redacted]	911	00:11:08	CO false alarm - equipment malfunction (no CO present)	$0	8	5	0	0	0	0	0
P_PUS_1	2026-103	May 11 2026 20:43:10	[redacted]	911	00:04:10	Other False Fire Call	None	10	5	0	0	0	0	0
P_PUS_3	2026-104	May 13 2026 07:51:17	[redacted]	From Ambulance	00:01:27	Medical Aid Not Required on Arrival	$0	6	3	0	0	0	0	0
P_PUS_6	2026-105	May 16 2026 07:12:39	[redacted]	From Ambulance	00:02:36	Medical Aid Not Required on Arrival	$0	9	4	0	0	0	0	0

Reviewed Incidents only. Pt = Total Personnel, Pe = Personnel on 1st Unit, Re = Rescued, In = Firefighter Injuries, Fa = Firefighter Fatalities, CIn = Civilian Injuries, CFa = Civilian Fatalities.

P_PUS_2	2026-106	May 19 2026 03:05:11	[redacted]	911	00:08:08	CO false alarm - equipment malfunction (no CO present)	$0	7	4	0	0	0	0	0
P_PUS_1	2026-107	May 19 2026 14:39:07	[redacted]	911	00:31:15	Human - Accidental (alarm accidentally activated by person)	$0	8	3	0	0	0	0	0
P_PUS_4	2026-108	May 21 2026 18:18:44	[redacted]	From Ambulance	00:13:30	Vehicle Collision	$0	16	6	0	0	0	0	0
P_PUS_5	2026-109	May 22 2026 14:01:57	[redacted]	Telephone from Monitoring Agency	00:03:21	Other False Fire Call	$0	3	3	0	0	0	0	0
P_PUS_5	2026-110	May 22 2026 20:53:26	[redacted]	From Police Services	00:50:27	Vehicle Collision	$0	11	6	0	0	0	0	0
P_PUS_6	2026-111	May 23 2026 02:17:57	[redacted]	From Police Services	00:51:37	Vehicle Collision	$0	7	5	0	0	0	0	0
P_PUS_6	2026-112	May 23 2026 07:08:55	[redacted]	From Ambulance	00:12:55	Call cancelled on route	$0	8	5	0	0	0	0	0
P_PUS_1	2026-113	May 24 2026 19:20:17	[redacted]	911	00:19:45	CO false alarm - perceived emergency (no CO present)	$0	12	5	0	0	0	0	0
P_PUS_2	2026-114	May 26 2026 14:08:00	[redacted]	From Ambulance	01:23:11	Vehicle Collision	$0	8	4	0	0	0	0	0
	2026-115	May 27 2026 10:57:51	[redacted]	Telephone from Civilian (other than 911)	00:00:01	Other Public Service	$0	7	3	0	0	0	0	0
P_PUS_5	2026-116	May 29 2026 16:10:58	[redacted]	911	00:07:23	Vehicle Collision	$0	7	3	0	0	0	0	0

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P_PUS_5	2026-116	May 29 2026 16:10:58	[redacted]	911	00:07:23	Vehicle Collision	$0	7	4	0	0	0	0	0
P_PUS_5	2026-117	May 29 2026 20:55:14	[redacted]	From Ambulance	00:00:00	Medical/resuscitator call no action required	$0	8	4	0	0	0	0	0
P_PUS_5	2026-118	May 29 2026 22:23:51	[redacted]	From Ambulance	00:04:40	Medical Aid Not Required on Arrival	$0	9	4	0	0	0	0	0
P_PUS_6	2026-119	May 30 2026 15:41:32	[redacted]	911	00:08:07	Open air burning/unauthorized controlled burning (no uncontrolled fire)	$0	12	5	0	0	0	0	0
P_PUS_4	2026-120	May 31 2026 12:06:17	[redacted]	Telephone from Civilian (other than 911)	00:06:38	Incident not found	$0	11	4	0	0	0	0	0
P_PUS_1	2026-121	May 31 2026 13:58:27	[redacted]	911	00:00:00	Vehicle Collision	$0	11	6	0	0	0	0	0
P_PUS_1	2026-122	May 31 2026 14:14:12	[redacted]	From Ambulance	01:28:48	Vehicle Collision	$0	11	6	0	0	0	0	0
P_PUS_1	2026-123	May 31 2026 16:25:55	[redacted]	Verbal Report to Station (in person)	00:31:13	Other Cooking/toasting/smoke/steam (no fire)	$0	12	4	0	0	0	0	0
P_PUS_1	2026-124	May 31 2026 21:25:34	[redacted]	911	00:14:09	CO false alarm - equipment malfunction (no CO present)	$0	8	5	0	0	0	0	0
P_PUS_1	2026-125	Jun 02 2026 00:16:34	[redacted]	911	00:19:39	Alarm System Equipment - Malfunction	$0	5	5	0	0	0	0	0
P_PUS_3	2026-126	Jun 03 2026 20:47:50	[redacted]	From Ambulance	00:06:59	Incident not found	$0	26	6	0	0	0	0	0

Reviewed Incidents only. Pt = Total Personnel, Pe = Personnel on 1st Unit, Re = Rescued, In = Firefighter Injuries, Fa = Firefighter Fatalities, CIn = Civilian Injuries, CFa = Civilian Fatalities.

P_PUS_3	2026-127	Jun 03 2026 23:49:28	[redacted]	From Ambulance	00:15:08	Vehicle Collision	$0	7	3	0	0	0	0	0
P_PUS_5	2026-128	Jun 05 2026 15:32:55	[redacted]	911	03:29:51	NO LOSS OUTDOOR fire (see exclusions)	None	11	2	0	0	0	0	0
P_PUS_1	2026-129	Jun 07 2026 03:02:38	[redacted]	911	00:29:08	Vehicle Collision	$0	7	5	0	0	0	0	0
P_PUS_1	2026-130	Jun 07 2026 21:28:27	[redacted]	Telephone from Civilian (other than 911)	00:18:56	CO false alarm - equipment malfunction (no CO present)	$0	9	5	0	0	0	0	0
P_PUS_1	2026-131	Jun 07 2026 22:33:25	[redacted]	911	00:35:23	CO false alarm - perceived emergency (no CO present)	$0	9	4	0	0	0	0	0
P_PUS_2	2026-132	Jun 09 2026 15:17:27	[redacted]	From Ambulance	00:22:07	Other Medical/Resuscitator Call	$0	7	4	0	0	0	0	0
P_PUS_4	2026-133	Jun 11 2026 12:33:41	[redacted]	From Police Services	00:13:12	Other Medical/Resuscitator Call	$0	5	5	0	0	0	0	0
P_PUS_6	2026-142	Jun 13 2026 14:32:00	[redacted]	911	00:00:00	Other Medical/Resuscitator Call	$0	8	6	0	0	0	0	0
P_PUS_3	2026-134	Jun 13 2026 17:02:36	[redacted]	911	00:27:23	Other False Fire Call	$0	13	4	0	0	0	0	0
P_PUS_3	2026-135	Jun 13 2026 17:46:30	[redacted]	911	00:13:45	Alarm System Equipment - Malfunction	$0	13	4	0	0	0	0	0
P_PUS_3	2026-136	Jun 13 2026 22:00:58	[redacted]	911	00:12:29	Incident not found	$0	11	5	0	0	0	0	0
P_PUS_3	2026-137	Jun 13 2026 23:28:59	[redacted]	From Police Services	01:32:56	Vehicle Collision	$0	9	6	0	0	0	0	0
P_PUS_2	2026-138	Jun 15 2026 21:08:53	[redacted]	From Ambulance	00:23:57	Vehicle Collision	$0	12	5	0	0	0	0	0

Reviewed Incidents only. Pt = Total Personnel, Pe = Personnel on 1st Unit, Re = Rescued, In = Firefighter Injuries, Fa = Firefighter Fatalities, CIn = Civilian Injuries, CFa = Civilian Fatalities.

P_PUS_3	2026-139	Jun 16 2026 07:35:10	[redacted]	911	00:19:49	Vehicle Collision	$0	9	3	0	0	0	0	0
P_PUS_3	2026-140	Jun 16 2026 08:12:01	[redacted]	From Ambulance	01:18:53	Vehicle Collision	$0	9	4	0	0	0	0	0
P_PUS_3	2026-141	Jun 16 2026 08:14:51	[redacted]	From Ambulance	01:36:38	Vehicle Collision	$0	9	2	0	0	0	0	0
P_PUS_5	2026-143	Jun 19 2026 12:05:52	[redacted]	Telephone from Civilian (other than 911)	00:21:26	Power Lines Down, Arcing	$0	4	2	0	0	0	0	0
P_PUS_5	2026-144	Jun 19 2026 17:06:20	[redacted]	From Police Services	00:48:44	Vehicle Collision	$0	12	5	0	0	0	0	0
P_PUS_1	2026-145	Jun 21 2026 14:13:00	[redacted]	From Ambulance	00:00:00	Vehicle Collision	$0	12		0	0	0	0	0
P_PUS_3	2026-146	Jun 24 2026 13:22:51	[redacted]	Telephone from Monitoring Agency	00:09:03	Alarm System Equipment - Accidental activation (exc. code 35)	$0	4	4	0	0	0	0	0
P_PUS_4	2026-147	Jun 25 2026 10:29:30	[redacted]	From Ambulance	00:00:05	Medical Aid Not Required on Arrival	$0	6	3	0	0	0	0	0
P_PUS_4	2026-148	Jun 25 2026 21:47:41	[redacted]	From Ambulance	00:28:24	Vehicle Collision	$0	11	4	0	0	0	0	0
P_PUS_6	2026-149	Jun 27 2026 10:32:14	[redacted]	911	00:06:44	Pot on Stove (no fire)	$0	11	2	0	0	0	0	0
P_PUS_6	2026-150	Jun 27 2026 11:46:48	[redacted]	From Ambulance	00:17:40	Vehicle Collision	$0	9	5	0	0	0	0	0
P_PUS_6	2026-151	Jun 27 2026 20:01:57	[redacted]	From Ambulance	00:02:20	Asphyxia, Respiratory Condition	$0	8	4	0	0	0	0	0
P_PUS_1	2026-152	Jun 28 2026 06:43:06	[redacted]	From Ambulance	00:00:15	Call cancelled on route	$0	6	4	0	0	0	0	0

Reviewed Incidents only. Pt = Total Personnel, Pe = Personnel on 1st Unit, Re = Rescued, In = Firefighter Injuries, Fa = Firefighter Fatalities, CIn = Civilian Injuries, CFa = Civilian Fatalities.

P_PUS_2	2026-153	Jun 30 2026 07:16:31	[redacted]		From Ambulance	00:21:17	Vehicle Collision	$0	9	3	0	0	0	0	0
P_PUS_2	2026-154	Jun 30 2026 07:54:12	[redacted]		Telephone from Civilian (other than 911)	00:07:21	Public Hazard call false alarm	$0	8	4	0	0	0	0	0

Reviewed Incidents only. Pt = Total Personnel, Pe = Personnel on 1st Unit, Re = Rescued, In = Firefighter Injuries, Fa = Firefighter Fatalities, CIn = Civilian Injuries, CFa = Civilian Fatalities.

REPORT FIN-2026-021

TO:	Mayor and Members of Council
PREPARED BY:	Mary Hasan, Director of Finance/Treasurer
PRESENTED BY:	Mary Hasan, Director of Finance/Treasurer
MEETING DATE:	September 16, 2026
SUBJECT:	2027 Proposed User Fees and Charges

RECOMMENDATIONS

That Report FIN-2026-021 entitled 2027 Proposed User Fees and Charges be received; and

That the Alcohol Risk Management Policy be brought forward to Council for consideration based on the recommendations outlined in this Report regarding security requirements and facility capacity limits; and

That Council direct staff to proceed with holding a Public Information Meeting on September 16, 2026 at 6:30 p.m. to obtain public input on the proposed User Fees and Charges By-law as outlined in Schedule A to Report FIN-2026-021; and

That staff report back to Council with the results of the public engagement process and Council's feedback into the final proposed 2027 User Fees and Charges By-law for consideration.

Purpose

The purpose of this report is to present the proposed 2027 User Fees and Charges By-law and obtain Council direction to proceed with a Public Information Meeting (PIM) to solicit input on the proposed User Fees and Charges.

The proposed fees have been developed in consultation with Township departments and reflect the Township's Budget Development and Control Policy, cost-recovery objectives, service delivery requirements and benchmarking against comparator municipalities.

Background

Municipalities may establish fees and charges for services, activities and the use of municipal property through a by-law approved by Council.

The Township's Budget Development and Control Policy provides that user fees and charges are to be adjusted annually based on the Ontario Consumer Price Index (CPI) from May to May. Where a new fee is proposed, or where an adjustment other than CPI is warranted, fees should reasonably reflect the cost of providing the service while remaining generally aligned with comparator municipalities.

The Ontario CPI increase from May 2025 to May 2026 was 2.60%. Accordingly, most existing 2026 user fees have been increased by 2.60% for 2027. The following sections identify those fees for which staff recommend a new fee, a change other than CPI, or a substantive change to the applicable fee structure.

Benchmarking Analysis

At its August 16, 2023 meeting, Council directed staff to undertake annual benchmarking of approximately 10 high-frequency user fees.

For the 2027 review, staff selected one representative fee from each of Schedules A through J and compared the Township's rates with applicable comparator and neighbouring municipalities, including the County of Wellington (County), Cambridge, Centre Wellington, Erin, Guelph, Guelph/Eramosa, Hamilton, Mapleton, Milton, Minto and Wellington North.

Table 1 summarizes the results.

Where Township fees are materially below comparator averages and the service supports greater cost recovery, staff have generally recommended an adjustment toward the comparator average. Benchmarking has not been applied in isolation; the nature of the Township's service or facility, local operating conditions, utilization and customer experience have also been considered.

Table 1: Benchmarking Analysis

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE WITH CPI	2027 RATE (NO TAX)	2026 Average
Agreements - Minor – Not Registered	Flat Fee	$305	$313	$379	$379
Rush Tax Certificate (NEW)	Per Rush Certificate	N/A	N/A	$93	$23 premium
Entrance Permit - Commercial/Industrial	Flat Fee	$482	$494	$537	$537
Fire Safety Plan Review	Per Plan	$146	$149	$189	$189
Interior Finishes and Alterations - All Classifications	Per Sq. Foot	$0.62	$0.63	$0.63	$0.61
Zoning By-Law Amendment	Note A	$17,925	$18,392	Note A	$15,301
Reinspection Fee	Flat Fee	$80	$82	$140	$140
Picnic Shelter	Per Day	$98.46	$101.02	$101.02	$119
Arena Floor - Resident Rental	Per Hour	$86.93	$89.19	$55	$88
Ice - Prime - Non-Resident Rental or Commercial Rental	Per Hour	$306.39	$314.36	$252	$252

Note A – See the Planning and Development section below for further information regarding the proposed changes to planning application fees, including the Zoning By-law Amendment fee.

Rush Tax Certificate

Staff recommend introducing an optional Rush Tax Certificate service at a fee of $93, providing a guaranteed processing time of 48 business hours following receipt of a complete request.

The service would respond to requests from lawyers and other parties requiring expedited certificates during time-sensitive transactions. Benchmarking indicates that municipalities offering an expedited service charge an average premium of approximately $23 above the standard tax certificate fee. The Township's proposed $23 premium is therefore generally consistent with comparator practices.

The regular five-business-day service would remain available. The proposed fee would allow customers requiring expedited service to obtain it while recovering the additional administrative costs associated with prioritizing the request.

Picnic Shelter

Staff recommend increasing the Picnic Shelter rental fee by CPI only.

Although the current fee is below the comparator average, the facility has limited amenities, including dated washrooms, no electricity, limited gravel parking and accessibility constraints. Utilization is also relatively low. Staff therefore do not recommend increasing the fee to the comparator average, as a significant increase may further discourage use of the facility.

Arena Floor and Prime Ice Rental Rates

Staff recommend reducing the Arena Floor and Prime Ice rental rates rather than applying the 2.60% CPI increase.

Although benchmarking indicates that the Township's 2026 rates are generally comparable to those of other municipalities, the Optimist Recreation Centre (ORC) is not directly comparable to fully enclosed arenas. The facility is weather dependent and exposed to environmental conditions such as dust, pollen, leaves and animal debris, which can affect operating conditions and the renter experience. In addition, the facility is not regulation-sized and its use is primarily recreational, limiting its ability to accommodate sanctioned events, competitive leagues and tournaments.

These facility limitations, together with renter feedback and utilization trends, support rates that reflect the ORC's level of service and functionality rather than relying solely on comparator averages.

<u>Administration and Planning and Development</u>

Land Registry Title Registrations, Releases and Corrections

Staff recommend establishing an administration fee of $250, plus applicable third-party costs, for requests relating to Township instruments registered on title and identified on a parcel register.

These requests can require staff review and coordination as well as legal, planning, engineering or other professional services. The proposed fee would recover the Township's administrative costs and ensure that property-specific costs are borne by the requesting party rather than the general tax base.

<u>Finance</u>

Online Service Fee

The Township currently charges an Online Service Fee of 1.75% to partially recover payment-processing costs. Customers may avoid the fee by using other available payment methods.

An analysis of Stripe transactions over the previous 12 months determined that processing costs averaged approximately 3.35% of transaction values. The current 1.75% fee therefore does not recover the Township's average processing costs.

Staff recommend changing the online service fee to 2.9% plus $0.37 per online transaction, consistent with the actual fee structure charged to the Township by its payment processor. The proposed fee would improve cost recovery and reduce the portion of online-payment processing costs funded through the general tax levy.

Fire and Rescue Services

Ministry of Transportation (MTO) Rate

The MTO increased the provincial highway fire-response rate effective January 1, 2026, from $570.50 to $583.05 per hour per full-size apparatus. The rate for qualifying auxiliary vehicles, which is set at 50% of the full-size apparatus rate, increased from $285.25 to $291.53 per hour per auxiliary vehicle.

The applicable rates have been incorporated into the proposed Fire and Rescue Services schedule. The Township's Pumper 32 qualifies for the auxiliary vehicle rate of $291.53 per hour.

Building

Building permit fees are intended to recover the Township's costs of administering and enforcing the *Building Code Act* and applicable regulations, including an allocation for administrative overhead and indirect costs. Where annual building permit revenues exceed expenditures, the surplus is transferred to the Building Surplus Reserve. The reserve is used to offset operating deficits in years where permit revenues are insufficient to recover the cost of delivering building services.

Table 2 summarizes the Township’s Building Surplus Reserve balance from 2022 to 2025.

Table 2: Building Surplus Reserve Balance from 2022 to 2025

Year	Building Surplus Reserve Balance
2022	$623,909
2023	$972,604
2024	$662,979
2025	$214,366

The Building Department recorded operating deficits of approximately $281K in 2024 and $434K in 2025. In 2025, actual revenues were approximately $332K compared with

expenditures of approximately $766K, resulting in the $434K operating deficit being funded from the Building Surplus Reserve.

For additional context, annual operating surpluses and deficits transferred to or from the Building Surplus Reserve from 2019 to 2025 were as follows:

- 2019 –$110K deficit
- 2020 – $51K deficit
- 2021 – $81K surplus
- 2022 – $39K surplus
- 2023 – $352K surplus
- 2024 – $281K deficit
- 2025 - $434K deficit

The reserve provides financial stability during periods when building activity and associated permit revenues are lower and current-year permit fees are insufficient to fully recover the cost of providing building services.

The Township's Employment Land Study, the proposed Aberfoyle Boundary Expansion, and the proposed reset of the rural residential severance date are intended to support future residential and non-residential growth. Increased development activity may result in additional building permit revenue and support future contributions to the Building Surplus Reserve; however, the timing and level of development activity will continue to vary from year to year.

Given the decline in the reserve balance over the past two years, staff recommend applying the standard 2.60% CPI increase to Building Department fees for 2027. Staff will continue to monitor building activity, permit revenues, operating expenditures and the adequacy of the Building Surplus Reserve as part of the annual budget and user fee review processes.

<u>Planning and Development</u>

Planning Application Administration Fee Model

Staff recommend returning to an administration fee plus applicable third-party cost-recovery model for *Planning Act* applications.

In recent years, changes to the *Planning Act* and related provincial requirements have affected how municipalities can structure and recover development application costs. In response, the Township has implemented and evaluated a number of different fee approaches.

Based on this experience, staff have determined that an administration fee model, combined with recovery of applicable third-party costs, would better align fees with the actual level of effort required to process individual applications.

Application complexity varies significantly. Under the current flat-fee approach, routine and complex applications may be charged similar fees even though complex applications can require substantially greater staff coordination, consultant review, meetings and technical analysis. This can result in application-processing costs being subsidized through the general tax levy.

Under the proposed model, the fixed administration fee would recover the Township's internal processing costs, while variable professional and legal costs would be recovered from the applicant based on the actual level of review required for each application or agreement, where applicable.

Applicable third-party costs would be recovered in addition to the administration fee and may include, but are not limited to, planning, engineering, environmental, hydrogeological, legal or other professional review services required to process or assess an application, permit, licence or agreement, or to review supporting technical studies.

The specific administrative activities and applicable third-party costs associated with each application type are outlined below.

Preliminary Planning Consultation and Comprehensive Development Consultations

Staff recommend establishing administration fees of $173 for a Preliminary Planning Consultation and $388 for a Comprehensive Development Consultation, plus applicable third-party costs. Staff further recommend that these fees no longer be credited toward a subsequent planning application.

The consultation itself requires staff resources and provides a separate service to the applicant. Removing the credit is also consistent with the proposed administration fee model, under which each stage of the development review process is intended to recover the costs associated with that service.

Applicants who completed a Preliminary Planning Consultation or Comprehensive Development Consultation in 2025 or 2026 will be advised that the existing credit may be applied to eligible applications submitted by December 31, 2026.

Zoning By-law Amendment

Staff recommend establishing an administration fee of $2,809, plus applicable third-party costs, for Zoning By-law Amendment applications.

Applicable administration costs may include, but are not limited to:

1.) facilitating the application review process and preparing consolidated peer review comment summaries for the applicant;
2.) preparing and issuing required notices and advertisements, including Notice of Complete Application, PIM notices and Notice of Decision;
3.) reviewing the application and coordinating comments from Township departments;
4.) preparing staff reports and related materials, including reports respecting application completeness, Planning and Development Advisory Committee consideration, the PIM and final recommendation report; and
5.) coordinating and facilitating meetings involving Council, the Planning and Development Advisory Committee, PIM(s), Township consultants and the applicant, as required.

Applicable third-party costs may include, but are not limited to:

1.) planning reports prepared by the Township's planning consultant;
2.) peer review of technical studies by Township consultants; and
3.) additional consultation or technical review by Township consultants where requested or required during the application process.

Site Plan Control Application and Agreement

Staff recommend establishing an administration fee of $1,057, plus applicable third-party costs, for Site Plan Control Applications and Agreements.

Applicable administration costs may include, but are not limited to:

1.) facilitating the application review process and preparing consolidated peer review comment summaries for the applicant;
2.) reviewing the application and coordinating comments from Township departments;
3.) coordinating and facilitating meetings involving Township consultants and the applicant, as required; and
4.) preparing and facilitating the Site Plan Control Agreement.

Applicable third-party costs may include, but are not limited to:

1.) peer review of technical studies by Township consultants;

2.) additional consultation or technical review by Township consultants where requested or required;
3.) preparation of the Site Plan Control Agreement by Township consultants; and
4.) registration of the Site Plan Control Agreement by the Township's legal counsel.

Site Plan Control Agreement Securities

Staff recommend incorporating the Site Plan Control Agreement security calculation into the User Fees and Charges By-law to improve transparency and consistency in how securities are calculated.

The calculation is:

- An amount equal to 50% of the site-servicing costs, including earthworks such as fill importation, cutting and grading, plus 50% of the landscaping costs, together with an additional 5% of the construction costs for site-servicing and landscaping to cover the Township's engineering review.

Including the calculation directly in the By-law will provide applicants with greater clarity regarding the Township's security requirements and support consistent application of the calculation to Site Plan Control Agreements.

Minor Variance

Staff recommend establishing an administration fee of $568, plus applicable third-party costs, for Minor Variance applications.

Applicable administration costs may include, but are not limited to:

1.) facilitating the application review process and preparing consolidated peer review comment summaries for the applicant;
2.) preparing and issuing required notices, including Notice of Public Hearing and Notice of Decision;
3.) reviewing the application and coordinating comments from Township departments; and
4.) coordinating and facilitating meetings involving the Committee of Adjustment, Township consultants and the applicant, as required.

Applicable third-party costs may include, but are not limited to:

1.) planning reports prepared by the Township's planning consultant;
2.) peer review of technical studies by Township consultants, where required; and

3.) additional consultation or technical review by Township consultants where requested or required.

Minor Variance Deferral

Staff recommend establishing an administration fee of $284, plus applicable third-party costs, where a Minor Variance application is deferred by the Committee of Adjustment or at the request of the applicant after notice of the public hearing has been issued.

Applicable administration costs may include, but are not limited to:

1.) preparing and issuing a subsequent Notice of Public Hearing; and
2.) coordinating and facilitating an additional Committee of Adjustment meeting.

Applicable third-party costs may include, but are not limited to:

1.) preparation or revision of the planning recommendation report by the Township's planning consultant;
2.) peer review of technical studies by Township consultants, where required; and
3.) additional consultation or technical review by Township consultants where requested or required.

Consent Consultation

Staff recommend establishing an administration fee of $173, plus applicable third-party costs, for the Township's review of County Consent applications where the Township is a commenting authority.

Applicable administration costs may include, but are not limited to:

1.) coordinating Township staff review and technical peer review, where required;
2.) coordinating and facilitating consideration by the Planning and Development Advisory Committee; and
3.) preparing and submitting the Township's municipal commenting form to the County.

Applicable third-party costs may include, but are not limited to:

1.) preparation of the planning recommendation report by the Township's planning consultant;
2.) peer review of technical studies required to support the Township's recommendation, where required;

3.) peer review of technical studies required to clear conditions of consent, where required; and
4.) additional consultation or technical review by Township consultants where requested or required.

External Development Application Studies Review – County

Staff recommend establishing an administration fee of $1,998, plus applicable third-party costs, where the Township is a commenting authority on a development application for which the County is the approval authority.

The fee would apply to applications including Official Plan Amendments, Plans of Subdivision and Plans of Condominium.

Applicable administration costs may include, but are not limited to:

1.) preparing and issuing notification of PIMs;
2.) coordinating and facilitating PIMs; and
3.) coordinating technical peer review and preparing and submitting Township comments to the County.

External Development Application Studies Review – Other

Staff recommend establishing an administration fee of $100, plus applicable third-party costs, where the Township is requested or required to review and comment on a development application, permit or licence for which another government, agency or approval authority is responsible.

This may include requests received directly from another level of government or agency, from a proponent, or through a legislated consultation process.

Where the Township has submitted an objection to a mineral aggregate application under the *Aggregate Resources Act* or to a Permit to Take Water under the *Ontario Water Resources Act*, staff further recommend that the Township not withdraw or release its objection until all outstanding third-party costs incurred by the Township in reviewing the application have been paid in full.

By-law

Designated Official Meetings

Staff recommend reducing the Designated Official Meeting fee to an administration fee of $250, plus applicable third-party costs.

The professional resources required for these meetings vary depending on the nature of the request and the specific technical questions raised by the applicant.

The administration fee is intended to recover the Township's internal costs associated with coordinating and facilitating the meeting.

Applicable third-party costs may include, but are not limited to:

1.) preparation and review of documentation by Township consultants;
2.) attendance by Township consultants at the meeting; and
3.) additional consultation or technical review by Township consultants following the meeting, where requested or required.

General Facility Rental Provisions

Township Employee Facility Rental Rate

Staff recommend that current Township employees be eligible for the applicable resident rental rate when renting a Township facility or park for personal use.

Eligibility would be limited to rentals where the employee is the named renter and is present during the rental. The benefit would not be transferable and would not apply to business, organizational or third-party bookings.

All other applicable fees, deposits, insurance requirements and rental conditions would continue to apply.

The proposed provision recognizes employee contribution and supports employee wellness, active living and engagement with Township facilities and parks while continuing to generate rental revenue. The financial impact is anticipated to be minimal.

ORC

Arena Floor and Gymnasium – Full Day Rental

Staff have received several inquiries regarding full-day rentals of the arena floor and gymnasium.

Staff recommend establishing a maximum full-day rental fee equivalent to eight hours at the applicable 2027 hourly rate. This would provide greater cost certainty for renters requiring extended use of either space while maintaining the applicable hourly rate for shorter rentals and establishing a consistent approach to full-day rentals at the ORC.

ORC Ice Rentals

Based on Council's previous direction, staff have continued to monitor ORC ice rental activity and revenues.

Ice rental activity during the 2025–2026 season was lower than the previous season, primarily because a significant third-party rental arrangement that generated a substantial number of booked hours was not renewed. Staff have also received feedback regarding the affordability and competitiveness of the Prime Ice rental rate and have experienced cancellations or lost rentals due, in part, to the weather-dependent nature of the facility.

Table 3 summarizes Prime Ice rental revenues from 2022 to 2026 year to date.

Table 3: Prime Ice Rental Revenues – 2022 to 2026 Year to Date

2022 Actuals	2023 Actuals	2024 Actuals	2025 Budget	2025 Actuals	2026 YTD	2026 Budget
$36,021	$23,542	$35,991	$38,867	$34,134	$26,672	$38,867

Based on current rental activity and historical trends, the $26,672 noted in Table 3 is anticipated to represent approximately the final revenue figure for 2026.

Prime Ice rental hourly resident rates, net of HST, have changed as follows:

- 2022 - $171
- 2023 Rate - $184
- 2024 Rate - $234

- 2025 Rate - $241
- 2026 Rate - $245 resident / $306 non-resident
- 2027 Proposed Rate - $202 resident / $252 non-resident

The increase in the 2024 rate was recommended through Report FIN-2023-030 at the October 18, 2023, Council Meeting following benchmarking completed at that time.

A significant proportion of facility users are non-residents. With the introduction of the non-resident rate in 2026, together with previous increases to the hourly rental rate, the overall cost of using the facility has increased. Staff have observed that these combined increases may be affecting the facility's affordability, competitiveness and utilization.

As noted above, the ORC is not directly comparable to a fully enclosed, regulation-sized arena. Its weather-dependent operating conditions and functional limitations reduce the range of activities and events that can be accommodated and should therefore be considered when establishing an appropriate rental rate.

As outlined in the benchmarking section of this report, staff recommend reducing the 2027 Prime Ice resident rate to $202 per hour and the corresponding non-resident rate to $252 per hour. The proposed reduction is intended to better reflect the nature and functionality of the facility, improve its competitiveness and encourage increased utilization.

<u>Puslinch Community Centre (PCC)</u>

PCC Revenue Analysis

At its March 26, 2025 meeting, Council, through Resolution No. 2025-105, directed staff to report on PCC rental revenues and the impact of updated facility capacity limits.

This matter was subsequently addressed through Report FIN-2025-029 – *2026 Proposed Operating Budget*, presented to Council on December 17, 2025. At that time, staff recommended maintaining the 2026 PCC revenue budget at 2025 levels while monitoring whether programming enhancements and Recreation and Parks Master Plan recommendations would support increased future utilization and revenue.

Council had previously approved revised PCC capacity limits on November 8, 2023, establishing a maximum capacity of 150 persons for non-resident rentals and 250 persons for resident rentals. These limits were incorporated into the Township's Facility Rental Agreements and Alcohol Risk Management Policy and came into effect in late 2023/early 2024.

Table 4 provides a comparison of PCC rental revenues prior to the COVID-19 closures and following implementation of the revised capacity limits.

Table 4: PCC Revenue Analysis

	Actual Revenues						
Description	2019 (pre-COVID)	2022	2023	2024	2025	2026 Year to Date	2026 Budget
Hall - Commercial	$1,547	$ -	$ -	$ -	$ -	$1,044	$1,016
Hall – Non-Prime	$19,969	$14,975	$20,756	$20,682	$15,733	$12,447	$21,047
Hall – Prime	$29,365	$15,587	$26,770	$19,859	$18,690	$17,976	$34,739
Kitchen – Non-Prime	$3,143	$686	$2,357	$3,886	$2,147	$1,602	$3,809
Licensed Events Using Patio	$285	$181	$126	$317	$152	$0	$346
Meeting Room	$13,427	$4,143	$11,047	$9,009	$6,850	$4,747	$11,378
Total	$67,736	$35,572	$61,055	$53,754	$43,573	$37,816	$72,335

Based on 2026 year-to-date revenues of approximately $38K, staff project total 2026 PCC rental revenues of approximately $57K. This represents a projected shortfall of approximately $16K compared with the 2026 budget of approximately $72K.

Staff do not recommend reducing PCC rental rates at this time. Instead, staff recommend addressing certain operational requirements that may be creating barriers to rental activity and affecting the overall customer experience.

The Township's facility staffing complement has improved and now includes three full-time facility staff. Full-time coverage for evening and weekend rentals has been in place and facility staff are scheduled to be present at large events. Some existing rental requirements were introduced, in part, during periods of staff vacancies and turnover. The improved staffing complement provides an opportunity to reassess whether those requirements remain appropriate.

Full-Day Rental Period

The current 12-hour full-day rental period must accommodate event set-up, the event itself and clean-up. For larger events, this can limit flexibility and may require renters to purchase additional hours, increasing the overall cost of the rental.

Staff recommend extending the full-day rental period to 10:00 a.m. to 1:00 a.m. This would provide additional flexibility for larger events while maintaining defined rental hours and appropriate facility oversight.

Staff recommend that the proposed full-day rental period be increased from 12 hours to 15 hours and that the applicable PCC fee schedule and rental requirements be updated

accordingly. Any additional-hour charges would apply only beyond the 15-hour full-day rental period.

Security Requirements for Licensed Events

The current Alcohol Risk Management Policy generally requires private security for licensed events. Staff have received feedback that this requirement can increase rental costs, particularly for lower-risk events where security personnel primarily provide a visible presence.

Given the improved facility staffing complement and the presence of Township staff at large events, staff recommend replacing the blanket private-security requirement with a risk-based approach.

Under this approach, trained Township facility staff could provide monitoring and initial response for lower-risk licensed events. Private security would continue to be required where warranted based on factors such as anticipated attendance, event type, event history or other identified risks.

Facility Capacity Limits

The current capacity limits must continue to reflect the operational limitations of the PCC, including the capacity of its well, septic system and aging infrastructure.

Given the improved staffing complement and increased staff presence at large events, staff recommend reviewing the existing capacity limits to determine whether a modest increase can be supported while maintaining appropriate infrastructure, operational and public-safety safeguards.

Related Policy and Rental Requirement Amendments

The proposed changes to security requirements and facility capacity limits are separate from the User Fees and Charges By-law and would require corresponding amendments to the applicable facility rental requirements and Alcohol Risk Management Policy.

Staff recommend that these amendments be brought forward for Council consideration through the appropriate amendments to the Alcohol Risk Management Policy.

Collectively, these changes are intended to reduce barriers for renters, improve the attractiveness and value of the PCC, and support increased utilization while maintaining appropriate public-safety, staffing and infrastructure safeguards.

Financial Implications

The proposed 2027 User Fees and Charges will be incorporated into the 2027 Operating Budget.

The majority of existing fees are proposed to increase by 2.60% in accordance with the Township's Budget Development and Control Policy. The exceptions outlined in this report are intended to improve cost recovery, align fees with the level of service provided, or respond to facility utilization and operating conditions.

The proposed reductions to certain ORC rental rates and the Township employee resident-rate provision may result in lower revenue on individual rentals; however, these changes are intended to encourage utilization. The PCC operational changes are similarly intended to reduce barriers to rentals without reducing the applicable PCC rental rates.

The overall financial impact will depend on utilization and will be monitored through the 2027 operating year.

Strategic Plan Alignment and Implications

Strategic Priority #4: Good Governance, Financial Stewardship, and Organizational Excellence
This report supports Strategic Priority #4 by promoting responsible financial management, transparent decision-making, and long-term municipal sustainability.

Objective 4.2: Maintain Financial Stewardship
The proposed User Fees and Charges apply the Township’s established fee methodology while considering service-delivery costs, cost recovery, comparator rates, facility utilization and local operating conditions.

Regular review of user fees supports predictable budgeting, legislative compliance, appropriate allocation of service costs, and a measured approach to fee adjustments, helping to avoid significant or unexpected changes in future years.

Action 4.2(d): Continue to Provide Financial Stewardship
The annual review of User Fees and Charges supports Action 4.2(d) by ensuring anticipated revenues are appropriately reflected in the operating budget, fees remain aligned with Council-approved policies and service levels, and Council receives transparent information to support financial decision-making.

Applicable Legislation and Requirements

The following legislation provides authority relevant to the Township's User Fees and Charges By-law:

- Section 391(1) of the *Municipal Act, 2001*;
- Section 7(1) of the *Building Code Act, 1992*; and
- Section 69 of the *Planning Act*.

Engagement Opportunities

The Township will provide the following opportunities for public and stakeholder input on the proposed 2027 User Fees and Charges:

- Recreation and Community Wellness Advisory Committee input;
- social media posts and advertisements through the Township's social media channels;
- information on the Township website and Budget webpage at puslinch.ca/government/budget/;
- a community engagement survey through EngagePuslinch.ca, open from September 1, 2026 to September 28, 2026 at 12:00 p.m.;
- Wellington Advertiser advertising;
- a PIM on September 16, 2026 at 6:30 p.m.; and
- media releases promoting the EngagePuslinch.ca community engagement survey.

Staff will report back to Council on the feedback received prior to the final 2027 User Fees and Charges By-law being presented for Council consideration.

Attachments

Schedule A: Proposed User Fees and Charges By-law

Respectfully submitted:	Contributors:	Reviewed by:
Mary Hasan, Director of Finance/Treasurer	Andrew Hartholt, Chief Building Official Connie Smith, Financial Assistant Daniel Hernandez, Taxation and Revenue Coordinator Justine Brotherston, Director of Corporate Services/Municipal Clerk Kari Pond, Procurement and Agreement Coordinator Laura Emery, Manager of Corporate Services/Deputy Clerk Michael Chant, Fire Chief Michelle Cassar, Deputy Treasurer Mike Fowler, Director of Public Works and Capital Projects Management Sarah Huether, Director of Community Services and Human Resources	Courtenay Hoytfox, Chief Administrative Officer

THE CORPORATION OF THE TOWNSHIP OF PUSLINCH

BY-LAW NO 2026-XXX

A by-law to permit the Municipality to impose fees or charges with respect to services or activities provided, related costs payable, and for the use of its property, and to repeal By-law 2025-084.

WHEREAS Section 391(1) of the *Municipal Act, 2001, S.O. 2001, c. 25*, as amended, a municipality may pass By-laws imposing fees or charges for services or activities provided or done by or on behalf of it, for costs payable by it for services or activities provided or done by or on behalf of any other municipality or any local board, and for the use of its property including property under its control; and

WHEREAS Section 7(1) of the *Building Code Act, 1992, S.O. 1992, c. 23,* as amended, provides that a municipality may pass By-laws imposing fees and charges; and

WHEREAS Section 69 of the *Planning Act, R.S.O. 1990, c.P.13,* as amended provides that the Council of a municipality may by By-law establish a tariff of fees for the processing of applications made in respect of planning matters; and

WHEREAS The Council of the Corporation of the Township of Puslinch deems it appropriate to update the Township's User Fees and Charges By-law.

NOW THEREFORE the Council of the Corporation of the Township of Puslinch enacts as follows:

1. For the purpose of this By-law:

a.) **"Cost(s)"** means any and all disbursements incurred by the municipality, and includes, but is not restricted to, any registration costs, title search costs, corporate search costs, survey costs, reference plan costs, advertising costs, outside counsel fees, paralegal fees, site inspection costs and any applicable taxes;

b.) **"Fire Department"** means a fire department established by the Township of Puslinch in accordance with the provisions of the *Fire Protection and Prevention Act, 1997, S.O. 1997, c. 4* as amended;

c.) **"Fire Department Specific Response Fees"** means cost recovery fees for **fire department** attendance at a **property** for which the **property owner(s)** have **fire department** insurance coverage;

d.) **Indemnification Technology®** shall mean **fire department** incident reporting, data collection and **property** insurance policy wording interpretation to maximize billing opportunities on behalf of fire departments by invoicing insurance companies for costs of fire department attendance with respect to insured perils;

e.) **"Property"** means any real property located within the geographical boundaries of the Township of Puslinch. Real property includes buildings, contents and structures of any nature and kind in or upon such lands to which service is provided. Real property can also include **property** to which the **fire department** is under a service agreement to provide **fire department** response services, automatic aid or mutual aid.

f.) **"Property Owner(s)"** means the registered owner of **property** or any person, firm, corporation, partnership or society and their heirs, executors, administrators or other legal representatives, including a property manager, tenant, occupant, mortgagee in possession, receiver, manager, trustee or trustee in bankruptcy having control over or possession of the **property** or any portion thereof;

g.) **"Township"** means the Corporation of the Township of Puslinch.

draft

2. The fees, costs and charges, as outlined in the schedules attached hereto and forming part of this By-law shall be automatically adjusted annually based on the Consumer Price Index for Ontario from May to May.

3. Any person requesting, applying or utilizing the services, applications or approvals listed in the attached schedules and forming part of this By-law shall pay the fees listed for that service, application or approval as set out in the attached schedules.

4. These fees, **costs**, and charges are applicable to residents and non-residents at the rates noted unless there is a specified exemption in the attached schedules.

5. No request by any person for a service, application or approval listed in the attached schedules shall be acknowledged or performed by the **Township** unless and until the person requesting the service, application or approval has paid the fees, **costs** or charges as set out in the attached schedules, unless noted otherwise.

6. All **Township** accounts and invoices are due and payable when rendered.

7. All unpaid fees, **costs** or charges imposed by this By-law on a person constitute a debt of the person to the **Township**.

8. The Treasurer shall add the fees, **costs** and charges imposed pursuant to this By-law to the tax roll for any **property** in the **Township** for which all of the **property owners** are responsible for paying the fees, **costs** and charges under this By-law and collect them in the same manner as municipal taxes in accordance with Section 398 of the *Municipal Act, 2001, S.O. 2001, c. 25* as amended.

9. If third-party **costs** are incurred by the **Township** in the processing or review of an application or approval by the **Township**, the applicant or requesting party is required to pay these **costs** to the **Township**. The following are the applications, permits, licences, agreements, reviews, or approvals subject to third-party **costs:**

    a. Agreements – Subdivision/Condominium
    b. Application Reactivation
    c. Comprehensive Development Consultation
    d. Consent Consultation
    e. Consent Review and Condition Clearance - Safe Access Clearance
    f. Consultation – Subsequent Submissions
    g. Designated Official Meeting
    h. External Development Application Studies Review – County of Wellington
    i. External Development Application Studies Review – Other
    j. Garden Suites and Renewals (Zoning)
    k. Land Registry Title Registrations, Releases and Corrections
    l. Lifting of Holding Designation (Zoning)
    m. Minor Variance
    n. Minor Variance Deferral
    o. Part Lot Control Exemption By-law
    p. Preliminary Planning Consultation
    q. Radiocommunication Tower Pre-Consultation Fee
    r. Radiocommunication Tower Proposals
    s. Red Line Agreement Review
    t. Sign Refusal Appeal - Council Approval
    u. Sign Variance - Council Approval
    v. Sign Variance - Staff Approval
    w. Site Alteration Normal Farm Practices Waiver
    x. Site Alteration Permit Application Fee - Minor
    y. Site Alteration Permit Application Fee – Intermediate
    z. Site Alteration Permit Application Fee – Large
    aa. Site Alteration Permit Application Fee – Major
    bb. Site Plan Control Application and Agreement
    cc. Third and Subsequent Submission
    dd. Third Party Cost Recovery
    ee. Zoning By-law Amendment – Aggregate

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ff. Zoning By-law Amendment

10. The **Township** is not obligated to further process or review an application, permit, licence, agreement, review or approval, or provide further comments in respect of such matter, until all outstanding third-party **costs**, fees and other disbursements have been paid by the applicant or requesting party.

11. Where the Township has submitted an objection to an application under the *Aggregate Resources Act* or to a Permit to Take Water under the *Ontario Water Resources Act*, the Township shall not withdraw or release its objection until all outstanding third-party costs incurred by the Township in reviewing the application have been paid in full.

12. The fees, **costs** and charges listed in the schedules to this By-law shall, where applicable, be subject to any applicable provincial and federal taxes.

13. Any fee, **cost** or charge:

    a. authorized by a by-law or council resolution that comes into effect on the same or a later date than this By-law; or

    b. included in a valid agreement entered into by the **Township** and one or more other parties,

    shall be the approved and imposed fee, **cost** or charge for the service, activity or use of **property** specified.

14. The payment of any fee**, cost** or charge in this By-law shall be in Canadian currency.

15. The following Schedules form part of this By-law:

Schedule	Department
A	Administration
B	Finance
C	Public Works
D	Fire and Rescue Services
E	Building
F	Planning and Development
G	By-law
H	Parks
I	Optimist Recreation Centre
J	Puslinch Community Centre

16. The fees, **costs** and charges, as outlined in the schedules attached hereto and forming part of this By-law, shall be implemented and take effect on January 1, 2027.

<u>Fire Department Specific Response Fees</u>

17. The **property owner** shall be responsible for the payment of **fire department specific response fees** imposed by this By-law in accordance with Schedule D attached to this By-law.

18. The **Township** may use **Indemnification Technology®** to assess applicable insurance coverage for **fire department specific response fees**.

19. Where the **Township** believes and/or **Indemnification Technology®** indicates **fire department specific response fees** are applicable but the **property owner** does not have, in part or in full, insurance coverage for **fire department** charges for the **property**, the **Township** may adjust the **fire department specific response fees** to the extent of insurance coverage upon provision by the **property owner** of evidence, to the satisfaction of the **Township**, that no such insurance coverage exists or to demonstrate the limits of such coverage.

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Cancellation Terms – Parks, Optimist Recreation Centre, Puslinch Community Centre

20. A refund of 80 percent will be provided where 30 days' notice of cancellation is given prior to the rental date for the following:

    a. Puslinch Community Centre rentals.
    b. Parks and Optimist Recreation Centre rentals of eight or more bookings.

21. A full refund will be provided where 72 hours or 3 days' notice of cancellation is given prior to the rental date for Parks and Optimist Recreation Centre rentals.

Payment Terms – Parks, Optimist Recreation Centre, Puslinch Community Centre

22. One-Time Rentals - Payment is required within five business days of contract creation.

23. Recurring Rentals Throughout the Year - Payment is required on a quarterly basis. The first payment is required within five business days of contract creation. Future payments are required quarterly.

24. Recurring Seasonal Bookings - Payment is required in two instalments. The first payment is required within five business days of contract creation. The second payment is required halfway through the season.

Exemptions, Fee Waivers, Fee Reductions

25. Government organizations are exempt from the agreement fees imposed by this By-law.

26. The Optimist Club of Puslinch is exempt from the photocopy fees imposed by this By-law for **Township** Clean-up and Remembrance Day. The Aberfoyle Agricultural Society is exempt from the photocopy fees imposed by this By-law for the Fall Fair and the Junior Garden Club.

27. The following events are exempt from the rental fees imposed by this By-law:

    a. Fall Fair
    b. Santa Claus Parade
    c. Canada Day
    d. Family Day
    e. Remembrance Day
    f. Local Growers Event

28. The Winter Classic Tournament held during the Family Day Long Weekend including events held on the statutory holiday are exempt from the payment of rental fees with the exception of staffing **costs.**

29. The following requests are not eligible for a fee reduction or waiver:

    a. Religious services
    b. Licences, development charges, cash in lieu of parkland, planning fees, permits, inspections, insurance, personnel costs

30. Where the Township is the applicant for a permit related to Township-owned property, the applicable permit fee shall be waived. This exemption applies only where the Township is both the property owner and the applicant.

31. Eligible organizations can obtain one complimentary two-hour room rental for one meeting during non-prime times in the Meeting Room.

32. Usage of **Township** property must comply with the **Township**'s requirements including but not limited to necessary insurance, permits and approvals within the required timelines.

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33. A current employee of the Township shall be eligible for the applicable resident rental rate when renting a Township facility or park for personal use, provided that:

    a. the employee is the named renter on the rental agreement;
    b. the employee is present for the duration of the rental;
    c. the rental is for the employee's personal use and is not made on behalf of, or for the benefit of, a business, organization, association, group or other third party; and
    d. the benefit is not transferable.

    For greater certainty, eligibility for the resident rental rate under this section does not exempt the employee from any other applicable fees, charges, deposits, insurance requirements, permits, terms and conditions, or rental requirements imposed by the Township.

34. Reduced rates are not offered during prime-time for facilities or parks that have a prime-time and non-prime time rate.

35. A 90% reduced rate shall apply to Seniors' Community Events that meet the eligibility criteria.

36. A 90% reduced rate shall apply to Whistle Stop Co-operative Pre-school and Guelph Community Health Centre (The Playgroup).

37. Seniors' Recreation Programs that meet the eligibility criteria shall receive a 50% reduced rate.

38. A 75% reduced rate shall apply to organizations that host community events and meet the eligibility criteria.

39. All other organizations that meet the eligibility criteria shall receive a 50% reduced rate.

Reduced Rate Eligibility Criteria

40. Organizations applying for a reduced rate must meet the following eligibility criteria:

    a. Be in existence for at least one year; and
    b. have its principal address in the **Township**; and
    c. be a not-for-profit organization or an unincorporated community group; and
    d. offer services that benefit the **Township** and its residents; and
    e. be in good financial standing with the **Township** and not in litigation with the **Township**; and
    f. be in compliance with any other **Township** by-laws and policies; and,

For the purposes of this By-law, Puslinch Minor Sports Organizations, Puslinch Religious Organizations, Guelph Community Health Centre (The Playgroup), YMCA/YWCA of Guelph, Hospice Wellington, and the Aberfoyle Agricultural Society are deemed to meet the eligibility criteria.

41. For the purposes of this By-law, services that benefit the **Township** and its residents include:

    a. Charitable community services
    b. Artistic endeavours, including literature, dance, music, theatre, painting, sculpture, movies, photography and live performances
    c. Specific cultural and heritage activities
    d. Programs that improve the health and well-being of the community
    e. Programs that encourage participation in organized athletic activities
    f. Services or events directed for youth and older adults
    g. Public safety enhancement services

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42. The following organizations are not eligible for a reduced rate:

    a. Adult sports organizations ie. Old Timers, Puslinch Kodiak's, Morriston Men's League, The Aberfoyle Dukes.
    b. County, Provincial and Federal organizations.
    c. Groups or organizations affiliated with any political party or event.
    d. Individuals, commercial organizations, and coalitions such as ratepayer associations.
    e. Hospitals, hospital foundations and hospital auxiliary groups or agencies.
    f. Educational institutions including universities, colleges, schools and associated auxiliary groups.

43. The following information will be required to review an organization's eligibility:

    a. A copy of the letters patent or articles of incorporation, if applicable.
    b. A copy of its Notification of Charitable Registration letter from the Canada Revenue Agency with any supporting documentation indicating the organization's status and terms of registration, if applicable.
    c. A copy of mandate, constitution and by-laws, as applicable.
    d. A copy of the reporting as outlined in Paragraph 44 of this By-law.

44. In order to maintain the reduced rate eligibility status, the following information must be submitted annually electronically on the Township's website at www.puslinch.ca by 2:00 pm on the last business day of January or to the attention of the Community Services Department at the address noted below:

    The Corporation of the Township of Puslinch
    7404 Wellington Road 34
    Puslinch, ON, N0B 2J0
    Attention: Reduced Rate Eligibility Program

    a. Number of resident and non-resident participants; and,
    b. Financial reports for membership fees and/or donations collected for the programming/services including how the funds are used to support the program/service.

45. Should any part of this By-law including any part of the schedules, be determined by a Court of competent jurisdiction to be invalid or of no force and effect, such invalid part of the By-law shall be severable and that the remainder of this By-law including the remainder of the Schedules, as applicable, shall continue to operate and to be in force and effect.

46. This By-law shall be known as the "User Fees and Charges By-law".

47. That By-law No. 2025-084 is hereby repealed, effective January 1, 2027.

READ A FIRST, SECOND AND THIRD TIME AND FINALLY PASSED THIS 7th DAY OF OCTOBER 2026.

_____
James Seeley, Mayor

_____
Justine Brotherston, Municipal Clerk

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SCHEDULE A: ADMINISTRATION USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Agreements - Major - Not Registered	Flat Fee	$613.00	$629.00	$0.00	$629.00	2.6%	E	For recovery of the costs of facilitating and preparing agreements, ie. a lease agreement on Township lands. See Report FIN-2024-024.
Agreements - Minor - Not Registered	Flat Fee	$305.00	$379.00	$0.00	$379.00	24.3%	E	For recovery of the costs of facilitating and preparing agreements, ie. miscellaneous agreements. See Report FIN-2024-024 and Report FIN-2026-021.
Agreements - Registered	Flat Fee	$1,505.00	$1,544.00	$0.00	$1,544.00	2.6%	E	For recovery of the costs of facilitating and preparing agreements, ie. an encroachment agreement or a conditional building permit. See Report FIN-2024-024.
Red Line Agreement Review *	Administration fee	$101.00	$103.00	$0.00	$103.00	2.0%	E	See Report FIN-2024-024
Title Search	Flat Fee	$178.00	$182.00	$0.00	$182.00	2.2%	E	See Report FIN-2024-024
Land Registry Title Registrations, Releases and Corrections *	Administration fee	N/A	$250.00	$0.00	$250.00	100.0%	E	See Report FIN-2026-021.
Burial Permit/Death Registration	Flat Fee	$45.00	$46.00	$0.00	$46.00	2.2%	E	See Report FIN-2025-028
Doors of Puslinch Poster	Per Poster	$10.17	$10.43	$1.36	$11.79	2.6%	T	See Report FIN-2024-028
Freedom of Information	Charged at the rate permitted per the legislation.						E	Regulated by Statute - See Report FIN-2017-024.
Logo Pins	Per Pin	$5.09	$5.22	$0.68	$5.90	2.6%	T	See Report FIN-2024-024
Routine Disclosure	Per Request	$5.09	$5.22	$0.00	$5.22	2.6%	E	Note 1
Signature of Commissioner	Per Document	$26.46	$27.15	$3.53	$30.68	2.6%	T	See Report FIN-2024-024
Third Party Cost Recovery	Actual costs incurred + $100.00 cumulative administration fee for all invoices						T	Material, equipment, labour/benefits, administration costs, third party consultant/specialist costs - See Report FIN-2020-034

* the fees denoted with an asterisk are also subject to applicable third-party costs in accordance with this By-law.

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SCHEDULE A: ADMINISTRATION USER FEES AND CHARGES
EFFECTIVE 2027

Note 1: Routine Disclosure									
Applies to records that may not be subject to the Municipal Freedom of Information and Protection of Privacy Act and may include but are not limited to the following types of record requests:									
*building drawings, septic drawings, surveys, occupancy permits, Committee of Adjustment or Planning and Development Advisory Committee records, environmental records, site plan records,									
detailed financial records/invoices and Council records that are not available in a digital format (agendas and minutes) $5.00 per request including the first 15 minutes of search time; $7.50 shall be									
charged for each additional 15 minutes spent by Township staff to search for the records.									

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SCHEDULE B: FINANCE USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Online Service Fee	Total Transaction Amount	1.75 Percent	2.9% + $0.37 per online transaction				E	See Report FIN-2026-021
Photocopying/Printing	Per Page	$0.33	$0.34	$0.04	$0.38	3.0%	T	This fee is exempt for Township Clean-up and Remembrance Day in accordance with Council Resolution No. 2017-363. This fee applies when more than ten (10) single-sided pages are requested. Any pages exceeding this allowance will be charged at the established per-page rate for black and white photocopying/printing.
Returned Cheque Fee	Per Returned Cheque	$46.00	$47.00	$0.00	$47.00	2.2%	E	For any cheques that do not clear the Township's bank account. See Report FIN-2024-024.
Tax Arrears Mailed Notice	Per Notice	$5.00	$5.13	$0.00	$5.13	2.6%	E	See Report FIN-2025-028
Tax Certificate	Per Certificate	$69.00	$70.00	$0.00	$70.00	1.4%	E	
Rush Tax Certificate	Per Rush Certificate	N/A	$93.00	$0.00	$93.00	100.0%	E	See Report FIN-2026-021
Tax Sale Charges	Actual costs incurred						T	Cost recovery of fees and disbursements as charged by consultants and solicitors.
Third Party Cost Recovery	Actual costs incurred + $100.00 cumulative administration fee for all invoices						T	Material, equipment, labour/benefits, administration costs, third party consultant/specialist costs - See Report FIN-2022-029.
Tile Drainage Loan Application and Inspection Fee	Flat Fee	$245.00	$251.00	$0.00	$251.00	2.4%	E	See Report FIN-2018-028

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SCHEDULE C: PUBLIC WORKS USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Entrance Permit - Commercial/Industrial	Flat Fee	$482.00	$537.00	$0.00	$537.00	11.4%	E	See Report FIN-2019-027, By-law No. 2020-032, and Report FIN-2026-021
Entrance Permit - Farm	Flat Fee	$259.00	$265.00	$0.00	$265.00	2.3%	E	See By-law No. 2020-032
Entrance Permit - Field/Woodlot	Flat Fee	$241.00	$247.00	$0.00	$247.00	2.5%	E	See Report FIN-2019-027 and By-law No. 2020-032
Entrance Permit - Residential	Flat Fee	$288.00	$295.00	$0.00	$295.00	2.4%	E	See Report FIN-2019-027
Entrance Permit - Temporary	Flat Fee	$178.00	$182.00	$0.00	$182.00	2.2%	E	See By-law No. 2020-032
Entrance Permit Security Deposit	Security Deposit	$1,000.00	$1,000.00	$0.00	$1,000.00	0.0%	E	Deposit fully refundable upon completion of the entrance and pending no damages to the roadway. See Report FIN-2021-025
Haul Route Permit	Flat Fee	$121.00	$124.00	$0.00	$124.00	2.5%	E	See Report FIN-2024-024.
Haul Route Permit Security Deposit	Security Deposit	To be determined by the Designated Official.				0.0%	E	See Council Resolution No. 2024-314 from the September 25, 2024 Council Meeting.
Municipal Street Naming: Initial Application Review	All costs associated with any third party review, if required.						T	This fee is applicable to all Municipal Street Naming and Renaming requests in accordance with the Municipal Street Naming Policy - See Report FIN-2022-029.
Municipal Street Renaming: Application Notice Requirement	Flat Fee	$757.00	$777.00	$0.00	$777.00	2.6%	E	This fee is applicable to Municipal Street Renaming requests that comply with the naming standards in accordance with the Municipal Street Naming Policy - See Report FIN-2022-029.

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SCHEDULE C: PUBLIC WORKS USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Municipal Street Renaming: Aid Distribution Per Residential Property (if opted in) on the Street Proposed to be Renamed	Flat Fee	$215.00	$220.00	$0.00	$220.00	2.3%	E	This fee is to be paid in full by the Requester for Municipal Street Renaming requests that comply with the naming standards - See Report FIN-2022-029. This fee is to be shared equally by the Township and the Requester for Municipal Street Renaming requests that do not comply with the naming standards - See Report FIN-2022-029.
Municipal Street Renaming: Aid Distribution Per Legal Business (if opted in) on the Street Proposed to be Renamed	Flat Fee	$539.00	$553.00	$0.00	$553.00	2.6%	E	This fee is to be paid in full by the Requester for Municipal Street Renaming requests that comply with the naming standards - See Report FIN-2022-029. This fee is to be shared equally by the Township and the Requester for Municipal Street Renaming requests that do not comply with the naming standards - See Report FIN-2022-029.
Municipal Street Renaming: Street Name Signage	Per Sign	$268.00	$275.00	$35.75	$310.75	2.6%	T	This fee is applicable to Municipal Street Renaming requests that comply with the naming standards in accordance with the Municipal Street Naming Policy - See Report FIN-2022-029.
Municipal Street Renaming: Street Name Signage Installation	Flat Fee	$107.00	$109.00	$14.17	$123.17	1.9%	T	This fee is applicable to Municipal Street Renaming requests that comply with the naming standards in accordance with the Municipal Street Naming Policy - See Report FIN-2022-029.

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SCHEDULE C: PUBLIC WORKS USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Municipal Street Renaming: Private Streets	To a Maximum of	$539.00	$553.00	$0.00	$553.00	2.6%	E	Additional fees may be borne by the owner of a private street where the street re-naming requires the amendment of existing documents. Upon verification, the Township shall notify the requester of the additional fees and the Township and the requester shall each be responsible to pay 50% of the cost to a maximum of $1,000 total ($500 paid by the Township and $500 paid by the requester). Any amount exceeding $1000 shall be the responsibility of the private street owner.
Oversize-Overweight Load Permits	Per Trip	$121.00	$124.00	$0.00	$124.00	2.5%	E	
Third Party Cost Recovery	Actual costs incurred + $100.00 cumulative administration fee for all invoices						T	Material, equipment, labour/benefits, administration costs, third party consultant/specialist costs

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SCHEDULE D: FIRE AND RESCUE SERVICES USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Burning Permit Violations or Unauthorized Open Air Burning	Note 1						E	Emergency responses to illegal burning or burning without a permit.
Daycare & Home Daycare Inspections	Per Inspection	$121.00	$124.00	$16.12	$140.12	2.5%	T	As mandated in the Fire Code.
Emergency Responses to Incidents such as Collisions/Fires/Hazardous Material Releases on Roadways	Note 1						E	Township residents are exempt from payment of fee for emergency responses where emergency occurs on a Township of Puslinch or County of Wellington Road.
Fire Alarm False Alarm Calls	Note 1						E	A false alarm call after the second false alarm in any calendar year.
Fire Department Specific Response Fees	Note 1 and Note 2						T	See Report FIR-2019-010
Fire Extinguisher Training	Per Person	$18.42	$18.90	$2.46	$21.36	2.6%	T	
Fire Safety Plan Review	Per Plan	$146.00	$189.00	$24.57	$213.57	29.5%	T	See Report FIN-2026-021
Industrial/Commercial/Institutional/Assembly/Apartment	Base Inspection	$121.00	$124.00	$16.12	$140.12	2.5%	T	Any inspections completed by the fire department that are new, complaint driven, requested or mandated.
Industrial/Commercial/Institutional/Assembly/Apartment	Plus each tenant/occupant/ apartment unit	$31.00	$31.80	$4.13	$35.93	2.6%	T	Any inspections completed by the fire department that are new, complaint driven, requested or mandated.
Information or Fire Reports	Flat Fee	$114.00	$117.00	$0.00	$117.00	2.6%	E	Requested for emergency incidents or other fire related information. See Report FIN-2024-024.
Key Boxes	Per Box	$181.00	$185.00	$24.05	$209.05	2.2%	T	For rapid entry for firefighters. See Report FIN-2020-044.
Occupancy Load	Flat Fee	$121.00	$124.00	$0.00	$124.00	2.5%	E	
Open Air Burning Permit Inspection Fee	Per Inspection	$75.00	$76.00	$9.88	$85.88	1.3%	T	As a result of a request to modify the terms and conditions of the Open Air Burning Permit. See Report FIN-2025-024.
Open Air Burning Permit	Per Permit	$29.00	$30.00	$0.00	$30.00	3.4%	E	Permit must be renewed annually. See Report FIN-2023-030.
Post Fire Watch	Note 1						E	

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SCHEDULE D: FIRE AND RESCUE SERVICES USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Replacement of Equipment and Resources Used	Actual costs incurred						T	Materials used in emergency responses.
Sale of Fireworks Permit	Per Permit	$121.00	$124.00	$0.00	$124.00	2.5%	E	
Setting Off or Discharge of High Hazard Fireworks Permit	Per Permit	$121.00	$124.00	$0.00	$124.00	2.5%	E	Fireworks By-law No. 039/14
Setting off or Discharge of Low Hazard Fireworks Exemption Waiver	Per Waiver	$121.00	$124.00	$0.00	$124.00	2.5%	E	See Report FIN-2024-024. Fireworks By-law No. 039/14
Third Party Cost Recovery	Actual costs incurred + $100.00 cumulative administration fee for all invoices						T	Material, equipment, labour/benefits, administration costs, third party consultant/specialist costs - See Report FIN-2022-029.
Water Tank Locks	Per Lock	$21.87	$22.44	$2.92	$25.36	2.6%	T	For locking water tank lids closed.
Special Events	No fee at this time							Requests for Attendance.
Authorized Requester Agreement - Search Fee	No fee at this time							Standard information product per record search fee - See Report FIN-2017-024.

Note 1: Standard Rate as approved by the Ministry of Transportation (MTO) adjusted periodically in accordance with the consumer price index:
MTO rate in effect as of January 1, 2026: $583.05 per hour per truck and an Auxiliary Vehicle Rate of $291.53 per hour per truck. The Auxiliary Vehicle Rate applies to Pumper 32.
MTO rate in effect as of January 1, 2027: Not released at time of by-law preparation.

Note 2: Fire Department Specific Response Fees
Fire department specific response fees shall be the total of:
a. Current MTO* rate per unit per hour or portion thereof for each unit
b. rate per person per hour or portion thereof for each firefighter
c. other costs including but not limited to: foam, metered water, and any other consumable supplies. Air tank re-filling, cleaning equipment, DSPA or similar type units, cost to replace damaged or destroyed equipment, specialized response costs from automatic/mutual aid agreements, fire protection agreements, water bomber drops, etc.

* The MTO rate per unit per hour is set by the Ministry of Transportation. This rate is adjusted periodically in accordance with the consumer price index.
Such fees shall be charged and calculated on the basis of each fire department vehicle attending, resources consumed in attendance to the property incident. The time shall be measured from the time of departure of each unit from the fire department's facilities to the time the unit is cleared for the next call out.

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SCHEDULE E: BUILDING USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Minimum Permit Fee	Flat Fee	$189.00	$194.00	$0.00	$194.00	2.6%	E	For all work unless otherwise noted. See Report FIN-2024-024.
NEW BUILDING, ADDITIONS, MEZZANINES								
Group A & B: Assembly & Care and Detention Buildings								
Shell	Per Sq. Foot	$2.96	$3.03	$0.00	$3.03	2.4%	E	See Report FIN-2017-024
Finished	Per Sq. Foot	$3.30	$3.38	$0.00	$3.38	2.4%	E	See Report FIN-2017-024
Group C: Residential Buildings								
Houses, Townhouses, and Apartments	Per Sq. Foot	$2.36	$2.42	$0.00	$2.42	2.5%	E	
Manufactured Home	Per Sq. Foot	$1.78	$1.82	$0.00	$1.82	2.2%	E	
Garage/carport/shed/boathouse	Per Sq. Foot	$0.92	$0.94	$0.00	$0.94	2.2%	E	See Report FIN-2018-028
Deck, porch, dock	Flat Fee	$189.00	$194.00	$0.00	$194.00	2.6%	E	
Group D & E: Business and Personal Service and Mercantile Buildings								
Shell	Per Sq. Foot	$2.23	$2.28	$0.00	$2.28	2.2%	E	See Report FIN-2017-024
Finished	Per Sq. Foot	$2.63	$2.69	$0.00	$2.69	2.3%	E	See Report FIN-2017-024
Group F: Industrial Buildings								
Shell	Per Sq. Foot	$0.89	$0.91	$0.00	$0.91	2.2%	E	See Report FIN-2017-024
Finished	Per Sq. Foot	$1.14	$1.17	$0.00	$1.17	2.6%	E	See Report FIN-2017-024
Farm Buildings								
New Building	Per Sq. Foot	$0.38	$0.39	$0.00	$0.39	2.6%	E	See Report FIN-2017-024
INTERIOR FINISHES AND ALTERATIONS - ALL CLASSIFICATIONS								
Finishes to all areas	Per Sq. Foot	$0.62	$0.63	$0.00	$0.63	1.6%	E	
SEWAGE SYSTEMS								
New Installation	Flat Fee	$766.00	$786.00	$0.00	$786.00	2.6%	E	
Replacement or alteration	Flat Fee	$573.00	$588.00	$0.00	$588.00	2.6%	E	
ALTERNATIVE SOLUTIONS								
All buildings/systems within scope of Part 9	Flat Fee	$613.00	$629.00	$0.00	$629.00	2.6%	E	See Report FIN-2017-024
All buildings/systems within scope of Part 3	Flat Fee	$1,229.00	$1,261.00	$0.00	$1,261.00	2.6%	E	See Report FIN-2017-024
SPECIAL CATEGORIES AND MISCELLANEOUS								
Change of Use Permit (No Construction)	Flat Fee	$245.00	$251.00	$0.00	$251.00	2.4%	E	See Report FIN-2017-024
Construction prior to issuance of a permit	100% of permit fee						E	Fee is in addition to all other required permit fees.
Conditional Permits	20% of permit fee						E	Fee is in addition to all other required permit fees.

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SCHEDULE E: BUILDING USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Demolition Permit	Flat Fee	$189.00	$194.00	$0.00	$194.00	2.6%	E	
Designated Structure Permit	Flat Fee	$509.00	$522.00	$0.00	$522.00	2.6%	E	Listed per Div.A, 1.3.1.1 Solar installation
Fireplace/Woodstove	Flat Fee	$189.00	$194.00	$0.00	$194.00	2.6%	E	
Inspection of works not ready	Flat Fee	$189.00	$194.00	$0.00	$194.00	2.6%	E	At the discretion of the Chief Building Official. Includes code violations and deficiencies.
Occupancy Permit	Flat Fee	$189.00	$194.00	$0.00	$194.00	2.6%	E	
Occupancy without an Occupancy Permit	Flat Fee	$305.00	$313.00	$0.00	$313.00	2.6%	E	At the discretion of the Chief Building Official. This fee is not imposed as it relates to the current initiative of closing old open building permits as approved by Council in the 2018 Budget.
Portables	Flat Fee	$245.00	$251.00	$0.00	$251.00	2.4%	E	
Reproduction of Digital Drawings	Per Page	$5.39	$5.53	$0.72	$6.25	2.6%	T	Current rate covers the cost for the digital reproduction of (1) digital copy of drawings - See Report FIN-2022-029.
Revision to Approved Plans	Flat Fee	$382.00	$392.00	$0.00	$392.00	2.6%	E	Before or after a permit is issued - significant changes to approved plans requiring further review. Minor revisions which result in no fee include eliminating a closet, finishing a three-piece bathroom, cosmetic changes, layout changes, removing non-load bearing walls, etc.
Sign Permits	Flat Fee	$318.00	$326.00	$0.00	$326.00	2.5%	E	With building permit
Storefront replacement	Flat Fee	$245.00	$251.00	$0.00	$251.00	2.4%	E	
Tents	Flat Fee	$255.00	$261.00	$0.00	$261.00	2.4%	E	Tents and air-supported structures shall be in conformance with the Building Code and Section 2.9 of the Fire Code. See Report FIN-2019-031
Third Party Cost Recovery	Actual costs incurred + $100.00 cumulative administration fee for all invoices						T	Material, equipment, labour/benefits, administration costs, third party consultant/specialist costs - See Report FIN-2020-034
Transfer of Permit	Flat Fee	$189.00	$194.00	$0.00	$194.00	2.6%	E	

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INTERPRETATION

The following requirements are to be applied in the calculation of permit fees:

· Floor area of the proposed work is to be measured to the outer face of exterior walls and to the centre line of party walls or demising walls.

· Unfinished loft space, habitable attics, mezzanines and interior balconies are to be included in all floor area calculations.

· Unfinished basement space and attached residential garages are not included in floor area calculations.

· The occupancy categories in this Schedule correspond with the major occupancy classifications in the Ontario Building Code. For multiple occupancy floor areas, the permit fees for each of the applicable occupancy categories may be used.

SCHEDULE E: BUILDING USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS

· In the case of interior alterations or renovations, area of proposed work is the actual space receiving the work, e.g. tenant suite.
· For classes of permits not described in this Schedule, a reasonable permit fee shall be determined by the Chief Building Official.

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SCHEDULE F: PLANNING AND DEVELOPMENT USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Additional Public Information Meeting	Flat Fee	$3,254.00	$3,338.00	$0.00	$3,338.00	2.6%	E	See Report FIN-2024-024.
Agreements - Minor - Not Registered	Flat Fee	$305.00	$379.00	$0.00	$379.00	24.3%	E	For recovery of the costs of facilitating and preparing agreements, ie. maintenance and operations agreement. See Report FIN-2024-024 and Report FIN-2026-021.
Agreements - Registered	Flat Fee	$2,299.00	$2,358.00	$0.00	$2,358.00	2.6%	E	For recovery of the costs of facilitating and preparing agreements, ie. planning act applications and building permit agreements (ie. permission to have a second dwelling while another is being built), etc. See Report FIN-2024-024.
Agreements - Subdivision/Condominium *	Administration fee	$2,299.00	$2,358.00	$0.00	$2,358.00	2.6%	E	For recovery of the costs of facilitating and preparing agreements and clearing conditions for approvals of Subdivision and Condominium Agreements. See Report FIN-2024-024.
Red Line Agreement Review *	Administration fee	$101.00	$103.00	$0.00	$103.00	2.0%	E	See Report FIN-2024-024
Title Search	Flat Fee	$178.00	$182.00	$0.00	$182.00	2.2%	E	See Report FIN-2024-024
Land Registry Title Registrations, Releases and Corrections *	Administration fee	N/A	$250.00	$0.00	$250.00	100.0%	E	See Report FIN-2026-021.
Application Reactivation *	Administration Fee	$3,254.00	$3,338.00	$0.00	$3,338.00	2.6%	E	See Report FIN-2024-024.
Compliance Letter - Type 1	Flat Fee	$90.00	$92.00	$0.00	$92.00	2.2%	E	Note 1
Compliance Letter - Type 2	Flat Fee	$138.00	$141.00	$0.00	$141.00	2.2%	E	Note 2
Consent Consultation *	Administration fee	N/A	$173.00	$0.00	$173.00	100.0%	E	See Report FIN-2026-021.
Consent Review and Condition Clearance	Flat Fee	$162.00	$166.00	$0.00	$166.00	2.5%	E	
Consent Review and Condition Clearance - Safe Access Clearance *	Administration fee	$58.00	$59.00	$0.00	$59.00	1.7%	E	See Report FIN-2022-029
External Development Application Studies Review - County of Wellington *	Administration fee	N/A	$1,998.00	$0.00	$1,998.00	100.0%	E	See Report FIN-2026-021.
External Development Application Studies Review - Other *	Administration fee	N/A	$100.00	$0.00	$100.00	100.0%	E	See Report FIN-2026-021.
Garden Suites and Renewals (Zoning) *	Administration fee	$1,449.00	$1,486.00	$0.00	$1,486.00	2.6%	E	See Report FIN-2019-034

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SCHEDULE F: PLANNING AND DEVELOPMENT USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Lifting of Holding Designation (Zoning) *	Administration fee	$1,542.00	$1,582.00	$0.00	$1,582.00	2.6%	E	See Report FIN-2023-025
Minor Variance - Type 1	Flat Fee	$966.00	N/A - see below				E	See Report FIN-2024-024.
Minor Variance - Type 2	Flat Fee	$1,639.00	N/A - see below				E	See Report FIN-2024-024.
Minor Variance *	Administration fee	N/A	$568.00	$0.00	$568.00	100.0%	E	See Report FIN-2026-021.
Minor Variance Deferral *	Administration fee	N/A	$284.00	$0.00	$284.00	100.0%	E	See Report FIN-2026-021.
Ownership List Confirmation	Flat Fee	$82.00	$84.00	$0.00	$84.00	2.4%	E	See Report FIN-2019-027
Part Lot Control Exemption By-law *	Administration fee	$1,542.00	$1,582.00	$0.00	$1,582.00	2.6%	E	See Report FIN-2023-025
Permitted Use Letter	Flat Fee	$90.00	$92.00	$0.00	$92.00	2.2%	E	See Report FIN-2024-024
Preliminary Planning Consultation	Flat Fee	$500.00	N/A - see below				E	For recovery of the costs to review planning policy relating to preliminary planning proposals.
Preliminary Planning Consultation *	Administration fee	N/A	$173.00	$0.00	$173.00	100.0%	E	See Report FIN-2026-021.
Comprehensive Development Consultation	Flat Fee	$5,085.00	N/A - see below				E	For recovery of the costs to review and provide comments on a comprehensive development/planning proposal or application.
Comprehensive Development Consultation *	Administration fee	N/A	$388.00	$0.00	$388.00	100.0%	E	See Report FIN-2026-021.
Consultation - Subsequent Submissions*	Administration fee	$100.00	$102.00	$0.00	$102.00	2.0%	E	See Report FIN-2025-024 - request for further consultation prior to application submission.
Radiocommunication Tower Pre-Consultation Fee *	Administration fee	$1,097.00	$1,125.00	$0.00	$1,125.00	2.6%	E	See Report FIN-2024-024
Radiocommunication Tower Proposals *	Administration fee	$3,028.00	$3,107.00	$0.00	$3,107.00	2.6%	E	See Report FIN-2021-25 - Township administration fee and third party costs. Radiocommunication Tower and Antenna Protocol Policy
Site Plan Application and Agreement - New Application	Flat Fee	$25,377.00	N/A - see below				E	See Report FIN-2024-024.
Site Plan Application and Agreement - Amendment Application	Flat Fee	$6,210.00	N/A - see below				E	See Report FIN-2024-024.
Site Plan Control Application and Agreement *	Administration fee	N/A	$1,057.00	$0.00	$1,057.00	100.0%	E	See Report FIN-2026-021.
Site Plan Control Agreement Securities	Security Deposit	An amount equal to 50% of the site-servicing costs, including earthworks such as fill importation, cutting and grading, plus 50% of the landscaping costs, together with an additional 5% of the construction costs for site-servicing and landscaping to cover the Township's engineering review.						See Report FIN-2026-021.

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SCHEDULE F: PLANNING AND DEVELOPMENT USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Third and Subsequent Submission *	Administration fee	$203.00	$208.00	$0.00	$208.00	2.5%	E	See Report FIN-2024-024.
Third Party Cost Recovery	Actual costs incurred + $100.00 cumulative administration fee for all invoices						T	Material, equipment, labour/benefits, administration costs, third party consultant/specialist costs - See Report FIN-2020-034
Zoning By-Law Amendment - Aggregate *	Administration fee	$81,360.00	$83,476.00	$0.00	$83,476.00	2.6%	E	Note 3 and see Report FIN-2023-025 and Report FIN-2024-024.
Zoning By-Law Amendment	Flat Fee	$17,925.00	N/A - see below				E	See Report FIN-2022-029, Report FIN-2023-025, and Report FIN-2024-024.
Zoning By-Law Amendment *	Administration fee	N/A	$2,809.00	$0.00	$2,809.00	100.0%	E	See Report FIN-2026-021.

INTERPRETATION

* the fees denoted with an asterisk are also subject to applicable third-party costs in accordance with this By-law.

Note 1: Compliance Letter - Type 1
Includes known building permit history and status as well as applicable zoning designation and permitted uses.
Note 2: Compliance Letter - Type 2 (Type 1 fee plus 50%)
Includes known building permit history and status as well as applicable zoning designation and permitted uses, the status of registered site plans and securities but does not include a title search.
Note 3: Zoning By-law Amendment Aggregate
The Zoning By-law Amendment – Aggregate fee is applicable in the following circumstances:
a.) When a property is being proposed to be re-zoned to an extractive or seeking to amend or expand its existing extractive zoning.
b.) When a property is zoned extractive and is being proposed to be rezoned either on a temporary (including requests for renewals) or permanent basis (including applications to rezone to a non-extractive after-use) .
Refund of Application Fees
In the case of a withdrawal or abandonment of an application, staff shall determine the amount of paid fees that may be refunded to the applicant, if any, in accordance with the following:
a.) 80 percent (80%) if administrative functions have only been performed;
b.) 70 percent (70%) if administrative and zoning functions have only been performed;
c.) 45 percent (45%) if administrative, zoning, and a completed application has been circulated with comments;
d.) 35 percent (35%) if application has been sent for second submission and comments have been received;
e.) no refund shall be made if the application has been approved by Committee and/or Council.

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SCHEDULE G: BY-LAW USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
After Hours Response for Violation	Per Site Attendance	$356.00	$365.00	$0.00	$365.00	2.5%	E	See Report FIN-2024-024
Dog Tags	Per Tag	$36.00	$37.00	$0.00	$37.00	2.8%	E	No more than 3 dogs are permitted per dwelling unit, to a maximum of 5 dogs per property (only where a legal accessory apartment is permitted).
Replacement Dog Tag	Per Tag	$11.88	$12.19	$0.00	$12.19	2.6%	E	See Report FIN-2020-044
Fence Viewer's Application	Per Application	$368.00	$377.00	$0.00	$377.00	2.4%	E	
Filming Permit Fee	Flat Fee	$614.00	$630.00	$0.00	$630.00	2.6%	E	Filming of special events on Township lands/roads.
Filming Permit Security Deposit	Per Filming Permit - days 1 to 3	$5,000.00	$5,000.00	$0.00	$5,000.00	0.0%	E	For filming projects one (1) to three (3) days in duration - see Report FIN-2022-029 and Filming Policy No. 2022-005.
Filming Permit Security Deposit	Per Filming Permit - each subsequent day after day 3	$2,000.00	$2,000.00	$0.00	$2,000.00	0.0%	E	After three days of filming, an additional $2,000 will be required for each subsequent day. See Report FIN-2022-029 and Filming Policy No. 2022-005.
Kennel Licence - New Application	Per Application	$580.00	$595.00	$0.00	$595.00	2.6%	E	See By-law No. 024-2021
Kennel Licence - Renewal Application	Per Application	$231.00	$237.00	$0.00	$237.00	2.6%	E	See By-law No. 024-2021
Kennel Licence - Alteration Application	Per Application	$231.00	$237.00	$0.00	$237.00	2.6%	E	See Report FIN-2023-025
Kennel Licence - Retiring Application	Per Application	$86.00	$88.00	$0.00	$88.00	2.3%	E	See By-law No. 024-2021
Liquor License Letter	Per Inspection	$190.00	$195.00	$0.00	$195.00	2.6%	E	Requested or required inspection of licensed sales establishments (as defined by the Liquor Licence Establishment Board of Ontario) that requires an inspection and/or a letter.
Lottery Licence	3% of prize value						E	Fee regulated by AGCO (Nevada, Raffle, Bazaar, etc.).
Municipal Addressing Sign	Flat Fee	$24.96	$25.61	$3.33	$28.94	2.6%	T	
Municipal Addressing Post	Flat Fee	$24.96	$25.61	$3.33	$28.94	2.6%	T	
Property Standards Appeal Fee	Flat Fee	$313.00	$321.00	$0.00	$321.00	2.6%	E	See Report FIN-2019-031
Publicized Displays Application Fee	Flat Fee	$160.00	$164.00	$0.00	$164.00	2.5%	E	See Report FIN-2022-029 and Publicized Displays By-law No. 2022-008
Publicized Displays Appeal Fee	Flat Fee	$32.39	$33.23	$0.00	$33.23	2.6%	E	See Report FIN-2022-029 and Publicized Displays By-law No. 2022-008

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SCHEDULE G: BY-LAW USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Reinspection Fee	Flat Fee Per Reinspection	$80.00	$140.00	$0.00	$140.00	75.0%	E	Not charged on first inspections (ie. the inspection to determine if a violation is occurring). Reinspection will be charged each subsequent time by-law attends the site to inspect and compliance has not been achieved (does not include inspections for the purpose of gathering further information). See Report FIN-2022-029 and Report FIN-2026-021.
Septic Compliance Letter	Flat Fee	$98.00	$100.00	$0.00	$100.00	2.0%	E	Fee charged is consistent for all Township departments. See Report FIN-2025-024.
Sign Permit - Temporary	Flat Fee	$114.00	$117.00	$0.00	$117.00	2.6%	E	See Sign By-law No. 2024-062.
Sign Refusal Appeal - Council Approval *	Administration Fee	$1,097.00	$1,125.00	$0.00	$1,125.00	2.6%	E	See Sign By-law No. 2024-062.
Sign Variance - Council Approval *	Administration Fee	$1,307.00	$1,341.00	$0.00	$1,341.00	2.6%	E	See Sign By-law No. 2024-062.
Sign Variance - Staff Approval *	Administration Fee	$209.00	$214.00	$0.00	$214.00	2.4%	E	See Sign By-law No. 2024-062.
Site Alteration Normal Farm Practices Waiver *	Administration Fee	Subject to recovery of all actual third party costs. May be required to provide a Security Deposit at the discretion of the Designated Official.					E	See Site Alteration By-law No. 2023-057.
Site Alteration Permit Application Fee - Minor *	Administration Fee	$1,047.00	$1,074.00	$0.00	$1,074.00	2.6%	E	Non-refundable and due at the application submission for the coordination and administration of an application. See Site Alteration By-law No. 2023-057.
Site Alteration Permit Security Deposit - Minor **	Security Deposit	$3,000.00	$3,000.00	$0.00	$3,000.00	0.0%	E	Due prior to permit issuance. See Site Alteration By-law No. 2023-057.
Site Alteration Permit Application Fee - Intermediate *	Administration Fee	$2,095.00	$2,149.00	$0.00	$2,149.00	2.6%	E	Non-refundable and due at the application submission for the coordination and administration of an application. See Site Alteration By-law No. 2023-057.
Site Alteration Permit Security Deposit - Intermediate **	Security Deposit	$5,000.00	$5,000.00	$0.00	$5,000.00	0.0%	E	Due prior to permit issuance. See Site Alteration By-law No. 2023-057.
Site Alteration Permit Application Fee - Large *	Administration Fee	$3,666.00	$3,761.00	$0.00	$3,761.00	2.6%	E	Non-refundable and due at the application submission for the coordination and administration of an application. See Site Alteration By-law No. 2023-057.
Site Alteration Permit Security Deposit - Large **	Security Deposit	$10,000.00	$10,000.00	$0.00	$10,000.00	0.0%	E	Due prior to permit issuance. See Site Alteration By-law No. 2023-057.

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SCHEDULE G: BY-LAW USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Site Alteration Permit Application Fee - Major *	Administration Fee	$5,237.00	$5,373.00	$0.00	$5,373.00	2.6%	E	Non-refundable and due at the application submission for the coordination and administration of an application. See Site Alteration By-law No. 2023-057.
Site Alteration Permit Security Deposit - Major **	Security Deposit	To be determined by the Designated Official.				0.0%	E	Due prior to permit issuance. See Site Alteration By-law No. 2023-057.
Site Alteration Permit Service Fee	Per m³	$0.24	$0.24	$0.00	$0.24	0.0%	E	Paid at time of application. See Site Alteration By-law No. 2023-057.
Violation Fees	The Township may recover its costs of remedying a violation of the Site Alteration By-law No. 2023-057 by invoicing the Owner, by instituting court proceedings or by adding the cost, including interest, to the tax roll, and the exercise of any other available remedy.						E	Double all application fees. See Site Alteration By-law No. 2023-057.
Inspector Attendance at a Property Due to Verified Violation	Per Site Attendance	$156.00	$160.00	$0.00	$160.00	2.6%	E	Per site attendance by the Inspector as a result of a verified violation. See Site Alteration By-law No. 2023-057.
Designated Official Meeting	Per Meeting Flat Fee	$457.00	N/A - see below				E	Administration fee and cost recovery of third party consultant costs for attendance. See Report FIN-2024-024.
Designated Official Meeting *	Administration Fee	N/A	$250.00	$0.00	$250.00	100.0%	E	See Report FIN-2026-021.
Site Alteration Permit Renewal Fee	Per Application	50% of the original application administration fee.					E	See Site Alteration By-law No. 2023-057.
Special Events Permit	Per Letter	$91.00	$93.00	$0.00	$93.00	2.2%	E	See Report FIN-2022-029
Swimming Pool Enclosure Permit	Flat Fee	$262.00	$268.00	$0.00	$268.00	2.3%	E	See Report FIN-2024-024.
Third Party Cost Recovery	Actual costs incurred + $100.00 cumulative administration fee for all invoices						T	Material, equipment, labour/benefits, administration costs, third party consultant/specialist costs - See Report FIN-2020-034

INTERPRETATION

* the fees denoted with an asterisk are also subject to applicable third-party costs in accordance with this By-law.

** Security Deposit funds are held by the Township and will be returned to the applicant upon fulfilment of all Permit Conditions. This includes any costs incurred by the Township related to enforcement of the permit conditions or the Site Alteration By-law. If the funds are drawn upon, the applicant is required to top up the funds to the amount determined in Schedule "C" of the Site Alteration By-law No. 2023-057 or as determined by the Designated Official.

Refund of Permit/Application Fees

In the case of a withdrawal or abandonment of an application, staff shall determine the amount of paid fees that may be refunded to the applicant, if any, in accordance with the following:

a.) 80 percent (80%) if administrative functions have only been performed;

b.) 70 percent (70%) if administrative and internal review functions have only been performed;

c.) 45 percent (45%) if administrative, internal review, and a completed application has been circulated with comments;

d.) 35 percent (35%) if application has been sent for second submission and comments have been received;

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TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)		2027 RATE (NO TAX)	13% HST	RATE INCL HST		% CHANGE	HST STATUS	COMMENTS
e.) no refund shall be made if the application has been approved by staff and/or Council										

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SCHEDULE H: PARKS USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Ball Diamonds - No Lights - Non Resident Rental or Commercial Rental	Per Hour	$40.69	$41.75	$5.43	$47.18	2.6%	T	See Report COR-2025-029
Ball Diamonds - No Lights	Per Hour	$32.55	$33.40	$4.34	$37.74	2.6%	T	See Report FIN-2024-024
50% Reduced Rate - Ball Diamonds - No Lights	Per Hour	N/A	$16.70	$2.17	$18.87	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Ball Diamonds - No Lights	Per Hour	$8.14	$8.35	$1.09	$9.44	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Ball Diamonds - No Lights	Per Hour	$3.26	$3.34	$0.43	$3.77	2.6%	T	See Report COR-2025-029
Ball Diamonds - Lights - Non Resident Rental or Commercial Rental	Per Hour	$48.13	$49.39	$6.42	$55.81	2.6%	T	See Report COR-2025-029
Ball Diamonds - Lights	Per Hour	$38.50	$39.51	$5.14	$44.65	2.6%	T	
50% Reduced Rate - Ball Diamonds - Lights	Per Hour	N/A	$19.76	$2.57	$22.32	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Ball Diamonds - Lights	Per Hour	$9.63	$9.88	$1.28	$11.16	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Ball Diamonds - Lights	Per Hour	$3.85	$3.95	$0.51	$4.46	2.6%	T	See Report COR-2025-029
All Ball Diamonds - Non Resident Rental or Commercial Rental	Per Day	$240.65	$246.91	$32.10	$279.01	2.6%	T	See Report COR-2025-029
All Ball Diamonds	Per Day	$192.52	$197.53	$25.68	$223.21	2.6%	T	
50% Reduced Rate - All Ball Diamonds	Per Day	N/A	$98.77	$12.84	$111.60	100.0%	T	See Report COR-2025-029
75% Reduced Rate - All Ball Diamonds	Per Day	$48.13	$49.38	$6.42	$55.80	2.6%	T	See Report COR-2025-029
90% Reduced Rate - All Ball Diamonds	Per Day	$19.25	$19.75	$2.57	$22.32	2.6%	T	See Report COR-2025-029
Ball Diamonds - Dragging - Non Resident Rental or Commercial Rental	Per Occurrence	$61.49	$63.09	$8.20	$71.29	2.6%	T	See Report COR-2025-029
Ball Diamonds - Dragging	Per Occurrence	$49.19	$50.47	$6.56	$57.03	2.6%	T	
50% Reduced Rate - Ball Diamonds - Dragging	Per Occurrence	N/A	$25.24	$3.28	$28.52	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Ball Diamonds - Dragging	Per Occurrence	$12.30	$12.62	$1.64	$14.26	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Ball Diamonds - Dragging	Per Occurrence	$4.92	$5.05	$0.66	$5.70	2.6%	T	See Report COR-2025-029
Soccer Field - No Lights - Non Resident Rental or Commercial Rental	Per Hour	$48.59	$49.86	$6.48	$56.34	2.6%	T	See Report COR-2025-029 and Report FIN-2025-024
Soccer Field - No Lights	Per Hour	$38.87	$39.89	$5.19	$45.08	2.6%	T	See Report FIN-2017-012 and Report FIN-2025-024
50% Reduced Rate - Soccer Field - No Lights	Per Hour	N/A	$19.95	$2.59	$22.54	100.0%	T	See Report COR-2025-029 and Report FIN-2025-024
75% Reduced Rate - Soccer Field - No Lights	Per Hour	$9.72	$9.97	$1.30	$11.27	2.6%	T	See Report COR-2025-029 and Report FIN-2025-024
90% Reduced Rate - Soccer Field - No Lights	Per Hour	$3.89	$3.99	$0.52	$4.51	2.6%	T	See Report COR-2025-029 and Report FIN-2025-024
Soccer Field - Lights - Non Resident Rental or Commercial Rental	Per Hour	$49.75	$51.04	$6.63	$57.67	2.6%	T	See Report COR-2025-029
Soccer Field - Lights	Per Hour	$39.80	$40.83	$5.31	$46.14	2.6%	T	See Report FIN-2023-025
50% Reduced Rate - Soccer Field - Lights	Per Hour	N/A	$20.42	$2.65	$23.07	100.0%	T	See Report COR-2025-029

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SCHEDULE H: PARKS USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
75% Reduced Rate - Soccer Field - Lights	Per Hour	$9.95	$10.21	$1.33	$11.53	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Soccer Field - Lights	Per Hour	$3.98	$4.08	$0.53	$4.61	2.6%	T	See Report COR-2025-029
Soccer Field - No Lights - Non Resident Rental or Commercial Rental	Per Day	$415.36	$426.16	$55.40	$481.56	2.6%	T	See Report COR-2025-029
Soccer Field - No Lights	Per Day	$332.29	$340.93	$44.32	$385.25	2.6%	T	See Report FIN-2017-012
50% Reduced Rate - Soccer Field - No Lights	Per Day	N/A	$170.47	$22.16	$192.63	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Soccer Field - No Lights	Per Day	$83.07	$85.23	$11.08	$96.31	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Soccer Field - No Lights	Per Day	$33.23	$34.09	$4.43	$38.53	2.6%	T	See Report COR-2025-029
Soccer Field - Lights - Non Resident Rental or Commercial Rental	Per Day	$506.20	$519.36	$67.52	$586.88	2.6%	T	See Report COR-2025-029
Soccer Field - Lights	Per Day	$404.96	$415.49	$54.01	$469.50	2.6%	T	See Report FIN-2023-025
50% Reduced Rate - Soccer Field - Lights	Per Day	N/A	$207.75	$27.01	$234.75	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Soccer Field - Lights	Per Day	$101.24	$103.87	$13.50	$117.38	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Soccer Field - Lights	Per Day	$40.50	$41.55	$5.40	$46.95	2.6%	T	See Report COR-2025-029
Ball Diamond Advertising	Per Season	$215.56	$221.17	$28.75	$249.92	2.6%	T	
50% Reduced Rate - Ball Diamond Advertising	Per Season	N/A	$110.59	$14.38	$124.96	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Ball Diamond Advertising	Per Season	$53.89	$55.29	$7.19	$62.48	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Ball Diamond Advertising	Per Season	$21.56	$22.12	$2.88	$24.99	2.6%	T	See Report COR-2025-029
Horse Paddock - Non Resident Rental or Commercial Rental	Per Day	$307.89	$315.90	$41.07	$356.97	2.6%	T	See Report COR-2025-029
Horse Paddock	Per Day	$246.31	$252.72	$32.85	$285.57	2.6%	T	
50% Reduced Rate - Horse Paddock	Per Day	N/A	$126.36	$16.43	$142.79	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Horse Paddock	Per Day	$61.58	$63.18	$8.21	$71.39	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Horse Paddock	Per Day	$24.63	$25.27	$3.29	$28.56	2.6%	T	See Report COR-2025-029
Picnic Shelter - Non Resident Rental or Commercial Rental	Per Hour	$30.76	$31.56	$4.10	$35.67	2.6%	T	See Report COR-2025-029
Picnic Shelter	Per Hour	$24.61	$25.25	$3.28	$28.53	2.6%	T	
50% Reduced Rate - Picnic Shelter	Per Hour	N/A	$12.63	$1.64	$14.27	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Picnic Shelter	Per Hour	$6.13	$6.31	$0.82	$7.13	3.0%	T	See Report COR-2025-029
90% Reduced Rate - Picnic Shelter	Per Hour	$2.45	$2.53	$0.33	$2.85	3.1%	T	See Report COR-2025-029

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SCHEDULE H: PARKS USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Picnic Shelter - Non Resident Rental or Commercial Rental	Per Day	$123.08	$126.28	$16.42	$142.69	2.6%	T	See Report COR-2025-029
Picnic Shelter	Per Day	$98.46	$101.02	$13.13	$114.15	2.6%	T	
50% Reduced Rate - Picnic Shelter	Per Day	N/A	$50.51	$6.57	$57.08	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Picnic Shelter	Per Day	$24.62	$25.26	$3.28	$28.54	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Picnic Shelter	Per Day	$9.85	$10.10	$1.31	$11.42	2.6%	T	See Report COR-2025-029
Tennis Courts - No Lights - Non Resident Rental or Commercial Rental	Per Hour	$29.11	$29.88	$3.88	$33.76	2.6%	T	See Report COR-2025-029
Tennis Courts - No Lights	Per Hour	$23.29	$23.90	$3.11	$27.01	2.6%	T	See Report FIN-2021-025
50% Reduced Rate - Tennis Courts - No Lights	Per Hour	N/A	$11.95	$1.55	$13.50	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Tennis Courts - No Lights	Per Hour	$5.82	$5.98	$0.78	$6.75	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Tennis Courts - No Lights	Per Hour	$2.33	$2.39	$0.31	$2.70	2.6%	T	See Report COR-2025-029
Tennis Courts - Lights - Non Resident Rental or Commercial Rental	Per Hour	$43.69	$44.83	$5.83	$50.65	2.6%	T	See Report COR-2025-029
Tennis Courts - Lights	Per Hour	$34.95	$35.86	$4.66	$40.52	2.6%	T	See Report FIN-2021-025
50% Reduced Rate - Tennis Courts - Lights	Per Hour	N/A	$17.93	$2.33	$20.26	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Tennis Courts - Lights	Per Hour	$8.74	$8.97	$1.17	$10.13	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Tennis Courts - Lights	Per Hour	$3.50	$3.59	$0.47	$4.05	2.5%	T	See Report COR-2025-029
Bench	Per Bench	$2,500.00	$2,565.00	$333.45	$2,898.45	2.6%	T	See Donation Policy No. 2025-001
Native Tree	Per Native Tree	$1,350.00	$1,385.10	$180.06	$1,565.16	2.6%	T	See Donation Policy No. 2025-001
Personnel Costs	Per Hour Per Personnel	Actual Costs Incurred					T	
Fireworks Security Deposit	Per Display	$500.00	$500.00	$0.00	$500.00	0.0%	E	Clean up of Township lands after fireworks display.
Baseball Equipment and Lights Security Deposit	Per Season	$50.00	$50.00	$0.00	$50.00	0.0%	E	Lights key provided to ball diamond rentals with light use. Equipment key provided to renters with a minimum of eight rentals.
Picnic Shelter Washroom Key Security Deposit	Per Rental	$50.00	$50.00	$0.00	$50.00	0.0%	E	
Horse Paddock Security Deposit	Per Rental	$300.00	$300.00	$0.00	$300.00	0.0%	E	

INTERPRETATION

· Booking availability of Township fields are dependent on field conditions.

· Lights fees are effective after 8:30 p.m.

· Ball Diamond dragging is upon request and approval - June 15, 2016 Special Council Meeting.

· Ball Diamond Advertising is available from May to October

· Horse Paddock rental is restricted to horse paddock and tractor pull area.

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SCHEDULE H: PARKS USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
· Personnel Costs are applicable for any additional staffing requirements for events at the discretion of the Director of Public Works, Parks and Facilities subject to operational demands and								
staff availability. See Report REC-2023-004 and Report FIN-2023-030.								
· Example of Commercial Rentals include Auctions, Sale of Merchandise - See Report FIN-2019-031								
Fee Reductions								
· A 90% reduced rate shall apply to Seniors' Community Events that meet the eligibility criteria.								
· A 90% reduced rate shall apply to Whistle Stop Co-operative Pre-school and Guelph Community Health Centre (The Playgroup).								
· Seniors' Recreation Programs that meet the eligibility criteria shall receive a 50% reduced rate.								
· A 75% reduced rate shall apply to organizations that host community events and meet the eligibility criteria.								
· All other organizations that meet the eligibility criteria shall receive a 50% reduced rate.								

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SCHEDULE I: OPTIMIST RECREATION CENTRE USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Arena Floor - Non Resident Rental or Commercial Rental	Per Hour	$108.66	$68.75	$8.94	$77.69	-36.7%	T	See Report COR-2025-029, Report FIN-2025-024, and Report FIN-2026-021.
Arena Floor	Per Hour	$86.93	$55.00	$7.15	$62.15	-36.7%	T	See Report FIN-2025-024 and Report FIN-2026-021.
50% Reduced Rate - Arena Floor	Per Hour	N/A	$27.50	$3.58	$31.08	100.0%	T	See Report COR-2025-029, Report FIN-2025-024, and Report FIN-2026-021.
75% Reduced Rate - Arena Floor	Per Hour	$21.73	$13.75	$1.79	$15.54	-36.7%	T	See Report COR-2025-029, Report FIN-2025-024, and Report FIN-2026-021.
90% Reduced Rate - Arena Floor	Per Hour	$8.69	$5.50	$0.72	$6.22	-36.7%	T	See Report COR-2025-029, Report FIN-2025-024, and Report FIN-2026-021.
Arena Floor - Non Resident Rental or Commercial Rental	Per Day	N/A	$550.00	$71.50	$621.50	100.0%	T	See Report FIN-2026-021.
Arena Floor	Per Day	N/A	$440.00	$57.20	$497.20	100.0%	T	See Report FIN-2026-021.
50% Reduced Rate - Arena Floor	Per Day	N/A	$220.00	$28.60	$248.60	100.0%	T	See Report FIN-2026-021.
75% Reduced Rate - Arena Floor	Per Day	N/A	$110.00	$14.30	$124.30	100.0%	T	See Report FIN-2026-021.
90% Reduced Rate - Arena Floor	Per Day	N/A	$44.00	$5.72	$49.72	100.0%	T	See Report FIN-2026-021.
Ice - Non - Prime - Non Resident Rental or Commercial Rental	Per Hour	$86.56	$88.83	$11.55	$100.37	2.6%	T	See Report COR-2025-029
Ice - Non - Prime	Per Hour	$69.25	$71.06	$9.24	$80.30	2.6%	T	
50% Reduced Rate - Ice - Non-Prime	Per Hour	N/A	$35.53	$4.62	$40.15	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Ice - Non-Prime	Per Hour	$17.31	$17.77	$2.31	$20.07	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Ice - Non-Prime	Per Hour	$6.93	$7.11	$0.92	$8.03	2.6%	T	See Report COR-2025-029
Ice - Prime - Non Resident Rental or Commercial Rental	Per Hour	$306.39	$252.00	$32.76	$284.76	-17.8%	T	See Report COR-2025-029 and Report FIN-2026-021.
Ice - Prime	Per Hour	$245.11	$201.60	$26.21	$227.81	-17.8%	T	See Report FIN-2023-030 and Report FIN-2026-021.

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SCHEDULE I: OPTIMIST RECREATION CENTRE USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Gymnasium - Non Resident Rental or Commercial Rental	Per Hour	$53.39	$54.78	$7.12	$61.90	2.6%	T	See Report COR-2025-029
Gymnasium	Per Hour	$42.71	$43.82	$5.70	$49.52	2.6%	T	See Report FIN-2024-024
50% Reduced Rate - Gymnasium	Per Hour	N/A	$21.91	$2.85	$24.76	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Gymnasium	Per Hour	$10.68	$10.96	$1.42	$12.38	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Gymnasium	Per Hour	$4.27	$4.38	$0.57	$4.95	2.6%	T	See Report COR-2025-029
Gymnasium - Non Resident Rental or Commercial Rental	Per Day	N/A	$438.20	$56.97	$495.17	100.0%	T	See Report FIN-2026-021.
Gymnasium	Per Day	N/A	$350.56	$45.57	$396.13	100.0%	T	See Report FIN-2026-021.
50% Reduced Rate - Gymnasium	Per Day	N/A	$175.28	$22.79	$198.07	100.0%	T	See Report FIN-2026-021.
75% Reduced Rate - Gymnasium	Per Day	N/A	$87.64	$11.39	$99.03	100.0%	T	See Report FIN-2026-021.
90% Reduced Rate - Gymnasium	Per Day	N/A	$35.06	$4.56	$39.61	100.0%	T	See Report FIN-2026-021.
Personnel Costs	Per Hour Per Personnel	Actual Costs Incurred					T	
Rink Board Advertising	Per Year	$431.09	$442.30	$57.50	$499.80	2.6%	T	
50% Reduced Rate - Rink Board Advertising	Per Year	N/A	$221.15	$28.75	$249.90	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Rink Board Advertising	Per Year	$107.77	$110.58	$14.37	$124.95	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Rink Board Advertising	Per Year	$43.11	$44.23	$5.75	$49.98	2.6%	T	See Report COR-2025-029

INTERPRETATION

· Ice - Non-Prime: Weekdays from 9:00 am to 5:00 pm
· Ice - Prime: Weekdays from 5:00 pm to 10:00 pm, Saturdays, Sundays
· Arena and Ice rentals include the use of the change rooms
· Personnel Costs are applicable for any additional staffing requirements for events at the discretion of the Director of Public Works, Parks and Facilities subject to operational demands and staff availability. See Report REC-2023-004 and Report FIN-2023-030.
· Example of Commercial Rentals include Auctions, Sale of Merchandise - See Report FIN-2019-031

Fee Reductions

· A 90% reduced rate shall apply to Seniors' Community Events that meet the eligibility criteria.
· A 90% reduced rate shall apply to Whistle Stop Co-operative Pre-school and Guelph Community Health Centre (The Playgroup).

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SCHEDULE I: OPTIMIST RECREATION CENTRE USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS

- Seniors' Recreation Programs that meet the eligibility criteria shall receive a 50% reduced rate.
- A 75% reduced rate shall apply to organizations that host community events and meet the eligibility criteria.
- All other organizations that meet the eligibility criteria shall receive a 50% reduced rate.

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SCHEDULE J: PUSLINCH COMMUNITY CENTRE USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Meeting Room - Non Resident Rental or Commercial Rental	Per Hour	$40.10	$41.15	$5.35	$46.50	2.6%	T	
Meeting Room	Per Hour	$32.08	$32.92	$4.28	$37.20	2.6%	T	
50% Reduced Rate - Meeting Room	Per Hour	N/A	$16.46	$2.14	$18.60	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Meeting Room	Per Hour	$8.02	$8.23	$1.07	$9.30	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Meeting Room	Per Hour	$3.21	$3.29	$0.43	$3.72	2.6%	T	See Report COR-2025-029
Hall - Non-Prime - Non Resident Rental or Commercial Rental	Per Hour	$94.09	$96.54	$12.55	$109.09	2.6%	T	See Report FIN-2025-024
Hall - Non-Prime	Per Hour	$75.27	$77.23	$10.04	$87.27	2.6%	T	See Report FIN-2025-024
50% Reduced Rate - Hall - Non-Prime	Per Hour	N/A	$38.62	$5.02	$43.63	100.0%	T	See Report COR-2025-029 and Report FIN-2025-024
75% Reduced Rate - Hall - Non-Prime	Per Hour	$18.82	$19.31	$2.51	$21.82	2.6%	T	See Report COR-2025-029 and Report FIN-2025-024
90% Reduced Rate - Hall - Non-Prime	Per Hour	$7.53	$7.72	$1.00	$8.73	2.6%	T	See Report COR-2025-029 and Report FIN-2025-024
Hall - Non-Prime - Non Resident Rental or Commercial Rental	Full Day Rental	$638.64	$655.25	$85.18	$740.43	2.6%	T	See Report FIN-2025-024
Hall - Non-Prime	Full Day Rental	$510.91	$524.20	$68.15	$592.35	2.6%	T	See Report FIN-2025-024
50% Reduced Rate - Hall - Non-Prime	Full Day Rental	N/A	$262.10	$34.07	$296.17	100.0%	T	See Report COR-2025-029 and Report FIN-2025-024
75% Reduced Rate - Hall - Non-Prime	Full Day Rental	$127.73	$131.05	$17.04	$148.09	2.6%	T	See Report COR-2025-029 and Report FIN-2025-024
90% Reduced Rate - Hall - Non-Prime	Full Day Rental	$51.09	$52.42	$6.81	$59.23	2.6%	T	See Report COR-2025-029 and Report FIN-2025-024
Hall - Prime - Non Resident Rental or Commercial Rental	15 Hour Rental	$1,033.02	$1,059.88	$137.78	$1,197.66	2.6%	T	See Report FIN-2023-030 and Report FIN-2023-032.
Hall - Prime	15 Hour Rental	$614.32	$630.30	$81.94	$712.24	2.6%	T	See Report FIN-2023-032.
Hall - Prime - Non Resident Rental or Commercial Rental	Per Hour	$86.13	$88.38	$11.49	$99.86	2.6%	T	See Report FIN-2023-032 and Report FIN-2024-024.
Hall - Prime	Per Hour	$68.90	$70.70	$9.19	$79.89	2.6%	T	See Report FIN-2023-032.
Hall - Set-up Fee - Non Resident Rental or Commercial Rental	Per Hour	$86.13	$88.38	$11.49	$99.86	2.6%	T	

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SCHEDULE J: PUSLINCH COMMUNITY CENTRE USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS
Hall - Set-up Fee	Per Hour	$68.90	$70.70	$9.19	$79.89	2.6%	T	
Use of Kitchen Facilities - Non Prime - Non Resident Rental or Commercial Rental	Per Hour	$49.24	$50.53	$6.57	$57.10	2.6%	T	
Use of Kitchen Facilities - Non Prime	Per Hour	$33.64	$34.52	$4.49	$39.01	2.6%	T	
50% Reduced Rate - Use of Kitchen Facilities - Non Prime	Per Hour	N/A	$17.26	$2.24	$19.50	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Use of Kitchen Facilities - Non Prime	Per Hour	$8.41	$8.63	$1.12	$9.75	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Use of Kitchen Facilities - Non Prime	Per Hour	$3.36	$3.45	$0.45	$3.90	2.7%	T	See Report COR-2025-029
Licensed Events - Fenced Outdoor Patio - Non Resident Rental or Commercial Rental	Flat Rate	$88.05	$90.35	$11.75	$102.10	2.6%	T	
Licensed Events - Fenced Outdoor Patio	Flat Rate	$70.44	$72.28	$9.40	$81.68	2.6%	T	
50% Reduced Rate - Licensed Events - Fenced Outdoor Patio	Flat Rate	N/A	$36.14	$4.70	$40.84	100.0%	T	See Report COR-2025-029
75% Reduced Rate - Licensed Events - Fenced Outdoor Patio	Flat Rate	$17.61	$18.07	$2.35	$20.42	2.6%	T	See Report COR-2025-029
90% Reduced Rate - Licensed Events - Fenced Outdoor Patio	Flat Rate	$7.04	$7.23	$0.94	$8.17	2.6%	T	See Report COR-2025-029
Personnel Costs	Per Hour Per Personnel	Actual Costs Incurred					T	
Facility Rental Security Deposit - Hall Rental Only or Hall and Meeting Room Rental	Per Booking	$1,500.00	$1,500.00	$0.00	$1,500.00	0.0%	E	See Report FIN-2022-029
Facility Rental Security Deposit - Meeting Room/Kitchen Facility Only	Per Booking	$365.00	$365.00	$0.00	$365.00	0.0%	E	See Report FIN-2022-029

INTERPRETATION

· An eight-hour Meeting Room booking is required when the Meeting Room is rented in conjunction with a 15-hour Hall rental between the hours of 10:00 a.m. to 1:00 a.m..
· A minimum of a 3 hour booking required for all hourly Hall and Kitchen Facility rentals.
· Additional hours beyond the 15-hour rental period are subject to availability and will be charged at the applicable hourly Hall rental rate.
· Hall rentals include the use of the kitchen facility (dishes, silverware, cooking utensils, dishwasher, coffee maker, etc. included).
· Hall - Non-Prime: Monday to Thursday and Sunday Rentals; Hall - Prime: Friday and Saturday
· If the outdoor patio has been included on the Special Occasion Permit or Caterer's Endorsement, Township Staff will fence the outdoor patio.
· The security deposit is fully refundable after the Event, provided there are no damages to the facility, the access key is returned, and all terms of the Township's Alcohol Risk Management policy, the Special Occasion Permit or Caterer's Endorsement, any Township agreements and all applicable federal, provincial and municipal laws, policies, guidelines, regulations and by-laws, including without limitation, the Liquor Licence and Control Act, 2019 are adhered to.
· The Hall - Set-up Fee - is after 5:00 p.m. on Friday only and must include a Saturday rental. This service is only available if the hall is not booked 7 days prior to the event date.
· Personnel Costs are applicable for any additional staffing requirements for events at the discretion of the Director of Public Works, Parks and Facilities subject to operational demands and staff availability. See Report REC-2023-004 and Report FIN-2023-030.
· Example of Commercial Rentals include Auctions, Sale of Merchandise - See Report FIN-2019-031.

Fee Reductions

· A 90% reduced rate shall apply to Seniors' Community Events that meet the eligibility criteria.

Draft

SCHEDULE J: PUSLINCH COMMUNITY CENTRE USER FEES AND CHARGES
EFFECTIVE 2027

TYPE OF REVENUE/USER	Unit/Descr	2026 RATE (NO TAX)	2027 RATE (NO TAX)	13% HST	RATE INCL HST	% CHANGE	HST STATUS	COMMENTS

- A 90% reduced rate shall apply to Whistle Stop Co-operative Pre-school and Guelph Community Health Centre (The Playgroup).
- Seniors' Recreation Programs that meet the eligibility criteria shall receive a 50% reduced rate.
- A 75% reduced rate shall apply to organizations that host community events and meet the eligibility criteria.
- All other organizations that meet the eligibility criteria shall receive a 50% reduced rate.

draft

REPORT FIN-2026-022

TO:	Mayor and Members of Council
PREPARED BY:	Michelle Cassar, Deputy Treasurer
PRESENTED BY:	Michelle Cassar, Deputy Treasurer
MEETING DATE:	September 16, 2026
SUBJECT:	2025 Commodity Price Hedging Agreements

RECOMMENDATIONS

That Report FIN-2026-022 entitled 2025 Commodity Price Hedging Agreements be received; and

That Council accepts the Treasurer's statement that based on the information supplied by Local Authority Services (LAS), all commodity price hedging agreements are consistent with the Township's statement of policies and goals related to the use of financial agreements to address commodity pricing and costs as outlined in Schedule A to Report FIN-2026-022.

DISCUSSION

Purpose

The purpose of this report is to comply with the Treasurer's reporting requirements as set out by Ontario Regulation 653/05 of the Municipal Act, 2001.

Background

Section 7(1) of Ontario Regulation 653/05, as amended states that if a municipality has commodity price hedging agreements in place, the Treasurer of the municipality must prepare and present to Council once every fiscal year a detailed report on those agreements. The report must contain the following information:

1. A statement about the status of the agreements during the period of the report, including a comparison of the expected and actual results of using the agreements.
2. A statement by the Treasurer that all of the agreements entered into during the period of the report are consistent with the municipality's statement of policies and goals related to the use of financial agreements to address commodity pricing and costs.

The Township entered into hedging agreements for natural gas and electricity procurement through Local Authority Services Limited (LAS), a wholly owned subsidiary of the Association of Municipalities of Ontario (AMO). These agreements are as follows:

- The Electricity Agency Appointment and Retainer Agreement dated September 19, 2012
- The Natural Gas Appointment and Retainer Agreement dated February 10, 2021

The Commodity Price Hedging Policy was approved by Council through adoption of By-law No. 56/12, attached as Schedule A to this Report.

Natural Gas Procurement Program

The LAS Natural Gas Procurement Program currently includes 160+ participating organizations. An annual price (per m^3) for all natural gas consumption is determined by LAS and reflects LAS's completed gas purchases and expectations for spot market natural gas costs for the one-year period. LAS purchases physical natural gas and provides it to all enrolled municipalities based on their consumption requirements.

There is not a hedge percentage in the LAS Natural Gas Procurement Program. In situations when LAS over collects fees (ie. when spot market prices are lower than LAS's expectations), LAS provides the municipality with a rebate.

Electricity Procurement Program

The LAS Electricity Procurement Program currently includes 145+ municipalities. LAS removes municipal accounts from government (default) pricing and instead purchases electricity forward price contracts for much of the municipality's consumption.

The Township hedges 50% of its electricity requirements while the remaining 50% is purchased at spot market prices. There are no rebates for the electricity program as LAS purchases a financial hedge for each participating municipality at a negotiated cost (per/kWh) and settles, as retailer, along with the spot market cost of power.

Purpose of Hedging

The purpose of hedging is to secure energy costs at an agreed-upon price, providing greater budget certainty. Volatile utility prices create significant challenges for municipalities to manage utility budgets. The LAS energy hedging programs help by providing more stable and predictable energy pricing over time. While utility costs remain unpredictable, hedging is intended to protect against significant price increases rather than guarantee the lowest possible cost in any given year. As a result, there may be periods when the hedged price exceeds the spot market price, resulting in higher energy costs for the Township in the short term. However, the overall objective is to reduce exposure to market volatility and provide greater long-term budget stability.

Financial Implications

Natural Gas

The 2025 actual natural gas costs amounted to $29,348 compared to $26,933 in 2024, with consumption volume increasing to 79,799 m^3 in 2025 compared to 65,764 m^3 in 2024.

The LAS Program Fee decreased to $0.0038 cents/$m^3$ for the period from November 2025 to the date of this report.

Table 1 summarizes the LAS Natural Gas Procurement Program rates from November 2023 to October 2026:

Table 1: LAS Natural Gas Procurement Program rates from November 2023 to October 2026

Time Period	Price per m^3 – includes LAS program fee
Nov. 2023 to Oct. 2024	$13.6 cents/$m^3$
Nov. 2024 to Oct. 2025	$14.0 cents/ m^3
Nov. 2025 to Oct. 2026	$13.8 cents/ m^3

The LAS natural gas rate was higher than the Enbridge Gas rates from January 2025 to December 31, 2025.

Table 2 outlines that from the 2021 to 2025 period, the Township has generated overall net savings of $7,224 by being enrolled in the program.

Table 2: Overall LAS Natural Gas Program Net Savings from 2021 to 2025

Year	Savings or (Loss) to the Township	LAS Rebate	Total Savings or (Loss) to the Township
2021	$2,780	$521	$3,301
2022	$4,612	$534	$5,146
2023	$3,262	$540	$3,783
2024	(1,560)	$521	($1,039)
2025	(4,560)	$593	($3,967)
Total Net Savings over the 5-year period			$7,224

If LAS collects more revenue through the set program rate than is required to run the program, an amount is rebated back to municipalities. The rebate cheque reflects a share of the reserve fund that the LAS program maintains and then returns to participating members once each year's balancing obligations are completed. The rebate provided is based on the quantity of natural gas consumed during the rebate period. The Township has consistently over the years received a rebate cheque. In 2025, the Township received a rebate of $593 for the period of November 1, 2023 to October 31, 2024. If a rebate is applicable for the November 1, 2024 to October 31, 2025 period, it will be determined in 2026.

Schedule B to this Report includes the results of using the LAS Natural Gas Procurement Program for 2025 obtained from LAS. It is a comparison of the LAS program's rate versus the default utility price. It is a metric to show how the program is doing at a point in time (2025) in comparison to Enbridge Gas and is best utilized by reviewing across longer periods of time as summarized in Table 2 above.

Electricity

The 2025 actual electricity costs excluding streetlight repair costs amounted to $75,709 compared to $79,826 in 2024.

The LAS Program Fees for all accounts remains unchanged from previous years with the fee excluding streetlights at $0.15 cents/kWh and the fee for streetlight accounts at $6 per month per account. The $1.50 transaction fee, representing half of the $3.00 transaction fee charged by the utility is now added to all accounts, including the streetlight accounts.

Table 3 summarizes the LAS Electricity Procurement Program rates for 50% of the Township's electricity for all accounts excluding streetlights from 2023 to 2025.

Table 3: LAS Electricity Procurement Program rates from 2023 to 2025

Year	Price per kWh – includes LAS program fee
2023	$7.05 cents/kWh
2024	$5.02 cents/kWh
2025	$5.85 cents/kWh

Schedule C to this Report includes the results of using the LAS Electricity Procurement Program for 2025 obtained from LAS. The Township's total savings based on hedging the electricity rates with the LAS Program were $985 in 2025 compared to $3,941 in 2024.

Strategic Plan Alignment and Implications

Strategic Priority #4: Good Governance, Financial Stewardship, and Organizational Excellence

This report directly supports Strategic Priority #4 by demonstrating transparent decision making, responsible financial management, and service excellence to maintain public trust and long-term municipal sustainability.

Objective 4.2: Maintain Financial Stewardship

This report advances Council's objective to maintain financial stewardship by ensuring Township hedging processes are compliant with applicable legislative requirements. The report demonstrates the Township's ongoing commitment to legislative compliance, financial accountability and transparent reporting.

Action 4.2(d): Continue to Provide Financial Stewardship Through Successful Audit, Balanced Budgets, and Oversight of Expenditures

This initiative aligns with Action 4.2(d) through the annual monitoring and reporting of the Township's hedges in compliance with the legislative parameters. The report supports sound financial planning and long-term sustainability by ensuring hedges are managed in a transparent, legislatively compliant, and fiscally responsible manner.

Applicable Legislation and Requirements

Ontario Regulation 653/05 of the Municipal Act, 2001

Engagement Opportunities

The Township posts its annual energy consumption reporting and its Five Year Energy Conservation and Demand Management Plan on the Energy Conservation page of the Township's website on Puslinch.ca/energy.

Attachments

Schedule A – By-law No. 56/12 - Commodity Price Hedging Policy

Schedule B – LAS Natural Gas Procurement Program Results for 2025

Schedule C – LAS Electricity Procurement Program Results for 2025

Respectfully submitted:

Michelle Cassar
Deputy Treasurer

Reviewed by:

Mary Hasan
Director of Finance/Treasurer

THE CORPORATION OF THE TOWNSHIP OF PUSLINCH

BY-LAW NUMBER 56/12

Being a by-law to authorize the Township of Puslinch to establish a policy respecting Commodity Price Hedging for the Township of Puslinch.

WHEREAS Council for the Corporation of the Township of Puslinch considers it desirable to establish a Commodity Price Hedging policy.

NOW THEREFORE BE IT RESOLVED THAT Council does hereby enact the following as a By-law;

1. THAT the Corporation of the Township of Puslinch does hereby adopt a policy respecting Commodity Price Hedging as attached hereto and marked as Schedule "A" to this By-law.

2. THAT this By-law shall take effect upon the date of passage.

READ A FIRST, SECOND AND THIRD TIME AND FINALLY PASSED THIS 19th DAY OF SEPTEMBER, 2012.

Mayor Dennis Lever

Brenda Law, CAO/Clerk-Treasurer

APPENDIX A

FINANCE POLICY

SUBJECT: COMMODITY PRICE HEDGING POLICY

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1. Interpretation

This policy is to be interpreted and applied in accordance with the requirements of the *Municipal Act, 2001* ("the Act") and any regulations passed thereunder ("the regulations"). Terms used in the policy have the meanings applicable to those terms in the corresponding sections of the Act and the regulations.

2. Purpose

The purpose of this policy is to adopt a statement of the municipality's commodity price hedging policies and goals. Section 6(1) of O. Reg. 653/05 requires the adoption of such a statement before the municipality may enter into commodity price hedging agreements.

3 Statement of Commodity Price Hedging Policies and Goals

(a) The Township of Puslinch will consider commodity price hedging agreements as a means of fixing, directly or indirectly, or enabling the municipality to fix, the price or range of prices to be paid by the municipality for the future delivery of some or all of the commodity or the future cost to the municipality of an equivalent quantity of the commodity, where it is advantageous for the municipality to do so.

(b) In determining whether a particular commodity price hedging agreement is advantageous for the municipality, the following considerations will be taken into account:

(i) Any and all projects of the municipality are projects for which commodity price hedging agreements will be appropriate;

(ii) If, at the time, it is the opinion that fixed costs and estimated costs of the municipality will be reduced by virtue of the use of such an agreement;

(iii) If, at the time, it is the opinion that the future price or cost to the municipality of the applicable commodity will be lower or more stable than it would be without the agreement;

(iv) If, at the time, the project includes a detailed estimate of the expected result of using such an agreement;

(v) If, at the time, it is the opinion that the financial and other risks to the municipality that would exist with the use of such an agreement will be lower than the financial and other risks to the municipality that would exist without such an agreement;

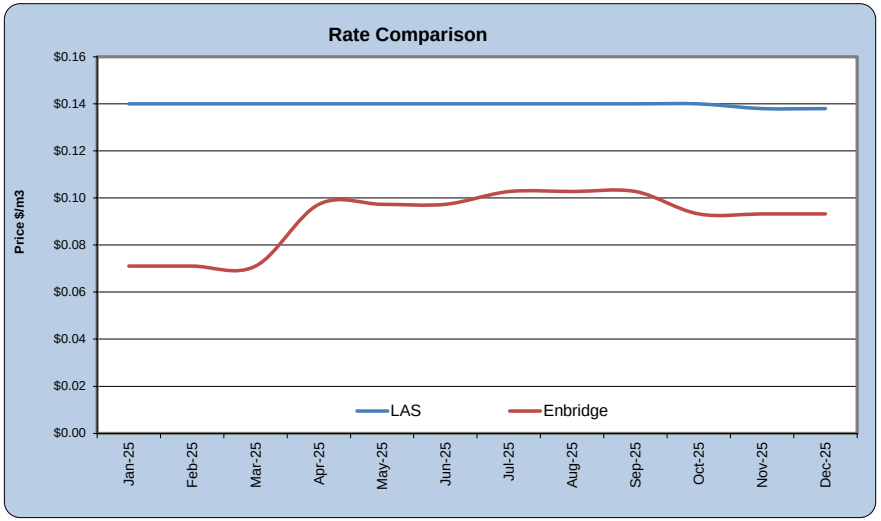
(vi) If, at the time, it is the opinion that the agreement contains adequate risk control measures relating to such an agreement, such as,

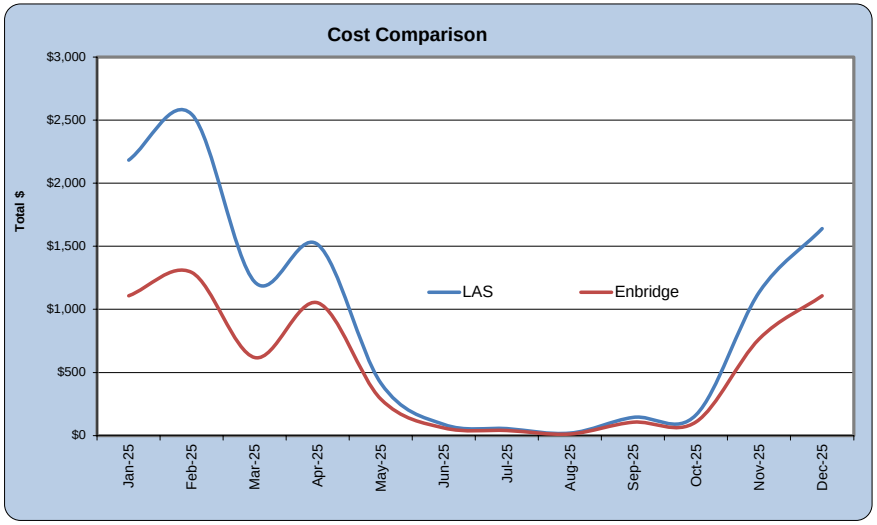
(1) Limited credit exposure based on credit ratings and/or on the degree of regulatory oversight and/or on the regulatory capital of the other party to the agreement,

(2) a standard agreement,

(3) ongoing monitoring with respect to the agreement.

Township of Puslinch





	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Total
Volume (m3)	*15,601*	*18,196*	*8,705*	*10,812*	*2,976*	*630*	*398*	*140*	*1,038*	*1,174*	*8,238*	*11,891*	79,799
LAS Rate ($/m3)	$ 0.1400	$ 0.1400	$ 0.1400	$ 0.1400	$ 0.1400	$ 0.1400	$ 0.1400	$ 0.1400	$ 0.1400	$ 0.1400	$ 0.1380	$ 0.1380	
LAS Cost	$ 2,184.14	$ 2,547.44	$ 1,218.70	$ 1,513.68	$ 416.64	$ 88.20	$ 55.72	$ 19.60	$ 145.32	$ 164.36	$ 1,136.84	$ 1,640.96	$ 11,131.60
Enbridge Rate ($/m3)	$ 0.0711	$ 0.0711	$ 0.0711	$ 0.0974	$ 0.0974	$ 0.0974	$ 0.1027	$ 0.1027	$ 0.1027	$ 0.0932	$ 0.0932	$ 0.0932	
Enbridge Cost	$ 1,108.51	$ 1,292.90	$ 618.53	$ 1,052.83	$ 289.79	$ 61.35	$ 40.89	$ 14.38	$ 106.64	$ 109.41	$ 767.75	$ 1,108.19	$ 6,571.17
Savings/(Loss)	$ (1,075.63)	$ (1,254.54)	$ (600.17)	$ (460.85)	$ (126.85)	$ (26.85)	$ (14.83)	$ (5.22)	$ (38.68)	$ (54.95)	$ (369.10)	$ (532.76)	$ (4,560.43)

LAS | AMO Business Services

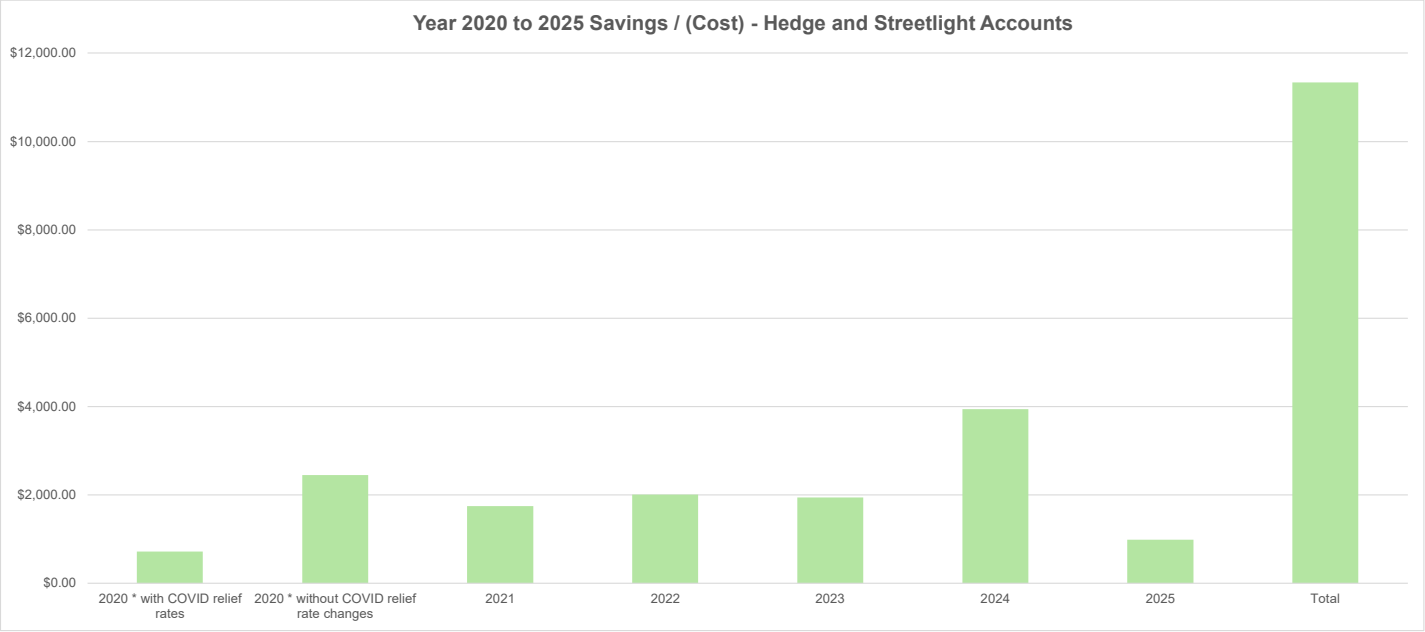
Puslinch

2025 Cost Summary

Hedge	Total Volume kWh	292,913.14
	LAS Rate $/kWh	0.058579
	LAS Cost $	17,158.56
	Global Adjustment Rate $/kWh	0.050392
	Global Adjustment Cost $	14,760.38
	Total Cost LAS + GA $/kWh	**31,918.94**
	TOU Rate $/kWh	0.109817
	Total TOU Cost $	**32,166.75**
	Hedge Savings/Cost $	**247.80**
Streetlights	Total Volume STL kWh	53,735.71
	LAS Rate $/kWh	0.050337
	LAS Cost $	2,704.89
	Global Adjustment Rate $/kWh	0.050392
	Global Adjustment Cost $	2,707.83
	Total Cost LAS + GA $/kWh	**5,412.73**
	TOU Tiered Rate $/kWh	0.114442
	Total TOU Tiered Cost $	**6,149.61**
	Streetlight Savings/Cost $	**736.88**
Total	**Savings/Cost $**	**984.68**

6 Year Cost Summary

Year	2020 * with COVID relief rates	2020 * without COVID relief rate changes	2021	2022	2023	2024	2025	Total
% Savings	2%	5%	6%	6%	4%	7%	3%	4%
$ Savings	$720.22	$2,449.71	$1,743.53	$2,009.45	$1,943.19	$3,940.73	$984.68	$11,341.80



REPORT FIN-2026-024

TO: Mayor and Members of Council

PREPARED BY: Michelle Cassar, Deputy Treasurer

PRESENTED BY: Michelle Cassar, Deputy Treasurer

MEETING DATE: September 16, 2026

SUBJECT: Municipal Performance Measurement Program Report for 2025

RECOMMENDATIONS

THAT Report FIN-2026-024 entitled Municipal Performance Measurement Program Report for 2025 be received.

Purpose

The purpose of this report is to provide Council with information regarding the Municipal Performance Measurement Program Report (MPMP) for 2025.

Background

Section 299 of the *Municipal Act, 2001* specifies that a municipality must provide the Ministry of Municipal Affairs and Housing (MMAH) with information measuring the efficiency and effectiveness of a municipality's operations and that this information shall be published in a manner and form determined by the municipality.

The reporting is commonly referred to as the MPMP report and is based on the Financial Information Return (FIR) that municipalities must also prepare annually.

The MMAH provides extensive FIR schedules for municipalities to complete each year. MMAH generally updates the schedules annually to streamline the data collection process or to reflect changes in Provincial information gathering requirements, trends, and other factors to help the Province better understand and obtain an overview of the finances of all Ontario municipalities.

The Township's financial statements are based on the FIR. The MPMP is based on statistical information collected on specific schedules in the FIR.

Schedule A attached to this report includes the statistical measures reported for 2024 to 2025 and is based on the Provincial data requirements as part of Schedule 80D of the FIR. These measures form the MPMP, a performance measurement and reporting system that promotes local government transparency and accountability.

The information has also been sent to the MMAH as part of the annual FIR submission.

Financial Implications

Discussed throughout this Report.

Strategic Plan Alignment and Implications

Strategic Priority #4: Good Governance, Financial Stewardship, and Organizational Excellence
This report directly supports Strategic Priority #4 by demonstrating responsible financial management and service excellence to maintain public trust and long-term municipal sustainability.

Objective 4.2: Maintain Financial Stewardship
This report advances Council's objective to maintain financial stewardship by ensuring Township financial and performance measurement reporting are compliant with applicable legislative requirements. The report demonstrates the Township's ongoing commitment to legislative compliance, financial accountability and transparent reporting.

Action 4.2(d): Continue to Provide Financial Stewardship Through Successful Audit, Balanced Budgets, and Oversight of Expenditures
This initiative aligns with Action 4.2(d) through the annual monitoring and reporting of the Township's financial and performance measurement reporting in compliance with the legislative parameters. The report supports sound financial planning and long-term sustainability by ensuring the Township is managed in a transparent, legislatively compliant, and fiscally responsible manner.

Applicable Legislation and Requirements

Section 299 of the *Municipal Act, 2001*

Engagement Opportunities

The MPMP report is posted on the Township's Financial Reporting Page on Puslinch.ca.

Attachments

Schedule A: 2025 MPMP Reporting

Respectfully submitted:

Michelle Cassar
Deputy Treasurer

Reviewed by:

Mary Hasan
Director of Finance/Treasurer

FIR2025: Puslinch Tp

Asmt Code: 2301
MAH Code: 75612

Schedule 80
STATISTICAL INFORMATION
for the year ended December 31, 2025

9. Building Permit Information (Performance Measures)

		Column 1 #	Column 2 #	Column 3 #	Description 4 LIST
1300	What method does your municipality use to determine total construction value?				Hanscomb Yardsticks for Costing
1302	If "Other Method" is selected in line 1300, please describe the method used to determine total construction value.				

Total Value of Construction Activity

		1 $
1304	Total Value of Construction Activity for 2025 based on permits issued.	27,634,143

Review of Complete Building Permit Applications:
Median number of working days to review a complete building permit application and issue a permit or not issue a permit, and provide all reasons for refusal (by Category):

		Median Number of Working Days 1#
1306	**Category 1: Houses** *(houses not exceeding 3 storeys / 600 square metres)* *Reference : provincial standard is 10 working days*	9
1308	**Category 2 : Small Buildings** *(small commercial/industrial not exceeding 3 storeys / 600 square metres)* *Reference : provincial standard is 15 working days*	15
1310	**Category 3 : Large Buildings** *(large residential / commercial / industrial / institutional)* *Reference : provincial standard is 20 working days*	20
1312	**Category 4 : Complex Buildings** *(post disaster buildings, including hospitals, power / water, fire / police / EMS, communications)* ***Note** : If no complete applications were submitted and accepted for a Category on lines 1306 to 1312, please leave the cell blank and do not enter zero.*	

Number Of Building Permit Applications

		Number of Complete Applications 1 #	Number of Incomplete Applications 2 #	Total Number of Complete and Incomplete Applications 3 #
1314	**Category 1 : Houses** *(houses not exceeding 3 storeys / 600 square metres)*	130		130
1316	**Category 2 : Small Buildings** *(small commercial/industrial not exceeding 3 storeys / 600 square metres)*	7		7
1318	**Category 3 : Large Buildings** *(large residential / commercial / industrial / institutional)*	14		14
1320	**Category 4 : Complex Buildings** *(post disaster buildings, including hospitals, power / water, fire / police / EMS), communications*			0
1322	**Subtotal**	151	0	151

Note: *Zero should be entered on lines 1314 to 1320 in column 1 if no complete applications were submitted and accepted for a category. Zero should be entered in column 2 if no incomplete applications were submitted and accepted for a category.*

10. Planning and Development

Land Use Planning *(using building permit information)*

		Residential Units within Settlement Areas 1 #	Total Residential Units 2 #	Total Secondary Units 3 #
1350	Number of residential units in new detached houses		11	6
1352	Number of residential units in new semi-detached houses			
1354	Number of residential units in new row houses			
1356	Number of residential units in new apartments / condo apartments			
1358	**Subtotal**	0	11	6

Land Designated for Agricultural Purposes

		Hectares 1 #
1370	Hectares of land designated for agricultural purposes in the Official Plan as of December 31, 2025	20,607

11. Transportation Services

		1 #
1710	**Roads:** Total Paved Lane Km	262
1720	**Condition of Roads:** Number of paved lane kilometres where the condition is rated as good to very good.	179

FIR2025: Puslinch Tp

Asmt Code: 2301
MAH Code: 75612

Schedule 80
STATISTICAL INFORMATION
for the year ended December 31, 2025

		Column 1 #	Column 2 #	Column 3 #	Description 4 LIST
1722	Has the entire municipal road system been rated?				Y
1725	Indicate the rating system used and the year the rating was conducted				2022 Pavement Condition Index

1730	**Roads:** Total Unpaved Lane Km	120
1740	**Winter Control:** Total Lane Km maintained in winter	381
1750	**Transit:** Total Number of Regular Service Passenger Trips on Conventional Transit in Service Area.	
1755	**Transit:** Population of Service Area	
1760	**Bridges and Culverts:** Total Square Metres of Surface Area on Bridges and Culverts	1,167

Rating Of Bridges And Culverts

		Number of structures where the condition of primary components is rated as good to very good, requiring only repair 1 #	Total Number 2 #
1765	Bridges	2	7
1766	Culverts	11	15
1767	**Subtotal**	13	22

		Column 1 #	Column 2 #	Column 3 #	Description 4 LIST
1768	Have all bridges and culverts in the municipal system been rated?				
1769	Indicate the rating system used and the year the rating was conducted.				2025 - detailed bridge and culvert

12. Environmental Services

		1 #
1810	**Wastewater Main Backups:** Total number of backed up wastewater mains	
1815	**Wastewater Collection / Conveyance:** Total KM of Wastewater Mains.	
1820	**Wastewater Treatment and Disposal :** Total Megalitres of Wastewater Treated	
1825	**Wastewater Bypasses Treatment:** Estimated megalitres of untreated wastewater.	
1835	**Urban Storm Water Management :** Total KM of Urban Drainage System plus *(0.005 KM times No. of Catch basins)*	
1840	**Rural Storm Water Management:** Total KM of Rural Drainage System plus *(0.005 KM times No. of Catch basins)* .	10
1845	**Water Treatment:** Total Megalitres of Drinking Water Treated.	
1850	**Water Main Breaks:** Number of water main breaks in a year	
1855	**Water Distribution/Transmission:** Total kilometres of Water Distribution / Transmission Pipe.	
1860	**Solid Waste Collection:** Total tonnes collected from all property classes.	
1865	**Solid Waste Disposal:** Total tonnes disposed of from all property classes.	
1870	**Waste Diversion:** Total tonnes diverted from all property classes.	

13. Recreation Services

		1 #
1910	**Trails:** Total kilometres of trails (*owned by municipality and third parties*).	34
1920	**Indoor recreation facility space:** Square metres of indoor recreation facilities *(municipally owned)* .	1,458
1930	**Outdoor recreation facility space:** Square metres of outdoor recreation facility space *(municipally owned)* .	200,678

14. Other Revenue (Used for the calculation of Operating Cost)

		1 $
2310	**Fire Services:** Other revenue.	
2320	**Paved Roads:** Other revenue.	
2330	**Solid Waste Disposal:** Other revenue.	
2340	**Waste Diversion:** Other Revenue	
2370	Assessment on Exempt Properties *(Enter data from returned roll)*	140,275,596

FIR2024: Puslinch Tp

Asmt Code: 2301
MAH Code: 75612

Schedule 80
STATISTICAL INFORMATION
for the year ended December 31, 2024

9. Building Permit Information (Performance Measures)

		Column 1 #	Column 2 #	Column 3 #	Description 4 LIST
1300	What method does your municipality use to determine total construction value?				Hanscomb Yardsticks for Costing
1302	If "Other Method" is selected in line 1300, please describe the method used to determine total construction value.				

Total Value of Construction Activity

		1 $
1304	Total Value of Construction Activity for 2024 based on permits issued.	45,362,461

Review of Complete Building Permit Applications:
Median number of working days to review a complete building permit application and issue a permit or not issue a permit, and provide all reasons for refusal (by Category):

		Median Number of Working Days 1#
1306	**Category 1: Houses** *(houses not exceeding 3 storeys / 600 square metres)* *Reference : provincial standard is 10 working days*	10
1308	**Category 2 : Small Buildings** *(small commercial/industrial not exceeding 3 storeys / 600 square metres)* *Reference : provincial standard is 15 working days*	10
1310	**Category 3 : Large Buildings** *(large residential / commercial / industrial / institutional)* *Reference : provincial standard is 20 working days*	
1312	**Category 4 : Complex Buildings** *(post disaster buildings, including hospitals, power / water, fire / police / EMS, communications)*	

Note *: If no complete applications were submitted and accepted for a Category on lines 1306 to 1312, please leave the cell blank and do not enter zero.*

Number Of Building Permit Applications

		Number of Complete Applications 1 #	Number of Incomplete Applications 2 #	Total Number of Complete and Incomplete Applications 3 #
1314	**Category 1 : Houses** *(houses not exceeding 3 storeys / 600 square metres)*	203	0	203
1316	**Category 2 : Small Buildings** *(small commercial/industrial not exceeding 3 storeys / 600 square metres)*	7	0	7
1318	**Category 3 : Large Buildings** *(large residential / commercial / industrial / institutional)*	1	4	5
1320	**Category 4 : Complex Buildings** *(post disaster buildings, including hospitals, power / water, fire / police / EMS), communications*	0	0	0
1322	**Subtotal**	211	4	215

Note: *Zero should be entered on lines 1314 to 1320 in column 1 if no complete applications were submitted and accepted for a category. Zero should be entered in column 2 if no incomplete applications were submitted and accepted for a category.*

10. Planning and Development

Land Use Planning *(using building permit information)*

		Residential Units within Settlement Areas 1 #	Total Residential Units 2 #	Total Secondary Units 3 #
1350	Number of residential units in new detached houses	3	16	29
1352	Number of residential units in new semi-detached houses			
1354	Number of residential units in new row houses			
1356	Number of residential units in new apartments / condo apartments			
1358	**Subtotal**	3	16	29

Land Designated for Agricultural Purposes

		Hectares 1 #
1370	Hectares of land designated for agricultural purposes in the Official Plan as of December 31, 2024	20,607

11. Transportation Services

		1 #
1710	**Roads:** Total Paved Lane Km	262
1720	**Condition of Roads:** Number of paved lane kilometres where the condition is rated as good to very good.	151

Column	Column	Column	Description

FIR2024: Puslinch Tp

Asmt Code: 2301
MAH Code: 75612

Schedule 80
STATISTICAL INFORMATION
for the year ended December 31, 2024

		1 # 1	2 # 2	3 # 3	4 LIST 4
1722	Has the entire municipal road system been rated?				Y
1725	Indicate the rating system used and the year the rating was conducted				2016 Pavement Condition Index

1730	**Roads:** Total Unpaved Lane Km	122
1740	**Winter Control:** Total Lane Km maintained in winter	385
1750	**Transit:** Total Number of Regular Service Passenger Trips on Conventional Transit in Service Area.	
1755	**Transit:** Population of Service Area	
1760	**Bridges and Culverts:** Total Square Metres of Surface Area on Bridges and Culverts	1,179

		Number of structures where the condition of primary components is rated as good to very good, requiring 1 #	Total Number 2 #
	Rating Of Bridges And Culverts		
1765	Bridges	3	7
1766	Culverts	11	15
1767	**Subtotal**	14	22

		Column 1 #	Column 2 #	Column 3 #	Description 4 LIST
1768	Have all bridges and culverts in the municipal system been rated?				
1769	Indicate the rating system used and the year the rating was conducted.				2021 - detailed bridge and culvert

12. Environmental Services

		1 #
1810	**Wastewater Main Backups:** Total number of backed up wastewater mains	
1815	**Wastewater Collection / Conveyance:** Total KM of Wastewater Mains.	
1820	**Wastewater Treatment and Disposal :** Total Megalitres of Wastewater Treated	
1825	**Wastewater Bypasses Treatment:** Estimated megalitres of untreated wastewater.	
1835	**Urban Storm Water Management :** Total KM of Urban Drainage System plus *(0.005 KM times No. of Catch basins)*	
1840	**Rural Storm Water Management:** Total KM of Rural Drainage System plus *(0.005 KM times No. of Catch basins)* .	10
1845	**Water Treatment:** Total Megalitres of Drinking Water Treated.	
1850	**Water Main Breaks:** Number of water main breaks in a year	
1855	**Water Distribution/Transmission:** Total kilometres of Water Distribution / Transmission Pipe.	
1860	**Solid Waste Collection:** Total tonnes collected from all property classes.	
1865	**Solid Waste Disposal:** Total tonnes disposed of from all property classes.	
1870	**Waste Diversion:** Total tonnes diverted from all property classes.	

13. Recreation Services

		1 #
1910	**Trails:** Total kilometres of trails (*owned by municipality and third parties*).	34
1920	**Indoor recreation facility space:** Square metres of indoor recreation facilities *(municipally owned)* .	1,458
1930	**Outdoor recreation facility space:** Square metres of outdoor recreation facility space *(municipally owned)* .	200,678

14. Other Revenue (Used for the calculation of Operating Cost)

		1 $
2310	**Fire Services:** Other revenue.	
2320	**Paved Roads:** Other revenue.	
2330	**Solid Waste Disposal:** Other revenue.	
2340	**Waste Diversion:** Other Revenue	
2370	Assessment on Exempt Properties *(Enter data from returned roll)*	138,766,798

REPORT CAO-2026-012

TO: Mayor and Members of Council

PREPARED BY: Courtenay Hoytfox, CAO

PRESENTED BY: Courtenay Hoytfox, CAO

MEETING DATE: September 16, 2026

SUBJECT: Temporary Use Conformity Request

RECOMMENDATION

That Report CAO-2026-012 entitled Temporary Use Conformity Request be received for information; and

That Council request that the County of Wellington amend Section 13.4 of the Wellington County Official Plan to ensure that the temporary use provisions accurately reflect the authority provided under Section 39 of the *Planning Act*, through whatever administrative or other process the County considers appropriate, having regard for the timeliness of the correction; and

That should the County determine that the correction cannot be made through an administrative process, the County advise the Township accordingly, at which time the Township will commence the appropriate Official Plan Amendment process.

Purpose

The purpose of this report is to request that the County amend Section 13.4 of the Wellington County Official Plan to ensure that its temporary use provisions are consistent with the *Planning Act.*

Background

Section 13.4 of the Wellington County Official Plan currently states that a temporary use by-law may allow a use that is otherwise prohibited by the Official Plan or Zoning By-law.

Section 39(1) of the *Planning Act* provides that a local council may, through a by-law passed under Section 34, authorize a temporary use for a purpose that is otherwise prohibited by the Zoning By-law.

Accordingly, staff recommend that Section 13.4 be amended to refer to a temporary use that is otherwise prohibited by the Zoning By-law, rather than the Official Plan or Zoning By-law, to more accurately reflect the authority provided under Section 39 of the *Planning Act*.

Financial Implications

There are no direct financial implications associated with the requested policy correction. If an Official Plan Amendment application is required, applicable fees and staff resources would be addressed through the Township's normal planning processes.

Strategic Plan Alignment and Implications

Strategic Priority #2: Managed growth and complete communities

This initiative directly supports Strategic Priority #2 by reinforcing managed growth and complete communities.

Objective 2.3 Encourage Responsible Land Use

The proposed approach advances Council's objective to encourage responsible land use by engaging oversight by Township staff and consultants to ensure land use compatibility and limit adverse impacts on the community.

Action 2.3(b): Township initiated Zoning By-law Amendment

This initiative aligns with Action 2.3(b) by continuing support responsible development and land use through collaboration with Township planning staff and the County of Wellington.

Applicable Legislation and Requirements

Planning Act, R.S.O. 1990, c. P.13
Wellington County Official Plan

Engagement Opportunities

None

Attachments

Respectfully submitted,

Courtenay Hoytfox,
CAO

TOWNSHIP OF
PUSLINCH
EST. 1850

Puslinch Development Design Guidelines

A Framework for Renewal, Reinvestment and Community Building

Council Presentation | September 16, 2026

pl.ural

Project Team

The Township of Puslinch

Mary Hasan
Director of Finance/Treasurer

Justine Brotherston
Director of Corporate Services/Municipal Clerk

Laura Emery
Manager of Corporate Services/Deputy Clerk

Planning, Design and Landscape Architecture

Sean Kelly
Kelsey Moore
Bethany Nelson
pl.ural Team

Purpose

The Guidelines will be supportive of implementing new rural and urban-centered development and renovation projects in its settlement areas, inform rural employment areas, and for maintaining and preserving existing infrastructure throughout the Township.

It will also provide a means for articulating a common purpose across the Township with a focus on both its urban and rural areas, and for communicating it to the Township and the community at large.

Guiding Principles

Convey a clear design direction for the Township.

Reinforce the rural character of the Township and its three settlement areas in Morriston, Aberfoyle, and Arkell.

Provide a practical and accessible document for implementation.

Guideline Intentions

Aimed at the Township's urban and rural areas; they also support other key documents, by-laws, and development/site plan approval processes, and contain insight and ideas applicable to the extended Township. The Guideline serves six (6) intentions.

1. Communal Action
2. Community Tool
3. Considers current fiscal realities
4. Contributes to a Municipal planning Process
5. Serves the Township and its Partners
6. Serves Communal and Constituent Projects

The Development Design Guidelines

A 70-page document covering 5 sections:

1. Introduction

Origin, Role & Scope, Communal Action, Community Tool, Guidelines Interaction, Fiscal Reality, Principal Audiences, Guidelines, Constituent & Communal Projects, Reinforce & Repair, Implementation Horizon, Application Beyond the 'Urban Corridor'.

2. Taking Stock

Existing Conditions, Study Area Context, Study Area, Defining Character, Community Engagement Summary, Focus Areas.

3. The Design Guidelines

Planning Principles, Enhancing Focus Areas, Established Character Meets Opportunity, Promoting Quality Development.

4. The Design Concepts

5. Implementation

Introduction

This section includes:

- Background
- Guiding Principles

Section 1:

Introduction

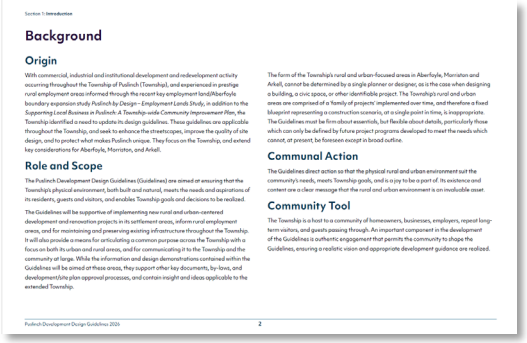
PUSLINCH Development Design Guidelines

This section provides background information including existing conditions, and overview of the study area, guidance on how to navigate the document and use the Guidelines, and a community engagement summary. This section sets a foundation for the Guidelines and development design concepts demonstrations.

Guiding Principles

- Convey a clear design direction for the Township.
- Reinforce the rural character of the Township and its three settlement areas.
- Provide a practical and accessible document for implementation.

1



Section 1: Introduction

Background

Origin

With commercial, industrial and institutional development and redevelopment activity occurring throughout the Township of Puslinch (Township), and experienced in prestige rural employment areas informed through the recent key employment land/Aberfoyle boundary expansion study *Puslinch by Design – Employment Lands Study*, in addition to the *Supporting Local Business in Puslinch: A Township-wide Community Improvement Plan*, the Township identified a need to update its design guidelines. These guidelines are applicable throughout the Township, and seek to enhance the streetscapes, improve the quality of site design, and to protect what makes Puslinch unique. They focus on the Township, and extend key considerations for Aberfoyle, Morriston, and Arkell.

Role and Scope

The Puslinch Development Design Guidelines (Guidelines) are aimed at ensuring that the Township's physical environment, both built and natural, meets the needs and aspirations of its residents, guests and visitors, and enables Township goals and decisions to be realized.

The Guidelines will be supportive of implementing new rural and urban-centered development and renovation projects in its settlement areas, inform rural employment areas, and for maintaining and preserving existing infrastructure throughout the Township. It will also provide a means for articulating a common purpose across the Township with a focus on both its urban and rural areas, and for communicating it to the Township and the community at large. While the information and design demonstrations contained within the Guidelines will be aimed at these areas, they support other key documents, by-laws, and development/site plan approval processes, and contain insight and ideas applicable to the extended Township.

The form of the Township's rural and urban-focused areas in Aberfoyle, Morriston and Arkell, cannot be determined by a single planner or designer, as is the case when designing a building, a civic space, or other identifiable project. The Township's rural and urban areas are comprised of a 'family of projects' implemented over time, and therefore a fixed blueprint representing a construction scenario, at a single point in time, is inappropriate. The Guidelines must be firm about essentials, but flexible about details, particularly those which can only be defined by future project programs developed to meet the needs which cannot, at present, be foreseen except in broad outline.

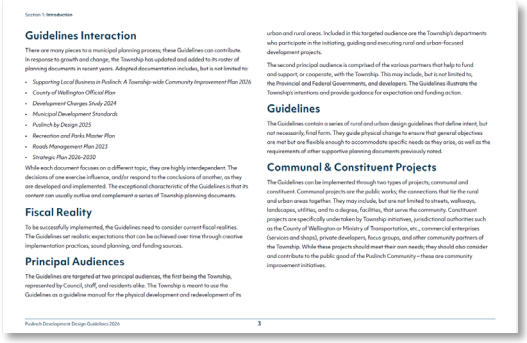
Communal Action

The Guidelines direct action so that the physical rural and urban environment suit the community's needs, meets Township goals, and is a joy to be a part of. Its existence and content are a clear message that the rural and urban environment is an invaluable asset.

Community Tool

The Township is a host to a community of homeowners, businesses, employers, repeat long-term visitors, and guests passing through. An important component in the development of the Guidelines is authentic engagement that permits the community to shape the Guidelines, ensuring a realistic vision and appropriate development guidance are realized.

Puslinch Development Design Guidelines 2026 2



Section 1: Introduction

Guidelines Interaction

There are many pieces to a municipal planning process; these Guidelines can contribute. In response to growth and change, the Township has updated and added to its roster of planning documents in recent years. Adopted documentation includes, but is not limited to:

- *Supporting Local Business in Puslinch: A Township-wide Community Improvement Plan 2026*
- *County of Wellington Official Plan*
- *Development Charges Study 2024*
- *Municipal Development Standards*
- *Puslinch by Design 2025*
- *Recreation and Parks Master Plan*
- *Roads Management Plan 2023*
- *Strategic Plan 2026-2030*

While each document focuses on a different topic, they are highly interdependent. The decisions of one exercise influence, and/or respond to the conclusions of another, as they are developed and implemented. The exceptional characteristic of the Guidelines is that its content can usually outline and complement a series of Township planning documents.

Fiscal Reality

To be successfully implemented, the Guidelines need to consider current fiscal realities. The Guidelines set realistic expectations that can be achieved over time through creative implementation practices, sound planning, and funding sources.

Principal Audiences

The Guidelines are targeted at two principal audiences, the first being the Township, represented by Council, staff, and residents alike. The Township is meant to use the Guidelines as a guideline manual for the physical development and redevelopment of its urban and rural areas. Included in this targeted audience are the Township's departments who participate in the initiating, guiding and executing rural and urban-focused development projects.

The second principal audience is comprised of the various partners that help to fund and support, or cooperate, with the Township. This may include, but is not limited to, the Provincial and Federal Governments, and developers. The Guidelines illustrate the Township's intentions and provide guidance for expectation and funding action.

Guidelines

The Guidelines contain a series of rural and urban design guidelines that define intent, but not necessarily, final form. They guide physical change to ensure that general objectives are met but are flexible enough to accommodate specific needs as they arise, as well as the requirements of other supportive planning documents previously noted.

Communal & Constituent Projects

The Guidelines can be implemented through two types of projects; communal and constituent. Communal projects are the public works, the connections that tie the rural and urban areas together. They may include, but are not limited to streets, walkways, landscapes, utilities, and to a degree, facilities, that serve the community. Constituent projects are specifically undertaken by Township initiatives, jurisdictional authorities such as the County of Wellington or Ministry of Transportation, etc., commercial enterprises (services and shops), private developers, focus groups, and other community partners of the Township. While these projects should meet their own needs; they should also consider and contribute to the public good of the Puslinch Community – these are community improvement initiatives.

Puslinch Development Design Guidelines 2026 3

Taking Stock

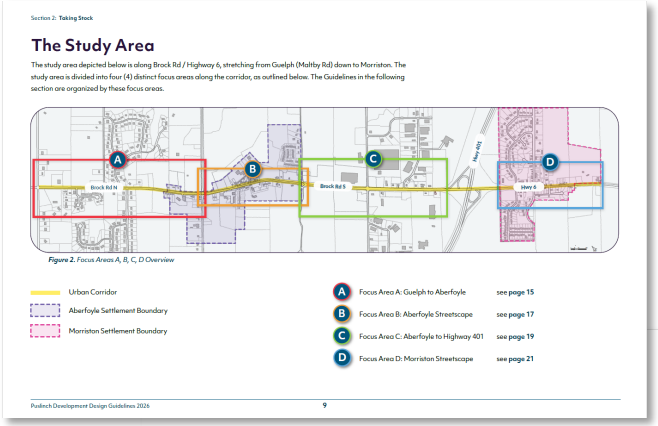
Section 2:

Taking Stock

PUSLINCH Development Design Guidelines

This section provides background information including existing conditions, and overview of the study area, specifically character definition and subsequent focus areas within Aberfoyle, Morriston, Arkell, the Employment Lands, and a community engagement summary. This section provides context and sets a foundation for the Guidelines and urban design concepts.

5



Section 2: Taking Stock

The Study Area

The study area depicted below is along Brock Rd / Highway 6, stretching from Guelph (Maltby Rd) down to Morriston. The study area is divided into four (4) distinct focus areas along the corridor, as outlined below. The Guidelines in the following section are organized by these focus areas.

Figure 2. Focus Areas A, B, C, D Overview

Urban Corridor
Aberfoyle Settlement Boundary
Morriston Settlement Boundary

A Focus Area A: Guelph to Aberfoyle see page 15
B Focus Area B: Aberfoyle Streetscape see page 17
C Focus Area C: Aberfoyle to Highway 401 see page 19
D Focus Area D: Morriston Streetscape see page 21

Puslinch Development Design Guidelines 2026 9

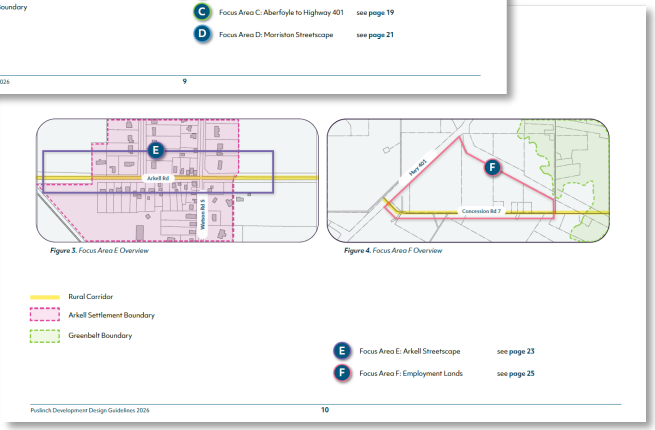


Figure 3. Focus Area E Overview

Figure 4. Focus Area F Overview

Rural Corridor
Arkell Settlement Boundary
Greenbelt Boundary

E Focus Area E: Arkell Streetscape see page 23
F Focus Area F: Employment Lands see page 25

Puslinch Development Design Guidelines 2026 10

This section includes:

- Existing Conditions
- The Study Area
- Community Engagement Summary

Section 2: Taking Stock

Defining Character

A Guelph to Aberfoyle	B Aberfoyle Streetscape	C Aberfoyle to Hwy 401	D Morriston Streetscape
Heading south on Brock Rd N / WR 46. Personal Barn Pizza Depot	Heading south on Brock Rd S / WR 46. Personal Aberfoyle Mill Restaurant	Heading south on Brock Rd S / WR 46. Personal Service station and Duff's Presbyterian Church	Heading south on Queen St / Hwy 6. Personal arriving Historic Downtown Morriston
Corridor Length			
2.0 km	1.25 km	1.75 km	1.25 km
Right-of-Way Width (Approx.)			
14 - 24 m	16 - 20 m	16 - 20 m	15 - 20 m
Speed			
Fast, 70 km/h	Slow, 50 km/h	Slow, 50 km/h	Very Slow, 50 km/h
Environment			
Vehicular	Vehicular/Pedestrian	Vehicular	Vehicular/Pedestrian
Keywords			
Rural Commercial	Community Commercial	Commercial Industrial	Commercial Downtown

Puslinch Development Design Guidelines 2026 11

Section 2: Taking Stock

Focus Area B: Aberfoyle Streetscape

Figure 6. Focus Area B

Brock Rd S / WR 46

Urban Corridor
Aberfoyle Settlement Area
Segment B1: Vehicular Transitional
Segment B2: Community Core
Segment B3: Community Extension
Segment B4: Commercial/Residential Mix
Major Intersection
Minor Intersection
Roundabout
Signalized Intersection

Puslinch Development Design Guidelines 2026 17

What We Heard

1. Open House Consultations (Nov'25 / Mar'25)

- Review of preliminary information denoted through a panel display and the opportunity to provide comment.
- The Open House combined content for both the Township's CIP and Development Design Guidelines.

2. Interest-holder Submissions

- Receipt of submitted comments, aside from the Open Houses, from individuals and agencies with a focus on streetscape, planning, movement & use, and climate change mitigation.

Comments reflected desire for '**Healthy Community Planning'** and a '**Complete Communities**' approach.

These included comments re inclusive, safe and accessible design outcomes with particular attention to active pedestrian frontages in the core areas, seating, lighting, artwork, bike parking, and integration/maintenance of both existing and new greenery.

Participants Identified...

Activity results showed the most important **urban design aspects**:

Open House 1 ★

1. Pedestrian-oriented
2. Accessibility
3. Compatibility
4. Adaptive Reuse
5. Façade
6. Branding
7. Gateways
8. Sustainability
9. Connectivity
10. Scale

Activity results showed **desirable theming** for streetscape treatments:

Open House 2 ★★

Pavements

- Rustic, Eco/Green

Lighting

- Traditional, Arts & Cultural

Greening

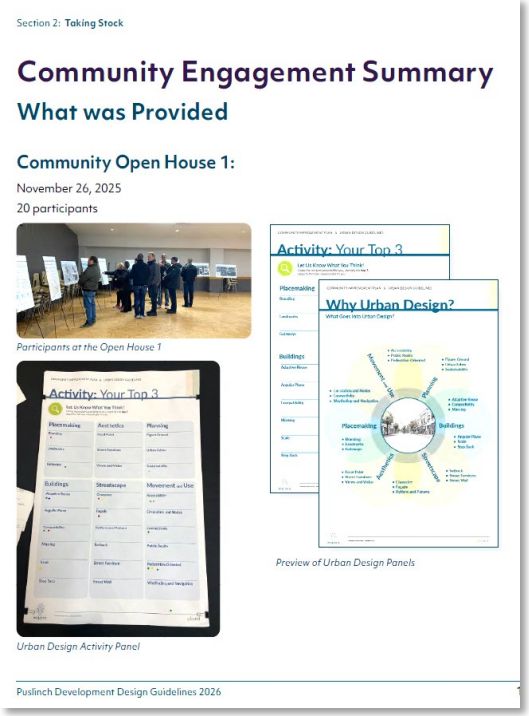
- Traditional, Rustic

Site Furnishings

- Traditional

Signage & Identity

- Modern


Section 2: Taking Stock

Community Engagement Summary

What was Provided

Community Open House 1:

November 26, 2025

20 participants

Participants at the Open House 1

Urban Design Activity Panel

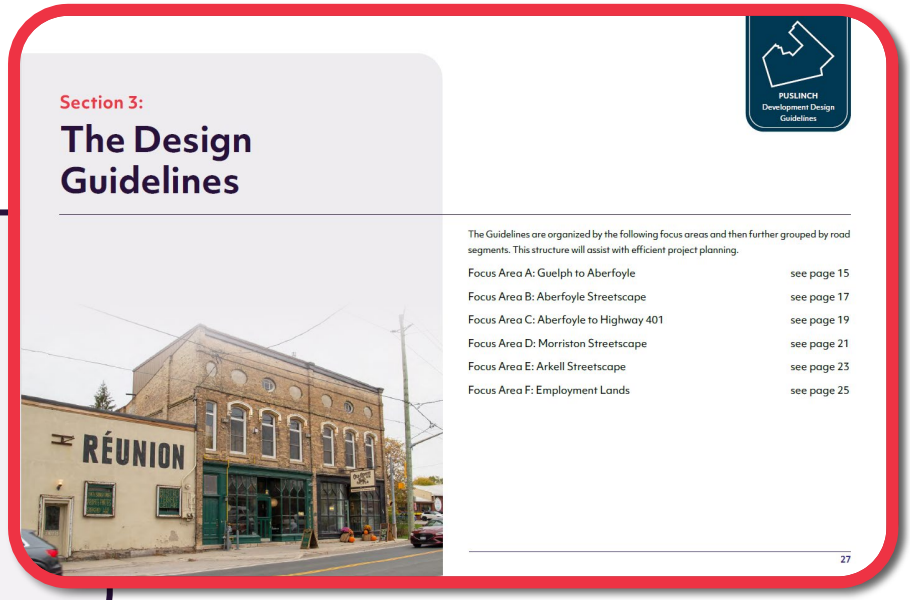
Preview of Urban Design Panels

Puslinch Development Design Guidelines 2026

The Design Guidelines

This section includes:

- Planning Principles
- Enhancing Focus Areas
- Established Character Meets Opportunity
- Promoting Quality Development



Section 3:

The Design Guidelines

PUSLINCH Development Design Guidelines

The Guidelines are organized by the following focus areas and then further grouped by road segments. This structure will assist with efficient project planning.

Focus Area A: Guelph to Aberfoyle see page 15
Focus Area B: Aberfoyle Streetscape see page 17
Focus Area C: Aberfoyle to Highway 401 see page 19
Focus Area D: Morriston Streetscape see page 21
Focus Area E: Arkell Streetscape see page 23
Focus Area F: Employment Lands see page 25

27

The Guidelines are organized by focus areas and then further grouped by road segments, including:

- A Focus Area A: Guelph to Aberfoyle
- B Focus Area B: Aberfoyle Streetscape
- C Focus Area C: Aberfoyle to Highway 401
- D Focus Area D: Morriston Streetscape
- E Focus Area E: Arkell Streetscape
- F Focus Area F: Employment Lands Streetscape

Areas of Change & Stability

Planning Principles: A Foundation to Good Development Design

Served by these three (3) considerations:

1. Responding to **Planning Principles**, which guide development, investment and decision-making toward long term community building;

2. Understanding the **Streetscape Components**, which describes the street classification within the focus areas and establishes a **hierarchy of treatments** (typically pavements, lighting, greening, and site furnishings) specifically in consideration to adjacent lands, roadside and road influences, and;

3. Promoting reasonable **Development Design** possibilities, which includes these Guidelines, **identifying areas of Stability and Change**, and demonstrating Development Design Concepts illustrating "what it could be like."

Towards the Future

A vision to inform the transformation of the focus areas within the Township over the coming years.

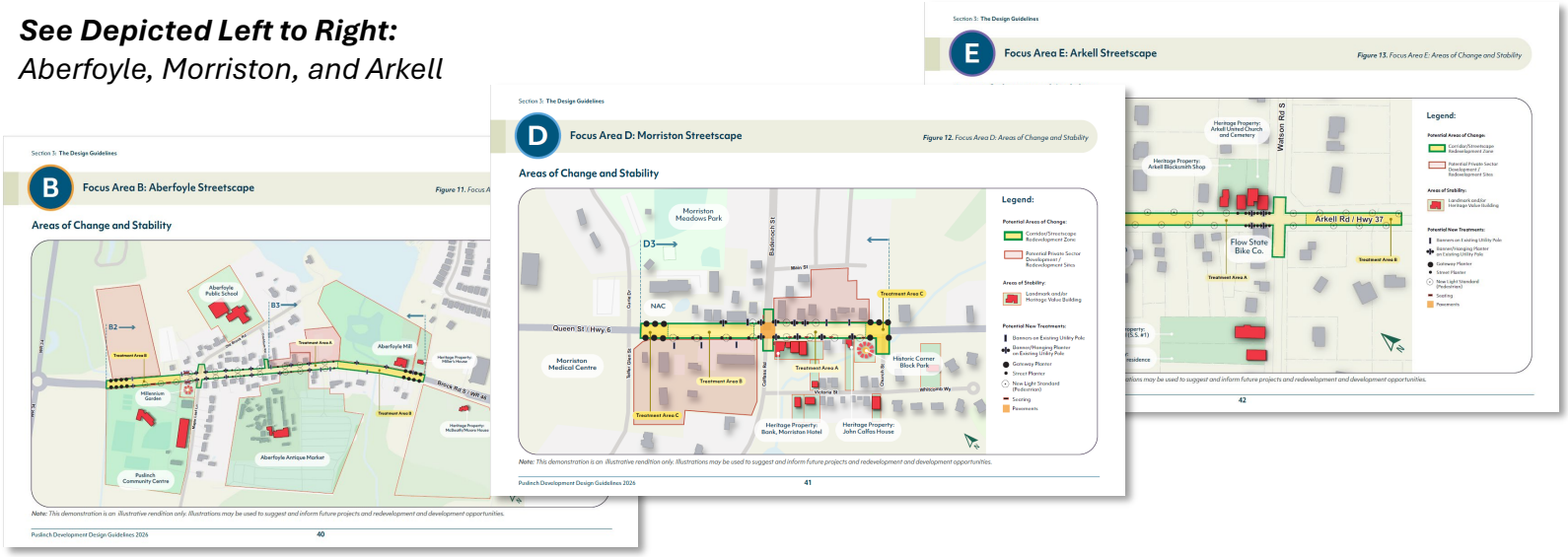
- Creating a true mixed-use vibrant main street by encouraging people to be on and live in proximity of the “main street” within the Aberfoyle and Morriston focus areas.
- Creating a great pedestrian friendly, high quality and distinctive streetscapes.
- Utilize every development opportunity to repair the gaps in the urban fabric and enhance the urban character of the street.
- Creating new and celebrating existing parks on the side streets as important places for meeting and gathering.
- Safeguard, expand and diversify the commercial retail sector.
- Promote a connected open space system.

Towards the Future Continued

- Protect and strengthen core assets – distinctive places and heritage resources.
- Promote a high quality of design excellence.
- Organize shared parking and promote the development of a connected system of rear drive laneways to free up the main thoroughfares for people, parks, buildings and activity.
- Regional Transit is an important catalyst for positive change, renewal and reinvestment along the corridor.
- The Township and the County have the power to make change happen.

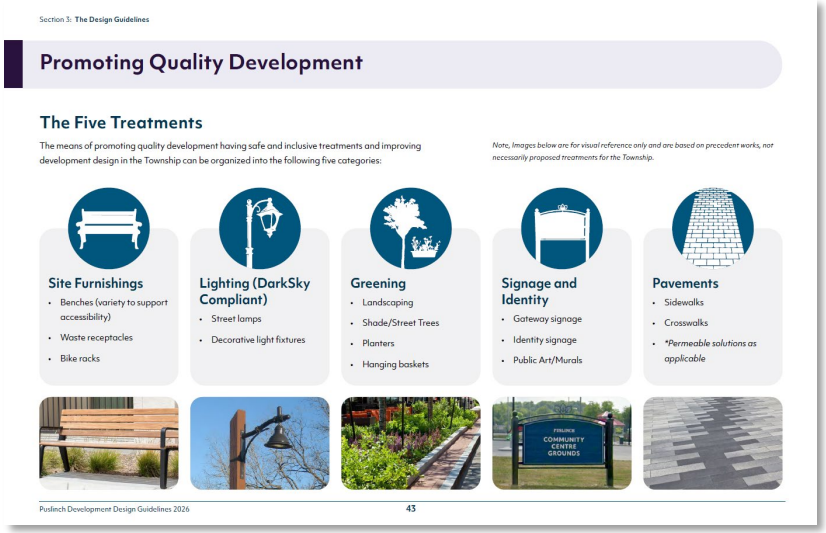
Areas of Change & Stability

See Depicted Left to Right:
Aberfoyle, Morriston, and Arkell



The Five Treatments

See Depicted: *The means of promoting quality development, with safe and inclusive treatments to improve development design in the Township.*



Family of Elements

Note, the product specification is a suggested functional/aesthetic approach and not an endorsement of one manufacturer or model; equals are available throughout a variety of manufacturers and can be managed on an 'approved equal' procurement basis.

Supportive Information

- Site Landscaping
- Landmarks
- Heritage Resources
- Natural Heritage Resources
- Development Next to Residential Areas
- Traffic Calming

The Design Concepts

This section includes:

- Aberfoyle Design Concepts
- Morriston Design Concepts
- Arkell Design Concepts

Aberfoyle

- A Treatments Overview Plan
- B Illustrative Demonstration
- C Streetscape Demonstration

Aberfoyle Community Gateway Sign Placement:

Sign 1 *Location: See Illustration Below*

Sign 2 *Location: Wellington Rd 34 – Southwest Aberfoyle Settlement Boundary*

Sign 3 *Location: See Illustration Below*

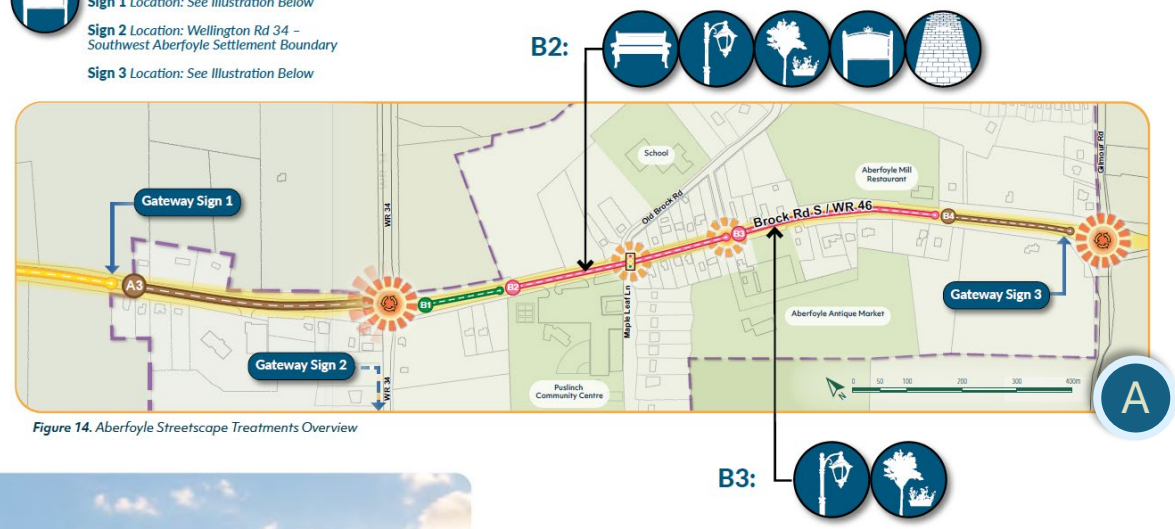
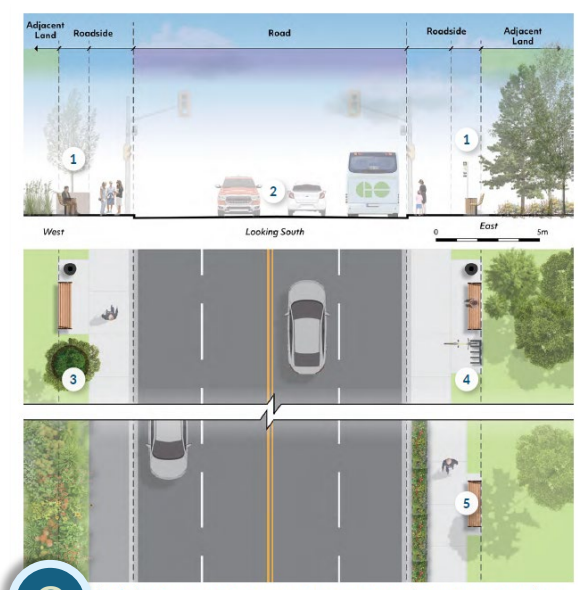


Figure 14. Aberfoyle Streetscape Treatments Overview

Figure 18. Aberfoyle, Segment B2 Streetscape Demonstration with Crosswalk: 3D Perspective Rendering

Note: This demonstration is an artist rendition only



Aberfoyle, Segment B2 Streetscape Demonstration with Streetscape Furnishings: Plan View

Morriston

- A Treatments Overview Plan
- B Illustrative Demonstration
- C Streetscape Demonstration

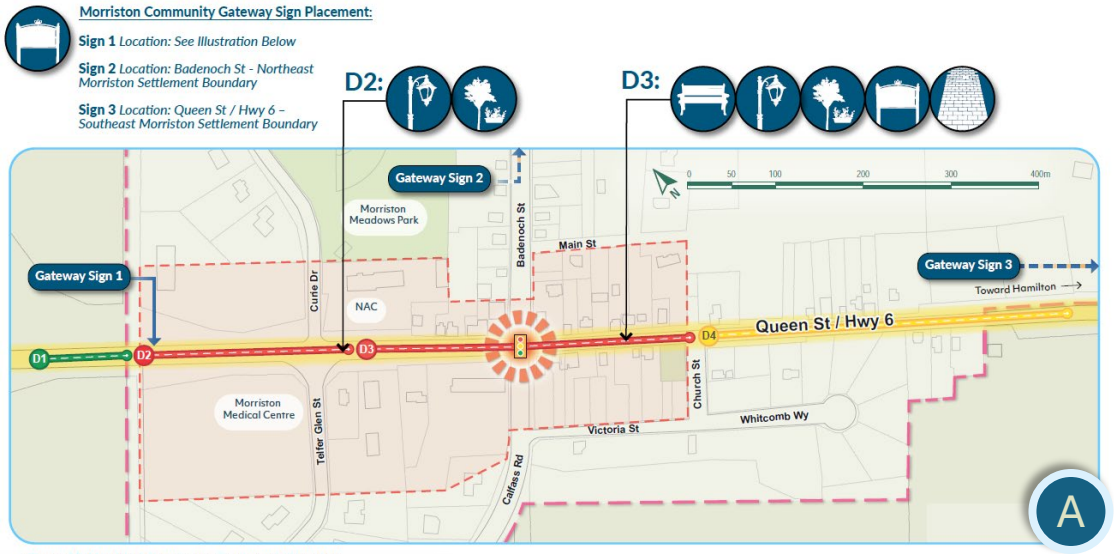
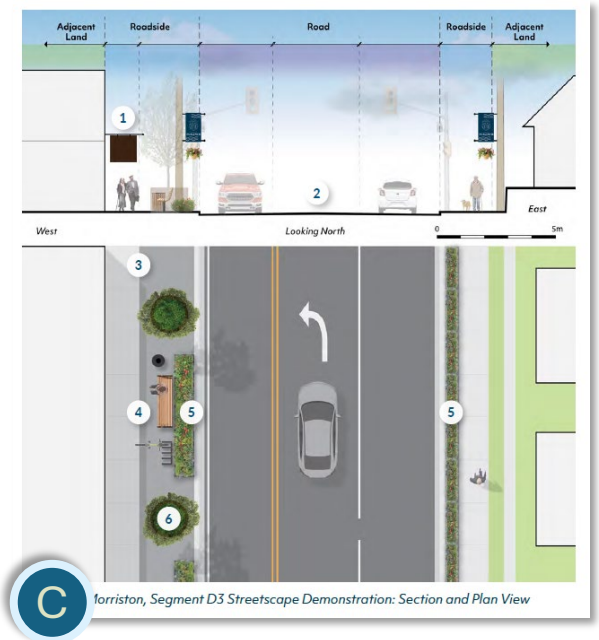


Figure 20. Morriston Streetscape Treatments Overview

Figure 22. Morriston, Segment D3 Streetscape Demonstration with Streetscape Amenities: 3D Perspective Rendering

Note: This demonstration is an artist rendition only



Morriston, Segment D3 Streetscape Demonstration: Section and Plan View

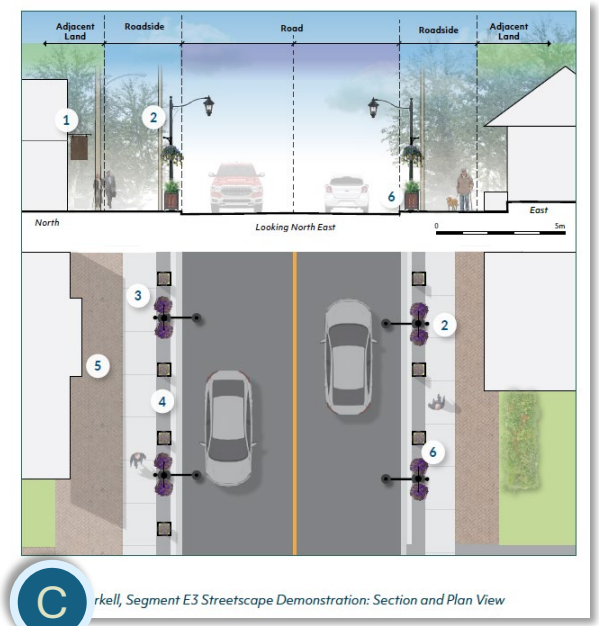
Arkell

- A Treatments Overview Plan
- B Illustrative Demonstration
- C Streetscape Demonstration

Figure 24. Arkell Streetscape Treatments Overview

re 26. Arkell, Segment E3 Streetscape Demonstration: erspective Rendering

Note: This demonstration is an artist rendition

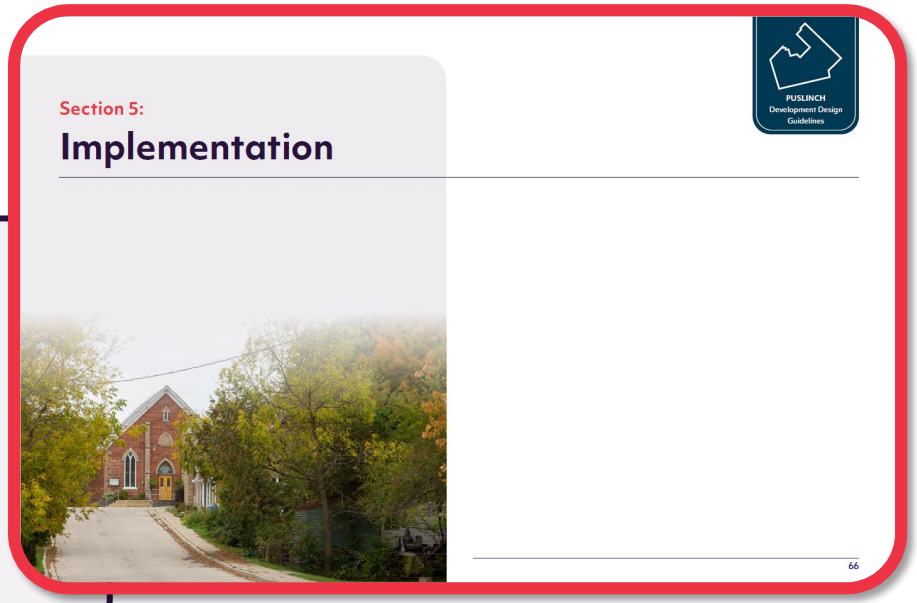


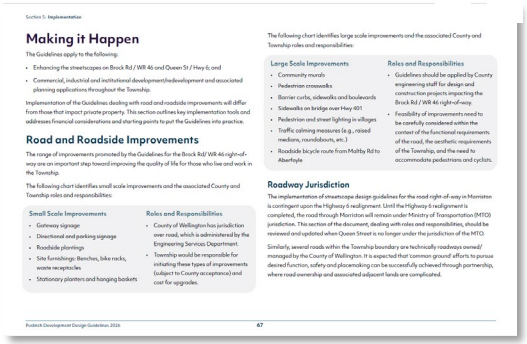
rkell, Segment E3 Streetscape Demonstration: Section and Plan View

Implementation

This section includes:

- Road & Roadside Improvements
- Financial Considerations
- Potential Grant Programs & Funding Opportunities





Section 5: Implementation

Making it Happen

The Guidelines apply to the following:

- Enhancing the streetscapes on Brock Rd / WR 46 and Queen St / Hwy 6; and
- Commercial, industrial and institutional development/redevelopment and associated planning applications throughout the Township.

Implementation of the Guidelines dealing with road and roadside improvements will differ from those that impact private property. This section outlines key implementation tools and addresses financial considerations and starting points to put the Guidelines into practice.

Road and Roadside Improvements

The range of improvements promoted by the Guidelines for the Brock Rd/ WR 46 right-of-way are an important step toward improving the quality of life for those who live and work in the Township.

The following chart identifies small scale improvements and the associated County and Township roles and responsibilities:

Small Scale Improvements	Roles and Responsibilities
• Gateway signage • Directional and parking signage • Roadside plantings • Site furnishings: Benches, bike racks, waste receptacles • Stationary planters and hanging baskets	• County of Wellington has jurisdiction over road, which is administered by the Engineering Services Department. • Township would be responsible for initiating these types of improvements (subject to County acceptance) and cost for upgrades.

The following chart identifies large scale improvements and the associated County and Township roles and responsibilities:

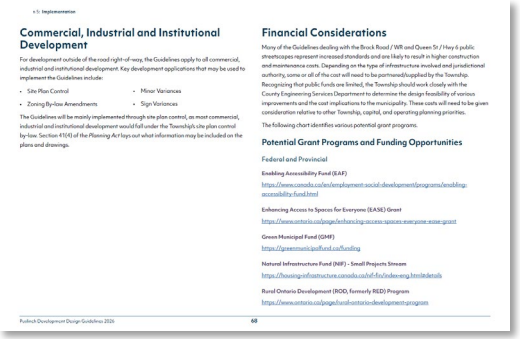
Large Scale Improvements	Roles and Responsibilities
• Community murals • Pedestrian crossovers • Barrier curbs, sidewalks and boulevards • Sidewalks on bridge over Hwy 401 • Pedestrian and street lighting in villages • Traffic calming measures (e.g., raised medians, roundabouts, etc.) • Roadside bicycle route from Maltby Rd to Aberfoyle	• Guidelines should be applied by County engineering staff for design and construction projects impacting the Brock Rd / WR 46 right-of-way. • Feasibility of improvements need to be carefully considered within the context of the functional requirements of the road, the aesthetic requirements of the Township, and the need to accommodate pedestrians and cyclists.

Roadway Jurisdiction

The implementation of streetscape design guidelines for the road right-of-way in Morriston is contingent upon the Highway 6 realignment. Until the Highway 6 realignment is completed, the road through Morriston will remain under Ministry of Transportation (MTO) jurisdiction. This section of the document, dealing with roles and responsibilities, should be reviewed and updated when Queen Street is no longer under the jurisdiction of the MTO.

Similarly, several roads within the Township boundary are technically roadways owned/managed by the County of Wellington. It is expected that 'common ground' efforts to pursue desired function, safety and placemaking can be successfully achieved through partnership, where road ownership and associated adjacent lands are complicated.

Puslinch Development Design Guidelines 2026 67



e 5: Implementation

Commercial, Industrial and Institutional Development

For development outside of the road right-of-way, the Guidelines apply to all commercial, industrial and institutional development. Key development applications that may be used to implement the Guidelines include:

- Site Plan Control
- Zoning By-law Amendments
- Minor Variances
- Sign Variances

The Guidelines will be mainly implemented through site plan control, as most commercial, industrial and institutional development would fall under the Township's site plan control by-law. Section 41(4) of the *Planning Act* lays out what information may be included on the plans and drawings.

Financial Considerations

Many of the Guidelines dealing with the Brock Road / WR and Queen St / Hwy 6 public streetscapes represent increased standards and are likely to result in higher construction and maintenance costs. Depending on the type of infrastructure involved and jurisdictional authority, some or all of the cost will need to be partnered/supplied by the Township. Recognizing that public funds are limited, the Township should work closely with the County Engineering Services Department to determine the design feasibility of various improvements and the cost implications to the municipality. These costs will need to be given consideration relative to other Township, capital, and operating planning priorities.

The following chart identifies various potential grant programs.

Potential Grant Programs and Funding Opportunities

Federal and Provincial

Enabling Accessibility Fund (EAF)
https://www.canada.ca/en/employment-social-development/programs/enabling-accessibility-fund.html

Enhancing Access to Spaces for Everyone (EASE) Grant
https://www.ontario.ca/page/enhancing-access-spaces-everyone-ease-grant

Green Municipal Fund (GMF)
https://greenmunicipalfund.ca/funding

Natural Infrastructure Fund (NIF) - Small Projects Stream
https://housing-infrastructure.canada.ca/nif-fin/index-eng.html#details

Rural Ontario Development (ROD, Formerly RED) Program
https://www.ontario.ca/page/rural-ontario-development-program

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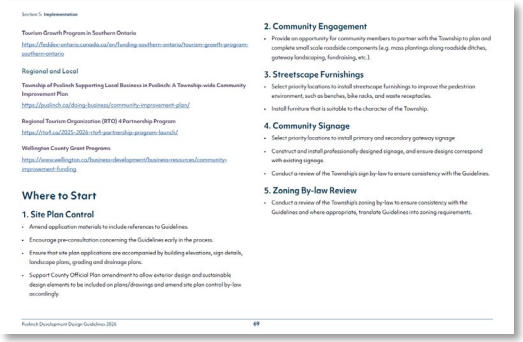

Section 5: Implementation

Tourism Growth Program in Southern Ontario
https://feddev-ontario.canada.ca/en/funding-southern-ontario/tourism-growth-program-southern-ontario

Regional and Local

Township of Puslinch Supporting Local Business in Puslinch: A Township-wide Community Improvement Plan
https://puslinch.ca/doing-business/community-improvement-plan/

Regional Tourism Organization (RTO) 4 Partnership Program
https://rtor4.ca/2025-2026-rto4-partnership-program-launch/

Wellington County Grant Programs
https://www.wellington.ca/business-development/business-resources/community-improvement-funding

Where to Start

1. Site Plan Control

- Amend application materials to include references to Guidelines.
- Encourage pre-consultation concerning the Guidelines early in the process.
- Ensure that site plan applications are accompanied by building elevations, sign details, landscape plans, grading and drainage plans.
- Support County Official Plan amendment to allow exterior design and sustainable design elements to be included on plans/drawings and amend site plan control by-law accordingly.

2. Community Engagement

- Provide an opportunity for community members to partner with the Township to plan and complete small scale roadside components (e.g. mass plantings along roadside ditches, gateway landscaping, fundraising, etc.).

3. Streetscape Furnishings

- Select priority locations to install streetscape furnishings to improve the pedestrian environment, such as benches, bike racks, and waste receptacles.
- Install furniture that is suitable to the character of the Township.

4. Community Signage

- Select priority locations to install primary and secondary gateway signage
- Construct and install professionally designed signage, and ensure designs correspond with existing signage.
- Conduct a review of the Township's sign by-law to ensure consistency with the Guidelines.

5. Zoning By-law Review

- Conduct a review of the Township's zoning by-law to ensure consistency with the Guidelines and where appropriate, translate Guidelines into zoning requirements.

Puslinch Development Design Guidelines 2026 69

In Summary

Analyzed existing conditions & Township character.

Engaged with the community; received input.

Guidelines prepared, Family of Elements created, considerations applied and demonstrated.

Implementation recommendations.

Puslinch Development Design Guidelines

Thank you!

If you would like more information, please contact:

Mary Hasan
Director of Finance/Treasurer

mhasan@puslinch.ca

Justine Brotherston
Director of Corporate Services/Municipal Clerk

jbrotherston@puslinch.ca

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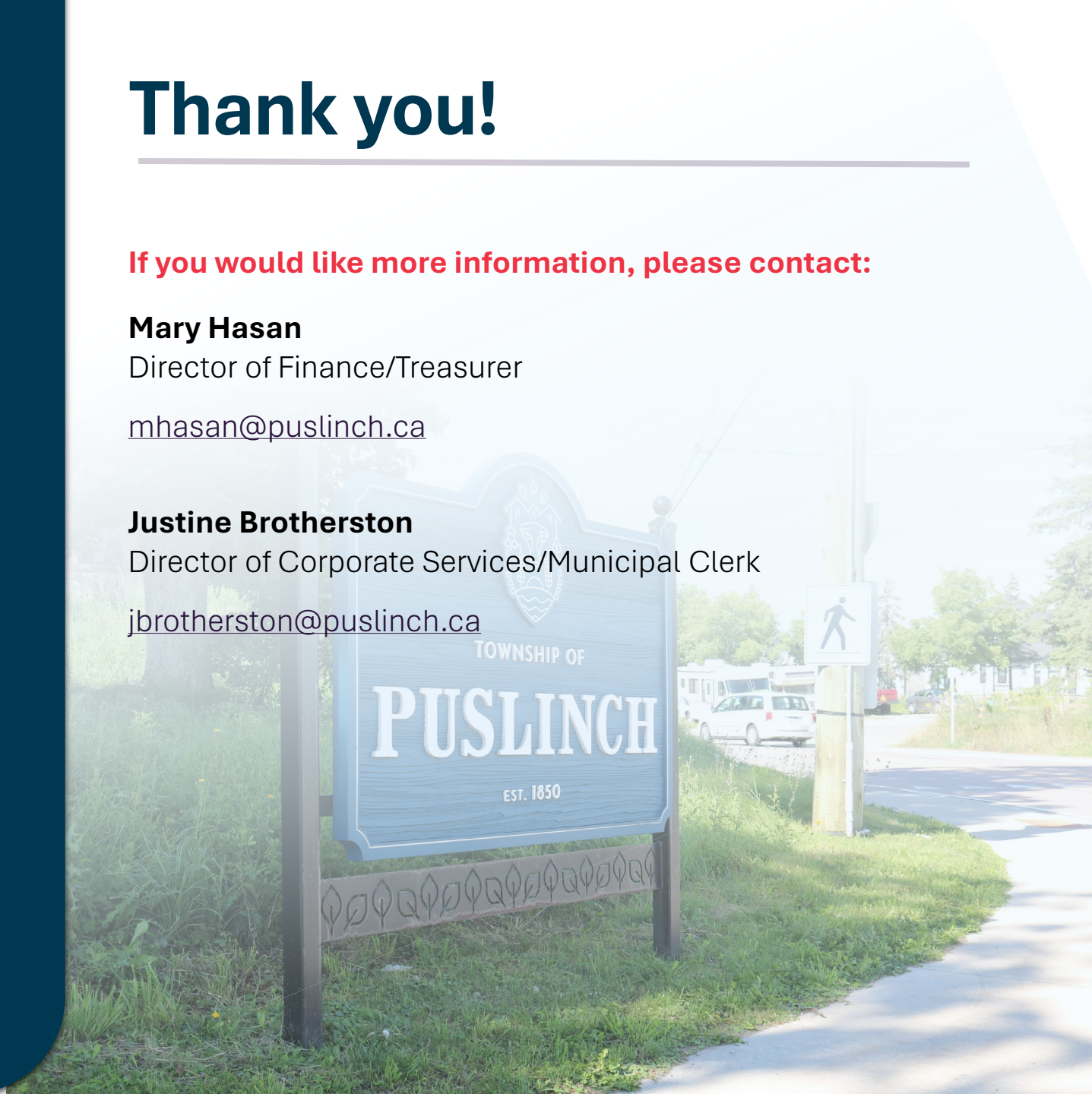
EST. 1850

This project is funded in part by Wellington County and the Ontario Ministry of Agriculture, Food and Agribusiness. Any views expressed therein are views of the Township of Puslinch and do not necessarily reflect those of the Province or Wellington County.



PUSLINCH
Development Design
Guidelines

TOWNSHIP OF
PUSLINCH
EST. 1850

Puslinch Development Design Guidelines

A Framework for Renewal, Reinvestment and Community Building

June 2026

Puslinch Development Design Guidelines

2026

Prepared for:

Mary Hasan

Director of Finance/Treasurer

Justine Brotherston

Director of Corporate Services/Municipal Clerk

Prepared by:

Sean Kelly

Kelsey Moore

Bethany Nelson

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Section 1:

Introduction

This section provides background information including existing conditions, and overview of the study area, guidance on how to navigate the document and use the Guidelines, and a community engagement summary. This section sets a foundation for the Guidelines and development design concepts demonstrations.

Guiding Principles

- Convey a clear design direction for the Township.
- Reinforce the rural character of the Township and its three settlement areas.
- Provide a practical and accessible document for implementation.

Background

Origin

With commercial, industrial and institutional development and redevelopment activity occurring throughout the Township of Puslinch (Township), and experienced in prestige rural employment areas informed through the recent key employment land/Aberfoyle boundary expansion study *Puslinch by Design – Employment Lands Study*, in addition to the *Supporting Local Business in Puslinch: A Township-wide Community Improvement Plan*, the Township identified a need to update its design guidelines. These guidelines are applicable throughout the Township, and seek to enhance the streetscapes, improve the quality of site design, and to protect what makes Puslinch unique. They focus on the Township, and extend key considerations for Aberfoyle, Morriston, and Arkell.

Role and Scope

The Puslinch Development Design Guidelines (Guidelines) are aimed at ensuring that the Township's physical environment, both built and natural, meets the needs and aspirations of its residents, guests and visitors, and enables Township goals and decisions to be realized.

The Guidelines will be supportive of implementing new rural and urban-centered development and renovation projects in its settlement areas, inform rural employment areas, and for maintaining and preserving existing infrastructure throughout the Township. It will also provide a means for articulating a common purpose across the Township with a focus on both its urban and rural areas, and for communicating it to the Township and the community at large. While the information and design demonstrations contained within the Guidelines will be aimed at these areas, they support other key documents, by-laws, and development/site plan approval processes, and contain insight and ideas applicable to the extended Township.

The form of the Township's rural and urban-focused areas in Aberfoyle, Morriston and Arkell, cannot be determined by a single planner or designer, as is the case when designing a building, a civic space, or other identifiable project. The Township's rural and urban areas are comprised of a 'family of projects' implemented over time, and therefore a fixed blueprint representing a construction scenario, at a single point in time, is inappropriate. The Guidelines must be firm about essentials, but flexible about details, particularly those which can only be defined by future project programs developed to meet the needs which cannot, at present, be foreseen except in broad outline.

Communal Action

The Guidelines direct action so that the physical rural and urban environment suit the community's needs, meets Township goals, and is a joy to be a part of. Its existence and content are a clear message that the rural and urban environment is an invaluable asset.

Community Tool

The Township is a host to a community of homeowners, businesses, employers, repeat long-term visitors, and guests passing through. An important component in the development of the Guidelines is authentic engagement that permits the community to shape the Guidelines, ensuring a realistic vision and appropriate development guidance are realized.

Guidelines Interaction

There are many pieces to a municipal planning process; these Guidelines can contribute. In response to growth and change, the Township has updated and added to its roster of planning documents in recent years. Adopted documentation includes, but is not limited to:

- *Supporting Local Business in Puslinch: A Township-wide Community Improvement Plan 2026*
- *County of Wellington Official Plan*
- *Development Charges Study 2024*
- *Municipal Development Standards*
- *Puslinch by Design 2025*
- *Recreation and Parks Master Plan*
- *Roads Management Plan 2023*
- *Strategic Plan 2026-2030*

While each document focuses on a different topic, they are highly interdependent. The decisions of one exercise influence, and/or respond to the conclusions of another, as they are developed and implemented. The exceptional characteristic of the Guidelines is that its content can usually outlive and complement a series of Township planning documents.

Fiscal Reality

To be successfully implemented, the Guidelines need to consider current fiscal realities. The Guidelines set realistic expectations that can be achieved over time through creative implementation practices, sound planning, and funding sources.

Principal Audiences

The Guidelines are targeted at two principal audiences, the first being the Township, represented by Council, staff, and residents alike. The Township is meant to use the Guidelines as a guideline manual for the physical development and redevelopment of its urban and rural areas. Included in this targeted audience are the Township's departments who participate in the initiating, guiding and executing rural and urban-focused development projects.

The second principal audience is comprised of the various partners that help to fund and support, or cooperate, with the Township. This may include, but is not limited to, the Provincial and Federal Governments, and developers. The Guidelines illustrate the Township's intentions and provide guidance for expectation and funding action.

Guidelines

The Guidelines contain a series of rural and urban design guidelines that define intent, but not necessarily, final form. They guide physical change to ensure that general objectives are met but are flexible enough to accommodate specific needs as they arise, as well as the requirements of other supportive planning documents previously noted.

Communal & Constituent Projects

The Guidelines can be implemented through two types of projects; communal and constituent. Communal projects are the public works; the connections that tie the rural and urban areas together. They may include, but are not limited to streets, walkways, landscapes, utilities, and to a degree, facilities, that serve the community. Constituent projects are specifically undertaken by Township initiatives, jurisdictional authorities such as the County of Wellington or Ministry of Transportation, etc., commercial enterprises (services and shops), private developers, focus groups, and other community partners of the Township. While these projects should meet their own needs; they should also consider and contribute to the public good of the Puslinch Community – these are community improvement initiatives.

Reinforce & Repair

The Guidelines support, and in specific instances, identify the existing and forthcoming urban and rural parts of the Township that are successful and make it 'Puslinch.' Likewise, the Guidelines identify areas that could benefit from improvement. It is understood that much of the existing 'public realm' infrastructure within the urban corridor has been incrementally developed over time. The Guideline seeks to enhance the positive aspects, while focusing on opportunities.

Implementation Horizon

The Guidelines are projected ideally to support the long-term planning horizon, i.e., the 20-to-30-year period of the County's Official Plan. Appropriate adjustment to reflect the updates to the Official Plan, i.e., every 10 years after a new Comprehensive Plan is prepared or every 5 years after an amendment, would be necessary. This ensures that the plans and guidelines align with current provincial legislation and community priorities.

In the shorter term, these Guidelines can be used to inform established projects which are in programming, design, or implementation phases. However, it also includes contemplated projects which reflect current and projected needs but have not yet been identified. This approach is firmly based on present realities but extends far enough into the future to adequately be useful to upcoming improvement and development decisions.

Application Beyond the Urban Corridor

The urban corridor will continue to accommodate residents, their guests, visitors, and travelers alike, facilitate commercial and civic opportunities, and possibly even host events. In its incredibly direct position within the core areas of Morriston and Aberfoyle, their surrounding communities, and in some instances some unique natural areas, it will continue to be a defining aspect of the Township. However, this document has been prepared to broaden design guidelines beyond the corridor to the full extent of the Township, and future enhancement will, therefore, occur through either addition, renovation, or replacement of existing built urban and rural form and landscapes.

Section 2:

Taking Stock

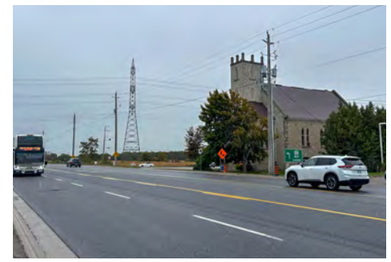
This section provides background information including existing conditions, and overview of the study area, specifically character definition and subsequent focus areas within Aberfoyle, Morriston, Arkell, the Employment Lands, and a community engagement summary. This section provides context and sets a foundation for the Guidelines and urban design concepts.

Existing Conditions

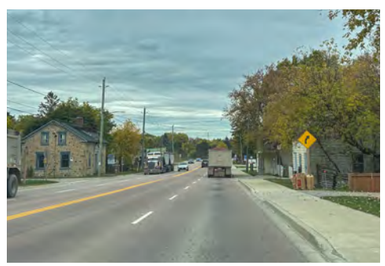
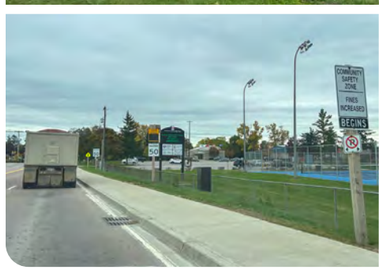
A variety of images show existing conditions captured between November 2025 and June 2026. These images provide an overview of roads and public right-of-way conditions, rural and urban character, pedestrian environments, signage, crosswalks, landscaping, and more. All of which will be addressed through the Guidelines in the following section.

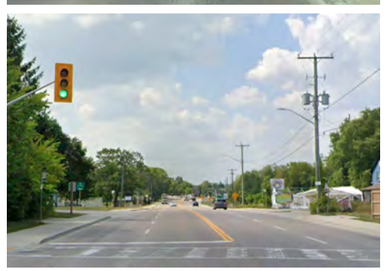
Guelph to Aberfoyle

Aberfoyle to Highway 401

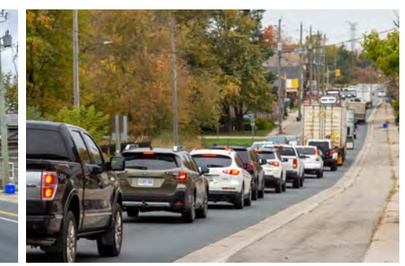
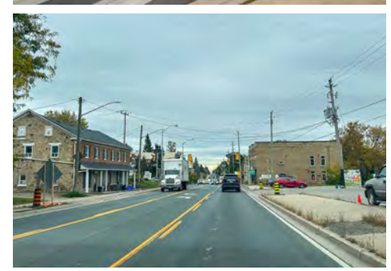


Aberfoyle



Morriston

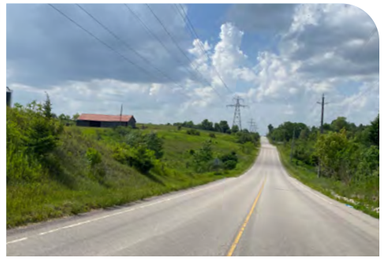



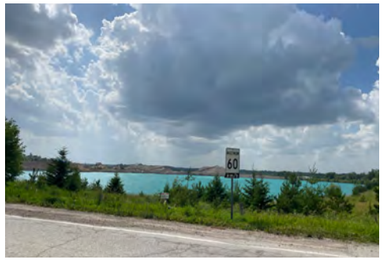
Existing Conditions

A variety of images show existing conditions captured between November 2025 and June 2026. These images provide an overview of roads and public right-of-way conditions, rural and urban character, pedestrian environments, signage, crosswalks, landscaping, and more. All of which will be addressed through the Guidelines in the following section.

Arkell

Employment Lands





Highway 401 Frontage to Concession Road 7

The Study Area Context

The study area depicted in Figure 1 is divided into six (6) distinct focus areas, as outlined below. The Guidelines in the following section are organized by these focus areas.

- **A** Focus Area A: Guelph to Aberfoyle
- **B** Focus Area B: Aberfoyle Streetscape
- **C** Focus Area C: Aberfoyle to Highway 401
- **D** Focus Area D: Morriston Streetscape
- **E** Focus Area E: Arkell Streetscape
- **F** Focus Area F: Employment Lands Streetscape

- Puslinch Boundary
- Settlement Area
- Rural Employment Lands
- Greenbelt Area

Taken From: *Official Plan - Schedule A7 - Puslinch*

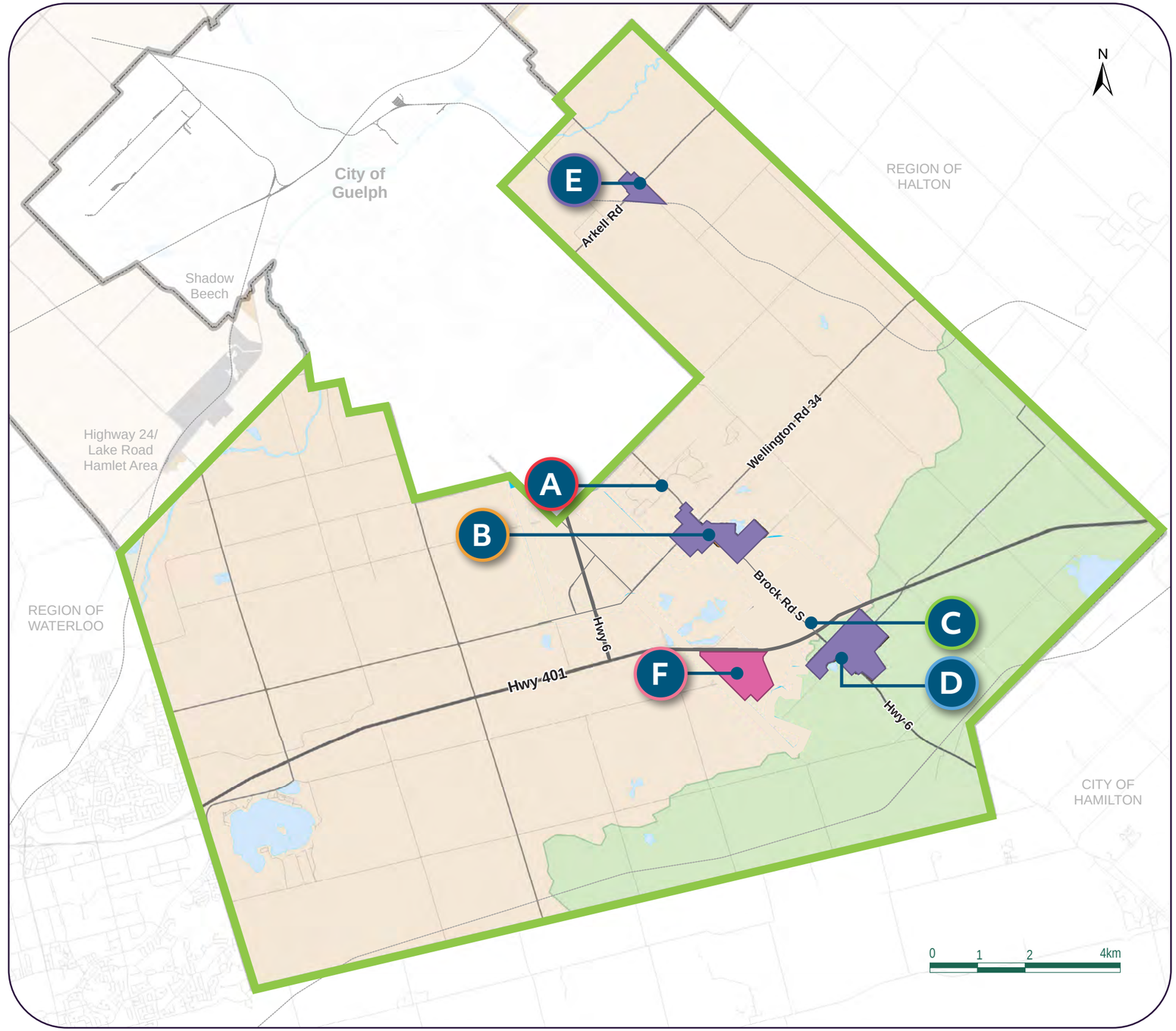


Figure 1. *Township Context*

The Study Area

The study area depicted below is along Brock Rd / Highway 6, stretching from Guelph (Maltby Rd) down to Morriston. The study area is divided into four (4) distinct focus areas along the corridor, as outlined below. The Guidelines in the following section are organized by these focus areas.

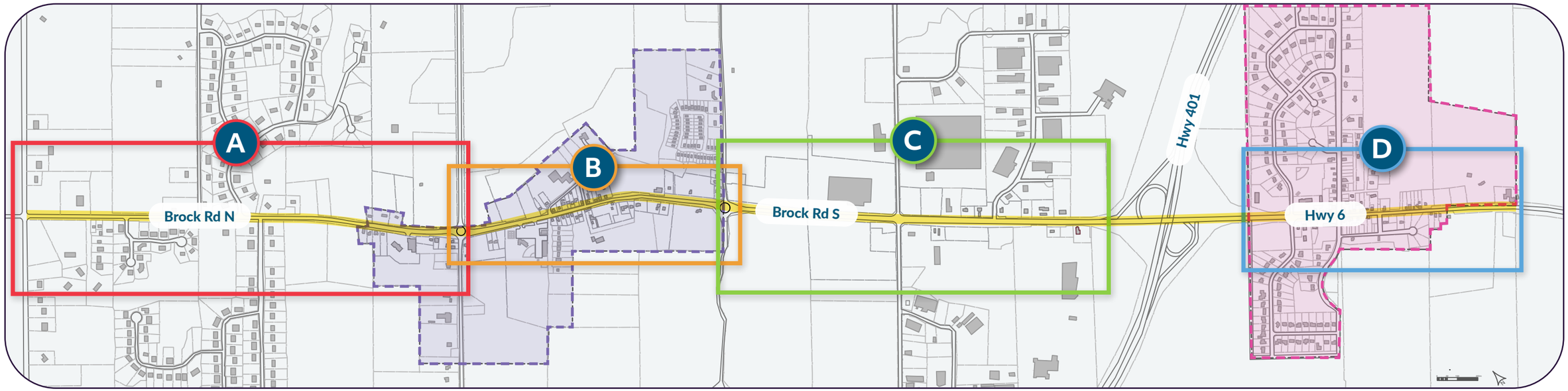


Figure 2. *Focus Areas A, B, C, D Overview*

Urban Corridor

Aberfoyle Settlement Boundary

Morriston Settlement Boundary

A Focus Area A: Guelph to Aberfoyle see **page 15**

B Focus Area B: Aberfoyle Streetscape see **page 17**

C Focus Area C: Aberfoyle to Highway 401 see **page 19**

D Focus Area D: Morriston Streetscape see **page 21**

The Study Area Continued

The study area below showcases the last two (2) distinct focus areas , the first along Arkell Road and the second along Concession Road 7, as outlined below. The Guidelines in the following section are organized by these focus areas.

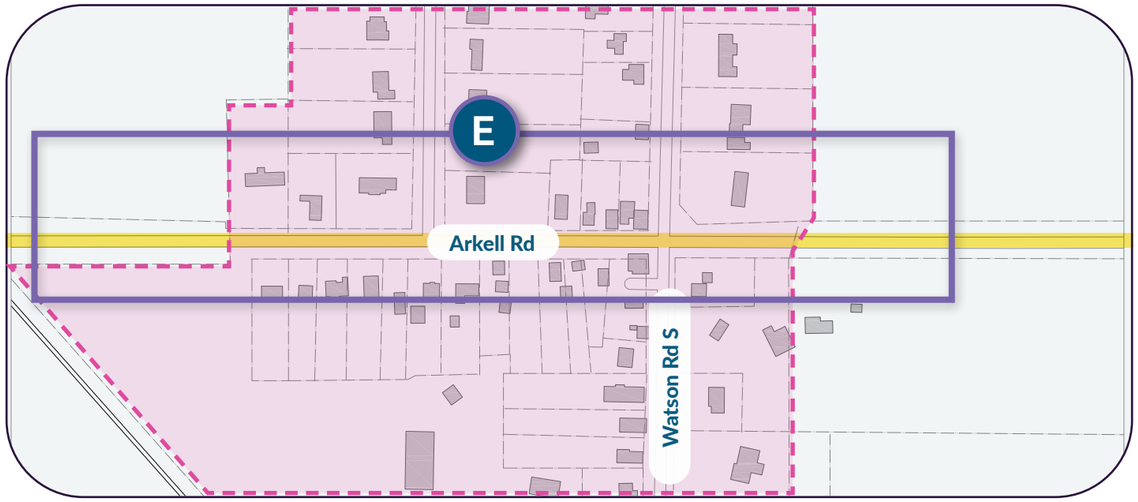


Figure 3. *Focus Area E Overview*

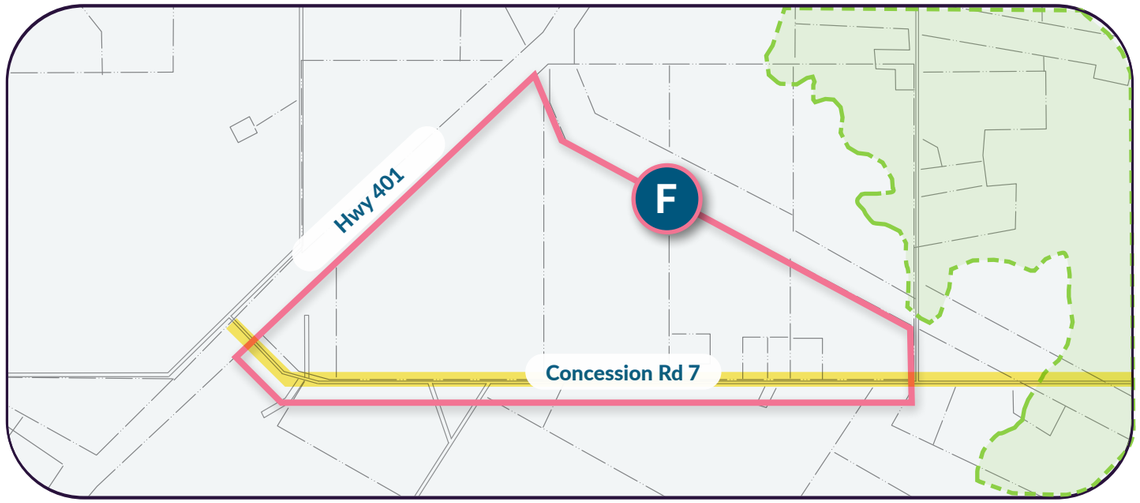


Figure 4. *Focus Area F Overview*

Rural Corridor

Arkell Settlement Boundary

Greenbelt Boundary

E Focus Area E: Arkell Streetscape see **page 23**

F Focus Area F: Employment Lands see **page 25**

Defining Character

A Guelph to Aberfoyle

Heading south on Brock Rd N / WR 46.
Pictured: Ren's Pets Depot

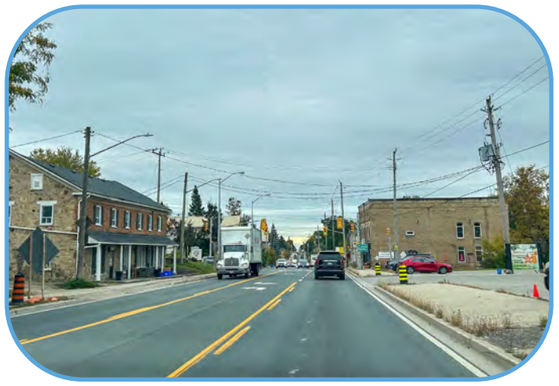
B Aberfoyle Streetscape

Heading south on Brock Rd S / WR 46.
Pictured: Aberfoyle Mill Restaurant

C Aberfoyle to Hwy 401

Heading south on Brock Rd S / WR 46.
Pictured: Service stations and Duff's Presbyterian Church

D Morriston Streetscape



Heading south on Queen St / Hwy 6.
Pictured: entering Historic Downtown Morriston

Corridor Length			
2.0 km	1.25 km	1.75 km	1.25 km
Right-of-Way Width (Approx.)			
14 - 24 m	16 - 20 m	16 - 20 m	15 - 20 m
Speed			
Fast, 70 km/h	Slow, 50 km/h	Slow, 50 km/h	Very Slow, 50 km/h
Environment			
Vehicular	Vehicular/Pedestrian	Vehicular	Vehicular/Pedestrian
Keywords			
Rural Commercial	Community Commercial	Commercial Industrial	Commercial Downtown

Defining Character

E Arkell Streetscape

Heading North East on Arkell Rd.
Pictured: Flow State Bike Co.

F Employment Lands

Heading North West on Concession Rd 7.

Corridor Length	
0.45 km	2.5 km
Right-of-Way Width (Approx.)	
14 - 20 m	9-12 m
Speed	
Slow, 50 km/h	Fast, 60km/h
Environment	
Vehicular/Pedestrian	Vehicular
Keywords	
Rural Community	Rural Agricultural

Community Engagement Summary

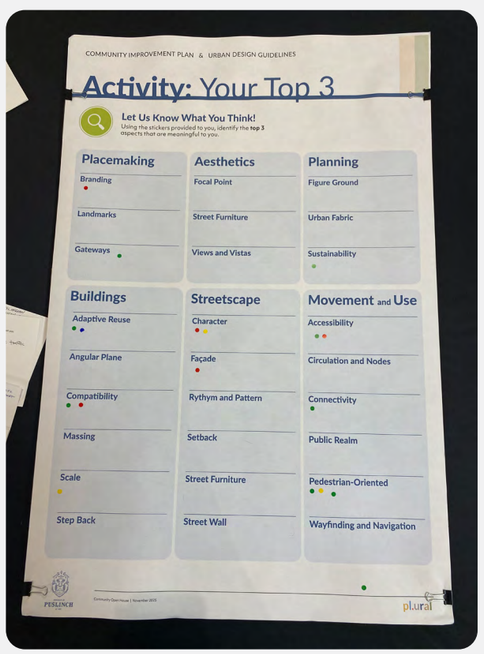
What was Provided

Community Open House 1:

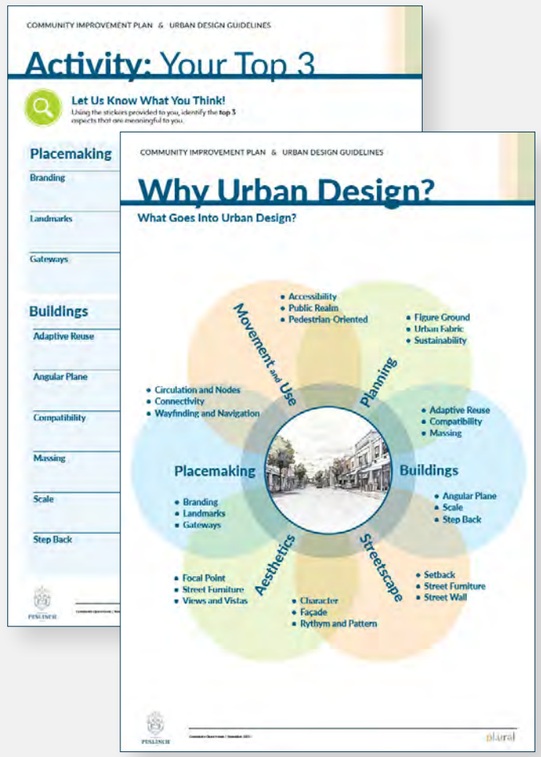
November 26, 2025

20 participants

Participants at the Open House 1



Urban Design Activity Panel



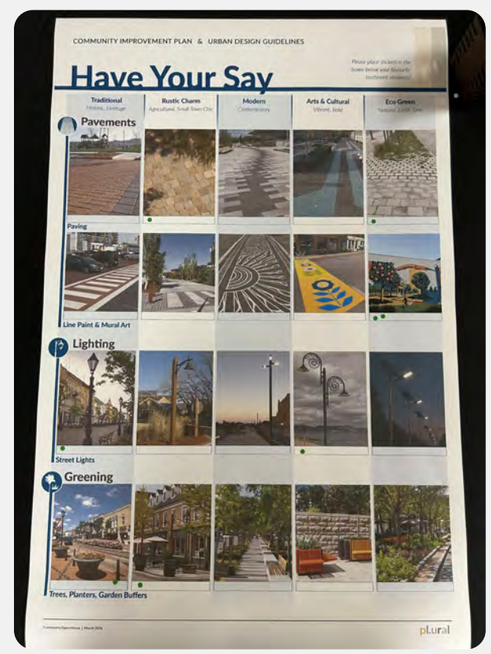
Preview of Urban Design Panels

Community Open House 2:

March 4, 2026

15 participants

Participants at the Open House 2



Urban Design Activity Panel

Preview of Urban Design Panels

What We Heard

General Comments

- Needs to be more walkable. Include more sidewalks. Pedestrians are not safe on streets.
- Heritage Character encouraged for buildings. Character for façades.
- Maintain character of the 'village'.
- Trees to hide the gravel pit and ponds.

Open House 1

Activity results showed the most important urban design aspects:

1. Pedestrian-oriented
2. Accessibility
3. Compatibility
4. Adaptive Reuse
5. Façade
6. Branding
7. Gateways
8. Sustainability
9. Connectivity
10. Scale

Open House 2

Activity results showed desirable theming for streetscape treatments:

Pavements

- Rustic, Eco/Green

Lighting

- Traditional, Arts and Cultural

Greening

- Traditional, Rustic

Site Furnishings

- Traditional

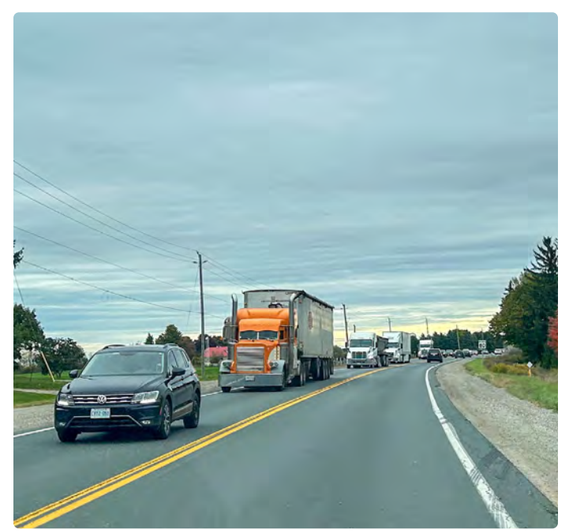
Signage and Identity

- Modern

What is Working

- Concentration of 'built form' defining core areas.
- Beautiful 'fabric' buildings having historic cues.
- Beautiful 'landmark' buildings such as the Aberfoyle Mill.
- Ample sidewalk width (Morriston).
- Scale conducive to pedestrian activity.

What is Not Working

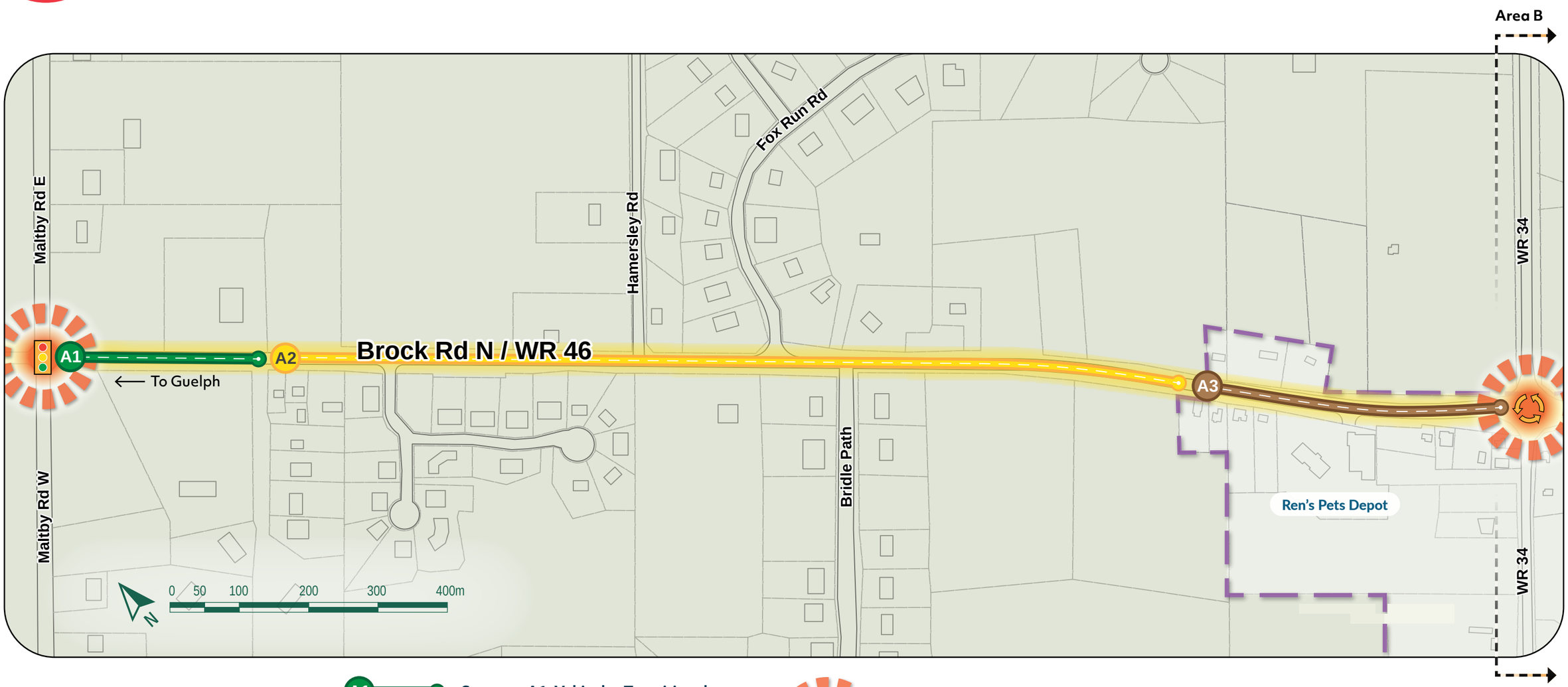


- Volume of through traffic, especially through Morriston and Aberfoyle.
- Emphasis on vehicular thoroughfare rather than community pedestrian environments.

A B C D E F

Focus Area A: Guelph to Aberfoyle

Figure 5. *Focus Area A*



Urban Corridor

Aberfoyle Settlement Area

Segment A1: Vehicular Transitional

Segment A2: Residential Thoroughfare

Segment A3: Commercial/Residential Mix

Major Intersection

Roundabout

Signalized Intersection

A Focus Area A: Guelph to Aberfoyle

Streetscape Components:

Adjacent Land

Private or public property, which may include **building façades, height, and setbacks, parking**, as well as **landscaping** as typically defined through zoning.

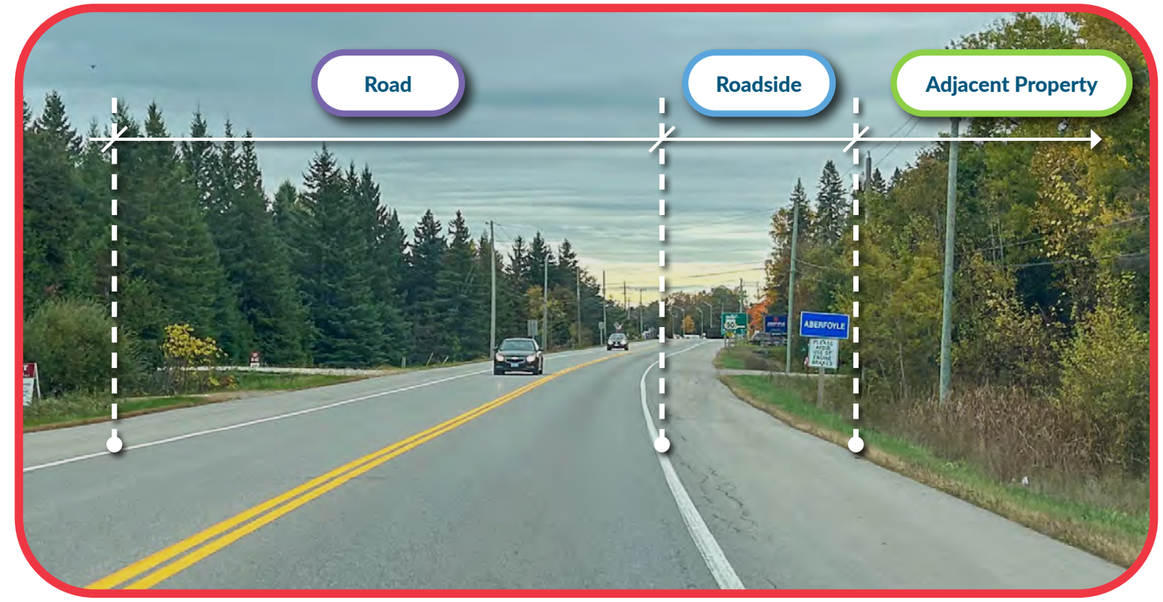
Roadside

The strip of **public** property beside a road typically used to provide **sidewalks**, **street trees**, **signs**, **amenities (i.e. pedestrian realm)**, in addition to **drainage** and **utilities**.

Road

The portion of the **public** right-of-way primarily used by vehicular traffic, but may also include **medians**, **pedestrian crossings** and **bicycle lanes**.

First, the Guidelines are organized by segment, then further organized by the following streetscape components. This page provides an overview of the existing character of **Area A** streetscape components.



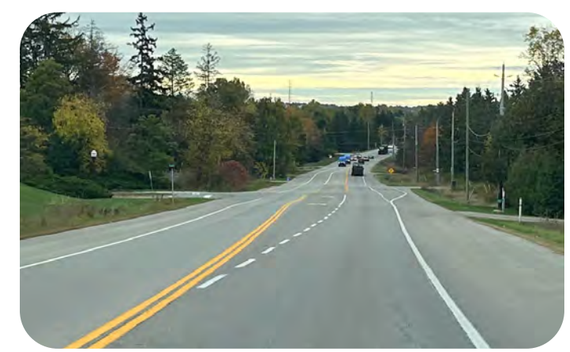
Heading south on Brock Rd N / WR 46. Pictured: standard MTO community sign, approaching a roundabout.

Adjacent Land

Adjacent lands in Focus Area A generally consists of natural landscaping, rural and residential frontage, and larger setbacks from the roadside to buildings.

Roadside

Roadsides in Focus Area A consist of large paved shoulders with no pedestrian amenities or accommodations.



Road

Roads in Focus Area A are posted at 70 km/h and have two lanes, with some turning lanes into residential neighbourhoods.

A — **B** — C — D — E — F

Focus Area B: Aberfoyle Streetscape

Figure 6. *Focus Area B*

B Focus Area B: Aberfoyle Streetscape

Streetscape Components:

Adjacent Land

Private or public property, which may include **building façades, height, and setbacks, parking**, as well as **landscaping** as typically defined through zoning.

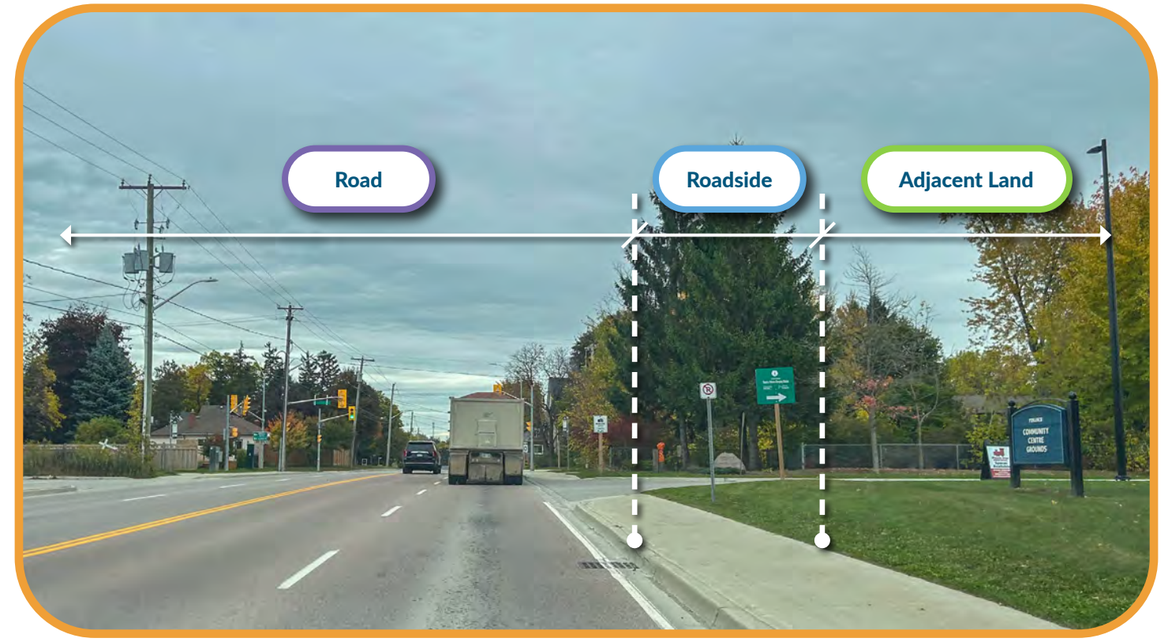
Roadside

The strip of **public** property beside a road typically used to provide **sidewalks**, **street trees**, **signs**, **amenities (i.e. pedestrian realm)**, in addition to **drainage** and **utilities**.

Road

The portion of the **public** right-of-way primarily used by vehicular traffic, but may also include **medians**, **pedestrian crossings** and **bicycle lanes**.

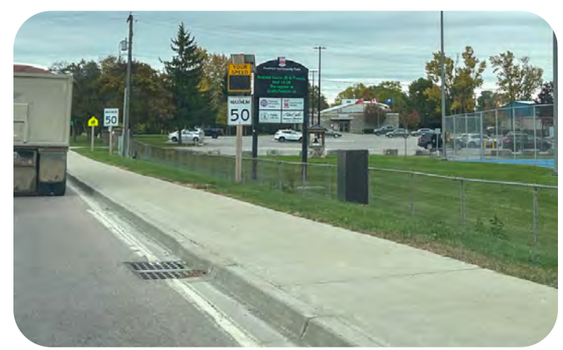
First, the Guidelines are organized by segment, then further organized by the following streetscape components. This page provides an overview of the existing character of **Area B** streetscape components.



Heading south on Brock Rd S / WR 46. Pictured: entrance to Community Centre Grounds on right.

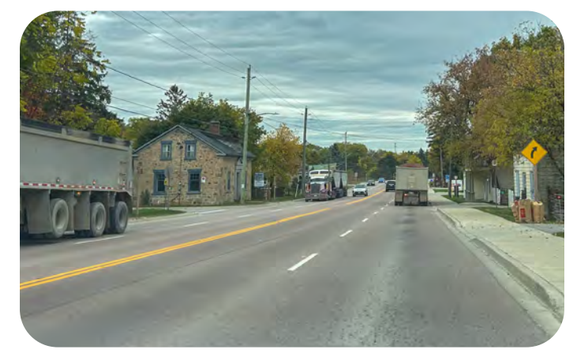
Adjacent Land

Adjacent lands in Focus Area B feature a mix of residential, institutional, and commercial property frontage.



Roadside

Roadsides in Focus Area B feature a mix of sidewalks and paved shoulders.



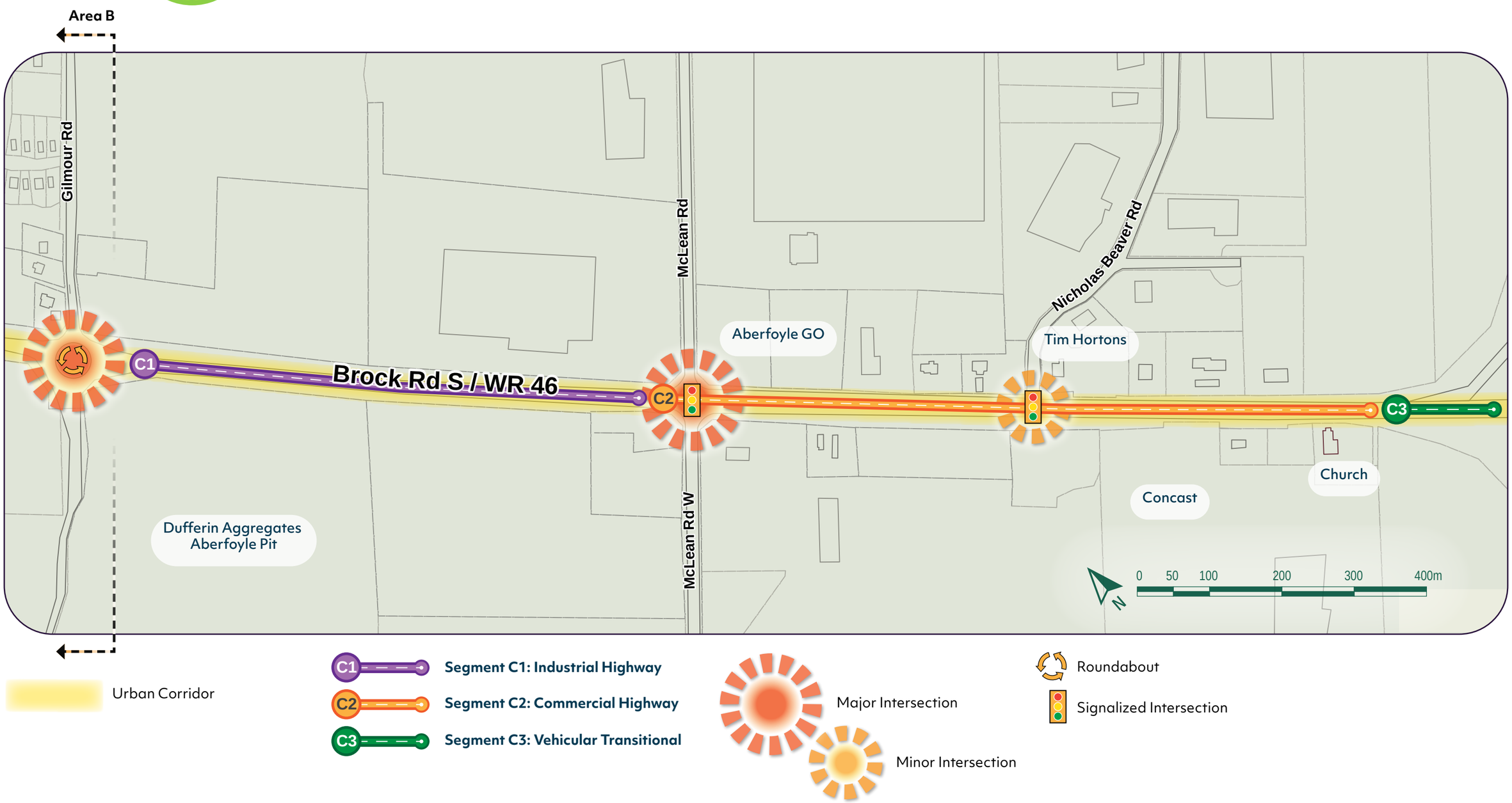
Road

Roads in Focus Area B are posted at 50 km/h and have four lanes of traffic, two roundabouts and one main signalized intersection.

A B **C** D E F

Focus Area C: Aberfoyle to Highway 401

Figure 7. *Focus Area C*



C Focus Area C: Aberfoyle to Highway 401

Streetscape Components:

Adjacent Land

Private or public property, which may include **building façades, height, and setbacks, parking**, as well as **landscaping** as typically defined through zoning.

Roadside

The strip of **public** property beside a road typically used to provide **sidewalks**, **street trees**, **signs**, **amenities (i.e. pedestrian realm)**, in addition to **drainage** and **utilities**.

Road

The portion of the **public** right-of-way primarily used by vehicular traffic, but may also include **medians**, **pedestrian crossings** and **bicycle lanes**.

First, the Guidelines are organized by segment, then further organized by the following streetscape components. This page provides an overview of the existing character of **Area C** streetscape components.

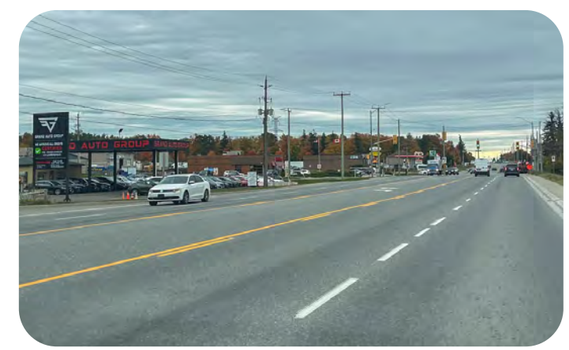
Heading south on Brock Rd S / WR 46. Pictured: Service stations and Duff's Presbyterian Church

Adjacent Land

Adjacent lands in Focus Area C feature a mix of primarily commercial and industrial property frontage, with larger setbacks from the roadside to buildings.

Roadside

Roadsides in Focus Area C are mainly paved shoulders with some sidewalks for pedestrian use. There are also multiple wide driveway entrances to commercial and industrial properties.



Road

Roads in Focus Area C are posted at 50 km/h and have four lanes of traffic plus a turning lane and two signalized intersections.

A B C **D** E F

Focus Area D: Morriston Streetscape

Figure 8. *Focus Area D*

Urban Corridor

Morriston Settlement Area

Central Business District (County Official Plan)

D1 **Segment D1: Vehicular Transitional**

D2 **Segment D2: Community Core**

D3 **Segment D3: Community Extension**

D4 **Segment D4: Residential Thoroughfare**

Major Intersection

Roundabout

Signalized Intersection

D Focus Area D: Morriston Streetscape

Streetscape Components:

Adjacent Land

Private or public property, which may include **building façades, height, and setbacks, parking**, as well as **landscaping** as typically defined through zoning.

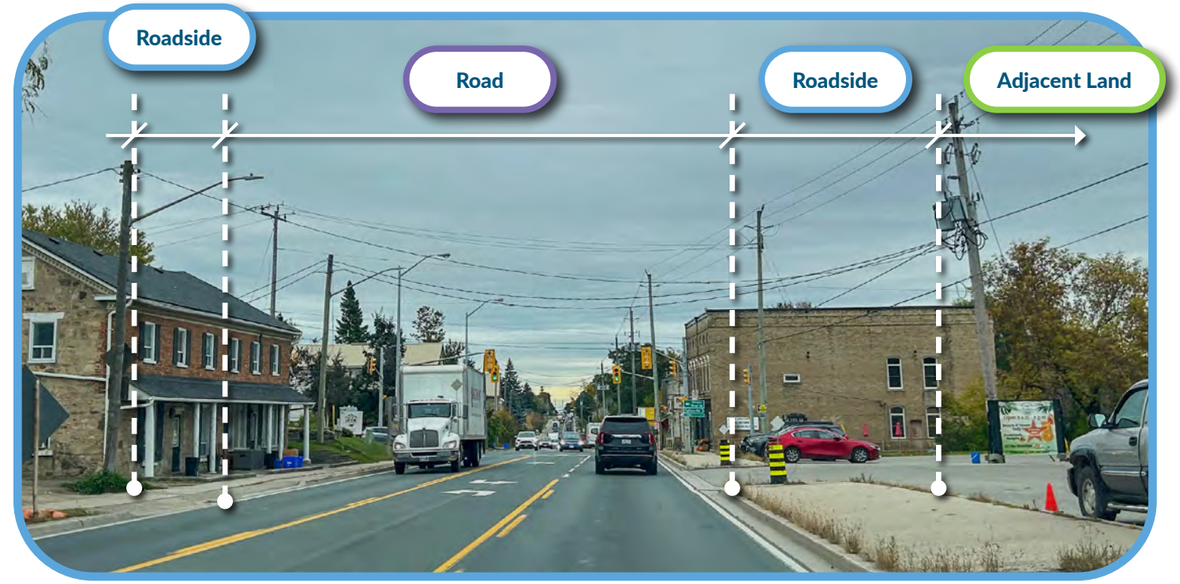
Roadside

The strip of **public** property beside a road typically used to provide **sidewalks**, **street trees**, **signs**, **amenities (i.e. pedestrian realm)**, in addition to **drainage** and **utilities**.

Road

The portion of the **public** right-of-way primarily used by vehicular traffic, but may also include **medians**, **pedestrian crossings** and **bicycle lanes**.

First, the Guidelines are organized by segment, then further organized by the following streetscape components. This page provides an overview of the existing character of **Area D** streetscape components.



Heading south on Queen St / Hwy 6. Pictured: entering Historic Downtown Morriston

Adjacent Land

Adjacent lands in Focus Area D feature a mix of residential and commercial property frontage. Commercial adjacent land is minimal with some buildings abutting the property line.

Roadside

Roadsides in Area D feature a mix of sidewalks and paved shoulders in varying conditions to support pedestrian activity.

Road

Roads in Focus Area D are posted at 50 km/h and have two lanes of traffic with a turning lane and one main signalized intersection.

A B C D **E** F

Focus Area E: Arkell Streetscape

Figure 9. *Focus Area E*

Rural Corridor

Arkell Settlement Area

Segment E1: Vehicular Transitional

Segment E2: Residential Thoroughfare

Segment E3: Community Core/Residential Mix

Segment E4: Vehicular Transitional

Minor Intersection

Signalized Four-way Stop Intersection

E Focus Area E: Arkell Streetscape

Streetscape Components:

Adjacent Land

Private or public property, which may include **building façades, height, and setbacks, parking**, as well as **landscaping** as typically defined through zoning.

Roadside

The strip of **public** property beside a road typically used to provide **sidewalks**, **street trees**, **signs**, **amenities (i.e. pedestrian realm)**, in addition to **drainage** and **utilities**.

Road

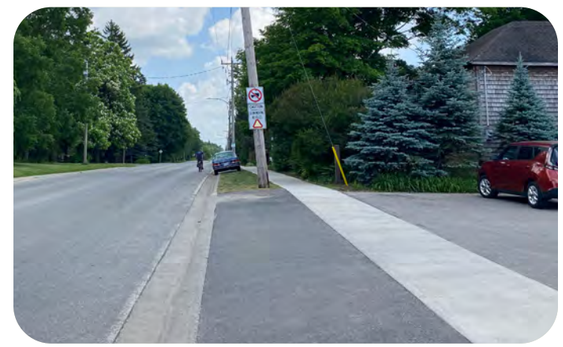
The portion of the **public** right-of-way primarily used by vehicular traffic, but may also include **medians**, **pedestrian crossings** and **bicycle lanes**.

First, the Guidelines are organized by segment, then further organized by the following streetscape components. This page provides an overview of the existing character of **Area E** streetscape components.

Heading North East on Arkell Rd ; Pictured: entering Arkell Community Core

Adjacent Land

Adjacent lands in Focus Area E feature a mix of residential and commercial property frontage. Commercial adjacent lands are minimal with the majority of Arkell being residential.



Roadside

Roadsides in Area E feature a mix of sidewalks and paved shoulders in varying conditions to support pedestrian activity.

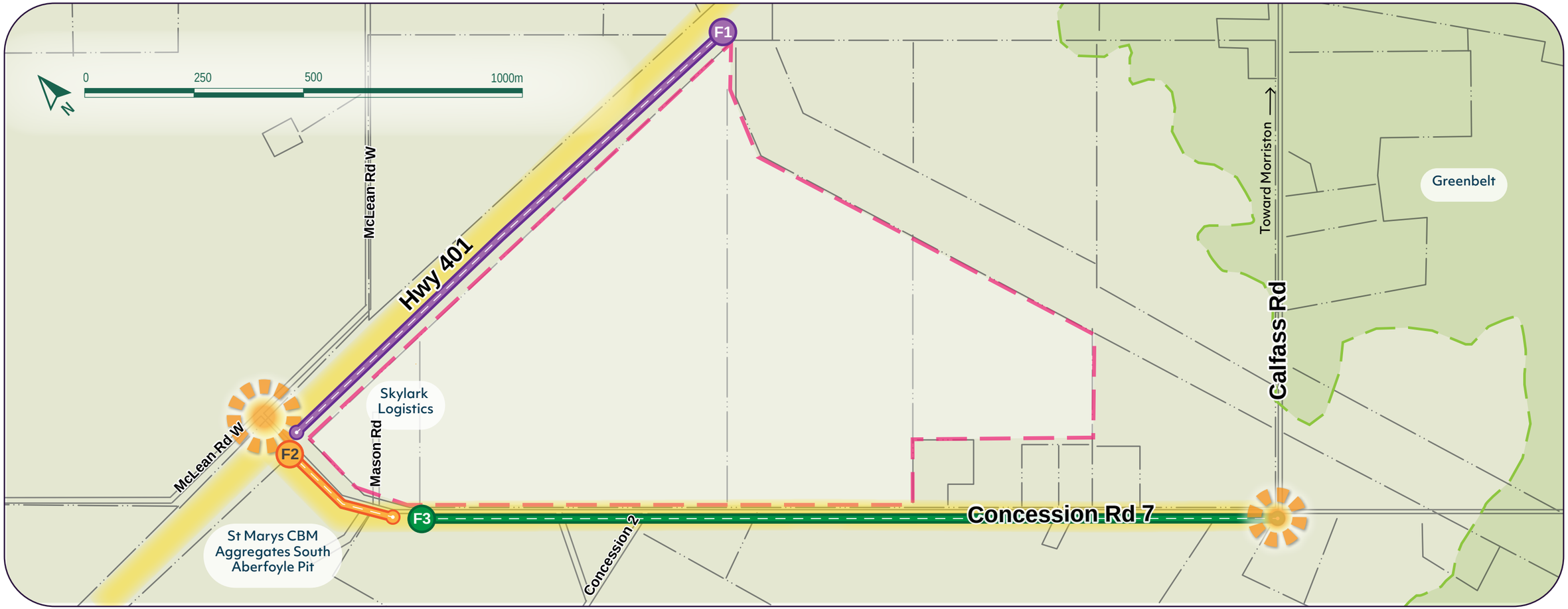
Road

Roads within Focus Area E are posted at a speed limit of 50 km/h and consist of two-lane roadways with one primary four-way stop-controlled intersection.

A B C D E **F**

Focus Area F: Employment Lands

Figure 10. *Focus Area F*



Vehicular Corridor

Rural Employment Lands

Greenbelt

Segment F1: Highway Frontage

Segment F2: Industrial Thoroughfare

Segment F3: Rural Vehicular

Minor Intersection

F Focus Area F: Employment Lands

Streetscape Components:

Adjacent Land

Private or public property, which may include **building façades, height, and setbacks, parking**, as well as **landscaping** as typically defined through zoning.

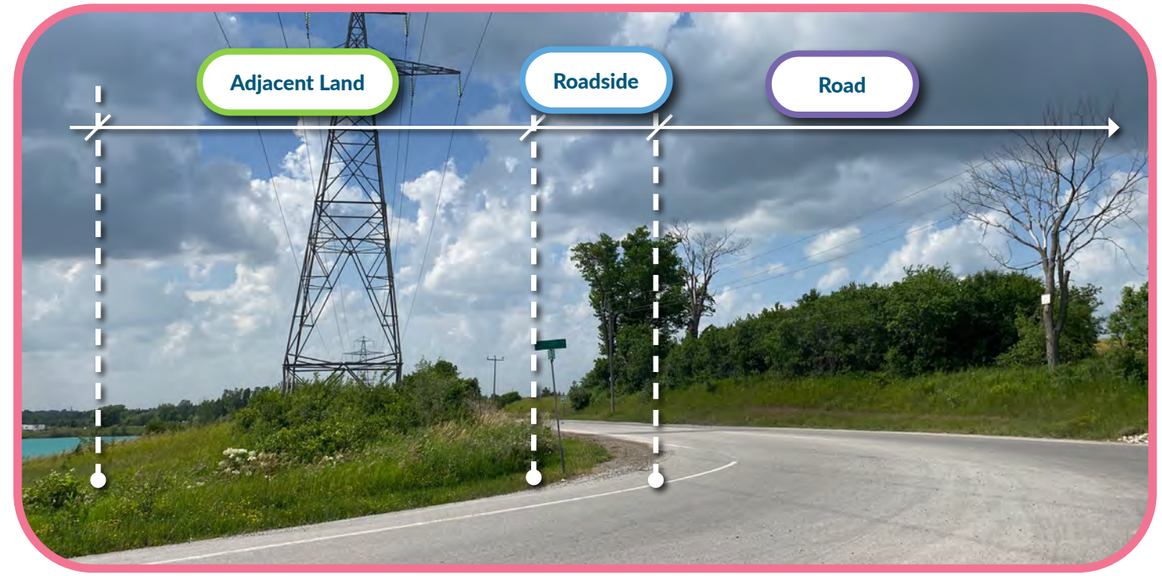
Roadside

The strip of **public** property beside a road typically used to provide **sidewalks**, **street trees**, **signs**, **amenities (i.e. pedestrian realm)**, in addition to **drainage** and **utilities**.

Road

The portion of the **public** right-of-way primarily used by vehicular traffic, but may also include **medians**, **pedestrian crossings** and **bicycle lanes**.

First, the Guidelines are organized by segment, then further organized by the following streetscape components. This page provides an overview of the existing character of **Area F** streetscape components.



Heading North East on Concession 2. Pictured: Turning left onto Concession Rd 7

Adjacent Land

Adjacent lands in Focus Area F feature a mix of residential and commercial property frontage. This land is inclusive of a portion of the Greenbelt and agricultural lands.

Roadside

Roadsides in Area F feature a mix of gravel shoulders in varying topography conditions; with no support for pedestrian activity.

Road

Roads in Focus Area F are posted at 60 km/h and have two lanes of traffic, with a series of bridge portions along Concession Rd 2.

Section 3:

The Design Guidelines

The Guidelines are organized by the following focus areas and then further grouped by road segments. This structure will assist with efficient project planning.

Focus Area A: Guelph to Aberfoyle — see page 15

Focus Area B: Aberfoyle Streetscape — see page 17

Focus Area C: Aberfoyle to Highway 401 — see page 19

Focus Area D: Morriston Streetscape — see page 21

Focus Area E: Arkell Streetscape — see page 23

Focus Area F: Employment Lands — see page 25

Planning Principles: A Foundation for Good Urban Design

The following is of particular relevance to the Guidelines and reflect the significant findings of the analysis, as summarized in Section Two: Taking Stock, as well as the valuable input from residents, businesses, property owners, and Township staff. Guidelines for renewal, reinvestment and community building throughout the Township and within the Aberfoyle, Morriston and Arkell settlement areas are served by several considerations:

1. Responding to Planning Principles, which guide development, investment and decision-making toward long term community building;
2. Understanding the Streetscape Components, which describes the street classification within the focus areas and establishes a hierarchy of treatments (typically pavements, lighting, greening, and site furnishings) specifically in consideration to adjacent lands, roadside and road influences, and
3. Promoting reasonable Development Design possibilities, which includes these Guidelines, identifying areas of Stability and Change, and demonstrating Development Design Concepts illustrating "what it could be like."

These all provide supportive recommendations to guide the evolution of the Aberfoyle, Morriston, Arkell and employment lands focus areas' main urban and rural elements. Guidelines provide specific performance criteria to guide elements of the built environment to ensure the creation of a high-quality pedestrian environment and an attractive mixed use main street that is compatible with adjacent neighbourhoods and appropriate to the provision of a supportive environment within the focus areas.

This also pursues an "intentional public realm," which includes benefits for public and private open spaces that will contribute to a cohesive and vibrant streetscape.

Specific streetscape improvement, intended to strengthen the character and amenity of the area contributes to a high-quality "place," and ideally encourages desired private sector reinvestment throughout the focus areas and the Township.

Planning Principles: Working Towards Good Urban Design

These principles have guided the creation of the vision and will be used by the Township to inform the transformation of the focus areas in Aberfoyle, Morriston and Arkell over the coming years. Many of these principles also build on established Township and heritage asset goals.

Creating a true mixed-use vibrant main street by encouraging people to be on and live in proximity of the "main street" within the Aberfoyle and Morriston focus areas.

Main street patronage and living is essential for creating a safe, animated, active and economically prosperous main street. While typically experienced in more populous areas, significant opportunities remain possible for mixed use residential infill and intensification within the core areas of rural communities. Understanding the present conditions and anticipating the future, changes to the focus areas of Aberfoyle and Morriston can enable mixed use intensification that can better support commercial growth and diversification, as well as community building and renewal.

Creating a great pedestrian friendly, high quality and distinctive streetscapes

A critical component of any healthy pedestrian environment is the quality and amenity of the public realm: the places where people walk, shop, meet, conduct business and socialize.

The focus area corridors in both Aberfoyle and Morriston need new streetscapes to 'calm' the street and re-balance as a place where pedestrians and vehicular movement have equal emphasis. The existence of the regional Go Bus transit-way presents a significant

opportunity to put in place a distinctive and enduring streetscape to re-image the corridor and encourage private sector renewal.

Utilize every development opportunity to repair the gaps in the urban fabric and enhance the urban character of the street.

Much of Aberfoyle and Morriston are characterized by a significant vehicular corridor with a predominance of one- and two-story buildings with various set back distances from the street. This has created a less appealing environment which is uninviting to pedestrians and traditional main street commercial activities. Additionally, in several locations, the setback of existing development is out of balance with the width of the street, and in many instances, has limited pedestrian opportunity. Consequently, street definition is weak – existing buildings and the scale of the street are mixed and imbalanced. There is significant potential to address these conditions and improve the character and definition of the area, and pedestrian environments, through new mixed-use development appropriately blending the old with the new. Conversely, Arkell poses a different character having a strong neighbourly atmosphere supporting a pedestrian-friendly scale. Development opportunities should strive to maintain this character.

Creating new and celebrating existing parks on the side streets as important places for meeting and gathering.

While the street frontage is the primary address and civic seam of Aberfoyle and Morriston, they establish the immediate first impression of the community; opportunities such as Morriston's Historic Block park and side streets have a unique role to play in the future of the areas. Lower volumes of traffic and narrower street widths make the side streets in general attractive locations for meeting, gathering, and engaging in outdoor communal pursuits. There are a number of opportunities to introduce new (or re-establish) green spaces, parkettes and plazas which can take advantage of southern corner locations, and provide distinct places for families, friends, residents and visitors.

Safeguard, expand and diversify the commercial retail sector.

Retail and commercial uses act as key economic drivers for many main streets. Much of the Township's retail spending is directed to locations outside the study area, and in many cases these developments have eclipsed the traditional commercial retail function of its focus areas' commercial street segments. Where appropriate, there is strong potential to evolve a distinct commercial role for the streets comprised of specialty retail concentration catering to niche markets, including food, lifestyle and boutique stores as well as neighbourhood and convenience shopping for the surrounding population. New retail development will come in the form of revitalization of existing structures and through future mixed-use developments adding a main street population to support and strengthen commercial vitality.

Promote a connected open space system.

A linked network of attractive streetscapes, parks, civic spaces and open space connections is a defining characteristic of all good rural and urban places. Proximity to the Puslinch Community Centre, Morriston Meadows Park, Boreham Park, and Starkey Hill, etc., is an asset; opportunities to effect improvements to the total open space resource, including parks, streets, streetscapes, trail linkages and pedestrian connections, and to adjacent destinations (Starkey Hill Conservation Area), will better link people and neighbourhoods to the focus area street segments in Arkell, Aberfoyle and Morriston, its commercial activities and regional transit opportunities.

Protect and strengthen core assets – distinctive places and heritage resources.

The Township has many unique assets, heritage and open space resources and other amenities which demonstrate "stability" and make the area a great place to live, work and play. Protecting and enhancing these assets will reinforce the unique identity and character of the area while enabling these locations to contribute to the overall success of main street renewal by acting as notable destinations or anchors for new development. There are a number of potential "change" sites that can enhance core assets and strengthen the sense of place and identity of the area.

Promote a high quality of design excellence.

Securing a successful, livable and meaningful vision for the future of the Township and its communities in Aberfoyle, Arkell and Morriston is as much about the quality and execution of its physical design as it is about the commitment of those who will oversee the implementation of the vision over many years. A high quality of design excellence and attention to the public environment, parks, streets, squares, trails, public buildings, signage and exterior architecture will ensure that the vision for the future of the Township is achieved and that each project fully contributes to community building and positive renewal. Specific streetscape and built form design criteria will ensure that future development is executed to the highest standards.

Organize shared parking and promote the development of a connected system of rear drive laneways to free up the main thoroughfares for people, parks, buildings and activity.

While regional transit can bring new pedestrian traffic to support commercial uses along the main thoroughfares in each of the Township's settlement areas, the provision of parking is important to the success of most commercial main streets, especially those situated in rural communities. Both re-development and development processes provide opportunity to reorganize parking toward shared parking and access solutions. As available, these service functions will be situated toward the rear of the properties and free up high value primary frontage for people, public space, buildings and activity.

Regional Transit is an important catalyst for positive change, renewal and reinvestment along the corridor.

Regional transit has the potential to improve access for people and business, offer an alternative to automobile usage, reduce congestion, improve and green the street and pedestrian environment, renew interest in development and re-investment along Aberfoyle's and Morriston's focus areas, and provide a rationale for appropriate intensification to support transit use. Township investment in spaces that support regional transit infrastructure should be paired with development intensification to fully capture the benefits transit can provide.

The Township and the County have the power to make change happen.

The implementation of the Township's Guidelines work with its other defining "planning" documents and can have a tremendously positive impact on the image and character of the focus areas in the short term. Through development and redevelopment processes, strategic development agreements, and the use of innovative tools for implementation, the Township can advance elements of the vision to make a significant contribution toward improving existing core assets and other elements of the public and civic realm.

Enhancing Focus Areas

Segments Overview

The six (6) focus areas are divided into distinct segments, determined by the context and unique character of each road segment. All segments are illustrated on the Focus Area Inventory Plans for reference.

Area A: Guelph to Aberfoyle

- A1 Vehicular Transitional
- A2 Residential Thoroughfare
- A3 Commercial/Residential Mix

Area B: Aberfoyle Streetscape

- B1 Vehicular Transitional
- B2 Community Core
- B3 Community Extension
- B4 Commercial/Residential Mix

Area C: Aberfoyle to Highway 401

- C1 Industrial Highway
- C2 Commercial Highway
- C3 Vehicular Transitional

Area D: Morriston Streetscape

- D1 Vehicular Transitional
- D2 Community Core
- D3 Community Extension
- D4 Residential Thoroughfare

Area E: Arkell Streetscape

- E1 Vehicular Transitional
- E2 Residential Thoroughfare
- E3 Community Core/Residential Mix
- E4 Vehicular Transitional

Area F: Employment Lands

- F1 Highway Frontage
- F2 Industrial Thoroughfare
- F3 Rural Vehicular

Aspects of Urban Design

The Guidelines address key aspects of development design across the following topic areas.

Aesthetics

- Beautification/Planters
- Character
- Family of Elements/Furnishings/ Amenities
- Landscaping/Planting
- Lighting
- Murals
- Street Trees

Buildings

- Building Design
- Building Height and Scale
- Setbacks
- Street Wall

Movement and Use / Circulation

- Crosswalks
- Pedestrian Realm/Sidewalks
- Traffic Calming/Medians

Placemaking and Navigation

- Branding and Identity
- Gateway/Entry
- Landmarks
- Signage

Note: Some segments may not include applicable guidelines due to their non-urban characteristics and will be identified as “None.”

A Focus Area A: Guelph to Aberfoyle

Design Guidelines by Segment

Note: *These design guidelines intend to conform with the applicable County Official Plan policies and the Township Zoning By-laws, as they prevail, and should uphold the overall design vision and guiding principles established for the focus area and its subsequent segments.*

A1 **Segment A1:** Vehicular Transitional

Adjacent Land

A1.1 Adhere to the minimum development setback from Brock Rd /WR 46 to preserve existing rolling topography, mature vegetation, and ponds.

A1.2 Provide landscaping enhancements appropriate to the rural setting (e.g., informal groupings and plant material that is not heavily manicured).

Roadside

A1.3 Identify entry into the Township from the City of Guelph at Brock Rd/WR46 and Maltby Rd with primary gateway signage, landscaping and lighting

A2 **Segment A2:** Residential Thoroughfare

None.

A3 **Segment A3:** Commercial/Residential Mix

Adjacent Land

A3.1 Provide enhanced building design where fronting on or visible from Brock Rd/WR 46; Incorporate natural materials, building elements and architectural character that complement the rural setting.

Roadside

A3.2 Highlight entry into Aberfoyle at the intersection (roundabout) of Brock Rd/WR 46 and WR 34 with primary gateway signage, landscaping, and lighting.

B Focus Area B: Aberfoyle Streetscape

Design Guidelines by Segment

Note: *These design guidelines intend to conform with the applicable County Official Plan policies and the Township Zoning By-laws, as they prevail, and should uphold the overall design vision and guiding principles established for the focus area and its subsequent segments.*

B1 Segment B1: Vehicular Transitional

None.

B2 Segment B2: Community Core

Adjacent Land

B2.1 Minimize building setbacks from Brock Rd/WR 46 to define the street edge.

B2.2 Ensure building heights match or complement the pre-existing building heights of adjacent developments on Brock Rd/WR 46.

B2.3 Incorporate consistent landscaping, including native plantings, street trees, and layered vegetation, to reinforce Aberfoyle's rural character and enhance the pedestrian experience.

B2.4 Encourage driver-oriented signage that suits the rural character of the area; municipal signage should reflect the Township brand to support a cohesive identity, while private commercial signage should clearly identify business properties.

Roadside

B2.5 Enhance pedestrian realm by providing continuous barrier curb, sidewalks, boulevards, and pedestrian/street lighting within Aberfoyle. Incorporate street trees and/or landscaping where right-of-way width is sufficient.

B2.6 Improve and maintain visibility to key properties, such as the Puslinch Community Centre

B2.7 Introduce a family of elements, including decorative light fixtures, wayfinding signage, planters, benches, bike racks, and waste receptacles. See **Family of Elements on page 44.**

B3 Segment B3: Community Extension

Same as B2

B4 Segment B4: Commercial/Residential Mix

Adjacent Land

B4.1 Provide enhanced building design where fronting on or visible from Brock Rd/WR 46; Incorporate natural materials, building elements and architectural character that complement the rural setting.

C Focus Area C: Aberfoyle to Highway 401

Design Guidelines by Segment

Note: *These design guidelines intend to conform with the applicable County Official Plan policies and the Township Zoning By-laws, as they prevail, and should uphold the overall design vision and guiding principles established for the focus area and its subsequent segments.*

C1 **Segment C1:** Industrial Highway

Adjacent Land

C1.1 Provide landscaping enhancements appropriate to the rural setting (e.g., informal groupings and plant material that is not heavily manicured).

Roadside

C1.2 Minimize the visual impact of commercial and industrial driveways by designing to the minimum width necessary and combine or eliminate entrances where feasible. (Refer to *Wellington County Official Plan*).

C1.3 Identify entry into the Township from the 401 into Aberfoyle with primary gateway signage, landscaping and lighting.

C2 **Segment C2:** Commercial Highway

Adjacent Land

C2.1 Provide a (minimum) perimeter landscape area abutting Brock Road measured from inside the property line to accommodate trees spaced a minimum at the required 'on centre' spacing minimum (refer to Site Plan Control).

C2.2 Provide landscaping such as native/non-invasive trees, shrubs, perennials, and groundcover in front of buildings and in parking areas.

Roadside

C2.3 Minimize the visual impact of commercial and industrial driveways by designing to the minimum width necessary and combine or eliminate entrances where feasible. (Refer to *Wellington County Official Plan*).

C2.4 Introduce a family of elements, including decorative light fixtures, wayfinding signage, and planters. See **Family of Elements on page 44.**

Road

C2.5 Provide a consistently designed change in material, texture and colour for pedestrian crossings at signalized intersections.

C3 **Segment C3:** Vehicular Transitional

None.

D Focus Area D: Morriston Streetscape

Design Guidelines by Segment

Note: *These design guidelines intend to conform with the applicable County Official Plan policies and the Township Zoning By-laws, as they prevail, and should uphold the overall design vision and guiding principles established for the focus area and its subsequent segments.*

D1 Segment D1: Vehicular Transitional

None.

D2 Segment D2: Community Core

Same as D3

D3 Segment D3: Community Extension

Adjacent Land

D3.1 Locate new commercial buildings in the designated Central Business District (*Wellington County Official Plan*) at the prescribed setback from Queen St/Hwy 6. Locate parking behind commercial buildings to define the street edge.

D3.2 Ensure buildings heights match or complement the pre-existing building heights of adjacent developments on Queen St/Hwy 6.

D3.3 Provide enhanced building design where fronting on or visible from Queen St/Hwy 6; Building façades should be strongly articulated through architectural detailing and building materials, wall projections, and windows.

D3.4 Incorporate coordinated planters and hanging baskets throughout the Morriston streetscape to add seasonal colour, reinforce community pride, and enhance the pedestrian experience along the main street.

D3.5 Incorporate murals and public art installations on prominent building façades and within the streetscape to celebrate Morriston's history, rural character, and community identity.

Roadside

D3.6 Enhance pedestrian realm by providing continuous barrier curb, sidewalks, boulevards, and pedestrian/street lighting within Morriston. Incorporate street trees and/or landscaping where right-of-way width is sufficient.

D3.7 Improve and maintain visibility to key properties, such as the Historic Corner Block (sight lines, pathways, signage, other amenities)

D3.8 Introduce a family of elements, including decorative light fixtures, wayfinding signage, planters, benches, bike racks, and waste receptacles. See **Family of Elements on page 44.**

D Focus Area D: Morriston Streetscape

D3.9 Highlight entry into Morriston at the both the northern and southern entry points with gateway signage, landscaping, and lighting.

Road

D3.10 Provide a consistently designed change in material, texture and colour for pedestrian crossings at signalized intersections.

D4 **Segment D4:** Residential Thoroughfare

None.

E Focus Area E: Arkell Streetscape

Design Guidelines by Segment

Note: *These design guidelines intend to conform with the applicable County Official Plan policies and the Township Zoning By-laws, as they prevail, and should uphold the overall design vision and guiding principles established for the focus area and its subsequent segments.*

E1 Segment E1: Vehicular Transitional

None.

E2 Segment E2: Residential Thoroughfare

None.

E3 Segment E3: Community Core/Residential Mix

Adjacent Land

E3.1 Locate new commercial buildings in the designated Central Business District (*Wellington County Official Plan*) at the prescribed setback from Arkell Rd/Watson Rd S. Locate parking behind commercial buildings to define the street edge.

E3.2 Provide enhanced building design where fronting on or visible from Arkell Rd/Watson Rd S; Building façades should be strongly articulated through architectural detailing and building materials, wall projections, and windows.

E3.3 Incorporate coordinated planters and hanging baskets throughout the Arkell streetscape to add seasonal colour, reinforce community pride, and enhance the pedestrian experience along the main intersection streets.

E3.4 Incorporate public art installations on prominent building façades and/or within the streetscape to celebrate Arkell's history, rural character, and community identity.

Roadside

E3.5 Enhance pedestrian realm by providing continuous barrier curb, sidewalks, boulevards, and pedestrian/street lighting within Arkell. Incorporate landscaping and greening where right-of-way width is sufficient.

E3.6 Improve and maintain visibility to key properties, such as the Arkell United Church (sight lines, pathways, signage, other amenities).

E3.7 Introduce a family of elements, including decorative light fixtures, pavement treatments, wayfinding signage, mobile planters, and hanging plant baskets. See **Family of Elements on page 44.**

E3.8 Highlight entry into Arkell at both the northwestern and southeastern entry points with gateway signage.

Road

E3.9 Provide a consistently designed change in material, texture and colour for pedestrian crossings at signalized intersections.

E4 Segment E4: Vehicular Transitional

None.

F Focus Area F: Employment Lands

Design Guidelines by Segment

Note: *These design guidelines intend to conform with the applicable County Official Plan policies and the Township Zoning By-laws, as they prevail, and should uphold the overall design vision and guiding principles established for the focus area and its subsequent segments.*

Through the Puslinch By Design: Employment Land Study (2025), the Township has recommended several new Rural Employment Areas including the Highway 401 and Concession 7 Rural Employment Area and the County Road 34 Rural Employment Area (Options G and H). These areas are proposed to be implemented through Official Plan Amendment 131 (OPA 131) and shown in Schedule A7 and B7 of the County of Wellington Official Plan. Refer to Section 5.3, Page 58-65 of the Puslinch by Design - Employment Lands Study - Recommended Land Option and Land Use Report for respective design guidelines, as noted below for each segment.

F1 **Segment F1:** Highway Frontage

Refer to **Section 5.3, Page 58-65** of the *Puslinch by Design - Employment Lands Study - Rural Employment Area Design Guidelines* for design guidelines.

F2 **Segment F2:** Industrial Thoroughfare

Refer to **Section 5.3, Page 58-65** of the *Puslinch by Design - Employment Lands Study - Rural Employment Area Design Guidelines* for design guidelines.

F3 **Segment F3:** Rural Vehicular

Refer to **Section 5.3, Page 58-65** of the *Puslinch by Design - Employment Lands Study - Rural Employment Area Design Guidelines* for design guidelines.

Established Character Meets Opportunity

Areas of Change and Stability

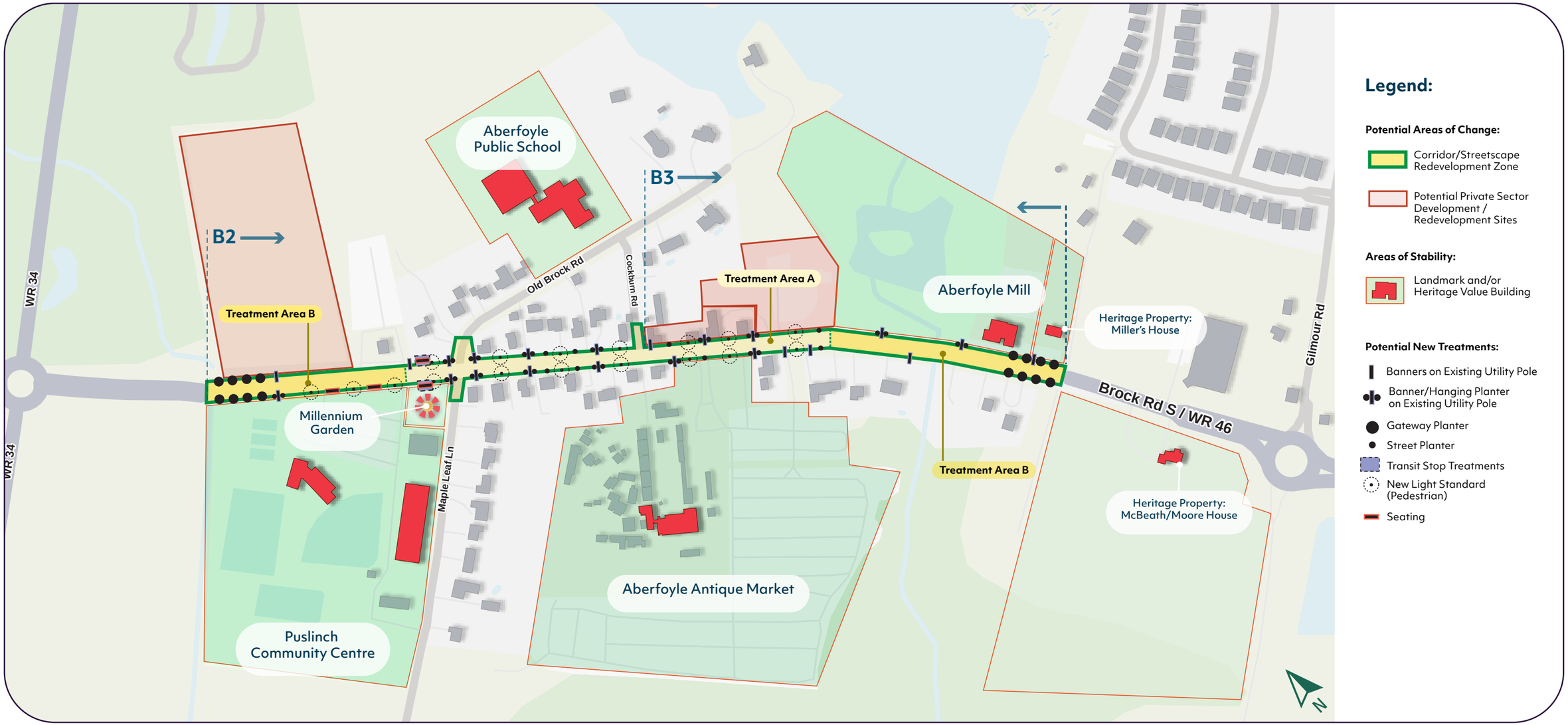
The three main subject areas for the Guidelines are Aberfoyle, Morriston, and Arkell.

The following plans schematically illustrate opportunities for enhancement while respecting established character. These illustrations may be used to suggest and inform future projects and redevelopment and development opportunities in the three specific focus areas. Generally, landmarks and surroundings, built and natural heritage, and development next to residential areas are important community resources to consider in the application of the Guidelines.

B Focus Area B: Aberfoyle Streetscape

Figure 11. *Focus Area B: Areas of Change and Stability*

Areas of Change and Stability

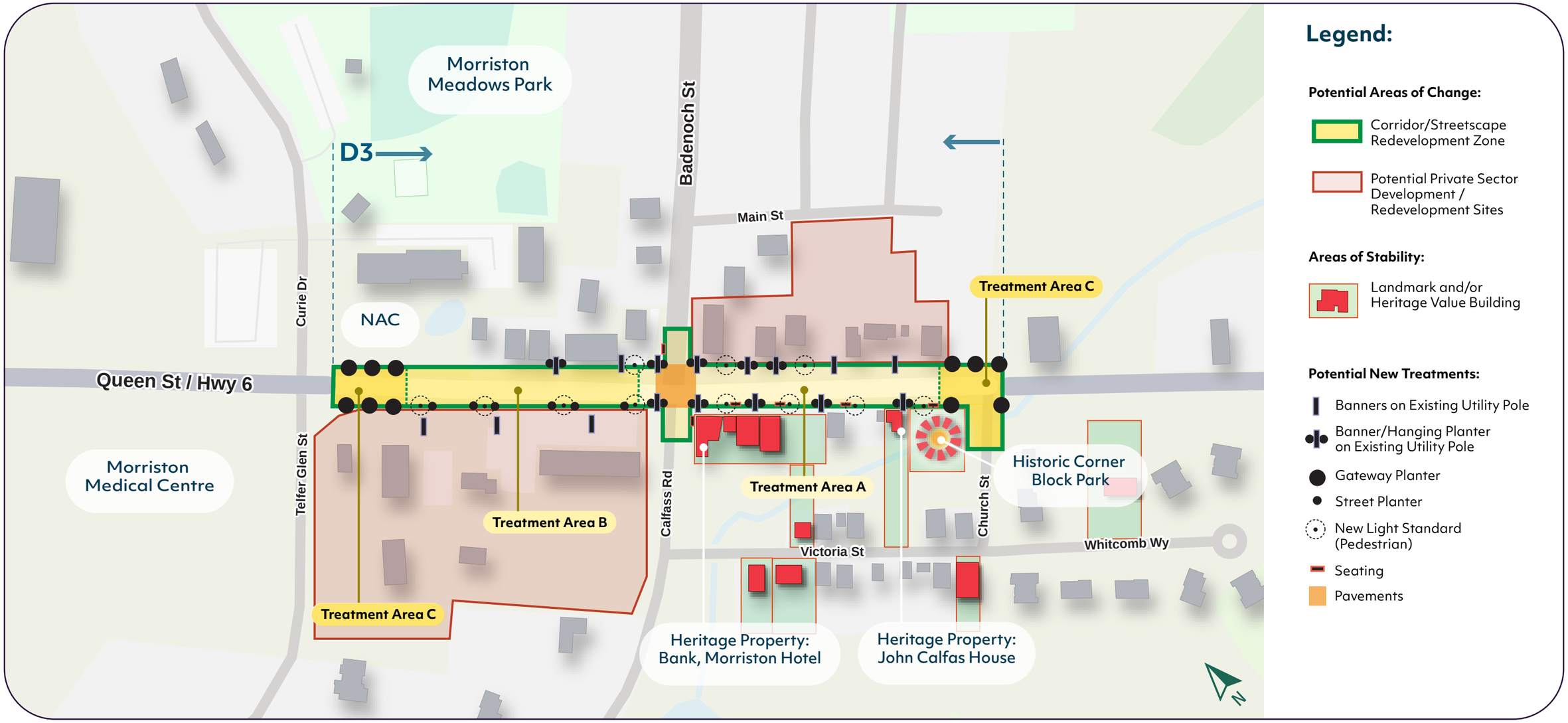


Note: *This demonstration is an illustrative rendition only. Illustrations may be used to suggest and inform future projects and redevelopment and development opportunities.*

D Focus Area D: Morriston Streetscape

Figure 12. *Focus Area D: Areas of Change and Stability*

Areas of Change and Stability

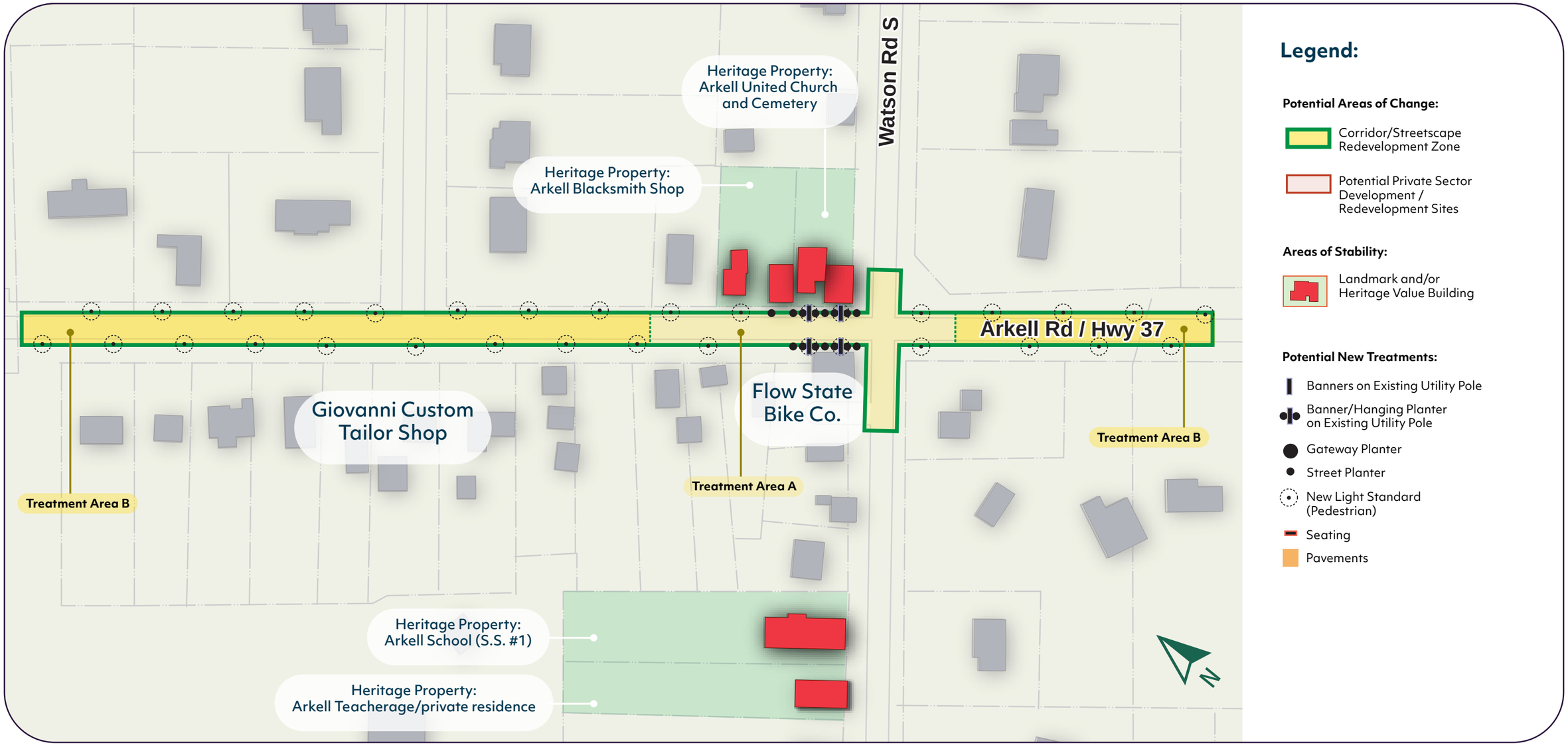


Note: *This demonstration is an illustrative rendition only. Illustrations may be used to suggest and inform future projects and redevelopment and development opportunities.*

E Focus Area E: Arkell Streetscape

Figure 13. *Focus Area E: Areas of Change and Stability*

Areas of Change and Stability



Note: *This demonstration is an illustrative rendition only. Illustrations may be used to suggest and inform future projects and redevelopment and development opportunities.*

Promoting Quality Development

The Five Treatments

The means of promoting quality development having safe and inclusive treatments and improving development design in the Township can be organized into the following five categories:

Note, Images below are for visual reference only and are based on precedent works, not necessarily proposed treatments for the Township.

Site Furnishings

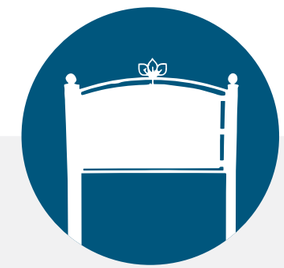
- Benches (variety to support accessibility)
- Waste receptacles
- Bike racks

Lighting (DarkSky Compliant)

- Street lamps
- Decorative light fixtures

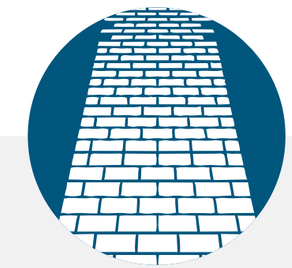
Greening

- Landscaping
- Shade/Street Trees
- Planters
- Hanging baskets



Signage and Identity

- Gateway signage
- Identity signage
- Public Art/Murals



Pavements

- Sidewalks
- Crosswalks
- **Permeable solutions as applicable*

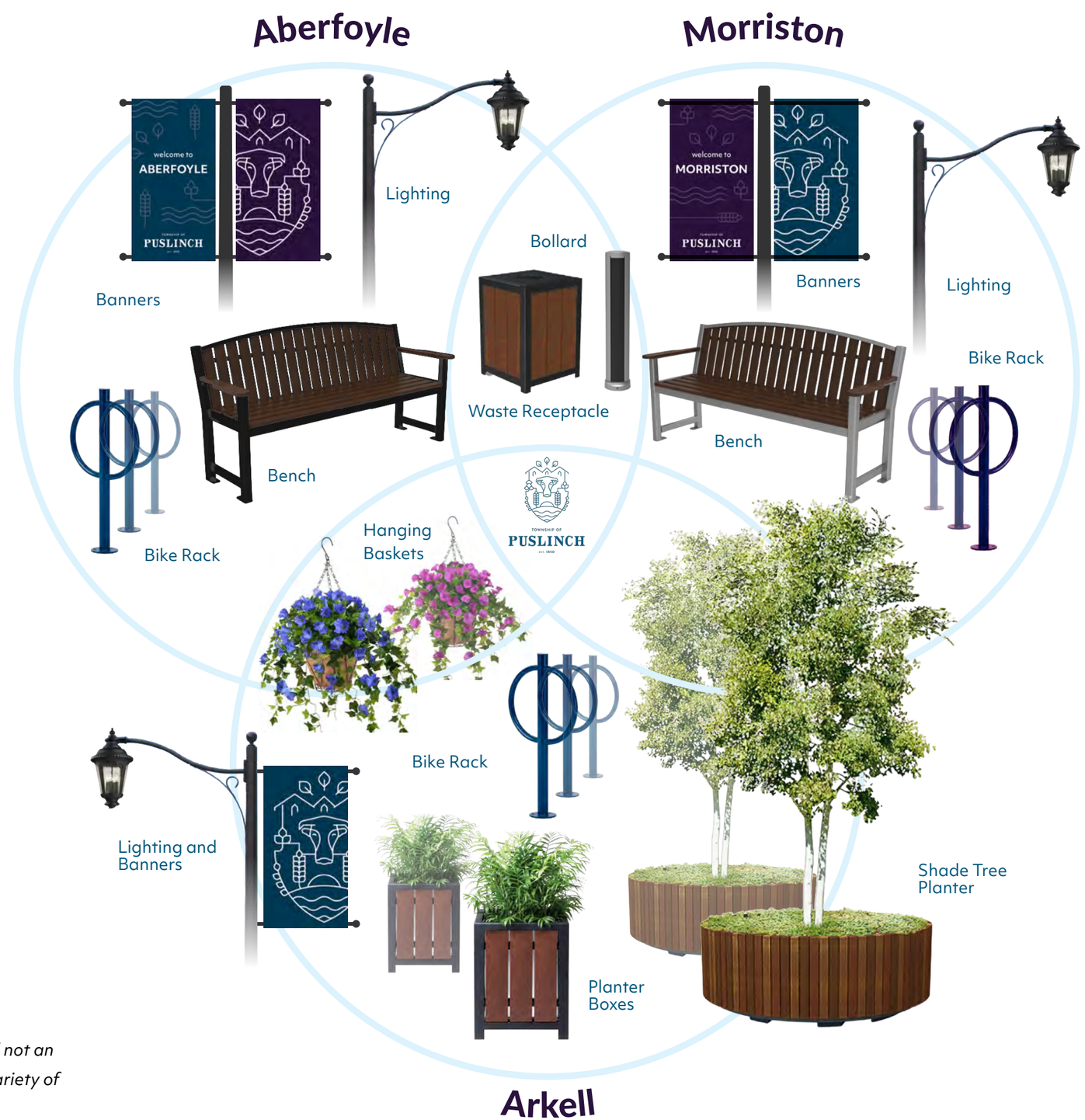
Family of Elements

The selection of a Family of Elements (right) is shown as an example only to guide future product selection. Elements have been chosen to reflect an appropriate character for the Township while providing a subtle degree of differentiation between the Aberfoyle, Arkell and Morriston communities.

Considerations for choosing streetscape elements and furnishings:

- Matching colours and materials to coordinate different types of elements
- Intent is to provide a variety of seating options to be inclusive, ie, with backs, backless, with arms, with single arm, etc.
- Varying colours or materials between the same types of elements to strengthen identity of a specific area
- Choose materials (e.g., wood, steel, stone, etc.) that reflect the character of the Township and complement existing architecture.
- When appropriate, choose colours for materials or plantings to align with the Township brand and reinforce identity

Note, the product specification is a suggested functional/aesthetic approach and not an endorsement of one manufacturer or model; equals are available throughout a variety of manufacturers and can be managed on an 'approved equal' procurement basis.



Product Selection

Note that wood selection, powder coating, and vinyl wrapping can customize the look of each piece below.

Bench

Steel backed bench with wood or composite slats, frame finished in 'black'. Township to seek seating variety having backs, no backs, arm rests an no arm rests, etc, to best serve accessibility. Placement to be strategic to user group and effects of climate.

Waste Receptacle

Steel framed waste receptacle with wood or composite slats, frame finished in 'black'.

Planter Box (Street)

Steel framed planter with wood or composite slats, frame finished in 'black'.

Street Tree Planter Box (Gateway)

Large planter with 'black' container and wood or composite 'tan' slats.

Bike Rack

Single steel bike rack finished in 'black'.

Bollard

Steel bollards, finished in 'black', with wood or composite slat details.

Street Lighting

Traditional luminaire pendant mounted to a decorative scroll arm, finished in 'black'. All new lighting should adhere to DarkSky standards.

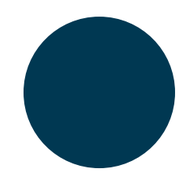
Materials

Powder-coat steel in 'black'

Wood with 'dark, natural' stain

Township Brand Colours

Purple
Pantone 2765



Blue
Pantone 302

Site Landscaping

The overall objectives of site landscaping is to encourage landscape design in consideration of the distinct character of the rural and urban areas of the Township, and to improve the aesthetic quality of development and screen less attractive elements of a site.

Site Landscaping Guidelines

Trees

- Brock Road Trees: Provide an average of one tree for every 10 metres of Brock Road frontage. Street trees are not to be accommodated within the road allowance, but are to be provided on private property close to the road allowance.
- Provide tree plantings in parking areas and on the perimeter of the property
- Minimum acceptable sizes for trees:
  - Deciduous trees: 60 mm caliper, 3-3.5 m height
  - Coniferous trees: 1.5 m height
- Choose trees with salt/urban tolerance to withstand harsh roadside conditions.
- Choose native plants when possible. Ensure all plants are non-invasive.
- Consider the trees full growth habit when locating trees (e.g., plant smaller trees under hydrolines, ensure full crown width will not obstruct sightlines, etc.)

List of Recommended Trees

- American Hop-Hornbeam (*Ostrya virginiana*) N
- American Mountain Ash (*Sorbus americana*)
- Bitternut Hickory (*Carya cordiformis*) N
- Basswood (*Tilia americana*) N
- Black Cherry (*Prunus serotina*) N
- Bur Oak (*Quercus macrocarpa*) N
- Freeman Maple (Acer x Freemanii)
- Ginkgo biloba* (Maidenhair Tree)
- Hackberry (Celtis occidentalis) N
- Honeylocust (Gletitsia triacanthos var inermis)
- Ivory Silk Lilac (Syringa reticulata 'Ivory Silk')
- Kentucky Coffee Tree* (Gymnocladus dioicus 'Espresso') N
- Littleleaf Linden (Tilia cordata)
- London Planetree (*Platanus x acerifolia*)
- Ohio Buckeye (Aesculus glabra) N
- Pin Cherry (Prunus pensylvanica) N
- Red Oak (Quercus rubra) N
- Shagbark Hickory (Carya ovata) N
- Showy Mountain Ash (Sorbus decora)
- Serviceberry (*Amelanchier canadensis - tree form*) N
- Smooth Serviceberry (Amelanchier laevis - tree form) N
- Swamp White Oak (Quercus bicolor) N
- White Elm 'Valley Forge' (Ulmus americana 'Valley Forge') N

Notes: * male species

N - Native

Shrubs and Groundcovers

- Use shrubs and groundcovers in large masses for lower maintenance and seasonal planting. Place special emphasis on early spring colour, fall colour, and September flower.
- Use shrubs to define and control pedestrian circulation and to screen undesirable views.
- Minimum acceptable sizes for shrubs:
  - 60-100 cm in height
- Choose shrubs and groundcovers with salt/urban tolerance to withstand harsh roadside conditions.
- Choose native plants when possible. Ensure all plants are non-invasive.

List of Recommended Shrubs and Groundcovers

Shrubs

- American Elderberry (*Sambucus canadensis*) N
- Alternate-leaved Dogwood (*Cornus alternifolia*) N
- Black Chokeberry (Aronia melanocarpa) N
- Chokecherry (*Prunus virginiana*) N
- Fragrant Sumac (Rhus aromatica) N
- Grey Dogwood (*Cornus racemosa*) N
- Highbush Cranberry (*Viburnum trilobum*) N
- Meadowsweet (*Spiraea alba*) N
- Nannyberry (*Viburnum lentago*) N
- Pussy Willow (*Salix discolor*) N
- Red-osier Dogwood (*Cornus sericea*) N
- Shrubby Cinquefoil (*Potentilla fruticosa*) N
- Smooth Wild Rose (*Rosa blanda*) N
- Staghorn Sumac (*Rhus typhina*) N
- Winterberry (*Ilex verticillata*) N

Evergreen Shrubs

- Junipers (*Juniperus sp.*)
- Mugo Pine (*Pinus mugo*)

Perennials, Grasses and Groundcovers

- Autumn Joy Sedum (*Sedum*)
- Big Bluestem (Andropogon gerardii) N
- Black-Eyed Susan (*Rudbeckia hirta*) N
- Catmint (Nepeta faassenii)
- Cranesbill (Geranium sp.)
- Daylily (*Hemerocallis sp.*)
- Ladies Mantle (Alchemilla mollis)
- Little Bluestem (Schizachyrium scoparium) N
- Oak Sedge (Carex pensylvanica) N
- Prairie Dropseed (Sporobolus heterolepis) N
- Purple Cone Flower (*Echinacea purpurea*) N
- Running Strawberry Bush (*Euonymus obovata*) N
- Russian Sage (Perovskia atripicifolia)
- Side-oats Grama (Bouteloua curtipendula) N
- Switchgrass (Panicum virgatum) N
- Tickseed (Coreopsis sp.)
- Yarrow (Achillea millefolium)
- Wild Geranium (Geranium maculatum) N

Notes: N - Native

Buffer Planting

- Provide buffers to screen undesirable views. Buffers may consist of architectural screening, landscaping, berming, or a combination.
- Where landscaping is used, planting is to consist of shrubs and trees, with 50% being coniferous planting. Site-specific circumstances may warrant continuous coniferous planting.
- Where berming is used, the berm should be 1 m high minimum, with maximum 33% side slopes and planted with shrubs and coniferous trees.
- Choose shrubs and groundcovers with salt/urban tolerance to withstand harsh roadside conditions, where applicable.
- Choose native plants when possible. Ensure all plants are non-invasive.

List of Recommended Trees for Buffer Planting

- Colorado Blue Spruce (Picea pungens 'Glauca')
- Eastern Hemlock (Tsuga canadensis) N
- Red Pine (Pinus resinosa) N
- Norway Spruce (Picea abies)
- White Cedar (Thuja occidentalis) N
- White Spruce (Picea glauca) N

Notes: N - Native

Landmarks

Objective: Preserve the Aberfoyle Mill and pond, a historically significant and highly visible local landmark.

Aberfoyle Mill

- Aberfoyle is known for its early rural mill, which operated under various ownerships to manufacture oatmeal and flour. The Aberfoyle Mill is a landmark for residents and travelers alike, and is a significant built heritage resource with scenic grounds.

Mill Pond

- The Mill Pond and adjacent open space also dates back to the early operation of the mill. Together with the Mill, these features form a larger area of heritage value.

Aberfoyle Mill

Heritage Resources

Objective: Respect the historic character of buildings identified as part of the Township's Heritage Inventory.

Conserve and Restore

- Conserve and restore heritage buildings as a priority. Of note are remaining former hotels and taverns, which are an important reminder of what was once an essential part of early commerce on Brock Road.
- Complement heritage building attributes when developing or altering adjacent properties.

Incorporate Heritage Elements

- Incorporate elements of the architectural heritage of the Township into new development. This heritage is most prominent in the early farmhouses throughout the Township, which includes, but is not limited to:
  - Materials such as fieldstone, limestone, granite, brick (yellow, red), and wood.
  - Architectural elements such as gables (Gothic or arched; chapel window), dormers, and porches
  - Details such as stone or brick soldier, arched lintels, quoins, and gingerbread trim
  - Small paneled windows, front entrance transom, and side lights

Natural Heritage Resources

Objective: Preserve, enhance and integrate natural heritage resources.

Visibility

- Make nature visible by site configurations that maximize visibility and, where appropriate, accessibility to natural features.

Preservation

- Preserve rural landscape, including rolling topography, ponds, hedgerows, trees, etc.

Morriston Pond

Development Next to Residential Areas

Objective: Minimize the impact of new development on established residential uses.

Complement

- Design new buildings to complement the scale, proportion and materials of nearby residential uses.

Locating and Screening

- Locate site service, delivery and parking areas away from residential uses, and provide buffers to screen undesirable uses.

Aerial View of Morriston

Traffic Calming

Sourced from: *Canadian Guide to Traffic Calming – Second Edition (2018)*

Objective: Preserve the pedestrian experience, enhance safety, and reduce speeding, with all measures considered in accordance with the Township's Roads Management Plan and the Township's guiding document for traffic-calming interventions.

Note: *Provincial, county, or municipal thoroughfares have a variety of 'traffic calming' measures available; the following are techniques that may be useful dependent on jurisdiction/approval.*

Road Speed Interventions

- Integrate **Speed Display Devices** as necessary. Speed display devices are most effective on single-lane roads, providing drivers with immediate feedback on their speed.
- Explore **Vertical Centreline Treatment**, which incorporates vertical elements like flexible post-mounted delineators or raised pavement markers to form a central median. This setup gives drivers the impression of a narrower lane and induces a sense of constriction, ultimately leading to lower operating speeds.

Paint Treatments

- Optimize the spacing between line paint interventions to create the illusion that a motorist's speed is increasing or that the lane is narrowing, a method to alert drivers that they are entering a rural or urban community.
- Consider the usage of **line treatment techniques** such as Converging Chevrons, Dragons Teeth, Full-Lane Transverse Bars, or Peripheral Transverse Bars.

Medians & Buffers

- Consider **raised median islands,** a physical barrier placed in the middle of a road, separating traffic moving in opposite directions, often seen on two-way streets. Optimize the median islands to help narrow the roadway, encouraging drivers to slow down, also providing a safe haven for pedestrians crossing the road.
- Integrate **speed cushions**, which are similar to speed humps but are narrower and placed in the center of each travel lane. Optimize their placement to reduce passenger-vehicle speeds while allowing larger vehicles, such as emergency services vehicles and buses, to pass without obstruction.

Intersection Treatments

- Consider implementing **raised crosswalks** or entirely **raised intersections**. Make sure that the height and width of the raised crosswalk align with the sidewalk entries on both sides of the road. These enhancements are applicable to all kinds of crosswalks, including unsignalized, midblock, and intersection crosswalks.
- Incorporate textured, coloured, or multiple material **surfaces for pavements and crosswalks**. The variation in texture is designed to notify drivers that they need to slow down.

Section 4:

The Design Concepts

The Guidelines are applicable throughout the Township, however the design concepts in this section provide additional details for Aberfoyle, Morriston and Arkell. The following section provides a proposed family of elements, and demonstrations of guideline application. These concepts may be used to inspire and inform future projects and developments in the Township, and several may be under authority other than the Township, i.e., County, MTO, etc., yet within the extents of the Township; noting not each and every segment or situation has been demonstrated.

Aberfoyle

Streetscape Treatments Overview

Streetscape treatment icons correspond to The Five Treatments on page 43.

- Site Furnishing
- Lighting
- Greening
- Signage and Identity
- Pavements

Aberfoyle Community Gateway Sign Placement:

Sign 1 *Location: See Illustration Below*

Sign 2 *Location: Wellington Rd 34 – Southwest Aberfoyle Settlement Boundary*

Sign 3 *Location: See Illustration Below*

B2:

Figure 14. *Aberfoyle Streetscape Treatments Overview*

B3:

Aberfoyle — Segment B2

Streetscape Demonstration

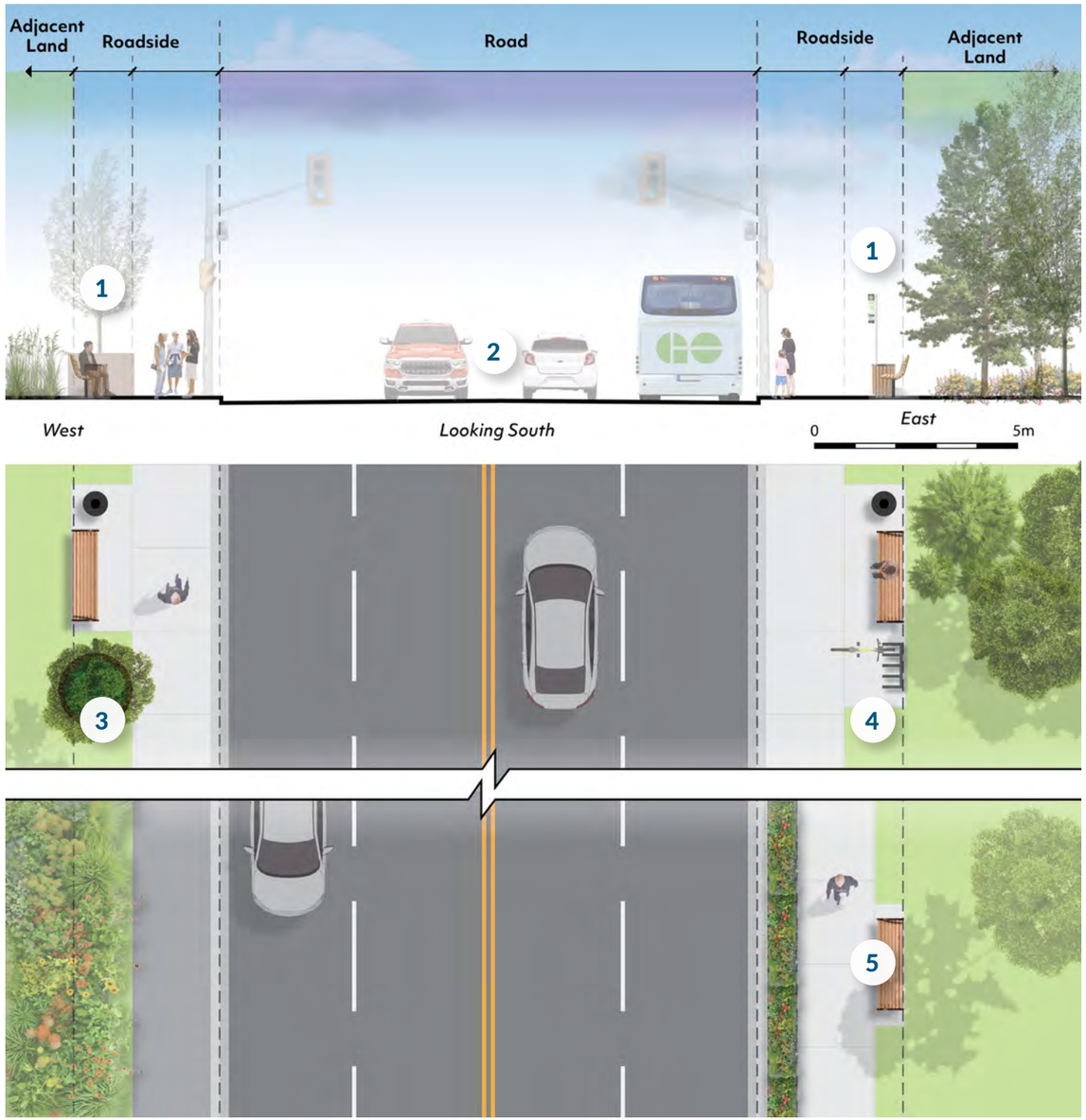


Figure 15. *Aberfoyle, Segment B2 Streetscape Demonstration with Streetscape Furnishings: Section and Plan View*

Specific Suggestions for B2

1. Place streetscape furnishings at gathering points, such as regional transit stops.
2. Crosswalks to be located at main intersections for safe pedestrian crossing.
3. Place street trees along the roadside where space allows; ensure trees are placed as not to obstruct important sight lines (e.g., regional transit stops, intersections, driveways, etc.).
4. Locate amenities where they are likely to be used most (e.g., regional transit stops, near major destinations, along pathways with highest use, etc.).
5. Amenities, such as benches, are placed intermittently along the pedestrian realm.

Aberfoyle

Streetscape Demonstration

Figure 16. *Aberfoyle, Segment B2 Streetscape Demonstration with Crosswalk: 3D Perspective Rendering*

Note: This demonstration is an artist rendition only

Aberfoyle — Segment B2

Streetscape Demonstration

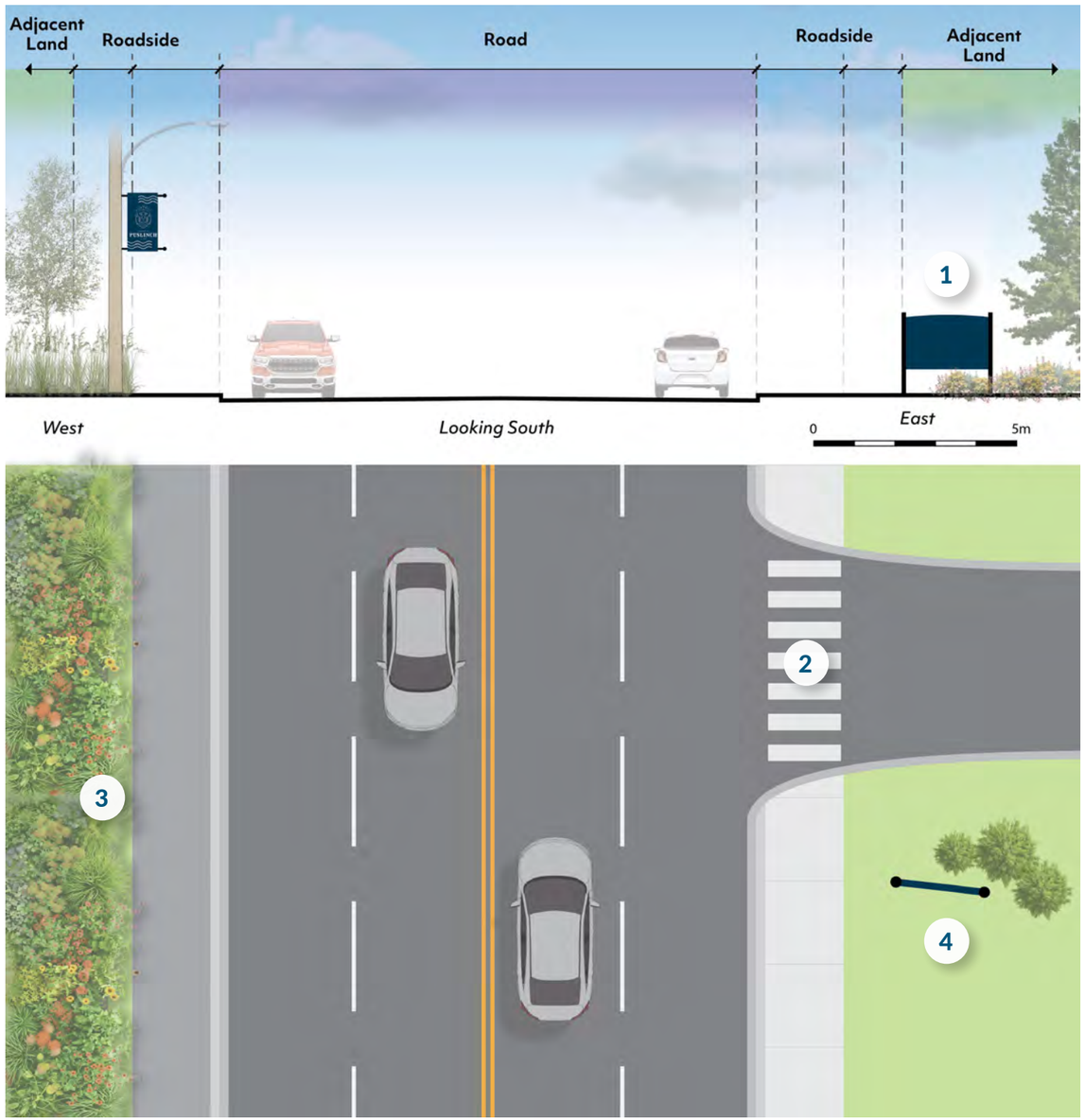


Figure 17. *Aberfoyle, Segment B2 Streetscape Demonstration with Crosswalk: Section and Plan View*

Specific Suggestions for B2

1. Signage is perpendicular to the road for optimal view as driver approaches/passes the signed destination.
2. Crosswalks to be located at busy intersections/driveways for safe pedestrian crossing.
3. Vegetated utility strip (unmanicured, non-lawn) along naturalized adjacent lands.
4. Sign is angled for optimal view and to reduce glare; landscaping behind the sign strengthens presence and adds visual interest.

Aberfoyle

Streetscape Demonstration

Figure 18. *Aberfoyle, Segment B2 Streetscape Demonstration with Crosswalk: 3D Perspective Rendering*

Note: This demonstration is an artist rendition only

Aberfoyle

Streetscape Demonstration

Figure 19. *Aberfoyle, Segment B3 Streetscape Demonstration with Gateway Planters: 3D Perspective Rendering*

Note: This demonstration is an artist rendition only

Morriston

Streetscape Treatments Overview

Streetscape treatment icons correspond to The Five Treatments on page 43.

- Site Furnishing
- Lighting
- Greening
- Signage and Identity
- Pavements

Morriston Community Gateway Sign Placement:

Sign 1 *Location: See Illustration Below*

Sign 2 *Location: Badenoch St - Northeast Morriston Settlement Boundary*

Sign 3 *Location: Queen St / Hwy 6 – Southeast Morriston Settlement Boundary*

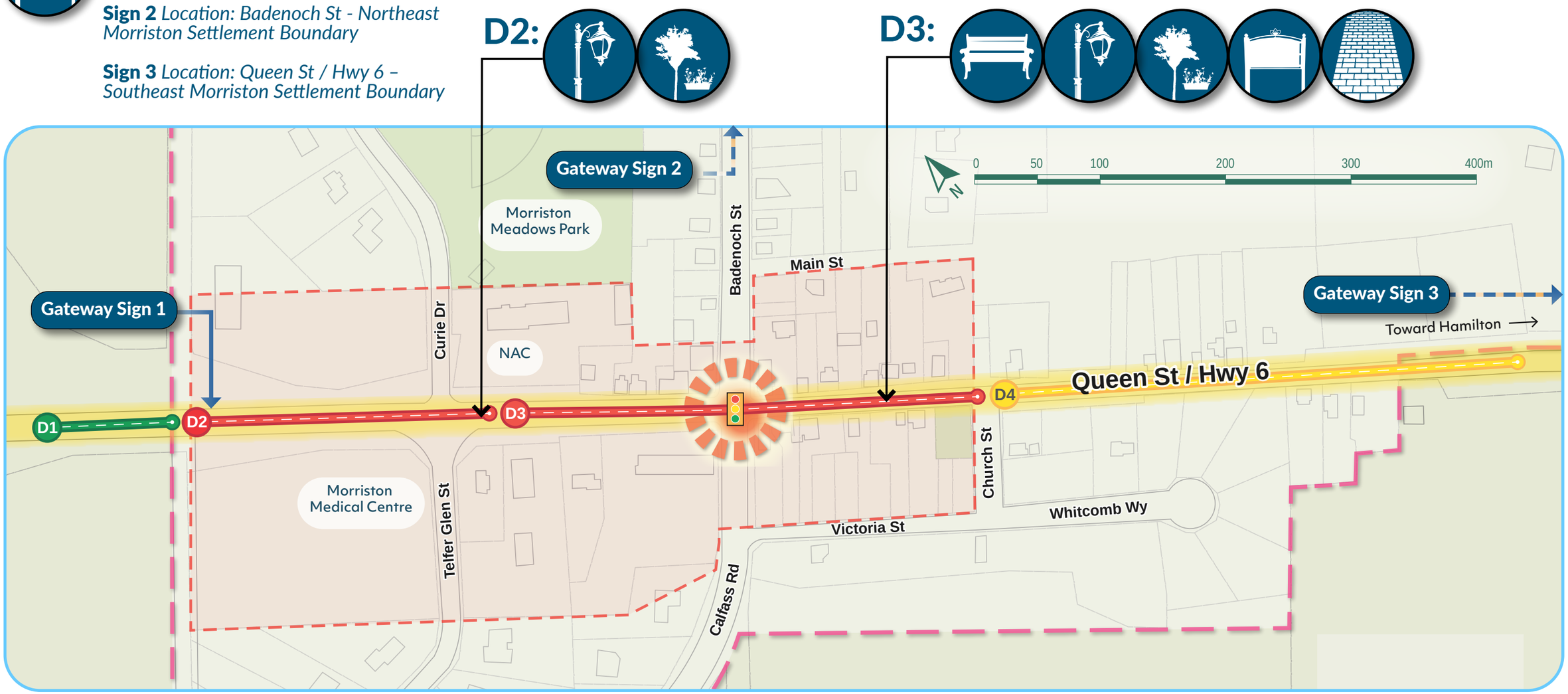


Figure 20. *Morriston Streetscape Treatments Overview*

Morriston — Segment D3

Streetscape Demonstration

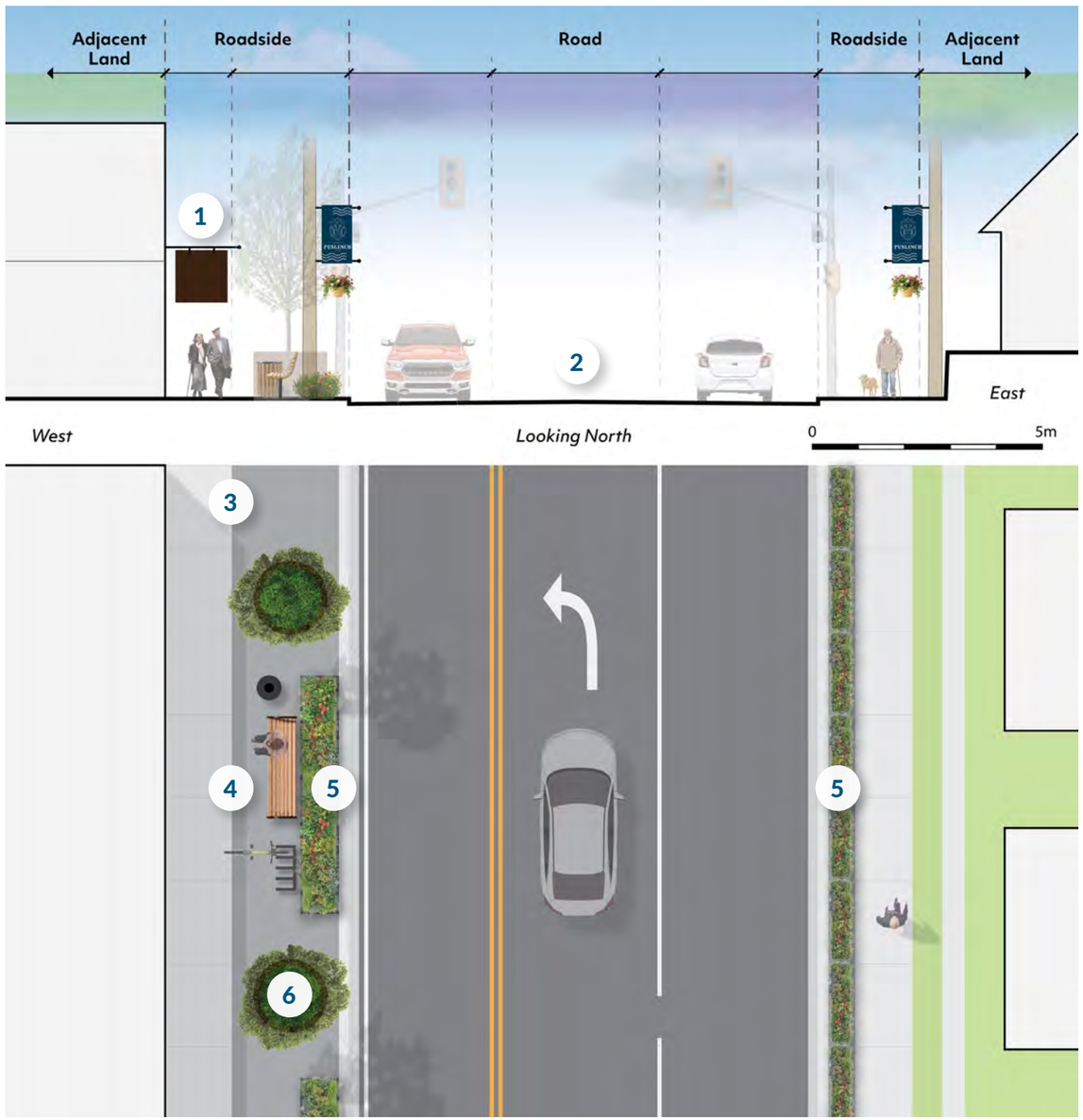


Figure 21. *Morriston, Segment D3 Streetscape Demonstration: Section and Plan View*

Specific Suggestions for D3

1. Business signage located on the building or within the roadside.
2. Crosswalks to be located at main intersections for safe pedestrian crossing.
3. Concrete sidewalk should be clear for pedestrian traffic; paved utility section may include amenities such as benches, waste receptacles, and bike racks.
4. Amenities may be placed at intervals along the roadside; configuration of elements may vary depending on site context and conditions.
5. Where appropriate, low vegetated buffer for pedestrian safety and greening.
6. Street trees promote traffic calming and improves greening in an urban environment; planting them in moveable planters allows them to be easily relocated.

Morriston

Streetscape Demonstration

Figure 22. *Morriston, Segment D3 Streetscape Demonstration with Streetscape Amenities: 3D Perspective Rendering*

Note: This demonstration is an artist rendition only

Morriston

Streetscape Demonstration

Figure 23. *Morriston, Segment D3 Streetscape Demonstration at Main Intersection: 3D Perspective Rendering*

Note: This demonstration is an artist rendition only

Arkell

Streetscape Treatments Overview

Streetscape treatment icons correspond to The Five Treatments on page 43.

- Pavements
- Lighting
- Signage and Identity
- Greening

Arkell Community Gateway Sign Placement:

Sign 1 *Location: Watson Rd S - Northwest Settlement Arkell Boundary*

Sign 2 *Location: Watson Rd S / Guelph Junction Line*

Figure 24. *Arkell Streetscape Treatments Overview*

Arkell — Segment E3

Streetscape Demonstration

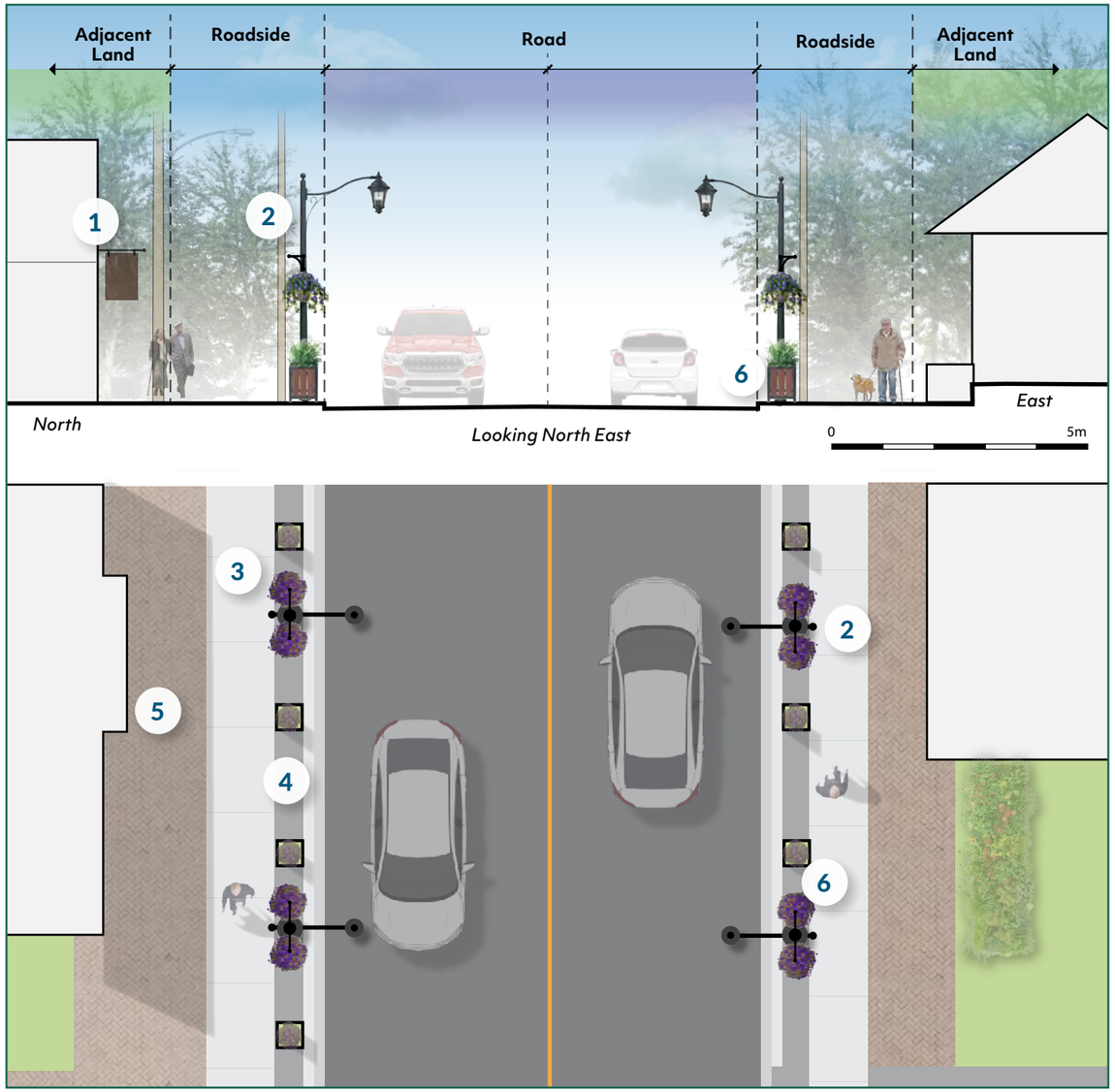


Figure 25. *Arkell, Segment E3 Streetscape Demonstration: Section and Plan View*

Specific Suggestions for E3

1. Business signage located on the building or within the roadside.
2. Hanging planter baskets are incorporated onto new light poles.
3. Concrete sidewalk should be clear for pedestrian traffic; paved utility section may include amenities such as benches, waste receptacles, and bike racks.
4. Amenities may be placed at intervals along the roadside; configuration of elements may vary depending on site context and conditions.
5. Where appropriate, unit pavers can enhance the character of the streetscape and clearly highlight the pedestrian traffic.
6. Planter baskets and planters can promote traffic calming and improves greening in an urban environment; planting them in moveable planters allows them to be easily relocated.

Arkell

Streetscape Demonstration

Figure 26. *Arkell, Segment E3 Streetscape Demonstration: 3D Perspective Rendering*

Note: This demonstration is an artist rendition only

Section 5:

Implementation

Making it Happen

The Guidelines apply to the following:

- Enhancing the streetscapes on Brock Rd / WR 46 and Queen St / Hwy 6; and
- Commercial, industrial and institutional development/redevelopment and associated planning applications throughout the Township.

Implementation of the Guidelines dealing with road and roadside improvements will differ from those that impact private property. This section outlines key implementation tools and addresses financial considerations and starting points to put the Guidelines into practice.

Road and Roadside Improvements

The range of improvements promoted by the Guidelines for the Brock Rd/ WR 46 right-of-way are an important step toward improving the quality of life for those who live and work in the Township.

The following chart identifies small scale improvements and the associated County and Township roles and responsibilities:

Small Scale Improvements	Roles and Responsibilities
• Gateway signage • Directional and parking signage • Roadside plantings • Site furnishings: Benches, bike racks, waste receptacles • Stationary planters and hanging baskets	• County of Wellington has jurisdiction over road, which is administered by the Engineering Services Department. • Township would be responsible for initiating these types of improvements (subject to County acceptance) and cost for upgrades.

The following chart identifies large scale improvements and the associated County and Township roles and responsibilities:

Large Scale Improvements	Roles and Responsibilities
• Community murals • Pedestrian crosswalks • Barrier curbs, sidewalks and boulevards • Sidewalks on bridge over Hwy 401 • Pedestrian and street lighting in villages • Traffic calming measures (e.g., raised medians, roundabouts, etc.) • Roadside bicycle route from Maltby Rd to Aberfoyle	• Guidelines should be applied by County engineering staff for design and construction projects impacting the Brock Rd / WR 46 right-of-way. • Feasibility of improvements need to be carefully considered within the context of the functional requirements of the road, the aesthetic requirements of the Township, and the need to accommodate pedestrians and cyclists.

Roadway Jurisdiction

The implementation of streetscape design guidelines for the road right-of-way in Morriston is contingent upon the Highway 6 realignment. Until the Highway 6 realignment is completed, the road through Morriston will remain under Ministry of Transportation (MTO) jurisdiction. This section of the document, dealing with roles and responsibilities, should be reviewed and updated when Queen Street is no longer under the jurisdiction of the MTO.

Similarly, several roads within the Township boundary are technically roadways owned/ managed by the County of Wellington. It is expected that 'common ground' efforts to pursue desired function, safety and placemaking can be successfully achieved through partnership, where road ownership and associated adjacent lands are complicated.

Commercial, Industrial and Institutional Development

For development outside of the road right-of-way, the Guidelines apply to all commercial, industrial and institutional development. Key development applications that may be used to implement the Guidelines include:

- Site Plan Control
- Zoning By-law Amendments
- Minor Variances
- Sign Variances

The Guidelines will be mainly implemented through site plan control, as most commercial, industrial and institutional development would fall under the Township's site plan control by-law. Section 41(4) of the *Planning Act* lays out what information may be included on the plans and drawings.

Financial Considerations

Many of the Guidelines dealing with the Brock Road / WR and Queen St / Hwy 6 public streetscapes represent increased standards and are likely to result in higher construction and maintenance costs. Depending on the type of infrastructure involved and jurisdictional authority, some or all of the cost will need to be partnered/supplied by the Township. Recognizing that public funds are limited, the Township should work closely with the County Engineering Services Department to determine the design feasibility of various improvements and the cost implications to the municipality. These costs will need to be given consideration relative to other Township, capital, and operating planning priorities.

The following chart identifies various potential grant programs.

Potential Grant Programs and Funding Opportunities

Federal and Provincial

Enabling Accessibility Fund (EAF)

https://www.canada.ca/en/employment-social-development/programs/enabling-accessibility-fund.html

Enhancing Access to Spaces for Everyone (EASE) Grant

https://www.ontario.ca/page/enhancing-access-spaces-everyone-ease-grant

Green Municipal Fund (GMF)

https://greenmunicipalfund.ca/funding

Natural Infrastructure Fund (NIF) - Small Projects Stream

https://housing-infrastructure.canada.ca/nif-fin/index-eng.html#details

Rural Ontario Development (ROD, formerly RED) Program

https://www.ontario.ca/page/rural-ontario-development-program

Tourism Growth Program in Southern Ontario

https://feddev-ontario.canada.ca/en/funding-southern-ontario/tourism-growth-program-southern-ontario

Regional and Local

Township of Puslinch Supporting Local Business in Puslinch: A Township-wide Community Improvement Plan

https://puslinch.ca/doing-business/community-improvement-plan/

Regional Tourism Organization (RTO) 4 Partnership Program

https://rto4.ca/2025-2026-rto4-partnership-program-launch/

Wellington County Grant Programs

https://www.wellington.ca/business-development/business-resources/community-improvement-funding

Where to Start

1. Site Plan Control

- Amend application materials to include references to Guidelines.
- Encourage pre-consultation concerning the Guidelines early in the process.
- Ensure that site plan applications are accompanied by building elevations, sign details, landscape plans, grading and drainage plans.
- Support County Official Plan amendment to allow exterior design and sustainable design elements to be included on plans/drawings and amend site plan control by-law accordingly.

2. Community Engagement

- Provide an opportunity for community members to partner with the Township to plan and complete small scale roadside components (e.g. mass plantings along roadside ditches, gateway landscaping, fundraising, etc.).

3. Streetscape Furnishings

- Select priority locations to install streetscape furnishings to improve the pedestrian environment, such as benches, bike racks, and waste receptacles.
- Install furniture that is suitable to the character of the Township.

4. Community Signage

- Select priority locations to install primary and secondary gateway signage
- Construct and install professionally designed signage, and ensure designs correspond with existing signage.
- Conduct a review of the Township's sign by-law to ensure consistency with the Guidelines.

5. Zoning By-law Review

- Conduct a review of the Township's zoning by-law to ensure consistency with the Guidelines and where appropriate, translate Guidelines into zoning requirements.

The Township of Puslinch

Recreation and Parks Master Plan

Process to Date

June – October 2026

BACKGROUND ANALYSIS

Review of existing municipal information, demographics, financial information, asset management, facilities, parks, programs, operations, policies, trends and service delivery.

COMMUNITY ENGAGEMENT

Consultation with staff, residents, youth, community organizations, service clubs, sports organizations, school boards, Conservation Authorities, City of Guelph representation, and other key stakeholders to understand current experiences, needs, priorities and opportunities. The community-wide survey provided additional input on recreation programs, parks, trails, facilities satisfaction and importance, as well as future priorities.

DRAFTING THE PLAN

The findings from the background analysis and engagement process were reviewed together to identify common themes, service gaps, opportunities and priorities.

FINALIZING THE PLAN

Recommendations were developed based on the identified needs and opportunities and organized by subject area. Each recommendation considers the appropriate timing, operating and capital financial implications, strategic alignment, and resources required for implementation.

Online Survey Results

Top ranked **NEW PARK AMENITIES** residents would like to have in Puslinch:

- WALKING TRACK
- SPLASHPAD
- PLAYGROUNDS
- ALL-SEASON TRAILS

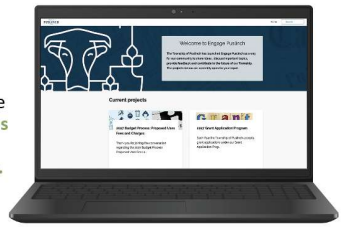
**Shaded seating at sports fields/diamonds, safety netting and risky play elements were shared as suggestions in the 'Other' category.*

TOP RECREATION FACILITIES

- Trails/Parks & Open Spaces
- Optimist Recreation Centre (Rink & Gym)
- Tennis/Pickleball Courts
- Playgrounds

62% TOP PRIORITY INVEST IN IMPROVING EXISTING PARKS

70% of respondents believe the Township of Puslinch **shares information** in a **timely, accurate & effective way.**



123 survey responses

85% of survey respondents chose the **PUSLINCH COMMUNITY CENTRE PARK** as the park their household uses most often.

ADDITIONAL PROGRAMMING DESIRES:

Fitness & Exercise Classes
Drop-in/pick-up, yoga, zumba, stretching, walking

Programming for Seniors
Fitness, recreation, social, educational

Youth & Teen Programming
Drop-in, hobbies and STEM clubs, camps, leadership

Focus of the Master Plan

- Protecting what we have
- Improving what we own
- Expanding opportunities through partnership and volunteers
- Think regionally where it makes sense
- Working within financial and human resources
- Responding to changes in community profile and limited growth
- Making responsible, sustainable investments for the future

What is in the Master Plan

- SERVICE DELIVERY – 10 Recommendations
- INDOOR FACILITIES – 5 Recommendations
- ADMINISTRATION AND POLICIES – 2 Recommendations
- OUTDOOR FACILITIES – 12 Recommendations
- PARKS AND AMENITIES – 3 Recommendations
- PARKS PROGRAMMING – 2 Recommendations
- PARK SPECIFIC RECOMMENDATIONS – 17 Recommendations

“This Master Plan is not a wish list of new facilities; it is a practical 10-year roadmap for strengthening what Puslinch already has, responding to changing community needs, building partnerships, planning for growth and making strategic investments that are financially sustainable.”

THANK YOU!

Next steps – not finalized yet:

September 16th – community workshop

EMAIL: info@mgagroup.ca until **September 25th**.
Also posted on Puslinch's website with the survey results

We will evaluate the feedback and findings from this engagement to make edits to the Master Plan

COUNCIL: Final Recreation and Parks Master Plan will be presented to Council on **October 21st** (https://engagepuslinch.ca/puslinch-recreation-parks-master-plan)

THE TOWNSHIP OF
PUSLINCH

RECREATION & PARKS MASTER PLAN

WHY A RECREATION AND PARKS MASTER PLAN?

The Township of Puslinch (Puslinch) should be recognized for undertaking a Recreation and Parks Master Plan (Plan) at an important time in the municipal cycle. The Plan provides the new term of Council and staff with a practical framework to guide decision-making and establish priorities for community services over the next decade.

THE RECREATION AND PARKS MASTER PLAN:

1. ESTABLISHES A CLEAR DIRECTION FOR COMMUNITY SERVICES

The Plan provides a strategic framework to guide future decisions related to parks, recreation facilities, programs, community spaces, trails, open spaces and other community services.

2. RESPONDS TO CHANGING COMMUNITY NEEDS

Demographic changes, recreation trends, changing volunteer capacity and evolving expectations for municipal services require the Township of Puslinch to regularly review how services are planned and delivered.

3. PROVIDES AN EVIDENCE-BASED FRAMEWORK FOR DECISION-MAKING

The Plan brings together quantitative information, financial and asset information, facility and park assessments, utilization information, trends and community input to support informed decisions.

4. SUPPORTS RESPONSIBLE FINANCIAL PLANNING

Puslinch faces the same financial pressures experienced by many smaller municipalities, including aging infrastructure, increasing operating costs and competing demands for limited tax resources. The Plan identifies priorities that can be considered within Puslinch's financial capacity and long-term asset management requirements.

5. IDENTIFIES PRIORITIES FOR EXISTING FACILITIES AND PARKS

The Plan recognizes that maintaining and maximizing existing community assets is an important priority. It identifies opportunities for improvements, accessibility, lifecycle planning, utilization and service delivery before significant new infrastructure is considered.

6. STRENGTHENS PARTNERSHIPS AND VOLUNTEER CAPACITY

Volunteers and community organizations have historically played an important role in delivering recreation, sports, programs and parks throughout Puslinch. The Plan identifies opportunities for the Community Services Department to strengthen these relationships and provide the support necessary for community organizations to remain sustainable.

7. IMPLEMENTATION AND ACCOUNTABILITY

Recommendations are prioritized according to short-, medium- and long-term implementation and identify the resources and strategic alignment required to move priorities forward.

8. FRAMEWORK TO MONITOR AND UPDATE

A Master Plan is not intended to remain static. Priorities may need to change as demographics, participation, funding opportunities, staffing, volunteer capacity and other community conditions change. The Plan therefore provides a framework that Council and staff can use and revisit over time.

DEMOGRAPHIC PROFILE

Sources: 2021 Census and Wellington County Planning Profile

2051
10,000
residents

26%

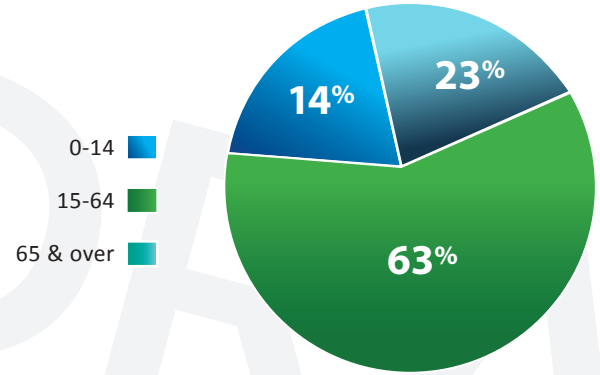
2021
7,944
residents

PUSLINCH POPULATION PROJECTION

Puslinch is expected to grow from a population of 7,944 in 2021 to 10,000 by 2051. This represents **an increase of 2,056 net new residents or a population increase of 26%.**

THE AGE PROFILE OF PUSLINCH IS UNIQUE

from the provincial age profile **showing consistently high age cohort of adults.**



$221,400
The **average household income for Puslinch**.

- Puslinch is **experiencing population growth at a rate of 8.3%**, which is higher than the National average (5.2%).
- **Median resident age:** 49.2 years
- **Average household size:** 2.8 people
- **Average number of children per household:** 1.8

STRATEGICALLY POSITIONED

Puslinch sits at the crossroads between the Greater Toronto Area, Guelph and Kitchener-Waterloo, creating unique growth pressures as well as opportunities.

88% **of residents have completed secondary or post-secondary education**

AVERAGE COMMUTE TIME

has decreased by 12% (-3.3 min) since 2016.

24.6 **MINUTES**

A shift to hybrid and home-based work, as well as strong County employment opportunities are contributing factors.

DRAFT

THE RECREATION AND PARKS MASTER PLAN PROCESS

The Puslinch Recreation and Parks Master Plan is grounded in a proven, evidence-based methodology. The process brings together background research and quantitative analysis, community and stakeholder engagement, current trends and best practices, facility and park assessments, financial considerations and ongoing validation through input received.

The development of the Recreation and Parks Master Plan included four broad phases:

BACKGROUND ANALYSIS

Review of existing municipal information, demographics, financial information, asset management, facilities, parks, programs, operations, policies, trends and service delivery.

COMMUNITY ENGAGEMENT

Consultation with staff, residents, youth, community organizations, service clubs, sports organizations, school boards, Conservation Authorities, City of Guelph representation, and other key stakeholders to understand current experiences, needs, priorities and opportunities. The community-wide survey provided additional input on recreation programs, parks, trails, facilities satisfaction and importance, as well as future priorities.

DRAFTING THE PLAN

The findings from the background analysis and engagement process were reviewed together to identify common themes, service gaps, opportunities and priorities.

FINALIZING THE PLAN

Recommendations were developed based on the identified needs and opportunities and organized by subject area. Each recommendation considers the appropriate timing, operating and capital financial implications, strategic alignment, and resources required for implementation.

PUBLIC ENGAGEMENT

This section summarizes the public engagement activities undertaken to inform the Recreation and Parks Master Plan. Engagement activities were conducted specifically for the Plan. Additionally, the Township of Puslinch shared relevant engagement findings from the recently completed 2026-2030 Strategic Plan which contained recreation and parks related feedback.

SUMMARY OF ENGAGEMENT METHODS

A variety of engagement approaches were used to capture community perspectives. Key methods included:

INTERACTIVE WORKSHOPS (JULY 8, 2026):

These back-to-back interactive sessions were held with the following groups;

- Youth Advisory Committee
- Recreation and Community Wellness Advisory Committee
- User Groups/Sports Groups
- Optimist Club of Puslinch
- Aberfoyle Agricultural Society

The evening featured a "S.O.A.R." (Strengths, Opportunities, Aspirations, Recommendations) exercise and a collaborative "Build your Future Park or Indoor/Outdoor Facilities" design activity.

POP-UP ENGAGEMENT EVENT

MGA attended the Puslinch Fire Open House on July 11th to engage with residents and gather input on the indoor and outdoor recreation amenities they feel are currently missing or would like to see in the future.

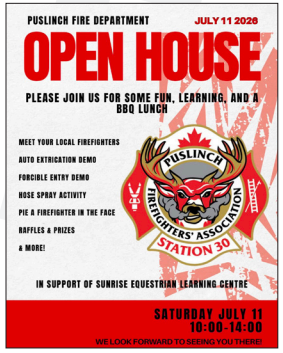
The event also served to raise awareness of the Recreation and Parks Master Plan and encourage residents to participate in the online community survey, helping to broaden public engagement and ensure the plan reflects broader community needs and priorities.

ONLINE COMMUNITY SURVEYS:

Digital surveys deployed through Engage Puslinch captured feedback from the public, community groups, and the development community. The survey was available for 17 days from July 10th to July 27th. The survey was promoted within the community through various methods. A total of 123 surveys were submitted.

PUBLIC OPEN HOUSE:

A public open house is scheduled for September 2026 to present the key findings and recommendations from the Recreation and Parks Master Plan. The Open House represents the final opportunity for public comments.



SUMMARY OF FEEDBACK

The engagement activities outlined above produced a variety of comments, findings, and recommendations from individuals and groups. It is important to note that while every comment was considered by the consultants, not every comment translates into a recommendation. The consultants look for common themes from various sources which serve to uncover common issues and needs. The following are key findings from the collective engagement process.

ADDITIONAL PROGRAMMING DESIRES:

Fitness & Exercise Classes
Drop-in/pick-up, yoga, zumba, stretching, walking

Programming for Seniors
Fitness, recreation, social, educational

Youth & Teen Programming
Drop-in, hobbies and STEM clubs, camps, leadership

TOP RECREATION FACILITIES

- Trails/Parks & Open Spaces
- Optimist Recreation Centre (Rink & Gym)
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62%
TOP PRIORITY
INVEST IN IMPROVING EXISTING PARKS

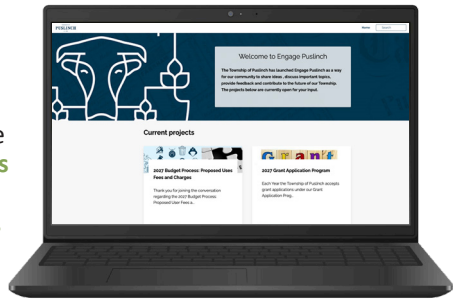
85% of survey respondents chose the **PUSLINCH COMMUNITY CENTRE PARK** as the park their household uses most often.

Top ranked **NEW PARK AMENITIES** residents would like to have in Puslinch:

- **WALKING TRACK**
- **SPLASHPAD**
- **PLAYGROUNDS**
- **ALL-SEASON TRAILS**

**Shaded seating at sports fields/diamonds, safety netting and risky play elements were shared as suggestions in the 'Other' category.*

70% of respondents believe the Township of Puslinch **shares information** in a **timely, accurate & effective way.**



Throughout this Plan, specific references to engagement findings will be highlighted under "**What we heard**" to offer supporting rationale for associated recommendations.

DRAFT

THE RECREATION AND PARKS MASTER PLAN RECOMMENDATIONS

The recommendations in this Recreation and Parks Master Plan are intentionally grouped by subject area. Each section provides the context and analysis supporting the recommendations and identifies the opportunities and challenges that should be considered by Council and staff, including both capital and operating implications.

TIMELINE	RECOMMENDATION	RESOURCES	ALIGNMENT
	SERVICE DELIVERY		
SHORT/ MEDIUM	**1. Hire a Community Development Coordinator*** Hire a Community Development Coordinator to increase recreation participation by expanding programming, building partnerships, improving facility utilization, explore opportunities with instructors and volunteers, and fostering relationships with community organizations, local leaders, and private providers to encourage the	**Internal B** Cost Estimate: $65,000	Strategic Plan

The recommendations are intended to provide direction rather than prescribe a fixed course of action. Implementation should be responsive to changing community needs, funding opportunities, staff capacity, volunteer support, asset conditions and other factors that may influence municipal priorities. Township staff are in control of how they implement the recommendations based on available resources.

For implementation purposes, recommendations are identified by timeline and resources, including both capital and operation implications:

RESOURCES LEGEND

Internal A – Existing Staffing Resources
(Recommendation can be implemented with current staffing resources)
Internal B – Additional Staffing Resources
(Recommendation requires additional staffing resources to implement)
External – Initial Cost and Operating Cost *(*2026 current dollar estimates)*

TIMING LEGEND

Short = 1-3 years **Medium** = 4-7 years **Long** = 8+ years **Ongoing**

The timing of recommendations may be adjusted as conditions change. Council and staff should continue to monitor trends, participation, financial capacity, funding programs, asset conditions, staffing resources and community priorities to ensure that the Recreation and Parks Master Plan remains relevant and responsive.

Ultimately, the Recreation and Parks Master Plan is intended to provide Puslinch with a practical and sustainable roadmap for the next decade—one that builds on the community's existing strengths, recognizes its rural character and strong volunteer base, protects and maximizes existing investments, and establishes priorities that will enhance the quality of life and enjoyment for current and future residents.

DRAFT

FUNDING THE PLAN

To support the recommendations and associated capital and operating costs identified in this Plan, Puslinch should pursue a diversified funding strategy that maximizes opportunities for growth-related revenues, government funding, sponsorships, service club support and strategic partnerships, while minimizing impacts on the tax base.

Development Charges should continue to be maximized for eligible growth-related parks and recreation projects. Puslinch's Development Charges By-law, passed in September 2024, provides an important funding source for eligible growth-related recreation facilities, park development, trails, vehicles and equipment. Future Development Charges Background Studies should continue to identify eligible recreation infrastructure associated with Puslinch's anticipated growth and the next background study should incorporate the recommendations that Council endorses as part of this Plan.

Parkland Dedication and cash-in-lieu should continue to be maximized to support the acquisition and development of parks and open spaces and any recreation related infrastructure in accordance with the Parks Plan appended to this Plan. This approach will help to ensure that new growth contributes to the additional recreational opportunities it generates.

Provincial and Federal funding should be actively pursued for priority projects. The Community Sport and Recreation Infrastructure Fund (CSRIF) is particularly relevant to Puslinch, with funding opportunities that can support improvements such as HVAC, accessibility, arena upgrades and the renewal of existing recreation facilities, as well as larger new or transformative projects. Puslinch should continue to maintain a current inventory of government funding opportunities and ensure priority projects are sufficiently planned and costed to respond when funding programs become available.

Sponsorships, service clubs, community fundraising and partnerships should also continue to be explored for recreation facilities, parks, programs, events and amenities. Puslinch should identify appropriate sponsorship opportunities and develop partnerships with local businesses, organizations and service clubs to leverage community investment in recreation.

Finally, tax-supported reserves and continued annual contributions to the Asset Management Discretionary Reserve will remain essential to address the lifecycle, rehabilitation and replacement needs of Puslinch's existing recreation infrastructure. A strong reserve strategy, combined with external funding and growth-related revenues, will help Puslinch implement the capital priorities identified in this Plan while managing the long-term impact on taxpayers.

TRENDS

Trends relevant to Puslinch

AGING POPULATION AND ACTIVE AGING

Ontario's older adult population continues to grow, but today's seniors are healthier and more active than previous generations. Rather than passive recreation, there is increasing demand for wellness programming, social recreation, outdoor activities, lifelong learning and volunteer opportunities.

CONSIDERATION FOR PUSLINCH

Continue to work with Wellington County and community partners to explore opportunities for healthy aging programs, such as walking clubs, pickleball, low-impact fitness, educational workshops, outdoor recreation and volunteer leadership opportunities that encourage social connection and help reduce isolation.

OUTDOOR RECREATION CONTINUES TO GROW

Since COVID-19, participation in outdoor recreation has remained consistently high. Residents continue to value trails, natural areas, waterfronts, parks and outdoor gathering spaces more than ever before.

CONSIDERATION FOR PUSLINCH

Consider how future planning and investment can prioritize outdoor amenities that reflect these preferences, support year-round use and respond to changing community needs.

FLEXIBILE PROGRAMMING

Residents increasingly prefer shorter, drop-in and seasonal programs rather than committing to long sessions. Pop-up programming allows municipalities to test new ideas before making permanent investments.

CONSIDERATION FOR PUSLINCH

These types of opportunities can help build community awareness, encourage participation and provide insight into what activities and locations resonate with residents.

TECHNOLOGY AND CUSTOMER SERVICE

Residents increasingly expect convenient online registration, facility booking systems and software, digital communication, ease of payment and access to real-time program information.

CONSIDERATION FOR PUSLINCH

Consider how staff can stay informed of emerging tools and changing resident needs to ensure its recreation services remain accessible, convenient and responsive.

FINANCIAL SUSTAINABILITY

Many municipalities are facing increasing operating costs, aging infrastructure and limited tax capacity. This has resulted in greater emphasis on maximizing existing assets before constructing new facilities.

CONSIDERATION FOR PUSLINCH

Consider the value of maximizing existing facilities and infrastructure in the context of rising operating costs, aging assets and limited tax capacity.

TRENDS

RURAL COMMUNITY HUBS

Across Ontario, municipalities are repositioning community centres, libraries, arenas and parks as multi-service community hubs. Rather than focusing solely on recreation, these facilities are becoming places where residents can participate in recreation, social programs, health initiatives, education, cultural activities and community events.

CONSIDERATION FOR PUSLINCH

Consider the importance of continued investment in community centres as welcoming, flexible spaces that support recreation, social connection and a range of community uses.

PARTNERSHIPS ARE BECOMING ESSENTIAL

Municipalities increasingly rely on partnerships with school boards, service clubs, conservation authorities, libraries, health organizations and community groups to deliver recreation opportunities more efficiently.

CONSIDERATION FOR PUSLINCH

Consider the role that partnerships with volunteers, community organizations, service clubs and other agencies can play in supporting recreation opportunities and community services.

YOUTH RETENTION THROUGH RECREATION

Smaller municipalities are recognizing recreation as an important strategy for retaining youth and attracting young families. Youth are seeking places to gather informally, participate in recreation and feel connected to their communities.

CONSIDERATION FOR PUSLINCH

Consider youth voices and perspectives as part of future recreation planning, particularly when shaping spaces, amenities and programs that reflect the interests and needs of younger residents.

VOLUNTEER RECRUITMENT AND RETENTION

Volunteerism continues to evolve across Ontario as municipalities face increasing challenges recruiting and retaining volunteers. An aging volunteer base, changing lifestyles, competing time commitments and volunteer burnout have reduced the capacity of many community organizations to sustain programs, events and facilities. In response, municipalities are investing in volunteer recruitment, training, recognition, succession planning and leadership development to help build long-term organizational capacity. There is also a growing emphasis on offering flexible and short-term volunteer opportunities that appeal to younger generations and busy families.

CONSIDERATION FOR PUSLINCH

Consider the changing volunteer landscape and its impact on the capacity of community organizations to sustain recreation and community opportunities.

SERVICE DELIVERY

Puslinch provides access to a range of recreation opportunities that reflect its rural character, available facilities, and staffing resources. These opportunities are centered primarily at the Optimist Recreation Centre and the Puslinch Community Centre and include seasonal public ice skating, roller skating, inline shinny, seniors' drop-in euchre, open gym, and other seasonal opportunities. Puslinch's role is primarily to provide facility space, designated drop-in time, and limited equipment to support community participation.

The Township of Puslinch also provides access to a variety of parks and recreation facilities including the gymnasium, outdoor tennis/pickleball courts, basketball court, sports fields, baseball diamonds, playgrounds, walking trails, community hall, and meeting room that support both municipal programming and community-led activities.

ARENA FLOOR OPPORTUNITIES

The arena floor presents an opportunity to increase community recreation by adopting an "open door" approach for informal, drop-in play when the facility is not booked, particularly during traditionally low-utilization periods. Drop-in times are recommended to be scheduled during regularly staffed hours, allowing the community to access available space with appropriate staffing, supervision, and ensuring operational considerations are maintained. Public drop-in times should be posted online and at the facility with 'Rules of Play', so residents know when the space is available and activity type.

Adding multi-sport court lines to the arena floor, walking lanes, portable basketball standards, mobile skate park equipment, and other recreation equipment will reduce barriers to participation and encourage spontaneous physical activity for residents of all ages. This approach maximizes facility use while creating a welcoming and flexible community recreation hub.

DROP-IN PROGRAMS OFFERED AT THE OPTIMIST RECREATION CENTRE (NON-ICE ARENA FLOOR):

SEASON	INLINE SHINNY	ROLLER-SKATING
Spring **Fall** (weather dependent)	3 hrs/week	3 hrs/week
Summer	3 hrs/week	3 hrs/week

What We Heard — Community Feedback

Residents emphasized the importance of **affordable programs, convenient scheduling, and opportunities that encourage social connections** while maintaining Puslinch's strong sense of community.

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DROP-IN GYM

Parent & Tot: 2 hrs/week

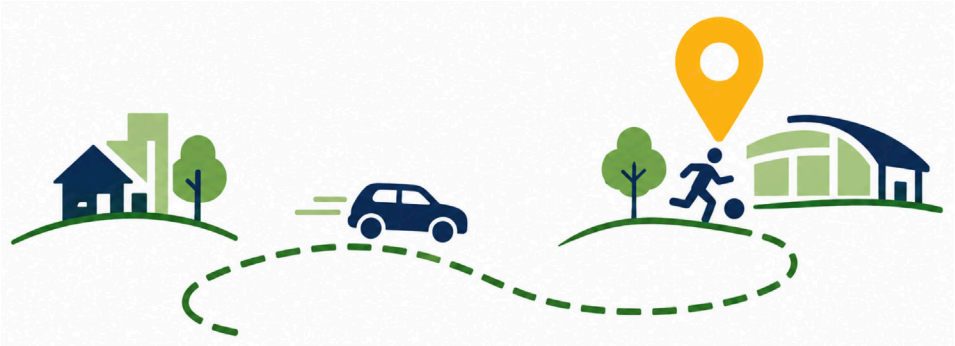
Youth Drop-in: 1 hr/week

Professional Activity Days (UGDSB and WCDSB): 2hrs/day

March Break Programming: hours vary/daily

PUSLINCH COMMUNITY CENTRE

Senior Drop-in Programming: 2 hrs/week (current activity is Euchre)



Currently Puslinch is only running one direct program that is currently a pilot program. Additional recreation opportunities are supported through community organizations, private facility rentals, and self-directed use of recreation facilities. This service delivery approach is appropriate given the Township of Puslinch's population and financial resources; however, it also limits the variety and frequency of recreation opportunities available to residents. While Puslinch may not have the resources to directly deliver a broad range of recreation programs, it is well positioned to leverage partnerships with neighbouring municipalities, private providers, and non-profit organizations to expand programming opportunities and improve access for residents.

What We Heard — Community Feedback

The community survey indicates that while residents appreciate the recreation opportunities currently available, they would like to see a broader range of programs offered. **Many respondents indicated they travel to neighbouring municipalities to participate in programs that are not available locally** or they are unaware of the offerings available.

Survey respondents expressed interest in expanding programs for all age groups, particularly:

- Fitness and wellness programs
- Children and youth recreation programs
- Seniors' social and active living programs
- Arts, culture, and creative programs
- Indoor walking and wellness opportunities
- Expanded pickleball opportunities
- Additional community events and family programming

COMMUNITY DEVELOPMENT

With limited existing staff resources, Puslinch relies on the support of community partners, including the Optimist Club of Puslinch, Puslinch Minor Soccer Club, Puslinch Minor Baseball and other local Baseball Clubs, and not-for-profit organizations such as the Aberfoyle Agricultural Society, Whistle Stop Cooperative Preschool, and active community members to deliver many recreation programs and services.

The Township of Puslinch's role should be to strengthen these partnerships by providing coordination of events, promotion, and support, while delivering programs directly only where community needs or service gaps exist.

What We Heard — Community Feedback

The survey findings suggest there is an opportunity to **gradually expand recreation programming through partnerships**, program instructors, volunteers, and neighbouring municipalities rather than creating a large municipally operated recreation department.

RECOMMENDATION 1: HIRE A COMMUNITY DEVELOPMENT COORDINATOR*

Hire a Community Development Coordinator to increase recreation participation by expanding programming, building partnerships, improving facility utilization, explore opportunities with instructors and volunteers, and fostering relationships with community organizations, local leaders, and private providers to encourage the delivery of recreation opportunities throughout the Township of Puslinch.

* Current staff would not be able to fulfill the recommendations to their fullest without this position.

RECOMMENDATION 2: DIVERSIFY DROP-IN RECREATION OPPORTUNITIES AT THE OPTIMIST RECREATION CENTRE (INDOOR AND OUTDOOR)

Offer additional activities within facility operating hours, such as basketball, soccer, pickleball, and family recreation during traditionally low-utilization periods, and school holidays to encourage casual participation and maximize facility utilization.

RECOMMENDATION 3: ESTABLISH PARTNERSHIPS WITH ORGANIZATIONS SUCH AS EQUIP SPORT, AND THE WELLINGTON COUNTY LIBRARY

Make storage and recreation equipment—including soccer balls, basketballs, pickleball paddles, balls, and other portable equipment like playboxes—available for public use.

RECOMMENDATION 4: DEVELOP A RECREATION PROGRAMMING AND INSTRUCTOR RECRUITMENT STRATEGY

Explore opportunities with instructors, coaches, community organizations, neighbouring municipalities, and private providers (i.e., YMCA's, senior organizations and agencies) to expand local recreation programming and introduce services such as summer camps, fitness, wellness, senior's and children's programs that are not currently available in Puslinch.

RECOMMENDATION 5: DEVELOP PARTNERSHIP OPPORTUNITIES

Staff should actively promote partnership opportunities, provide facility-use and marketing support, and provide administrative support to encourage new program offerings and broaden recreation opportunities without significantly increasing municipal staffing.

RECOMMENDATION 6: EXPAND NEIGHBOURING PARTNERSHIPS

Continue to strengthen partnerships with neighbouring municipalities to improve access to recreation programs and facilities that cannot be reasonably provided within Puslinch (i.e., swimming lessons). This may include reciprocal registration agreements, subsidized resident rates, shared programming opportunities, and coordinated marketing of regional recreation services.

RECOMMENDATION 7: INCREASE AWARENESS OF RECREATION OPPORTUNITIES

To improve awareness of recreation opportunities, recognizing that increasing awareness of programs emerged as a key theme from the community survey. Promote all programs and events—regardless of the provider—through multiple communication channels, including the Township of Puslinch website, social media, arena displays, the digital sign at the Puslinch Community Centre, community bulletin boards, and seasonal program guides. The Township of Puslinch should also partner with the Youth Advisory Committee to create engaging social media content that helps reach younger audiences and promotes local recreation opportunities

RECOMMENDATION 8: ESTABLISH AN ANNUAL COMMUNITY RECREATION PARTNERSHIP WORKSHOP

The Township of Puslinch should establish an annual Community Recreation Partnership Workshop that brings together service clubs, minor sport organizations, and community groups to share information on grant opportunities, volunteer recruitment and retention, governance, risk management, marketing, and partnership opportunities.

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VOLUNTEERS

Volunteers and community organizations are an essential part of life in Puslinch. Community groups, service clubs, sports organizations, cultural groups, event committees, and other local organizations contribute time and effort to deliver programs, events and activities, support parks and recreation, and bring residents together.

Many of the opportunities and community initiatives enjoyed by Puslinch residents would not be possible without this volunteer contribution. These organizations also provide important local knowledge, leadership, and a strong sense of community.

Volunteer organizations are facing increasing challenges in recruiting and retaining volunteers. Long-time volunteers are aging and retiring, while younger residents are balancing work, family and other commitments. At the same time, governance, insurance, risk management and legislative requirements can make volunteer roles more complex.

The staff are already doing great work to support Puslinch's volunteers and community organizations, including through the Annual Appreciation Night, Senior of the Year Award, Volunteer Appreciation Award, the Puslinch Community Showcase, the Puslinch Community Guide and Business Directory, Township Welcome Package on their website, and ongoing assistance to community groups. The Township of Puslinch should continue to build on these efforts by strengthening and supporting Puslinch's volunteer and community organizations, rather than replacing their role. This includes:

- **Promoting** and supporting volunteer opportunities;
- **Providing** orientation, support and resources;
- **Supporting** facility bookings, equipment, and administrative needs where appropriate;
- **Promoting** grant opportunities, fundraising initiatives, and community partnerships;
- **Recognizing** and celebrating volunteer contributions; and
- **Creating** opportunities for community groups to connect, collaborate, and share resources.

Effective volunteer support requires significant municipal staff time and resources. As volunteer capacity changes, the Township of Puslinch will need to work collaboratively with community organizations to ensure they have the tools, information, and support necessary to remain sustainable.

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RECOMMENDATION 9: DEVELOP A VOLUNTEER FRAMEWORK

Provide opportunities for municipal-led orientation, support, and appreciation opportunities for Puslinch volunteers and community groups.

Center image: Sardhar Katha

INDOOR FACILITIES

INDOOR FACILITY INVENTORY

The Township of Puslinch has two indoor recreation facilities including the **Optimist Recreation Centre** and the **Puslinch Community Centre.**

The Optimist Recreation Centre, built in **2010,** is Puslinch's largest multi-use recreation facility and serves as a flexible community recreation hub. The facility includes a gymnasium, a covered outdoor arena, a small activity/party room, four change rooms, and accessible washrooms. The gymnasium accommodates a broad range of recreational programming, including volleyball, basketball, pickleball, fitness classes, children's programs, and community events. The activity room accommodates approximately 15 to 20 people and is available as additional space when renting the gymnasium.

Attached to the Optimist Recreation Centre is a covered outdoor arena with four dressing rooms. The refrigerated rink is smaller than a standard ice pad (approximately 20 m × 43 m) and operates as an ice surface during the winter season, typically from January through March, weather permitting. During the spring, summer, and fall, the facility is converted for non-ice activities such as ball hockey, roller skating, and other community programming and rentals.

The Puslinch Community Centre compliments the Optimist Recreation Centre on the same property by serving as the community's primary indoor gathering place for community events and rentals. The facility includes the **Archie MacRobbie Hall,** a large meeting and social hall with a commercial kitchen and outdoor patio that can accommodate approximately 120 people, making it suitable for weddings, banquets, community events, and celebrations. The facility also includes the **Alf Hales Room,** a smaller meeting space accommodating approximately 30 people with a kitchenette, refrigerator, and sink, providing an ideal venue for meetings, workshops, and family gatherings. Accessible washrooms are available throughout the facility.

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INDOOR FACILITY SERVICE PROVISION

Based on the Township of Puslinch's current population of approximately **8,550 residents,** Puslinch meets or exceeds recognized provincial service level provision guidelines for most indoor recreation facilities.

INDOOR FACILITY	PUSLINCH SERVICE LEVEL	RECOGNIZED PROVINCIAL SERVICE LEVEL
Indoor Arena (0)	0	1:15,000
Outdoor Arena	1	No provision
Gymnasium	1:8,550	1:30,000
Community Hall	1:8,550	1:5,000
Multi-Purpose Room	1:8,550	1:5,000
Multi-Sport Indoor	0	1:30,000

While the Township of Puslinch exceeds recognized provincial service level benchmarks, it is important to recognize that these benchmarks measure the **quantity** of facilities rather than the overall quality or functionality. By example, while Puslinch has a gymnasium, the facility has limitations related to run-off space, entrance and viewing areas, and seating capacity. The lack of these amenities limits Puslinch in accommodating league play, tournaments, and other competitive sporting events.

Similarly, the covered outdoor arena is smaller than a standard ice surface and operates only seasonally, restricting the range of programming and events that can be accommodated. Most notably, it cannot accommodate a minor hockey games or figure skating sanctioned competitions, but accommodate all sanctioned practices and skill development opportunities.

Together, the Optimist Recreation Centre and the Puslinch Community Centre provide the Township of Puslinch with a solid foundation of indoor recreation and community gathering space. However, while Puslinch meets or exceeds provincial service level benchmarks, the limited size and functionality of the existing recreation amenities—particularly the gymnasium and covered outdoor arena—constrain opportunities for expanded programming, competitive sport, and tournament hosting.

INDOOR FACILITY CONDITION

The Optimist Recreation Centre is generally in good condition and is well maintained by Township staff. Despite being only **16 years old,** the facility is experiencing significant HVAC-related issues that have resulted in excessive humidity levels, condensation, and water dripping from the ceiling. These issues have affected the reliability of the facility, resulting in cancelled bookings and a loss of rental revenue. The facility's refrigeration system, which is used to cool and preserve the ice during the winter months, is also limited in the temperature it can maintain. During periods of warmer winter weather, the system may be unable to maintain the required ice conditions, resulting in facility closures

and the cancellation of programming and private rentals. Beyond the immediate financial impacts, the ongoing moisture concerns increase the risk of premature deterioration of building components and reduce user comfort. Prioritizing improvements to the HVAC system will help protect the Township of Puslinch's investment, enhance facility reliability and user comfort, and support the continued success of facility bookings and programming.

The Puslinch Community Centre has benefited from recent capital improvements, including upgrades to the commercial kitchen and accessible washrooms, enhancing the functionality and accessibility of the facility. The building is well maintained by Township staff and remains in good overall condition. To maintain its appeal as the community's primary community gathering space, the facility would benefit from cosmetic improvements to the interior décor and furnishings, such as floor replacement. Upgrades to amenities such as the sound system, audio-visual equipment, presentation technology and the current bar improvements area will enhance the user experience and better support community events, meetings, banquets, and rentals. These improvements would modernize the facility while complimenting the recent investments made in the building.

What We Heard — Community Feedback

80%

Residents consistently identified the Optimist Recreation Centre and Puslinch Community Centre as valued community assets that support recreation, community gatherings, and special events. Survey results indicate that both facilities are well used and considered important to the Township of Puslinch, with **more than 80% of respondents rating the Optimist Recreation Centre's outdoor arena and gymnasium as important**, and approximately three-quarters recognizing the importance of the community halls at the Puslinch Community Centre. Satisfaction with these facilities is generally high, reflecting their significant role in serving the community.

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ASSET MANAGEMENT

Investing in preventative maintenance, energy efficiency initiatives, lifecycle renewal, and operational improvements are critical to support the long-term sustainability of these important community assets. Additionally, investments in customer focused amenity improvements are important to maintaining and growing utilization and associated revenues.

Both facilities have significant infrastructure needs that require more immediate attention. At the Optimist Recreation Centre, mechanical systems, including the HVAC system, are approaching the point where major investment will be required, while the Puslinch Community Centre requires upgrades to its septic system. The existing septic system has sufficient capacity to support the Puslinch Community Centre. To support continued facility operations and minimize potential impacts on bookings, the Township of Puslinch should increase its operating maintenance budget to allow for more frequent inspections and pump-outs.

These projects should be identified and prioritized through the Township of Puslinch's Asset Management Plan and incorporated into the long-term capital budget. Proactive investment in these critical systems will help minimize the risk of unexpected failures, avoid costly emergency repairs, reduce service disruptions, and protect the Township of Puslinch's investment in these valued community facilities.

What We Heard — Community Feedback

While **residents value the Township of Puslinch's indoor facilities,** engagement participants also identified opportunities to improve their functionality and long-term sustainability.

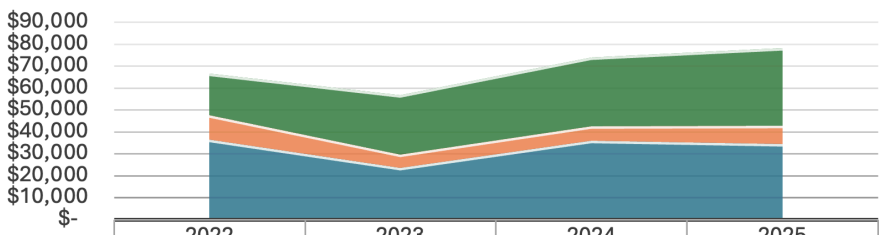
Priorities included enclosing and enhancing the outdoor rink with spectator seating, modernizing facilities through improved Wi-Fi and audio-visual technology, addressing aging building systems, and incorporating energy-efficient and sustainable building features into future upgrades. Participants also highlighted the need to address the septic system limitations at the Puslinch Community Centre, which may impact event bookings. Overall, **residents expressed a desire for more flexible, accessible, and functional indoor facilities that can better support year-round recreation, community programming, and events** while continuing to meet the needs of a growing community.

INDOOR FACILITY UTILIZATION ANALYSIS

In the absence of detailed utilization data from registration and permitting software, an analysis of revenues was conducted as an indicator of use. Annual revenue increases are not strictly related to utilization as there could be a compounding effect from fee increases. Conversely, revenue decreases are more clear indicators of decreased utilization.

The chart below is a consolidation of gymnasium, floor, and ice rental actual revenues between 2022 - 2025. Indoor facilities were still subject to Covid-19 restrictions in the first quarter of 2022.

The 2022 gymnasium revenues were substantially lower than subsequent years (2023-2025). This may have been a result of residual indoor facility restrictions and the subsequent uptake in outdoor facilities during the Pandemic. Gymnasium revenues continue to increase year-over-year from 2023 – 2025. Ice utilization appeared to decrease substantively in 2023 yet recovered in 2024 and 2025 closer to 2022 levels.



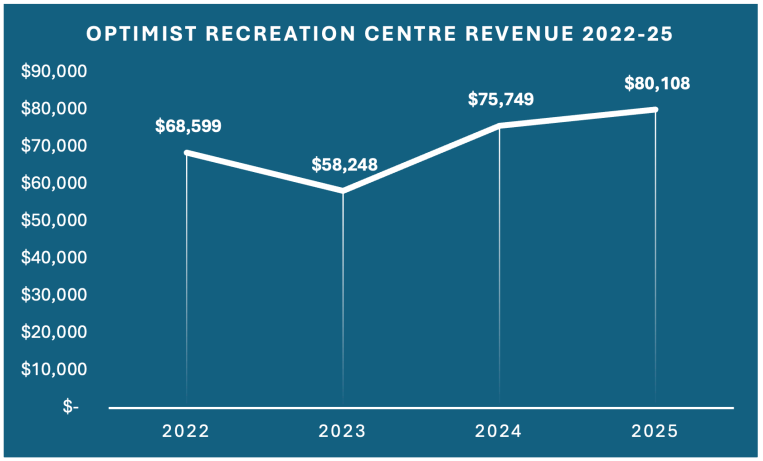
	2022	2023	2024	2025
Gym	$19,116	$27,107	$31,484	$35,404
Floor	$10,991	$6,048	$6,462	$8,260
Ice	$36,604	$23,542	$36,090	$34,602

Ice Floor Gym

Further utilization analysis was conducted by focussing on revenues within each of the indoor facilities.

OPTIMIST RECREATION CENTRE

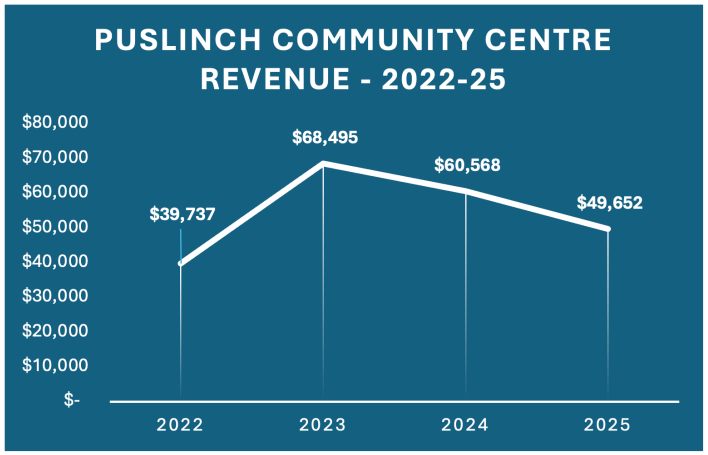
Total facility revenues have increased by approximately **16.7%, from $68,599 in 2022** to **$80,108 in 2025,** reflecting growing demand for recreation programming and facility rentals. Revenue generated through facility bookings also demonstrates increasing demand, particularly for gymnasium and ice rentals, reinforcing the Optimist Recreation Centre's role as the community's primary indoor recreation hub.



PUSLINCH COMMUNITY CENTRE

The Puslinch Community Centre experienced a steady decline in revenues from a high of **$68,495 in 2023** which was **$28,758 (72%) higher than 2022 revenues**. Residual restrictions from the Pandemic in the first quarter of 2022 may have contributed to this lower revenue, as outdoor recreation activities remained an accessible option for the public.

Revenues have decreased by **$18,843 since 2023** which is a concerning trend. Staff will need to complete a more thorough review of user experiences and fee trending through User Fees and Charges annual review processes to address shortfalls in this decline.



GYMNASIUM UTILIZATION

An analysis of current gymnasium use was undertaken to identify utilization patterns and opportunities for optimization. Pickleball is currently the dominant use of the gymnasium and is one of the fastest-growing sports, with participation extending across all age groups. The demand for pickleball is expected to continue to grow, and participants will increasingly look for better-quality, dedicated and year-round facilities to support their participation.

The Township of Puslinch needs to monitor gymnasium use from different perspectives; addressing gaps in activities and promoting use of the gymnasium for new purposes, and leveraging activities that provide strong community benefit and optimize facility revenues. As participation trends continue to evolve, the Township of Puslinch should consider how its existing facilities and future capital investments can respond to growing demand for year-round recreation opportunities.

Top image: Sardhar Katha

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REGIONAL RECREATION PARTNERSHIPS

It is important to look at indoor recreation facilities from a regional perspective for Puslinch as it is surrounded by larger municipalities i.e., Milton, Cambridge and Guelph. The City of Guelph (South End Community Centre) has recently opened twin ice pads, aquatic centre with a lap and leisure pool, double gymnasium, a walking track and multi-purpose rooms that is less than a 5-minute drive from Puslinch Community Centre Park facilities. Explore opportunities to work with neighbouring municipalities to pursue joint investment in regional recreation facilities. Partnering on high-cost amenities, indoor turf facilities, dedicated pickleball courts and fieldhouses, will improve resident access while sharing capital and operating costs with neighbouring municipalities. Any partnership agreement should clearly define funding, governance, resident access and shared benefits to ensure the arrangement is equitable for all participating municipalities.

RECOMMENDATION 1: IMPROVE EXISTING INDOOR FACILITIES THROUGH ASSET MANAGEMENT

Continue investing in the Optimist Recreation Centre and Puslinch Community Centre through lifecycle renewal and modernization. Prioritize upgrades to mechanical systems, septic system, accessibility, HVAC, refrigeration compressor, and energy efficiency.

RECOMMENDATION 2: MAXIMIZE CAPITAL BUDGETS FOR MODERNIZATION OF FACILITIES

Upgrades to interior finishes (such as floor replacement) and technology (audio-visual/Wifi improvements) to ensure the facilities continue to meet community needs and remain financially sustainable.

Image: Rendering of Guelph South End Arena

RECOMMENDATION 3: ENHANCE THE OPTIMIST RECREATION CENTRE RINK FOR MULTI-SEASON USE

Investigate opportunities to enhance the Optimist Recreation Centre covered outdoor arena, or improved netting, sport lines on ice pad floor and multi-season functionality.

RECOMMENDATION 4: OPTIMIST RECREATION CENTRE RINK ENCLOSURE AND EXPANSION

The Township should undertake a feasibility study to assess the operating and capital costs of enclosing and expanding the existing Optimist Recreation Centre rink to create a more functional, year-round recreation and community facility.

RECOMMENDATION 5: REGIONAL RECREATION OPPORTUNITIES

Explore opportunities with neighbouring municipalities to identify opportunities for shared recreation infrastructure and services like dedicated pickleball courts, indoor turf, and other specialized facilities.

ADMINISTRATION & POLICIES

The Township of Puslinch has several agreements in place with local organizations, including the Optimist Club of Puslinch, Puslinch Minor Baseball, Puslinch Minor Soccer Club, Seniors' Pickleball Group, Aberfoyle Agricultural Society, and Whistle Stop Cooperative Preschool. These agreements provide a clear framework for managing facility rentals, storage and shed arrangements and are a positive practice, as they help clarify responsibilities and mitigate potential risks.

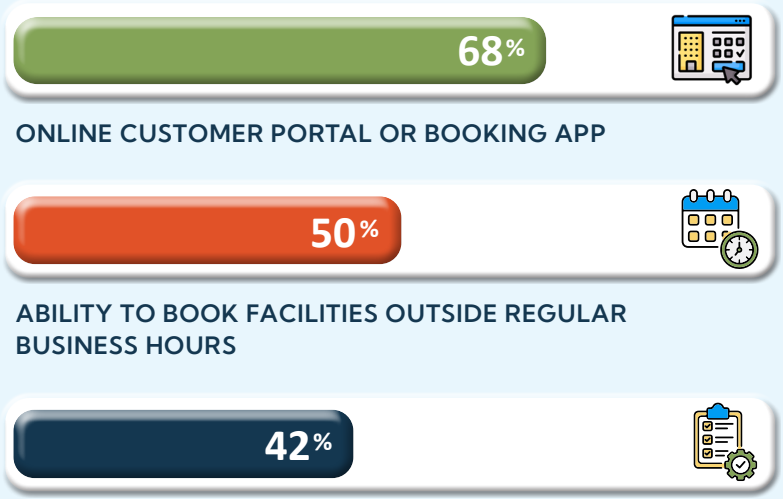
There is no formal allocation policy for ice, floor, gymnasiums or community centre space. Currently, requests are generally processed based on availability, with users completing a rental request form, providing required documentation (including proof of insurance), and submitting payment. A formal allocation process would provide greater transparency and consistency when there are competing requests. Priority should generally be given to local programs, youth and seniors, community-based not-for-profit groups open to the broader community, closed-membership organizations and, finally, private rentals. It will be important to have a well-balanced program and financial mix, as currently, there is a reduced rate for many of these programs.

Two formal allocation periods each year would allow staff to review requests collectively and confirm allocations within a defined timeframe. Improved recreation management software could also streamline online bookings, payments, permits and recurring rentals.

Currently the Township of Puslinch's booking software is limited, and staff should look into alternative software that can assist with improved online customer experience and expanded data collection.

What We Heard — Community Feedback

The TOP THREE additional features or improvements survey respondents would most like as **part of the rental process** are:



There was also interest in modifying/canceling bookings online and receiving booking updates electronically.

RECOMMENDATION 1: DEVELOP A FORMAL FACILITY ALLOCATION POLICY

Establish a formal allocation policy that identifies priority levels, eligibility requirements and criteria for resolving competing requests for facilities. Implement two annual allocation periods for regular user groups, with defined application deadlines, review criteria and confirmation timelines.

RECOMMENDATION 2: EXPLORE RECREATION MANAGEMENT SOFTWARE OPTIONS

Explore different recreation management software products to determine the most appropriate system for administration, with consideration given to online bookings, payments, permits, insurance tracking, recurring rentals and facility utilization reporting.

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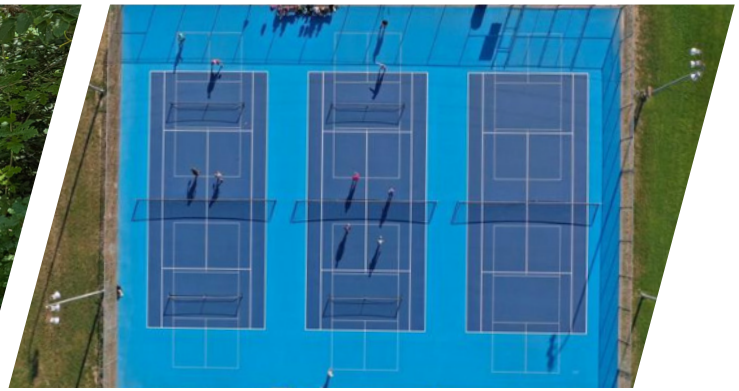

OUTDOOR FACILITIES

OUTDOOR RECREATION FACILITY INVENTORY AND PROVISION

Puslinch has a variety of outdoor recreation facilities that are found within five of their eight park spaces.

The following table denotes the facilities; how many the Township of Puslinch owns and where they are located and explores the service level provision. Based on the Puslinch's current population of approximately **8,550 residents**, the Township of Puslinch meets or exceeds recognized provincial service level provision guidelines for most outdoor recreation facilities. These targets are based on quantity of facilities and population.

OUTDOOR RECREATION FACILITY TYPE	TOTAL QUANTITY	PRIMARY LOCATIONS	TOTAL FACILITIES (UNLIT EQUIVALENT 1 LIT = 1.5 UNLIT)	EXISTING TOWNSHIP SERVICE LEVEL	RECOGNIZED PROVINCIAL SERVICE LEVEL
Senior Soccer Fields (11v11)*	2	Badenoch Field (1) unlit field Puslinch Community Centre Park (1) lit field	3.5	1:2,443	1:5,000
Youth Soccer Fields (7v7)**	1	Puslinch Community Centre Park (1) unlit field			
Senior Ball Diamonds	3	Puslinch Community Centre Park (1) lit. Old Morriston Ball Field (1) lit. Morriston Meadows (1) unlit	5	1:1,710	1:4,000
Junior / Practice Ball Diamonds	1	Morriston Meadows (1) unlit			
Batting Cages	2	Old Morriston Ball Field: 1 batting cage Puslinch Community Centre Park: 1 batting cage	N/A	N/A	N/A
Tennis Courts/Pickleball Courts	3 (tennis) 7(pickleball)	Puslinch Community Centre Park: 3 lit tennis courts; 6 lit pickleball courts Boreham Park (1) unlit, lined onto basketball court	4.5 (tennis) 10 (pickleball)	1:1,900 (tennis) 1:855 (pickleball)	1:5000 (both)
Basketball / Multi-Use Courts	2	Morriston Meadows (1) full-size unlit asphalt court Boreham Park (1) full-size unlit asphalt court	2	1:4,725	1:5,000

*Senior Fields – Width (45 to 90 metres) & Length (90 to 120 metres)

**Youth Fields – Width (30 to 36 metres) & Length (40 to 55 metres)[1]

The mini pitch (horse paddock) field at the Puslinch Community Centre Park, may be used for informal soccer play, however due to its size it cannot be categorized as a standard soccer field and also is not included in this inventory. Currently, Puslinch does not have agreements with private land owners for the use of their outdoor recreation facilities, therefore, their facilities are not included in this inventory.

[1]Canada Soccer Grassroots Standards. Retrieved on 09.03.2026 from https://canadasoccer.com/wp-content/uploads/2026/02/2026-CS-GrassrootsStandards-EN_final91.pdf

OUTDOOR RECREATION FACILITY CONDITIONS

OUTDOOR RECREATION FACILITY	FACILITY CONDITION
SOCCER FIELDS 	**THE PUSLINCH COMMUNITY CENTRE SENIOR SOCCER FIELD** was the most recently constructed with players benches and spectator bleachers as well as new lights installed in 2023. The youth soccer field was also reconstructed at this time and is unlit. Visually, there do not appear to be issues with the field. Weed growth observed in the playing field surface. **The fields are in good condition.** **BADENOCH SOCCER FIELD** also contains spectator bleachers, an older single light pole (not fully lit) and a portable washroom facility. **The field appears to be in good condition.**
BASEBALL DIAMONDS 	At the **MORRISTON MEADOWS BASEBALL DIAMONDS,** the infield and outfield for **both the adult and junior diamonds appear to be in good condition.** There is no lighting for either diamond at this park. The senior diamond features spectator seating which was recently upgraded as well as covered dugouts for both teams. The diamond is also fenced and features a warning track. The junior diamond has unshaded players benches and older spectator seating, both of which are in very poor condition as per the recent visual inspection conducted for the Recreation and Parks Master Plan (RPMP). The outfield is not fenced. The junior diamond (T-ball field) does not contain a warning track. Morriston Meadows contains a washroom and concession stand (access provided to renters only) in good to fair condition. There is no formal accessible route from the parking lot to the diamonds and there is significant grade differences between the parking lot and the two diamonds. Weed growth observed in the outfields. The **OLD MORRISTON BASEBALL DIAMOND** is sized for adult play, is fully fenced with unshaded players benches and recently upgraded spectator seating. The diamond is in **fair to good condition** and has recently upgraded field lighting. The diamond also features a washroom and concession stand (access provided to renters only) in good to fair condition. This amenity is also complemented by a batting cage in fair condition, and the field contains a warning track. The parking area for this diamond is informal with visitors parking on the open grass area to the northeast of the diamond. Weed growth observed in the maintained areas and outfields. **PUSLINCH COMMUNITY CENTRE PARK** baseball diamond appears to be **in good condition.** The lighting was recently upgraded at the same time of the senior soccer field upgrades. The spectator bleachers on the west side of the diamond appear to be recently constructed with metal on a concrete pad. The opposite team side however, has yet to be upgraded. The seating is deteriorating and there is no accessible route on this side. The diamond is fully fenced and features a warning track as well as a concession stand. Weed growth observed in the maintained areas and outfields.

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OUTDOOR RECREATION FACILITY	FACILITY CONDITION
TENNIS AND PICKLEBALL COURTS	The combined tennis/pickleball courts underwent recent renovations in 2024. They are considered to be in **very good condition** and are fully fenced, are lit and feature seating within the fenced area.
BASKETBALL / MULTI USE-COURTS	**BOREHAM PARK BASKETBALL / MULTI-USE COURT** was constructed as early as 2018. During the site inspections conducted for this RPMP, the paving is considered to be **in good condition** (no major distresses), but the linework has faded somewhat. The net posts are considered to be in good condition as well. **THE MORRISTON MEADOWS BASKETBALL COURT** consists of asphalt paving with hoops and backboards mounted on posts. This court is not lined. This court is considered to be in **fair to good condition.**

What We Heard — Community Feedback

- Respondents were looking for **lines to be painted at Morriston Meadows Basketball Court** for basketball as it is currently unlined.
- Sports groups mentioned **unsafe fields which could injure players**, and that regular maintenance (mowing/rolling/infield dragging) does not seem to adequately preserve the quality of the fields.
- The **quality of the players benches and bleachers** at the junior/practise ball diamond at Morriston Meadows **are very poor**.
- **High-quality sports fields** were the **fourth most popular** answer for **existing valued park amenities** (29%), compared to **Upkeep/maintenance/beautification** (33%), **Playgrounds** (34%), and **Public Washrooms** (68%).

OUTDOOR UTILIZATION ANALYSIS

SOCCER FIELDS – HOURS

Assuming all lit fields are rentable between the hours of 9AM–10:30PM Monday to Friday and 9AM–10PM Saturday and Sunday between May to October (approximately 30 weeks), the following table demonstrates the amount of hours fields were booked compared to total available hours. Unlit soccer fields are rentable between the hours of 9AM–8:30PM Monday to Sunday. Currently, the fields are available for bookings via facilities@puslinch.ca or Puslinch.ca/rentalrequest.

SOCCER FIELD	2022 (HOURS)	2023 (HOURS)	2024 (HOURS)	2025 (HOURS)	TOTAL AVAILABLE HOURS
Puslinch Community Centre Park Youth Soccer Field(Unlit)	339.5	86.00	275.50	233.00	**2,116**
Puslinch Community Centre Park Senior Soccer Field (Lit)	–	–	461.50	325.5	**2,485**
Badenoch Soccer Field (Unlit)	224.5	212.00	211.50	137.50	**2,116**

SOCCER FIELDS – REVENUE

SOCCER FIELD	2022 REVENUE	2023 REVENUE	2024 REVENUE	2025 REVENUE
Total Soccer Field Revenue	$4,102	$2,213	$6,102	$5,513

Both Puslinch Community Centre Park soccer fields exhibit the highest usage volumes overall and are used heavily by Puslinch Minor Soccer Club (PMSC). Bookings begin in mid-May and run through late October.

BASEBALL DIAMONDS – HOURS

Assuming all lit diamonds are rentable between the hours of 9AM–10:30PM Monday to Sunday , and between 9AM–10:00PM Saturday and Sunday between May to October (approximately 30 weeks), the following table demonstrates the amount of hours diamonds were booked compared to total available hours. Unlit diamonds are rentable between the hours of 9AM–8:30PM Monday to Sunday. Currently, the diamonds are available for bookings via facilities@puslinch.ca or Puslinch.ca/rentalrequest.

BASEBALL DIAMOND	2022 (HOURS)	2023 (HOURS)	2024 (HOURS)	2025 (HOURS)	TOTAL AVAILABLE HOURS
Puslinch Community Centre Park Ball Diamond (Lit)	188.78	209.50	225.00	230.00	2,485
Morriston Meadows Ball Diamonds (Unlit)	91	134	190.50	364.50	2,116
Old Morriston Ball Diamond (Lit)	87.9	208.50	295.00	208.50	2,485

Old Morriston and Puslinch Community Centre Park ball diamonds, as the only two lit diamonds allow for extended evening bookings, particularly for adult leagues. Puslinch Community Centre Park Ball Diamond is the most heavily used asset.

BASEBALL DIAMONDS – REVENUE

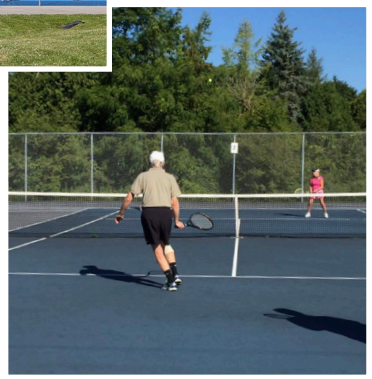
BASEBALL DIAMOND	2022 REVENUE	2023 REVENUE	2024 REVENUE	2025 REVENUE
Puslinch Community Centre Park Ball Diamond	$4,837	$5,696	$5,686	$6,724
Morriston Meadows Ball Diamond	$1,518	$1,776	$3,396	$5,304
Old Morriston Ball Diamond	$1,523	$2,496	$3,547	$2,960
Total Ball Diamond Revenue	$7,878	$9,986	$12,628	$14,988

Puslinch Community Centre Park Ball Diamond is the Township's highest revenue ball diamond asset, generating nearly $7,000 in 2025. Morriston Meadows exhibits a high concentration of bookings in June and July and also experiences seasonal tournament bookings and consecutive league play.

TENNIS AND PICKLEBALL COURTS – HOURS

Courts are bookable from 9:00 AM–10:00 PM Monday to Sunday between May to October (30 weeks), the following table demonstrates the amount of hours courts were booked compared to total available hours.

COURT NAME	2024 (HOURS)	2025 (HOURS)	TOTAL AVAILABLE HOURS
Court 1 (Multi-Use / Lined)	164.50	185.00	2,730
Court 2 (Multi-Use / Lined)	117.00	169.00	2,730
Court 3 (Public Access/Unlined)	32.00	49.00	2,730



TENNIS AND PICKLEBALL COURTS - REVENUE

COURT NAME	2024 REVENUE*	2025 REVENUE
Court 1 (Multi-Use / Lined)	$1,806	$612
Court 2 (Multi-Use / Lined)	$657	$408
Court 3 (Public Access / Unlined)	$271	$420
Total Tennis and Pickleball Revenue	$2,734	$1,440

*Courts were exclusively used by Puslinch Tennis Club with no public access prior to 2023.

The multi-use upgrades were completed in 2023, which added pickleball lining to the tennis courts, were a catalyst for their use. Courts 1 and 2 accounted for the majority of the outdoor court rentals. Court 3 accommodates extensive spontaneous un-booked recreational play by the public. The season for bookings is restricted to May through October with peak bookings in June and July.

Images left to right: Market Square, Guelph (image: City of Guelph); Bismark Park, Cambridge (image: City of Cambridge); and Milton Community Park, Milton (photo: Town of Milton)

AMENITIES NOT PRESENT TO CONSIDER

The Township of Puslinch's existing parks have created a baseline of services that have provided the community with numerous recreation and programming features for residents to enjoy. Some gaps or opportunities that have been mentioned during engagement include: disc golf, beach volleyball, skate parks, splash pads and off-leash areas.

OUTDOOR AMENITIES IN ADJACENT COMMUNITIES

It is important to highlight, that though Puslinch doesn't offer some of the amenities that have been requested, residents do enjoy convenient access to extensive outdoor recreation amenities such as parks, hiking trails, sports fields, and open spaces—in neighboring Guelph, Cambridge, and Milton. These municipalities do offer some of the larger more intensive amenities that were noted in the previous section.

The table below highlights key outdoor facilities available in these surrounding communities.

OUTDOOR RECOMMENDATIONS

As a note, higher-cost recommendations should be considered for implementation as third-party funding opportunities become available recognizing that timing may be influenced by grant eligibility, partnership/fundraising opportunities, municipal financial capacity, and other competing capital priorities. Significant capital investments will require more operational resources (staff, maintenance budgets, etc.).

MUNICIPALITY	SOCCER FIELDS	BALL DIAMONDS	TENNIS COURTS	MULTIPURPOSE / BASKETBALL COURTS	PLAYGROUNDS	SPLASH PADS	LEASH-FREE AREAS	SKATE PARK
Guelph	38	44	25	30	86	9	10	1
Cambridge	30	45	14	12	70	12	1	1
Milton	39	28	13	17	60	16	2	2

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PARKS AND PARK AMENITIES

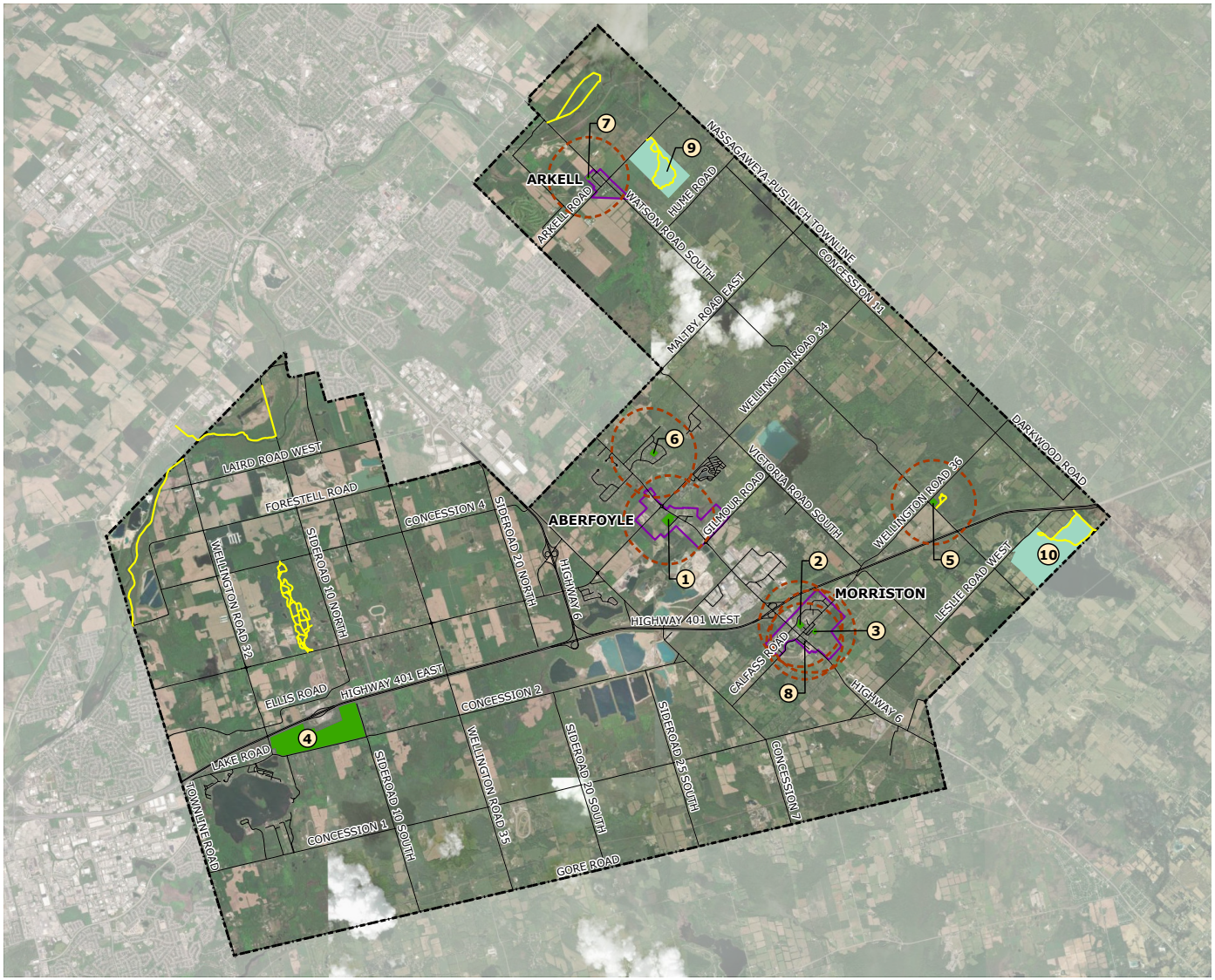
PARKLAND SUPPLY

The Township of Puslinch has eight parks within their inventory which total 21.6 hectares. The following table summarizes the inventory of the parks.

PARK NAME	CLASSIFICATION	ACRES*	HECTARES
Puslinch Community Centre Park	Community Park	23.2	9.4
Morriston Meadows Park	Community Park	6.1	2.5
Old Morriston Park	Community Park	6.1	2.5
Badenoch Soccer Field	Neighbourhood Park	5.5	2.2
Fox Run Park and Trail	Neighbourhood Park	5.7	2.3
Boreham Park	Neighbourhood Park	2.1	0.9
Historic Corner Block Park	Parkette	0.3	0.1
Telfer Glen Park (Trail Area)	Natural Park	4.3	1.8
	TOTAL	**53.3**	**21.6**

*2024 Development Charges Background Study

EXISTING PARKS AND RECREATION MAP



Township of Puslinch

Puslinch recreation and Parks Master Plan

Existing Parks and Recreation Map

Figure 1

- Puslinch Boundary
- Park
- Conservation Land
- Settlement Boundary
- Parkland Catchment Area (800m Buffer)
- Trail
- Road
- 1 Puslinch Community Centre
- 2 Morriston Meadows Park
- 3 Old Morriston Park
- 4 Future Puslinch Track
- 5 Badenoch Park
- 6 Fox Run Park
- 7 Boreham Park
- 8 Historic Corner Block Park
- 9 Starkey Hill Conservation Lands
- 10 Mountsberg Conservation Area

Map Drawing Information:
Data Provided by ESRI, Wellington County

Scale 1:80,000

0 1 2 4 KM

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Created By: RR | Project: 26-3707
Checked By: MK | Status: DRAFT
Map Projection: NAD 1983 UTM Zone 17N | Date: 2026-08-13

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TRAILS SUPPLY

In addition to the parks, Puslinch also has a number of trails in their inventory which complement the recreational amenities by providing passive opportunities. Trails owned by Puslinch include:

TRAIL NAME	LOCATION	LINEAR METRES
Fox Run Trail	Fox Run Park, Fox Run Drive	400
Telfer Glen Trail	Telfer Glen Park Trail, Calfass Road	270
Wayne Stokley Trail	Puslinch Community Centre Park	450
	TOTAL	**1,120**

There are also a number of trails within Puslinch that are owned and maintained by others:

- Starkey Hill Conservation Area, Grand River Conservation Authority (GRCA)
- Smith Side Trail – Radial Line Trail, GRCA
- Little Tract Trail, County of Wellington
- Speed River Trail, GRCA
- Badenoch Tract, County of Wellington
- Quarry Trail – Fletcher Ecological Preserve, Hamilton Conservation Authority (HCA)
- Lakeshore Lookout Trail – Mountsberg Conservation Area, Conservation Halton (CH)

Municipalities of similar size and condition have varying parkland provision targets. Larger municipalities have less available land for parks and larger populations which leads to lower provision targets. The following table summarizes comparative parkland provision targets.

MUNICIPALITY	LOCATION	2026 POPULATION ESTIMATES	PARKLAND PROVISION TARGET / STANDARD (PER 1,000 RESIDENTS)
Township of Puslinch	Rural / Wellington County	8,550[2]	3.0 ha
Guelph/Eramosa Township	Rural / Wellington County	14,540[3]	3.5 – 3.9 ha
Town of Erin	Rural / Wellington County	14,940[4]	3.5 ha
Township of Wilmot	Semi-Rural / Waterloo Region	22,500[5]	3.0 ha – 3.5 ha
Woolwich of Township	Semi-Rural / Waterloo Region	30,000[6]	2.5 ha
Township of Centre Wellington	Semi-Rural / Wellington County	35,520[7]	3.0 ha

[2] Current Population and Households. Wellington County. Retrieved on 09.04.2026 from: https://www.wellington.ca/business-development/planning-development/current-population-and-households

[3] Current Population and Households. Wellington County. Retrieved on 09.04.2026 from: https://www.wellington.ca/business-development/planning-development/current-population-and-households

[4] Current Population and Households. Wellington County. Retrieved on 09.04.2026 from: https://www.wellington.ca/business-development/planning-development/current-population-and-households

[5] Community Profile. Township of Wilmot. Retrieved on 09.04.2026 from: https://www.wilmot.ca/business-and-development/community-profile/

[6] Demographics. Woolwich Township. Retrieved on 09.04.2026 from: https://www.woolwich.ca/build-invest/demographics/

[7] Current Population and Households. Wellington County. Retrieved on 09.04.2026 from: https://www.wellington.ca/business-development/planning-development/current-population-and-households

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Based on the Township of Puslinch's current population of approximately 8,550 and an existing municipal parkland supply of 21.6 hectares, Puslinch currently provides approximately 2.5 hectares of parkland per 1000 residents. A parkland provision target of 3.0 hectares per 1000 residents is recommended, generally aligning with the provision targets identified for comparable municipalities in the geographical area. At the current population, approximately 25.7 hectares would be required to achieve the recommended target, representing a current shortfall of approximately 4.1 hectares. According to the 2021 Census and Wellington County Planning Profile, Puslinch is expected to grow to 10,000 residents by 2051. At that population, approximately 30.0 hectares of parkland would be required to maintain the recommended provision target. If Puslinch's municipal parkland supply remains at 21. 6 hectares, an additional approximately 8.4 hectares of parkland would therefore be required by 2051.

At the time of preparation of the RPMP, the Township of Puslinch was in negotiations to acquire approximately 107-hectare Puslinch Tract, located in the southwest area of Puslinch, south of Highway 401, west of County Road 32 and north of Concession Road 2. The property is currently owned and managed by the GRCA and includes naturalized forest plantations, deciduous and coniferous forests, meadows, ponds and wetlands. The potential acquisition would represent a significant addition to the Township of Puslinch's publicly owned open space and recreational land base and would help address an identified geographic gap in access to municipal recreation and open space opportunities in the western area of Puslinch.

Council is considering a multi-use vision for the Puslinch Tract that protects its natural character while supporting compatible recreation, including hiking and mountain biking, environmental education, and community use. Council is considering a potential setting for a science and environmental education centre or similar "living laboratory" opportunity, where research, ecological learning and public education can be integrated with the natural landscape. Any such use should complement, rather than

displace, existing recreational opportunities and should be appropriately scaled and designed to maintain ecological integrity and the site's rural character. Future improvements should enhance accessibility for people of different ages and abilities while protecting ecological integrity, natural character and sensitive habitats. Any expansion of uses should proceed through a phased approach that considers transportation, parking, infrastructure, impacts on the surrounding community, and all other relevant environmental and land use planning considerations.

If the acquisition is completed and the full 107 hectares is classified as municipal parkland, the total parkland inventory would increase from approximately 21.6 hectares to 128.6 hectares. This would equate to approximately 15.0 hectares per 1,000 residents based on the current population of 8,550, and approximately 12.9 hectares per 1,000 residents based on the projected population of 10,000.

Given the predominantly natural character of the Puslinch Tract, however, its contribution to the community parkland supply should be considered separately from the provision of active and developed parkland. Acquisition of the property would significantly enhance opportunities for passive recreation, trails, nature appreciation and conservation.

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PARKS AMENITIES INVENTORY

Outside of outdoor recreational facilities, there are also a number of other amenities that comprise the Township of Puslinch's park areas. The following table summarizes the Parks Amenities.

AMENITY TYPE	PARK / LOCATION	TOTAL QUANTITY
Playgrounds & Play Spaces	Puslinch Community Centre Park (1 accessible); Morriston Meadows Park (1); Boreham Park (1 accessible)	3
Picnic Pavilions	Morriston Meadows Park	1
Shade Structures	Puslinch Community Centre Park (2); Boreham Park (1)	3
Gardens / Horticultural Displays	Puslinch Community Centre Park (Millenium Garden); Historic Corner Block	2

PARKS AMENITIES SERVICE PROVISION

Parks amenities are slightly different than those for outdoor recreation facilities. The following table outlines comparable service levels for amenities found within the Township of Puslinch's inventory.

EXAMPLE MUNICIPALITY	AMENITY TYPE	PRIMARY TARGET MODEL	TYPICAL TARGET BENCHMARK
Centre Wellington / Wilmot	Playgrounds & Play Spaces	Geographic Radius (Service Area)	1 per 800-metre walking distance radius
Erin / Halton Hills	Picnic Pavilions (Bookable)	Park Hierarchy / Classification	1 per Community Park

The target for playgrounds and play spaces should be 1 playground per 800-metre radius of residential areas within the settlement boundaries. Puslinch's current playgrounds appear to adequately service the settlement areas within an 800-metre catchment radius for Arkell, Aberfoyle and Morriston.

The target for Picnic Pavilions or bookable picnic areas should be 1 per Community Park.

Shade structures, while prominent features in parks do not typically have a typical target. They are considered supporting amenities rather than standalone destination facilities. That said, due to the aging population and the effects of climate change with longer stretches of higher temperature days, shade structures should be included in both new and existing parks where destination amenities are present.

PARKS AMENITIES CONDITION

Playgrounds vary in their condition. **THE PUSLINCH COMMUNITY CENTRE PARK** playground was recently modernized in the spring of 2023 and is considered to be in **very good condition.** The old playground was replaced with a fully accessible play structure. **THE BOREHAM PARK** playground was recently upgraded in 2023 and is considered to be **in very good condition.** It was also built for accessibility. **THE MORRISTON MEADOWS PARK** playground is considered to be in **good to fair condition.**

The picnic pavilion at Morriston Meadows Park is considered to be in very good condition. During site visits, it was mentioned by staff that the picnic tables should be replaced in the near term due to their age and condition.

The shade structure and the shaded picnic area within the Puslinch Community Centre Park as well as Boreham Park are also newly constructed and are considered to be in very good condition.

THE MILLENIUM GARDEN at the Puslinch Community Centre Park is considered to be **in fair condition**. The benches and signage are fairly new; however, the planting beds are considered to be in poor condition due to their weeds. Pathways are also not accessible within the garden itself.

THE HISTORIC CORNER BLOCK PARK is a small parkette located in Morriston. Park entrance (name) signage is new. The pathways and benches are in **poor condition** due to age; pathway widths are not accessible. The plantings and lawn area are in poor condition due to weeds.

What We Heard — Community Feedback

Feedback received during community workshops, as well as feedback received from the survey, indicated **residents are dissatisfied with the quality of the Millenium Garden**, particularly the **weeds and lack of maintenance**.

During the 2026–2030 strategic planning workshops, residents and community groups explicitly highlighted **upgrading the Morriston Meadows Park playground equipment** as a key community priority.

What We Heard — Community Feedback

66% of survey residents **use the parks & trails.**

TOP THREE EXISTING PARK AMENITIES:

- **Public Washrooms** – 68%
- **Playgrounds** – 36%
- **Upkeep/Maintenance/Beautification** – 33%

TOP 10 NEW PARK AMENITIES desired by residents:

1. **Walking Track** – 27%
2. **New Playground**– 25%
3. **Splash Pad** – 24%
4. **All Season Trail** – 20%
5. **Public Washrooms** – 20%
6. **Beach Volleyball Courts** – 18%
7. **Enhancements to Outdoor Rink** – 18%
8. **Multi-use Courts** – 18%
9. **Designated Pickleball Courts** – 14%
10. **Biking Trails** – 11%

TOP THREE PRIORITIES:

The top 3 priorities residents chose for future parks and recreation investment:

- **Invest in new park infrastructure in existing parks** – 62%
- **Invest in more programs / services at recreation facilities** – 49%
- **Improve/upgrade existing park infrastructure** – 44%

PERFORMANCE DASHBOARD

TIMING LEGEND

Short = 1-3 years **Medium =** 4-7 years **Long =** 8+ years **Ongoing**

RESOURCES LEGEND

Internal A – Existing Staffing Resources
(Recommendation can be implemented with current staffing resources)
Internal B – Additional Staffing Resources
(Recommendation requires additional staffing resources to implement)
External – Initial Cost and Operating Cost *(*2026 current dollar estimates)*

TIMELINE	RECOMMENDATION	RESOURCES	ALIGNMENT
	SERVICE DELIVERY		
SHORT/ MEDIUM	**1. Hire a Community Development Coordinator*** Hire a Community Development Coordinator to increase recreation participation by expanding programming, building partnerships, improving facility utilization, explore opportunities with instructors and volunteers, and fostering relationships with community organizations, local leaders, and private providers to encourage the delivery of recreation opportunities throughout the Township of Puslinch.	**Internal B** **Cost Estimate: $75,000 to $100,000**	Strategic Plan
SHORT	**2. Diversify drop-in recreation opportunities at the Optimist Recreation Centre (indoor and outdoor)** Offer additional activities within facility operating hours, such as basketball, soccer, pickleball, and family recreation during traditionally low-utilization periods, and school holidays to encourage casual participation and maximize facility utilization.	**Internal A*** **Ongoing Cost: $30/hr**	Strategic Plan
MEDIUM	**3. Establish partnerships with organizations such as Equip Sport, and the Wellington County Library** Make storage and recreation equipment—including soccer balls, basketballs, pickleball paddles, balls, and other portable equipment like playboxes—available for public use.	**Internal A*** **or External** **Cost Estimate: $2,000 to $4,000** **Storage Solution: $1,000**	Strategic Plan
SHORT	**4. Develop a Recreation Programming and Instructor Recruitment Strategy** Explore opportunities with instructors, coaches, community organizations, neighbouring municipalities, and private providers (i.e., YMCA's, senior organizations and agencies) to expand local recreation programming and introduce services such as summer camps, fitness, wellness, senior's and children's programs that are not currently available in Puslinch.	**Internal A***	Strategic Plan

* Current staff would not be able to fulfill the recommendations to their fullest without the hiring of a Community Development Coordinator.

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PERFORMANCE DASHBOARD

TIMING LEGEND

Short = 1-3 years **Medium =** 4-7 years **Long =** 8+ years **Ongoing**

RESOURCES LEGEND

Internal A – Existing Staffing Resources
(Recommendation can be implemented with current staffing resources)
Internal B – Additional Staffing Resources
(Recommendation requires additional staffing resources to implement)
External – Initial Cost and Operating Cost *(*2026 current dollar estimates)*

TIMELINE	RECOMMENDATION	RESOURCES	ALIGNMENT
SHORT/ ONGOING	**5. Develop partnership opportunities** Staff should actively promote partnership opportunities, provide facility-use and marketing support, and provide administrative support to encourage new program offerings and broaden recreation opportunities without significantly increasing municipal staffing.	**Internal A** **Ongoing Cost: $200** (advertising)	Strategic Plan
MEDIUM	**6. Expand neighbouring partnerships** Continue to strengthen partnerships with neighbouring municipalities to improve access to recreation programs and facilities that cannot be reasonably provided within Puslinch (i.e., swimming lessons). This may include reciprocal registration agreements, subsidized resident rates, shared programming opportunities, and coordinated marketing of regional recreation services.	**Internal A** **Cost Estimate: $50,000+** depending on agreement or MOU. Many variables	Strategic Plan
SHORT	**7. Increase awareness of recreation opportunities** To improve awareness of recreation opportunities, recognizing that increasing awareness of programs emerged as a key theme from the community survey. Promote all programs and events—regardless of the provider—through multiple communication channels, including the Township of Puslinch website, social media, arena displays, the digital sign at the Puslinch Community Centre, community bulletin boards, and seasonal program guides. The Township of Puslinch should also partner with the Youth Advisory Committee to create engaging social media content that helps reach younger audiences and promotes local recreation opportunities	**Internal A***	Strategic Plan

* Current staff would not be able to fulfill the recommendations to their fullest without the hiring of a Community Development Coordinator.

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PERFORMANCE DASHBOARD

TIMING LEGEND

Short = 1-3 years **Medium =** 4-7 years **Long =** 8+ years **Ongoing**

RESOURCES LEGEND

Internal A – Existing Staffing Resources
(Recommendation can be implemented with current staffing resources)
Internal B – Additional Staffing Resources
(Recommendation requires additional staffing resources to implement)
External – Initial Cost and Operating Cost *(*2026 current dollar estimates)*

TIMELINE	RECOMMENDATION	RESOURCES	ALIGNMENT
SHORT/ ONGOING	**8. Establish an annual Community Recreation Partnership Workshop** The Township of Puslinch should establish an annual Community Recreation Partnership Workshop that brings together service clubs, minor sport organizations, and community groups to share information on grant opportunities, volunteer recruitment and retention, governance, risk management, marketing, and partnership opportunities.	**Internal A*** **Cost Estimate: $300/annually**	Strategic Plan
SHORT/ MEDIUM	**9. Develop a Volunteer Framework** Provide opportunities for municipal-led orientation, support, and appreciation opportunities for Puslinch volunteers and community groups.	**Internal A***	Strategic Plan
ONGOING	**10. Stay current with recreation trends** That staff stay informed of the emerging recreation trends and changing community expectations through ongoing training, participation in conferences (such as PRO) to ensure proactive responses to community needs.	**Internal A** **Cost Estimate: $1,000/annually**	

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TIMING LEGEND

Short = 1-3 years **Medium =** 4-7 years **Long =** 8+ years **Ongoing**

RESOURCES LEGEND

Internal A – Existing Staffing Resources
(Recommendation can be implemented with current staffing resources)
Internal B – Additional Staffing Resources
(Recommendation requires additional staffing resources to implement)
External – Initial Cost and Operating Cost *(*2026 current dollar estimates)*

TIMELINE	RECOMMENDATION	RESOURCES	ALIGNMENT
	INDOOR FACILITIES		
SHORT/ ONGOING	**1. Improve existing indoor facilities through asset management** Continue investing in the Optimist Recreation Centre and Puslinch Community Centre through lifecycle renewal and modernization. Prioritize upgrades to mechanical systems, septic system, accessibility, HVAC, refrigeration compressor, and energy efficiency.	**Internal A, Finance** **Cost Estimate: $500,000–Millions** [mechanical system: $1,000,00; septic: $350,000; accessibility improvements: $300,000+; HVAC/mechanical systems: $300,000+; energy efficiency: $200,000] **External** **Ongoing Trade Services: $100/hr**	Asset Management Plan
MEDIUM	**2. Maximize capital budgets for modernization of facilities** Upgrades to interior finishes (such as floor replacement) and technology (audio-visual/ Wifi improvements) to ensure the facilities continue to meet community needs and remain financially sustainable.	**Internal A, Finance** **Cost Estimate: increase of $50,000 annually** [audio-visual improvements: $10,000; floor replacement: approx. $12-20 sq/ft]	Strategic Plan
SHORT/ LONG	**3. Enhance the Optimist Recreation Centre rink for multi-season use** Investigate opportunities to enhance the Optimist Recreation Centre covered outdoor arena, or improved netting, sport lines on ice pad floor and multi-season functionality.	**Phase A – Internal B** **Cost Estimate:** sport lines: $15,000 **Phase B – External** **Cost Estimate: $75,000** (netting) **to 5 million** (enclosing the rink)	Asset Management Plan
MEDIUM/ LONG	**4. Optimist Recreation Centre Rink Enclosure and Expansion** The Township should undertake a feasibility study to assess the operating and capital costs of enclosing and expanding the existing Optimist Recreation Centre rink to create a more functional, year-round recreation and community facility.	**External** **Cost Estimate: $30,000**	Strategic Plan Asset Management Plan

PERFORMANCE DASHBOARD

TIMING LEGEND

Short = 1-3 years **Medium =** 4-7 years **Long =** 8+ years **Ongoing**

RESOURCES LEGEND

Internal A – Existing Staffing Resources
(Recommendation can be implemented with current staffing resources)
Internal B – Additional Staffing Resources
(Recommendation requires additional staffing resources to implement)
External – Initial Cost and Operating Cost *(*2026 current dollar estimates)*

TIMELINE	RECOMMENDATION	RESOURCES	ALIGNMENT
LONG	**5. Regional recreation opportunities** Explore opportunities with neighbouring municipalities to identify opportunities for shared recreation infrastructure and services like dedicated pickleball courts, indoor turf, and other specialized facilities.	**External, Finance** **Cost Estimate: $50,000 to Millions**	Asset Management Plan; County Official Plan; Strategic Plan
	ADMINISTRATION AND POLICIES		
SHORT	**1. Develop a formal Facility Allocation Policy** Establish a formal allocation policy that identifies priority levels, eligibility requirements and criteria for resolving competing requests for facilities. Implement two annual allocation periods for regular user groups, with defined application deadlines, review criteria and confirmation timelines.	**Internal A**	Strategic Plan
SHORT	**2. Explore recreation management software options** Explore different recreation management software products to determine the most appropriate system for administration, with consideration given to online bookings, payments, permits, insurance tracking, recurring rentals and facility utilization reporting.	**Internal A, Internal B, External** **Cost Estimate: $40,000** (initial); **$15,000** (ongoing license)	Strategic Plan

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TIMELINE	RECOMMENDATION	RESOURCES	ALIGNMENT
	OUTDOOR FACILITIES – GENERAL		
SHORT	**1. Complete a Peer Review of the Public Works, Parks, and Facilities Level of Service Policy** To evaluate the effectiveness of the policy due to feedback related to quality of sports fields (and maintenance of park spaces), the existing policy should be reviewed.	**External** **Cost Estimate: $10,000 to $20,000**	
SHORT	**2. Maintenance-in-lieu Agreements** Partner with sports groups (local baseball or soccer clubs) for collaborations / partnerships with routine, game-day maintenance activities such as field lining, diamond dragging, minor cleanup and post-game litter removal, while the Township of Puslinch would continue to be responsible for major maintenance, inspections, repairs and safety-related work. This shared approach could improve field quality and service levels while reducing municipal staff requirements.	**Internal A**	Strategic Plan
MEDIUM	**3. Consider commissioning a Turf Action Plan for the sports field spaces to improve quality of playing surfaces for user satisfaction and safety.** Turf Action Plans look at visual condition audits, capacity and booking reviews, standard turf maintenance protocols (mowing, aeration, overseeding schedules).	**External** **Cost Estimate: $15,000 to $25,000**	
LONG	**4. Explore municipal partnerships for the shared use of parkland and recreation facilities** As neighbouring municipalities face increasing demands for parkland associated with future development, opportunities to make Puslinch assets available for their recreation programming and rentals should be explored.	**Internal A**	Strategic Plan

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TIMELINE	RECOMMENDATION	RESOURCES	ALIGNMENT
LONG	**5. Consider co-investment matching models** Potential to require sports associations to co-fund minor capital upgrades such as covered dugouts, scoreboards, bench upgrades lighting etc. in exchange for multi-year priority booking access etc.	**Internal A**	Strategic Plan
SHORT	**6. Non-sport field permits** Rent field spaces during low-demand windows for commercial uses such as fitness boot camps, dog training groups, corporate team building events etc.	**Internal A**	Strategic Plan
	OUTDOOR FACILITIES – SOCCER FIELDS		
LONG	**1. Badenoch Soccer Field upgrades** Replace the single lighting pole with standard soccer field lighting and construct permanent washroom facilities at Badenoch Soccer Field to allow for more intense use and play.	**Internal B** **Cost Estimate: $300,000 to $1M+** [lighting: $300,000; washroom: $500,000]	Asset Management Plan
MEDIUM	**2. Puslinch Community Centre flooding resiliency upgrades** Consider constructing a berm between the Youth Soccer Field and the creek to mitigate the impacts of flooding. The granular trail and field flood regularly, remove granular trail and replace with berm instead.	**Internal B** **Cost Estimate: $50,000 to $150,000**	Asset Management Plan
LONG+	**3. Artificial turf Feasibility Study** Conduct a Feasibility Study to consider upgrading one soccer pitch to artificial turf to accommodate a higher intensity of use and longer season.	**Internal B** **Cost Estimate: $20,000 for Feasbility Study**	Asset Management Plan

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TIMELINE	RECOMMENDATION	RESOURCES	ALIGNMENT
	OUTDOOR FACILITIES – BASEBALL DIAMONDS		
MEDIUM	**1. Morriston Meadows lighting upgrades** Consider adding lighting to Morriston Meadows Baseball Diamond to further increase the amount of playable hours available to sports groups and the public.	**Internal A** **Cost Estimate: $200,000 to $350,000**	Asset Management Plan
	OUTDOOR FACILITIES – BASKETBALL		
SHORT	**1. Morriston Meadows basketball court lining** Provide new court lining for Morriston Meadows basketball court. Consider also lining for pickleball to provide additional facilities. Options include simple line painting to full acrylic coating.	**Internal A** **Cost Estimate: $3,500 to $14,000**	Asset Management Plan
	ADDITIONAL AMENITIES		
MEDIUM	**1. Conduct a splash pad Feasibility Study** Puslinch should still consider having one splash pad as part of its inventory. Due to the complicated nature of the municipal servicing, a feasibility study should be completed first to determine the future of a splash pad.	**External** **Cost Estimate: $15,000 to $40,000 for Feasibility Study** [Construction of a splash pad ranges from $20,000 to $45,000 for a <300 sq. ft. – 1 spray nozzle/head basic setup to $150,000 to $350,000 for a <1,500 sq. ft. – 3 to 5 nozzle/1-2 post/bucket setup.] Prices vary depending on the number of features, the finish on the pavement and the water collection/disposal used.	Asset Management Plan

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TIMELINE	RECOMMENDATION	RESOURCES	ALIGNMENT
	PARKS & AMENITIES – GENERAL		
SHORT	**1. Master Plan for Puslinch Tract** Finalize the Puslinch Tract purchase from GRCA and complete a Master Plan for the newly acquired lands in alignment with Counci's vision. Set aside enough of the new lands to utilize as active park space to reach the Township of Puslinch's 3.0 hectare per 1000-person target.	**External** **Cost Estimate: $75,000 to $150,000**	Strategic Plan
SHORT	**2. Interactive parks and recreation map** Develop a digital map illustrating the parks, recreation amenities and trails. It should allow users to search for particular amenities and zoom into specific parks.	**External** **Cost Estimate: $10,000 to $20,000**	Strategic Plan
SHORT	**3. Emergency / communication signage** Consider implementing signage for safety such as posting information in case of emergency as well as providing QR code signs to solicit parks feedback (e.g. broken equipment or reporting wildlife i.e. coyotes). Both can be integrated into a single sign.	**External** **Cost Estimate: $5,000 to $8,000 for 8 parks**	Asset Management Plan
	PARKS PROGRAMMING		
SHORT	**1. Park Toy Boxes** Provide boxes in parks for borrowing things such as kites, sand box toys, chalk, and other toys. Locate boxes in parks with playgrounds Boreham Park, Puslinch Community Centre Park and Morriston Meadows Park.	**Internal A** **Cost Estimate: $1,000**	Asset Management Plan
MEDIUM	**2. Interpretive / Interactive Signs** Include accessible, and educational signage which can provide the history of the Puslinch. Signs could include QR codes to link to additional information, videos, or audio clips and feature local artist's work. Locate in larger community parks: Puslinch Community Centre Park, Morriston Meadows Park, Old Morriston and Historic Centre Block Park.	**Internal A** **Cost Estimates: $10,000 to $20,000 for 4 signs**	Asset Management Plan

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TIMELINE	RECOMMENDATION	RESOURCES	ALIGNMENT
	PUSLINCH COMMUNITY CENTRE PARK		
MEDIUM	**1. Paving Park Pathways** Pave the existing granular park pathways to improve the overall accessibility of the park, including a paved, formalized park loop for a continuous walking track around the senior soccer field. Approximately 600 linear metres of trails.	**External** **Cost Estimate: $15,000 to $20,000**	Asset Management Plan
MEDIUM	**2. Implement Outdoor Fitness Stations** Develop outdoor fitness stations along the newly paved circuit path at Puslinch Community Centre Park with fitness equipment and a sign with a QR code to a website for instructions on use. One station every 150 metres, approximately 4 stations.	**External** **Cost Estimate: $26,000 to $40,000**	Asset Management Plan
MEDIUM	**3. Repurposing Horse Paddock for Additional Uses** Consider repurposing the Horse Paddock at the Puslinch Community Centre Park to accommodate Beach Volleyball.	**External** **Cost Estimate: $15,000 to $30,000**	Asset Management Plan
SHORT	**4. Millenium Park Upgrades** Upgrade the plantings and walkways in the Millenium Garden and include it as a feature of the Puslinch Community Centre Park. Include as part of park maintenance. Develop a Formal Volunteer Agreement or Volunteer Charter to define commitments, approve working hours, safety protocols, plant palettes etc. Provide on-site gardening tools via a lockable storage box.	**Internal A & External** **Cost Estimate: $12,000 to $20,000** [plantings: $5,000 to7,000; walkways: $7,000; toolbox: $500]	
MEDIUM	**5. Bookable Picnic Area** Consider creating a formal bookable picnic area at Puslinch Community Centre Park to the east of the senior soccer field, south of the shade shelter including a concrete pad and picnic tables.	**External** **Cost Estimate: $35,000 to $40,000**	Asset Management Plan

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TIMELINE	RECOMMENDATION	RESOURCES	ALIGNMENT
	MORRISTON MEADOWS PARK		
SHORT	1. **Replace Permitted Picnic Tables** Upgrade the picnic tables for the Morriston Meadows Park Picnic Pavilion.	**External** **Cost Estimate: $12,000 to $15,000**	Asset Management Plan
SHORT	2. **Accessible Pathway to Picnic Area** Create an accessible pathway from the parking area to the Picnic Pavilion.	**External** **Cost Estimate: $25,000 to $35,000**	Asset Management Plan
LONG	3. **New Accessible Playground** Remove the old playground and construct a new playground on the same elevation of the parking lot for improved accessibility. Morriston Meadows playground is the last to be upgraded for accessibility and lifecycle replacement.	**External** **Cost Estimate: $350,000 to $450,000**	Asset Management Plan
	OLD MORRISTON PARK		
MEDIUM	1. **Bookable Picnic Area** Consider constructing a formal bookable picnic area to align with providing picnic areas at all community parks (e.g. outside of outfield). Would also serve users during tournaments or rentals.	**Internal A** **Cost Estimate: $35,000 to $40,000**	Asset Management Plan
MEDIUM	2. **Parking Lot Gravel Surfacing** Potentially formalizing the parking area with at least gravel surfacing to be consistent with Morriston Meadows Park.	**External** **Cost Estimate: $25,000 to $35,000**	Asset Management Plan

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TIMELINE	RECOMMENDATION	RESOURCES	ALIGNMENT
	BADENOCH SOCCER FIELD		
SHORT	**1. Raptor Pole for Osprey** Create a specific raptor/osprey perch for nesting to attract birds and deter them from them using the lighting infrastructure.	**External** **Cost Estimate: $4,000 to $9,000**	Asset Management Plan
MEDIUM	**2. Granular Walking Pathway** Create a walking path around the perimeter of the park around the soccer field and consider creating a connection into the Badenoch Tract trail system.	**External** **Cost Estimate: $40,000 to $80,000**	Asset Management Plan
	FOX RUN PARK		
MEDIUM	**1. Municipal Property Fencing** Install fencing at municipal property line to eliminate private encroachment on park space. Approximately 600 linear metres.	**External** **Cost Estimate: $48,000 to $60,000**	Asset Management Plan
SHORT	**2. Disc Golf Course** Consider installing a modified disc golf course for a passive feature of the park.	**External** **Cost Estimate: $8,000 to $14,000**	Asset Management Plan
	HISTORIC CORNER BLOCK PARK		
MEDIUM	**1. Upgrade Pathways and Seating** Upgrade pathways and seating in Historic Corner Block Park to improve their poor condition and to improve accessibility. Approximately 50 metres of pathways and 2 benches.	**External** **Cost Estimates: $12,000 to $15,000**	Asset Management Plan

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TIMELINE	RECOMMENDATION	RESOURCES	ALIGNMENT
	BOREHAM PARK		
SHORT	**1. Low Maintenance Plantings** Replace plantings at Boreham Park with low maintenance grasses to reduce the need for maintenance and upkeep.	**External** **Cost Estimates: $1,000 to $5,000**	Asset Management Plan
MEDIUM	**2. Street Parking for Boreham Park** Consider implementing a compacted granular shoulder along the road to create parking along the street. Approximately 50 linear metres along park frontage.	**External** **Cost Estimates: $5,000 to $10,000**	Asset Management Plan

DRAFT

Ministry of the Environment, Conservation and Parks
Environmental Permissions Branch
2nd Floor
40 St. Clair Avenue W
Toronto ON M4V 1M2
Tel: 416 314-8001
Fax: 416 314-8452

Ministère de l'Environnement, de la Protection de la nature et des Parcs
Direction des permissions environnementales
2e étage
40, avenue St. Clair Ouest
Toronto ON M4V 1M2
Tél.: 416 314-8001
Téléc: 416 314-8452

Ontario

August 19, 2026

Township of Puslinch
Attn: Justine Brotherston, Municipal Clerk
7404 Wellington Road 34
Puslinch, ON, N0B 2J0

Sent via e-mail: jbrotherston@puslinch.ca

Re: Permit to Take Water Application No. 1000142989 (ERO No. 019-9325) – James Dick Construction Limited, Glenchristie Quarry, 2145 Waterloo Regional Road 24, Township of Puslinch – Summary of Stakeholder Comments and Ministry Response

Dear Justine Brotherston,

I am writing regarding the above-noted Permit to Take Water (PTTW) application submitted by James Dick Construction Limited for the dewatering of the Glenchristie Quarry, and to follow up on the comments submitted by the Township of Puslinch (the "Township") through Council Resolutions provided on January 16, 2025 and March 7, 2025.

I would like to thank the Township of Puslinch (the "Township") for taking the time to provide comments on this application. I would also like to acknowledge the technical review comments prepared by Wellington Hydrogeology Ltd. and Aboud & Associates Inc. on behalf of the Township, each of which were considered in the course of the Ministry's review. The Ministry of the Environment, Conservation and Parks (the "Ministry") values the perspectives and local knowledge of the commenting agencies, and the comments received have meaningfully informed the Ministry's technical review of this application.

The Ministry has completed a fulsome technical review of the PTTW application. As part of this review, a revised Hydrogeological Assessment Report, dated March 31, 2026, was submitted by the proponent's consultant. The revised report was informed by the Ministry's technical review as well as the submissions received from a number of local stakeholders, including the Township.

A summary document (Appendix A) has been prepared, which describes the principal concerns raised across all stakeholder submissions received for this application, and how each has been considered by the Ministry and the applicant's revised Hydrogeological Assessment Report. I would like to highlight below how the principal concerns raised in your submission were considered.

1. **Private well protection and notification**

   The Township requested notification of any well interference or threshold value exceedances, and that the applicant be required to take immediate action should well

interference occur. Any permit issued would include a monitoring program with multiple trigger values and associated response actions. Regarding notification and well interference responses, the Ministry could commit to a summary of any interference or trigger exceedances being provided to the Township.

2. **Hydrogeological review comments**

   The technical comments prepared by Wellington Hydrogeology Ltd. raised concerns including cumulative impacts and the potential for breaching the aquitard between the Guelph and Gasport Formations. Any permit issued would require the quarry floor to be maintained at least one metre above the Gasport Formation for the duration of the permit, along with geological mapping of the bedrock surface after the Lower Quarry Lake is dewatered to confirm the formation boundaries. Should the Gasport Formation be documented above 270 metres above sea level in any area, water taking would not be permitted to proceed in that area pending further delineation.

3. **Ecological review comments**

   In response to the baseline data gaps identified by Aboud & Associates Inc., the applicant's ecologist completed supplemental field surveys in 2023 and 2025, providing one full year of baseline data. Any permit issued would require annual ecological monitoring during dewatering, with continued monitoring through the permit term. The associated ecological triggers and response actions are described in the applicant's revised Hydrogeological Assessment Report.

I would also like to acknowledge the formal request for a meeting between Ministry reviewers, municipal staff, and other affected agencies prior to the issuance of any permit. This request has been noted and remains under consideration; the Ministry will follow up separately in this regard.

With respect to concerns relating to discharge water quality, the applicant (James Dick Construction Limited) has also submitted an application for an Environmental Compliance Approval (ECA Reference No. 1000303278; ERO No. 019-9378) for stormwater management works serving the site, consisting of a quarry sump, settling basin, and rock crib, with discharge directed to the Speed River. The ECA application remains under review. The comments and concerns relating to discharge water quality, including monitoring requirements, that have been raised to date would be carried forward and considered as part of the Ministry's review of that ECA application. Note that the proposed PTTW conditions would prohibit discharge to the natural environment without prior treatment in accordance with an approved Environmental Compliance Approval.

I hope that this letter and Appendix A provide clarity on how the Township's comments have been considered in the Ministry's review.

The Ministry intends to move forward with a decision on this application in the near future. In recognition of the changes to the proposed activity and the supporting Hydrogeological Assessment Report, the Ministry will accept further comments the Township may have for an additional 30-day commenting period ending **September 19, 2026,** for consideration before the review is finalized.

Should you have any questions or wish to discuss the above, please contact Ajay Persaud, Environmental Scientist, Permit to Take Water Unit, at ajay.persaud@ontario.ca. Thank you again for your engagement on this application.

Sincerely,

[redacted]

Neil Taylor
Supervisor, Permit to Take Water Program
Environmental Permissions Branch
Ministry of the Environment, Conservation and Parks

Encl.: Appendix A – Summary of Stakeholder Comments and Ministry Responses, Permit to Take Water Application #1000142989, Glenchristie Quarry (June 2026)

Appendix A: Summary of Stakeholder Comments and Ministry Responses

Permit to Take Water Application #1000142989

Applicant: James Dick Construction Limited

Site: 2145 Waterloo Regional Road 24, Township of Puslinch, Wellington County

Source and Purpose: Bedrock groundwater; quarry dewatering for aggregate extraction

James Dick Construction Limited has applied for a Permit to Take Water (PTTW) to dewater the Glenchristie Quarry for aggregate extraction from the Guelph Formation bedrock. The application proposes a two-stage approach: an initial phase removing water held in storage in the Lower Quarry Lake, discharged to the Speed River, followed by a maintenance phase in which all pumped water is returned to the aquifer through the Upper Quarry Lake and Spencer Pit Infiltration Gallery.

The Ministry received submissions on this application from seven stakeholders between November 2024 and July 2025: the Grand River Conservation Authority, the City of Guelph, the City of Cambridge, the Regional Municipality of Waterloo, the Township of Puslinch, Wellington Source Water Protection, and the Lake Erie Region Source Protection Committee.

The Ministry has considered all comments received and has incorporated responses into its review. The table below summarizes the principal concerns raised across the submissions and how each has been considered.

Summary of Concerns and Ministry Response

Theme	Concern	Ministry Response
Cumulative Impacts	Concerns were raised regarding the overlapping zones of influence from the Glenchristie Quarry, Lafarge Wellington Quarry, Spencer Pit, and municipal wells. Independent modelling commissioned by the City of Guelph estimated a potential cumulative reduction of up to 1,266 m³/day in municipal well capacity. A separate estimate prepared for the Regional Municipality of Waterloo identified a potential reduction of 18.4 L/s, affecting capacity for approximately 6,000 homes. The Guelph analysis did not include water reinjection.	Any permit issued would include a condition requiring the water pumped during Stage 2 maintenance dewatering to be returned to the aquifer, via the Upper Quarry Lake and the Spencer Pit Infiltration Gallery, making the long-term taking non-consumptive. Stage 1 would not be permitted to commence until water taking at the Spencer Pit (PTTW No. 0242-CWHQT7) is paused under an amendment to that permit, with aggregate washing needs met during this period by a portion of the water pumped from the quarry. A groundwater model update would also be required within three years of the commencement of water taking, and every four years thereafter, to verify predicted drawdown against monitoring data.

Municipal Water Supply	Concerns were raised regarding potential impacts to municipal water supply systems and the ability of nearby municipalities to meet provincially mandated housing growth targets.	The return of water to the aquifer during Stage 2 of the proposed dewatering is designed to preserve municipal well flow capacity. The Ministry intends to limit any permit to a five-year duration, allowing verification through monitoring and updated groundwater modelling before renewal.
Model Quality	Limitations were identified in the applicant's groundwater model, including discrepancies between field-measured and calibrated hydraulic conductivity values, the exclusion of municipal wells from the model domain, and a normalized root mean square error within certain parts of the model domain.	The Ministry acknowledges the model's limitations, including the exclusion of municipal wells from the model domain. Any permit issued would require a model update within three years of the commencement of water taking, calibrated with recorded water level and water taking data. The calibrated hydraulic conductivity values for the Guelph Formation are reasonably comparable to the regional Tier 3 models at the aquifer scale, and the model is considered a suitable planning tool for assessing the proposed taking.
Gasport Formation Protection	Concerns were raised regarding the potential for breaching the aquitard between the Guelph and Gasport Formations. Borehole logs indicate the contact occurs at variable elevations across the site. A minimum five-metre buffer above the contact was recommended.	Any permit issued would require the quarry floor to be maintained at least one metre above the Gasport Formation for the duration of the permit, along with geological mapping of the bedrock surface after the Lower Quarry Lake has been dewatered. Should the Gasport Formation be documented above 270 metres above sea level (masl) in any area, water taking would not be permitted to proceed in that area pending further delineation.
Ecological Impacts	Gaps were identified in baseline ecological data, including anuran, breeding bird, Brook Trout, and benthic macroinvertebrate surveys. Concerns were raised about potential impacts to the Provincially Significant Wetland and terrestrial communities from altered site hydrology.	The applicant's ecologist completed supplemental field surveys in 2025 which, combined with the 2023 surveys, provide one full year of baseline data. Any permit issued would require annual ecological monitoring during dewatering, with continued monitoring through the permit term. The associated ecological triggers and response actions are described in the applicant's revised Hydrogeological Assessment Report.
Water Quality	Concerns were raised about the suitability of discharge water for the	Under the PTTW, no surface water discharge would be permitted except

	Speed River, including potential water quality impacts to the receiving environment.	in accordance with an approved ECA; discharge water quality would be addressed through ECA Application No. 1000303278.
Subaqueous Mining	Subaqueous extraction was recommended as an alternative to full dewatering, noting that this approach would avoid the need for large-scale dewatering and reduce potential impacts to nearby groundwater users, surface water features, and wetlands. Successful operations at other Ontario quarries were cited.	The applicant has confirmed that subaqueous extraction was completed to the maximum practical extent at this site. However, the base of the licensed aggregate resource extends beyond the practical limits of subaqueous mining alone, and the remaining aggregate beneath the existing ponds is not recoverable without dewatering. The return of water to the aquifer during Stage 2 of the proposed dewatering, together with a comprehensive monitoring program, is designed to mitigate the potential impacts of the dewatering activities with respect to off-site aquifer drawdown.
Source Water Protection	Concerns were raised that the proposed water taking would constitute a Significant Drinking Water Threat under the Clean Water Act, given the quarry's location within the draft Wellhead Protection Area – Quantity (WHPA-Q) for both the City of Guelph and the Regional Municipality of Waterloo.	The non-consumptive water return (Stage 2 per the revised Report) addresses the drinking water threat classification associated with a consumptive taking. Any permit issued would be limited to a five-year duration, and the results of the groundwater model update would be shared with stakeholders to inform any future WHPA-Q assessment.
Permit Duration	A five-year permit was recommended rather than the ten years requested by the applicant, citing the sensitive hydrogeological setting, proximity to multiple municipal wells, and precedent for shorter permit terms within Wellhead Protection Areas.	The Ministry concurs and intends to limit any permit issued to a five-year duration and require annual monitoring reporting, with renewal contingent on satisfactory monitoring results and updated groundwater modelling.

Laura Emery

From: Angie Mason <amason@wellingtonhydrogeology.com>
Sent: September 8, 2026 3:10 PM
To: Justine Brotherston; Cheryl-Anne Ross; Kyle Davis; Denise Sharp
Cc: Keira Martinson; Kim Funk; Jordan Widmaier
Subject: RE: Glenchristie Quarry Addendum Comments - DRAFT
Attachments: 260908_HydroG comments_Glen Christie PTTW_WellingonHydrogeology.pdf

Follow Up Flag: Follow up
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Hi Justine,

My comments are attached.

The proposed five-year permit term, annual ecological monitoring and return of Stage 2 flows to the aquifer address several previous recommendations. Key outstanding items are:

- Supporting rationale for the limits on subaqueous mining without dewatering.
- Further Gasport contact delineation and justification for the proposed 1 m separation.
- Baseline and ongoing private well water quality sampling.
- Completion of the required baseline monitoring before dewatering and establishment of thresholds.
- Revised hydrographs and clearly defined monitoring thresholds and actions.
- Confirmed annual reporting and notification deadlines for both Townships.

Thanks,

Angie Mason, M.Sc., P.Geo. (Ontario), P.Geo. (Alberta), QP$_{ESA}$ (She/Her)
Senior Hydrogeologist and CEO

Wellington Hydrogeology Ltd.
Cell 519-831-9696
Email amason@wellingtonhydrogeology.com
Website www.wellingtonhydrogeology.com
Mailing Address 4662 Sideroad 20N, Guelph, ON N1H 6J3

WHL Project: 2404.01 (Glenchristie Quarry PTTW Review)

September 8, 2026

Wellington Source Water Protection
7444 Wellington Road 21
Elora, Ontario N0B 1S0

Attention: Kyle Davis
Risk Management Official

Re: **Glenchristie Quarry – James Dick Construction Ltd.**
Part Lot 1, 2 and 3, Concession 4, Township of Puslinch
2145 Waterloo Regional Road 24, Cambridge, Ontario
Permit To Take Water Application (MECP Ref. No. 1000142989)
Hydrogeological Comments in Response to 2026 Addendum

Wellington Hydrogeology Ltd. (WHL) is pleased to provide hydrogeological comments on the above-noted Permit To Take Water (PTTW) Application for the Glenchristie Quarry, located at Parts Lots 1, 2 and 3, Concession 4 in the Township of Puslinch, Ontario (the site), with a municipal address of 2145 Waterloo Regional Road 24 in Cambridge, Ontario. The PTTW applicant and site owner is James Dick Construction Limited (JDCL).

WHL's previous hydrogeological comments, dated January 10, 2025 and February 14, 2025, were submitted to the Ministry of the Environment, Conservation and Parks (MECP) as part of the stakeholder comments from the Township of Puslinch (Township) and Wellington Source Water Protection (WSWP). On August 19, 2026, the MECP provided the Township and WSWP with a response letter and an addendum hydrogeological report from the applicant.

The comments below are provided for the Township's and WSWP's consideration in response to the August 2026 correspondence and accompanying addendum hydrogeological report.

1.0 Reviewed Materials

WHL reviewed the following submission materials from a peer review perspective in preparation of these comments:

1. MTE Consultants Inc. (MTE, 2026). Glenchristie Quarry – Addendum Hydrogeology Assessment Report, Written in support of a Permit to Take Water Application and a Section 53 Environmental Compliance Approval. MTE File No. 47950-100, dated March 31, 2026.

2. MTE Consultants Inc. (MTE, 2024). Glenchristie Quarry – Hydrogeology Assessment Report, Written in support of a Permit to Take Water Application and a Section 53 Environmental Compliance Approval. MTE File No. 47950-100, dated October 18, 2024.

3. MacNaughton Hermsen Britton Clarkson Planning Limited. Approved Aggregate Resources Act (ARA) Site Plans. Guelph Dolime Limited. Project Name: Hespeler Site, Part Lots 1, 2, and 3, Concession 4, Township of Puslinch, County of Wellington. Revision Date: Jan 04, 1994.

4. Matrix Solutions Inc. (Matrix). 2021. Additional Excavation Scenario Modelling for Amendment of the Permit to Take Water for the Lafarge Canada Inc. Wellington County Quarry. Matrix 15072-527, Version 1.0, dated May 4, 2021.

5. Natural Resource Solutions Inc. (NRSI). 2024a. Glenchristie Quarry, Lower Quarry Lake Dewatering, Natural Environment Assessment. Project No. 3155, dated July 2024.

6. NRSI. 2024b. Quarry, Lower Quarry Lake Dewatering, Natural Environment Monitoring Plan. Project No. 3155, dated July 2024.

2.0 Technical Comments and Recommendations

WHL's previous comments addressed potential hydrogeological and ecological impacts associated with the proposed PTTW, including recommendations for additional assessment, monitoring and mitigation. Table 1 summarizes these recommendations, the responses provided in the addendum hydrogeological report (MTE, 2026) and the MECP's August 19, 2026 correspondence.

Table 1: Summary of responses to previous WHL comments

Previous WHL Comment	MECP / MTE Response	Status
Subaqueous mining: Consider extraction without dewatering to reduce potential impacts.	MECP's August response states that subaqueous extraction has reached its practical limit.	**Partially addressed.** The MECP has relayed the applicant's response; however, a feasibility assessment was not provided in the addendum.
Cumulative impacts: Complete a collaborative assessment of existing and proposed takings before permit issuance.	Modelling was completed using the City of Guelph and Region of Waterloo groundwater models, showing a potential reduction in municipal capacity of 1,266 m^3/day for the City of Guelph and 18.4 L/s (approximately 6,000 homes) for the Region of Waterloo. Note that	

Previous WHL Comment	MECP / MTE Response	Status
	WHL was not provided with the detailed groundwater flow model report for review. As mitigation, the MECP indicated that the PTTW will now require Stage 2 water to be returned through the Upper Quarry Lake and Spencer Pit Infiltration Gallery, "making the long-term taking non-consumptive." Spencer Pit taking would be paused during Stage 1 under an amended permit. A model update would be required within three years of commencing taking and every four years thereafter.	
Gasport Formation contact assessment and protection: Delineate the contact, revise cross-sections and maintain a 5m buffer, or another technically justified and MECP-approved separation. Update ARA plans accordingly.	The discrepancy between borehole logs and regional sections is acknowledged. No additional delineation or updated cross-sections have been provided. Quarry-face mapping after dewatering, additional delineation where necessary, and a 1 m separation are proposed.	**Acknowledged and partially addressed.** Delineation of Gasport Formation contact remains outstanding. Quarry-face mapping may not be sufficient to protect Gasport Fm if contact is breached to observe quarry face. No demonstrated basis for the 1 m buffer was identified. Revised cross-sections and pre-dewatering delineation remain outstanding.
Speed River separation and quarry stability: Clarify separation dimensions and assess breach risk.	MTE identifies a 15 m bedrock setback, plus a 44 m-wide rehabilitated side slope (upon rehabilitation; following extraction), and discusses flood levels, inspections and contingency storage.	**Addressed.** The response relies on approved ARA site plans.

Previous WHL Comment	MECP / MTE Response	Status
Dewatering and discharge arrangements: Provide detailed discharge plans for each stage and assess discharge quality against surface water criteria.	Stage 2 now proposes return to the aquifer. Updated routing, a water management figure, design attachments, baseline-quality assessment and comparison with PWQO and other aquatic-life guidelines are included. ECA required for surface water discharge.	**Addressed conceptually.** Baseline assessment and final site-specific effluent criteria will be required as part of the concurrent ECA application. Confirm in issued ECA.
Initial pumping limit: Limit 9,550 L/min to the first 120 days, followed by maintenance taking of up to 6,900 L/min.	The MECP letter acknowledges the requested phase-specific limit but does not confirm the rates or 120-day restriction.	**Addressed.** Although a strict limit was not added, the MECP acknowledges this concern and we defer further review to the MECP.
New monitors east of the Speed River: Provide MW4/MW5 construction details, monitor relevant hydrostratigraphic units, and obtain baseline data before dewatering.	MW4 and MW5 now include shallow/deep bedrock wells and associated overburden wells; two years of baseline data are specified.	**Incorporated in the proposed design.** Installation records and final screened intervals remain to be confirmed; the tables identify these wells as "to be installed."
Private wells: Offer baseline water quality sampling to all participating owners; monitor quarterly during the first year and at least annually thereafter.	The program retains six participating wells, proposes further invitations and continuous data collection using dataloggers.	**Partially addressed.** The revised private well monitoring rows specify water levels, without the requested routine quality sampling.
Private well complaints: Clarify complaint response plan.	A complaint or 25% reduction in available drawdown triggers investigation. Measures include pump adjustments, temporary supply, replacement/deepening and reduced quarry pumping.	**Partially incorporated.** Responsibilities are clearer, but immediate alternative supply, water quality sampling, and notification to both Townships are not clearly required.
Groundwater thresholds: Reconcile green thresholds with predicted drawdown and seasonal baseline	Revised hydrographs with groundwater elevations and threshold values were not provided; the 2026 Addendum still	**Not addressed.** Revised hydrographs should be provided showing revised trigger values. Green threshold

Previous WHL Comment	MECP / MTE Response	Status
conditions; strengthen review and escalation actions.	references the K1-K4 hydrographs from the 2024 report, which show green threshold values up to 2 m lower than the simulated drawdown on Figures 24 and 25 of the 2024 report.	are to be determined as the observed average pre-dewatering seasonal low minus the predicted drawdown, with no additional buffer or safety factor added for the green threshold.
Groundwater thresholds: Require substantive review at the green stage.	The hydrogeologist must review water-quantity data against precipitation and pumping; escalation follows where the exceedance is not climate-related.	**Incorporated.** This strengthens the original notification-only green response. Biologist involvement generally follows at the yellow stage.
Wetland instrumentation: Install dataloggers at all locations, nested piezometers where appropriate, and replace or relocate MP14-23 if feasible.	Nested pairs are proposed at locations where surface water may be absent for all or part of the year. MP14-23 remains in the program, with a proposed companion MP14d. Continuous hourly water-level and temperature monitoring is proposed throughout the expanded wetland network.	**Incorporated as a commitment.** Confirm installation and baseline data collection.
Hydrological baseline and follow-up: Obtain at least one full year of baseline data, including seasonal highs and lows; continue monitoring through operations and at least one year afterward.	Two years of baseline monitoring are now specified for groundwater, surface water and baseline water quality.	**Incorporated as a commitment.** Confirm baseline data collection.
Tributaries and Speed River: Add continuous level/temperature monitoring and seasonal quality sampling at Tributary #2; confirm downstream Speed River	Hourly levels and temperatures, stage–discharge relationships and nested pairs are proposed at several monitoring stations. An ecological station is also added near MP5-23. SG7 is a proposed downgradient monitoring station within the Speed River for water	**Addressed.** Continuous monitoring and twice annually water quality laboratory analyses incorporated.

Previous WHL Comment	MECP / MTE Response	Status
monitoring and dissolved-oxygen methods.	level, temperature and flow monitoring.	
Wetland/surface-water triggers: Establish receptor-specific level, temperature and quality triggers with ecological response surveys.	The program adds water-level/flow triggers, "abnormal" vertical-gradient triggers and water-quality criteria.	**Partially incorporated.** Many station-specific values remain to be developed. Numerical temperature triggers are not clearly established.
Ecological baseline and survey frequency: Complete outstanding studies and undertake annual surveys, with additional surveys following red triggers.	MECP reports supplemental field surveys in 2025 and one full year of baseline data. Updated ecological reports were not provided for review. MECP notes that annual ecological monitoring would be required during dewatering, continuing through the permit term.	**Partially addressed.** Reports were not provided to verify baseline data or survey completeness. We concur with MECP requirement for annual monitoring. Confirm in the issued permit.
Permit duration: Issue an initial five-year permit rather than ten years.	MECP intends to issue a five-year permit, with annual reporting and renewal dependent on satisfactory monitoring and updated modelling.	**Addressed.** Confirm in the issued permit.
DFO involvement: Verify DFO review/approval of the proposed monitoring arrangements.	A May 14, 2024 Letter of Advice is reproduced and summarized.	**Addressed** from a hydrogeological standpoint; any further commenting is deferred to the ecology peer reviewer.
Reporting and notification: Provide both Townships with annual hydrogeological/ecological reports and notifications of complaints and red exceedances.	Annual reporting is proposed. MECP indicated that it could provide the Township with a summary of interference or trigger exceedances.	**Partially addressed.** Require distribution of annual reports to both Townships and specify deadlines for reporting well interference complaints and red threshold exceedances.

WHL acknowledges the proposed revisions, particularly the five-year permit term, annual ecological monitoring and return of Stage 2 dewatering flows to the aquifer. Several recommendations have been addressed in principle; pending monitoring network expansion and collection of additional baseline data.

The following matters remain outstanding:

1. **Subaqueous mining**

   The MECP response indicates that subaqueous mining has reached its practical limit at Glenchristie Quarry. A supporting feasibility assessment was not provided.

   JDCL has proposed underwater extraction at the Reid Road Reservoir Quarry in Milton. WHL requests an explanation of the constraints at Glenchristie, including differences in geology, water depth, extraction depth and equipment limitations. Extraction without dewatering would reduce the potential for dewatering impacts.

2. **Gasport Formation delineation and separation**

   No additional drilling results or revised cross sections delineating the Gasport contact were provided. Mapping exposed quarry faces after dewatering does not establish the contact beneath unexcavated areas. WHL recommends sufficient drilling and geological interpretation to establish excavation and dewatering limits before work proceeds.

   The technical basis for a 1 m separation, rather than the recommended 5 m, has not been provided. The applicant should demonstrate that the separation accounts for uncertainty in the contact elevation, geological variability and blasting effects.

3. **Private well water quality sampling**

   The revised program proposes water level monitoring at additional private wells but does not include the requested baseline water quality sampling.

   WHL recommends offering baseline water quality sampling to all willing private well owners within the study area, including those whose wells cannot accommodate water level monitoring. Water quality sampling from private wells should also be incorporated into the approved monitoring program as well as in response to well interference complaints.

4. **Baseline monitoring data**

   The addendum proposes two years of baseline monitoring, but several stations remain to be installed. WHL recommends providing the installation status, available records, data gaps and completion dates for each station.

   The required baseline monitoring should be completed, including spring freshet and seasonal lows, and thresholds finalized and accepted by MECP before dewatering begins.

5. **Green/Yellow/Red Thresholds**

WHL requests revised hydrographs showing the baseline levels, predicted drawdown, numerical triggers and required actions. The green threshold values should be consistent with the simulated drawdown as this is the maximum drawdown expected. The green threshold values should not include any added buffer or safety factor, and should be calculated based on the average seasonal groundwater low rather than the extreme seasonal lows seen in fall 2022. The Yellow Threshold is 1 m lower than the Green Threshold and is meant to cover seasonal variation.

Flow, temperature, water quality and vertical gradient triggers should also be defined. Trigger levels may require revision once the proposed 2 years of baseline data has been completed.

6. **Township Notifications**

MECP has indicated that summaries of complaints and exceedances could be provided, but notification deadlines and report distribution have not been confirmed.

WHL recommends that the approved monitoring plan require annual hydrogeological and ecological reports to be provided to the Clerks of Puslinch and Guelph/Eramosa Townships. Both Townships should receive prompt notification of well interference complaints and red threshold exceedances, with defined deadlines.

3.0 Closure

We appreciate the opportunity to provide these comments. Should you have any questions or concerns, please do not hesitate to contact the undersigned.

WELLINGTON HYDROGEOLOGY LTD.

[redacted]

Angela Mason, M.Sc., P.Geo., QP_{ESA}
Senior Hydrogeologist and CEO
Cell: 519-831-9696
Email: amason@wellingtonhydrogeology.com

ABOUD & ASSOCIATES INC.
Consulting Arborists • Ecologists • Landscape Architects

3-5 Edinburgh Road South
Guelph . Ontario
N1H 5N8

519.822.6839
info@aboudtng.com
www.aboudtng.com

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MONITORING
CONTRACT ADMINISTRATION

ENVIRONMENTAL STUDIES
SUBWATERSHED STUDIES
ENVIRONMENTAL IMPACT STATEMENTS
ECOLOGICAL LAND CLASSIFICATION
WETLAND EVALUATION
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GREEN ROOFS
CONTRACT ADMINISTRATION

EXPERT OPINION
OLT TESTIMONY
LEGAL PROCEEDINGS
PEER REVIEW
RESEARCH
EDUCATION

September 11, 2026

Our Project #: AA21-049A-023
Sent by email: jbrotherston@puslinch.ca
mfarncombe@puslinch.ca
kfunk@centrewellington.ca

Justine Brotherston
Township of Puslinch
7404 Wellington Rd. 34
Puslinch, ON N0B 2J0

Re: Glenchristie Quarry- James Dick Construction Ltd.
Environmental Compliance Approval Application
(MECP Ref No. 1000303278)
Peer Review – Ecology, 2nd Submission

Dear Ms. Brotherston:

Aboud & Associates Inc. (AA) has been retained by the Township of Puslinch to provide ecological comments on the Environmental Compliance Approval (ECA) Application for the Glenchristie Quarry. The Glenchristie Quarry is located at Part Lots 1, 2 and 3, Concession 4 in the Township of Puslinch and is municipally located at 2145 Waterloo Regional Road 24 in Cambridge. The site is an existing aggregate operation, operating under an approved ARA license, which is seeking approval for a ECA to allow for further aggregate extraction. A ECA is required due to the potential of the proposed activities to impact the public or natural environment.

AA has previously reviewed the Natural Environment Assessment (NEA) & Natural Environment Monitoring Plan (NEMP) completed by Natural Resource Solutions Inc. (dated: July 2024) for the proposed stormwater management works related to the discharge associated with the dewatering of Lower Quarry Lake.

At this time, AA has completed a second submission peer review of additional information provided within the Addendum Hydrogeology Assessment Report completed by MTE Consultants (dated: March 31, 2026) and the MECP Summary of Stakeholder Comments and Ministry Response (August 19, 2026).

Background

It is the understanding of AA that stormwater management works have been proposed to address potential water quality impacts associated with discharging water from the Glenchristie Quarry into the Speed River. The proposed discharge of water into the Speed River requires an ECA from the Ontario Ministry of Environment, Conservation and Parks (MECP). The NEA report was completed to inform the proponent's request for an ECA.

Through review of the ECA application, AA understands that:

- JDC currently operates the quarry under an approved *Aggregate Resources Act*
- License (Class A) issued by the Ministry of Natural Resources and Forestry (dated: January 13, 1994).
- The current Official Plan designation of the Glenchristie Quarry is Mineral Aggregate Resource and the lands are zoned as Extractive (EXI).
- The receiver of the proposed effluent discharge is the Speed River.
- The proposed stormwater management works are comprised of a quarry sump, a settling basin, and a rock crib.
- The dewatering process consists of pumping water directly into the rock crib prior to entering the discharge outlet channel connected to the Speed River.
- The settling basin will be constructed once the water level in the quarry is low enough.
- The settling basin will maintain water quality through a permanent pool volume and 24 hour extended retention time for storm events.
- The drainage area associated with the proposed activity is 26.5 hectares.
- Erosion and sediment control will be provided by the rock crib and the settling basin.

Through review of the previously submitted NEA, AA understands that:

- The subject lands owned by the proponent are comprised of active bedrock and other aggregate extraction activities, agricultural and natural land covers, and are bisected by the Speed River.
- Lower Quarry Lake maintains a direct connection to the Speed River and is therefore considered an 'online' feature connected to fish habitat within the Speed River.
- Natural features within the subject lands consist of portions of the Speed River Provincially Significant Wetland (PSW) complex with lands immediately adjacent comprising portions of the Glen Christie and Ellis Creek PSW complexes.
- Significant features including Species at Risk and their habitat, as well as candidate and confirmed Significant Wildlife Habitat were identified within the subject lands and adjacent study area.

- Results of completed field investigations and background information from other available sources were used to assess the significance and sensitivity of the existing natural features, as well as a potential authorization under the *Fisheries Act*.
- Recommendations were provided to avoid, or otherwise minimize or mitigate impacts to natural features within the study area.

Methodology

The peer review was completed as a 'desktop review'. No site visit was conducted by AA as part of the review of the Addendum Hydrogeology Assessment Report. The peer review was completed based on company experience and knowledge, standards for Natural Environment Assessments in Wellington County and the GRCA, industry accepted methodology, and the requirements of federal, provincial and municipal policy documents.

Outstanding Comments from First Submission

The first submission included the Natural Environment Assessment (NEA) and Natural Environment Monitoring Plan (NEMP), prepared by Natural Resource Solutions Inc. (NRSI) in July 2024. AA's initial peer review identified a number of concerns requiring additional information, clarification, field investigations, and/or assessment. Key themes included the adequacy of baseline ecological information and natural heritage feature delineation, Species at Risk and Significant Wildlife Habitat, potential impacts to fish and fish habitat, including Brook Trout and potential discharge to Tributary #4, as well as the proposed mitigation, monitoring and regulatory agency coordination.

The Addendum Hydrogeology Assessment Report provides additional information regarding the proposed dewatering and monitoring plans; however, a number of ecological concerns identified through the initial peer review remain outstanding. These matters are discussed below.

Natural Environment Assessment

Relevant Policy

The comments regarding outdated legislative and policy references remain outstanding. The NEA should be updated to reflect applicable amendments to the *Species Conservation Act* (SCA), as well as the implementation of Ontario Regulation 41/24 under the *Conservation Authorities Act*. Corresponding Species at Risk habitat protections should also be incorporated into the assessment and mapping.

Please note, as the *Endangered Species Act* (ESA) has been replaced by the *Species Conservation Act* (SCA), the conclusions of the SAR assessment should be revised under current legislation.

Inclusion of Agency Correspondence

The NEA report identifies that correspondence with regulatory agencies, including the Grand River Conservation Authority, Ministry of Natural Resources, and Department of Fisheries and Oceans, occurred. As severe impacts to the existing natural features have the potential to occur due to the proposed dewatering, correspondence with agencies should be included as appendices to the NEA to ensure that all pertinent information regarding the proposed activity was communicated to the included agencies. This includes the Request for Information that was submitted to DFO, and communications related to scoping requirements from the GRCA.

Field Investigations

The comments regarding the adequacy of the baseline field investigation program remain outstanding. Additional surveys were required to address identified gaps in data, including the timing and completion of amphibian and breeding bird surveys. The results should be incorporated into an updated NEA and used to inform the proposed monitoring program.

It is noted in Section 7.3 of the Addendum Hydrogeology Assessment Report that additional baseline monitoring was completed in 2025, including salmonid spawning surveys. The baseline results of these surveys should be included in a future submission.

Limits of PSW Features

The discrepancy between mapped PSW limits and the limits identified within the NEA remains unresolved. ELC data cards for the relevant communities east of the Speed River should be provided to confirm whether these areas meet wetland criteria under the Ontario Wetland Evaluation System.

Confirmation of Proposed Receiving Waterbodies

Confirmation of the proposed receiving waterbodies and the information provided to DFO remains outstanding. In addition, the results of the added salmonid spawning surveys completed in 2025 should be included to address concerns regarding potential for discharge to Tributary #4 and the presence of potential Brook Trout spawning habitat.

Assessment of Impacts to Fish Habitat

The concerns regarding potential impacts to Brook Trout and fish habitat remain outstanding. The results of the added salmonid spawning surveys completed in 2025 should be included to address concerns regarding effects associated with the proposed discharge and appropriate mitigation measures.

Fisheries Timing Windows

The requirement to address potential effects on fish and fish habitat associated with continuous discharge and the inability to fully adhere to applicable fisheries timing windows remains outstanding. The NEA should discuss these potential effects and the implications for the conditions identified in the DFO Letter of Advice.

Impact of Stormwater Management on Terrestrial Features

The potential effects of installation of the proposed rock crib on adjacent terrestrial natural features remain to be addressed. The assessment should consider potential vegetation removal, grading, erosion and sedimentation, and wildlife disturbance, with appropriate mitigation measures and the proposed rock crib location identified on the relevant figures.

Natural Environment Monitoring Plan

Threshold Triggers and Field Investigations

It is recognized that empirical threshold triggers and additional monitoring stations have been included in the updated NEMP. However, the additional survey results representing existing baseline conditions that were required as part of the NEA have not been provided. As a result, it is unclear whether the proposed thresholds are sufficient to identify potential impacts to the natural features, given the uncertainty regarding baseline conditions. The baseline monitoring results and revised NEA should be provided to support the appropriateness of the proposed empirical thresholds.

Monitoring Frequency

It is noted that post-dewatering monitoring is proposed for Years 2, 4, and 6 following cessation of dewatering. Given the level of discharge expected for the project, monitoring should be completed annually to identify patterns of change and potential negative impacts over time. Annual monitoring should be maintained until the results of post-dewatering monitoring demonstrate that conditions have remained stable (unchanged) relative to the baseline monitoring year. Where monitoring demonstrates no changes to the identified natural features or other indicators of impact, consideration may be given to reducing the monitoring frequency to every two years.

Submission of Monitoring Reports

Annual monitoring reports are to be submitted to the Township of Puslinch Clerk and Wellington County for circulation to the appropriate parties.

Conclusion

A number of the comments identified through the initial peer review remain outstanding. In particular, additional information and assessment are required to address outstanding gaps in the baseline ecological information, natural heritage feature delineation, Species at Risk and fish and fish habitat assessments, and associated mitigation and monitoring

requirements. The baseline monitoring and survey results identified as required through the NEA, including the additional surveys completed in 2025, should be provided and incorporated into a revised NEA.

The outstanding baseline information is also necessary to support the proposed NEMP, including to demonstrate that the proposed empirical threshold triggers and monitoring frequency are appropriate for identifying potential changes to the natural features and initiating mitigation where required. Until the existing conditions and potential sensitivities of the natural features are adequately established, the appropriateness of the proposed monitoring thresholds and frequency cannot be fully evaluated.

Accordingly, a revised NEA addressing the outstanding comments identified above should be provided in addition to detailed responses to each comment in the attached comment matrix.

Please contact the undersigned should you require additional information of the above.

Yours truly,

ABOUD & ASSOCIATES INC.

[redacted]

Jordan Widmaier, B.Sc.
CAN-CISEC
Aquatic Ecologist

&

[redacted]

Cheryl-Anne Ross, B. Sc., F.W.T.
MNRF Certified ELC & OWES
Ecology Lead & Wildlife Ecologist

Attachments:
Appendix A NEA/NEMP Comment Table

S:\A+A Projects\2021\Approved\21-049A Puslinch Peer Review\AA File\21-049A-023A Glen christie Quarry NEA and NEMP 2024\Report\AA21-049A-023 Glenchristie Quarry ECA Ecology Peer Review NEA and NEMP.docx

Glen Christie Quarry, Puslinch, Ontario, Natural Environment Assessment	
AA Comment (February 19, 2025)	**AA Comment (September 11, 2026)**
Section 1.0- Introduction	
Please confirm how the study area was defined. The report states that the study area extends slightly beyond the ZOI, please define 'slightly'. Based on the study area identified on Map 1 and the ZOI on Map 7, the study area is inside the ZOI south of the property, to the east of Hespeler Road. Please identify why the study area was not extended beyond the ZOI in this area.	Comment remains outstanding.
It is noted that the information obtained through the report was used to inform a potential authorization under the federal Fisheries Act. Please provide all correspondence between the proponent, NRSI and DFO.	Comment remains outstanding.
Section 2.0- Relevant Policies, Legislation and Regulations	
Section 2.3- Ontario Regulation 150/06 is referenced; however, Ontario Regulation 41/24 came into effect in February 2024, prior to the report completion date of July 2024. Please update the report to reflect Ontario Regulation 41/24 and the GRCA Policies for the Administration of the Prohibited Activities, Exemptions and Permits Regulation (May 2024) document.	Comment remains outstanding.
Section 2.4.1 should be updated to reflect that the Provincial Planning Statement (2024) is now in force rather than the Provincial Policy Statement.	Comment remains outstanding.
Section 3.0- Summary of Background Information	
The NEA does not identify correspondence with MECP/NHIC. Please include any communication with MECP as an appendix or note that they were not contacted.	Comment remains outstanding.
Please include correspondence with the MNR and GRCA as an appendix.	Comment remains outstanding.
Please update references to GRCA policy documents to reflect Ontario Regulation 41/24.	Comment remains outstanding.
In addition to the ARA Survey Point mapping, the ARA Line Segment and Polygon Segment mapping should also be referenced.	Comment remains outstanding.
Appendices V & VI provide observation data from citizen science resources including eBird and iNaturalist. Please include these references within the sources listed in Section 3.0.	Comment remains outstanding.

Section 3.1- Species at Risk should also include those listed under SARA, as the study area includes waterways containing fish habitat and potential habitat for migratory bird species at risk. Please review and revise.	Comment remains outstanding.
Section 4.0- Field Methodology	
Section 4.4- Redd surveys were not included within the field investigations. As known habitat for Brook Trout occurs within Tributary #4, and discharge is identified as potentially occurring. Redd surveys completed in the appropriate season are required to adequately assess habitat use and impacts.	Comment remains outstanding.
Section 5.0- Existing Conditions	
Section 5.4.2- Zebra Mussels were observed in Lower Quarry Lake and the channel which connects it to the Speed River. Please confirm appropriate control and removal of this invasive species as part of the dewatering work.	Comment remains outstanding.
Section 5.4.3- The report notes that Brook Trout is considered a thermally-sensitive species that requires clear, cold water to survive. Brook Trout require the presence of groundwater to survive. Please revise and include groundwater.	Comment remains outstanding.
Section 6.0 Natural Environment Significance and Sensitivity	
Section 6.0- The report notes that the assessment focuses on natural features and ecological functions that may be susceptible to effects caused by dewatering; however, discharge of the removed water may also result in impacts to the existing features. Please revise this section to include assessment of the impacts resulting from the proposed discharge.	Comment remains outstanding.
Section 6.3- Table 10 identifies three waterbodies that have a cool-cold thermal regime; however, only two (Tributary #4 and Tributary #2) were identified as containing Brook Trout habitat. Please provide discussion on suitable habitat for Brook Trout within the Ellis Creek Tributary.	Comment remains outstanding.
Section 6.3- Discussion pertaining to impacts due to additional discharge to Tributary #4 including temperature, velocity etc. is to be included.	Comment remains outstanding.
Section 6.4.3- The report notes that the proposed dewatering will not result in any direct impacts on the identified Butternut or its associated habitat; however, the report does not consider potential impacts due to the proposed discharge. Please review and revise the section to consider potential impacts related to discharge.	Comment remains outstanding.
Section 6.5- The report notes that several of the candidate SWH types are not considered sensitive to effects caused by the proposed dewater or potential change in the shallow groundwater regime; however, impacts to the additional discharge as a result of the dewatering is not considered. Please include consideration for the proposed discharge and discussion on potential impacts to the candidate SWH.	Comment remains outstanding.
Section 7.0 Impact Assessment	

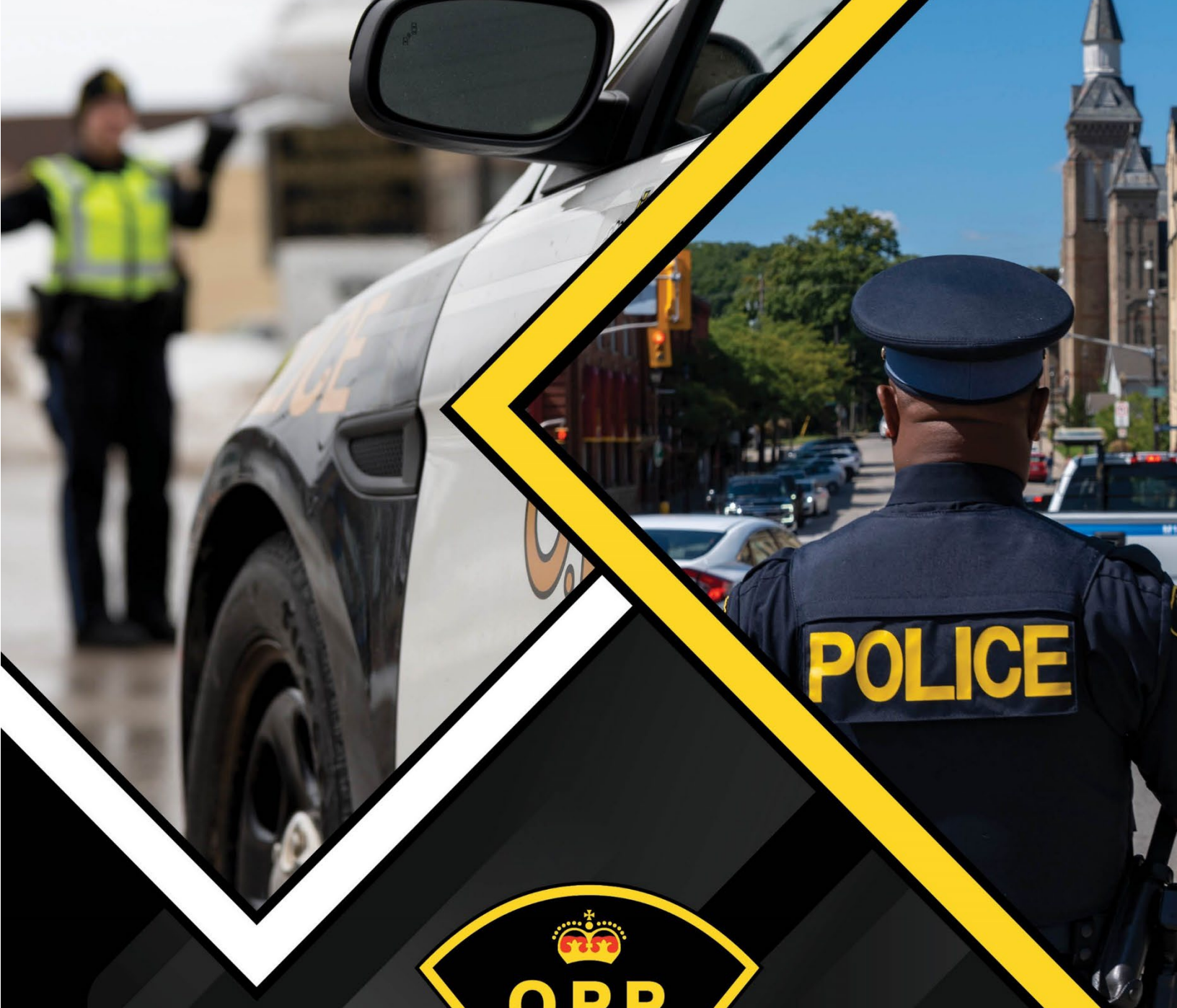
Section 7.2- The impact assessment must consider potential impacts due to the additional discharge as a result of the dewatering, including water quality measures and temperature. Please consider the additional discharge throughout the impact assessment for both direct and indirect impacts.	Comment remains outstanding.
Section 7.3.1.1- Please confirm that DFO was informed that Brook Trout spawning habitat may be present in Tributary #2 and Tributary #4, and that discharge may be introduced to Tributary #4 to maintain baseflow.	Comment remains outstanding.
Section 7.3.1.1- The report states that in-water works are to be maintained outside of the fisheries timing window. Please identify whether the timing window considers discharge timing to fish habitat in the Speed River and Tributaries, with specific regard for Brook Trout.	Comment remains outstanding.
Section 7.3.1.2- The report notes that the proposed discharge of water to the Speed River is not expected to result in the harmful alteration, damage or destruction of existing fish habitat; however, a discussion pertaining to changes in temperature and water chemistry at the outlet is not provided. Please provide discussion on the potential impact to current metrics may result due to the proposed discharge to the Speed River.	Comment remains outstanding.
Section 7.3.1.2- The report notes that pumping and discharge to the Speed River will be a continual activity, therefore the in-water works timing windows cannot be fully adhered to. Please provide consideration for and discussion regarding the potential impacts to fish and their habitat during sensitive spawning period.	Comment remains outstanding.
Section 7.4.1.4. Will this flow augmentation plan be able to replace the baseflow such that the habitat will still be suitable for Brook Trout spawning? How will water quality parameters (particularly temperature) be corrected if found to be out of range?	Comment remains outstanding.
Section 7.4.2- The report notes that monitoring via a turbidity meter will be initiated when the quarry lake approaches a depth of 2m above the existing floor. Will any monitoring occur prior to this to determine if sediment is reached earlier during drawdown?	Comment remains outstanding.
Section 7.4.2- The report notes that the water within the settling basin will be impounded for at least 24 hours to allow sediments to settle out prior to discharge to the Speed River. Please provide information on how water temperature may be impacted by the impound time.	Comment remains outstanding.
Section 7.4.2.2- The report identifies that water will be discharged onto a rock crib for energy dissipation and to attenuate flows prior to reaching the river; however, an impact assessment for the installation of the rock crib structure is not included. As it is understood the rock crib structure will be constructed immediately adjacent existing natural features, impacts to these features must be assessed. Please identify the potential location of the rock crib structure on appropriate mapping.	Comment remains outstanding.
Relevant Policies, Legislation and Regulations were identified in Section 2.0; however, conclusions following the impact assessment regarding how the proposed work complies with the relevant policies is not provided.	Comment remains outstanding.
Please include recommendations for ESC measures to minimize potential impacts (i.e., contamination, sedimentation) to the wetland communities and surrounding watercourses.	Comment remains outstanding.

Section 8.0 Monitoring	
The monitoring recommendations include characterizing the presence of Brook Trout, and quality assessment of Brook Trout spawning habitat and locations of redds. As these assessments were not completed during the NEA field investigations, they are required as part of a baseline assessment.	Comment remains outstanding. Please provide results of the added Salmonid Spawning Surveys completed in 2025.
The report provides recommendations that exclude monitoring methods involving different disciplines that are addressed under separate cover. Please ensure that all monitoring reports completed by other disciplines are provided to the Township for review.	Comment remains outstanding.
Section 9.0 Summary	
The report notes the development of a Mitigation and Monitoring Plan to monitor flows in Tributary #4. This Plan needs to also consider water temperature and quality, specifically in regards to Brook Trout.	Comment remains outstanding.
Table 11 notes that fish community assessments may include characterizing the presence of Brook Trout, quality assessment of Brook Trout spawning habitat and locations of redds. These studies are required.	Comment remains outstanding. Please provide results of the added Salmonid Spawning Surveys completed in 2025.
Table 11 does not provide any mitigation recommendations for wandering wildlife. Due to the confirmed presence of reptiles and amphibians, exclusion measures as identified in the Best Practices Technical Note: Reptile and Amphibian Exclusion Fencing (MNR, 2013) should be included in the recommendations.	Comment remains outstanding.
Maps	
Please include the defined study area on all maps.	Comment remains outstanding.
Appendices	
Appendix II- Amendments to the Endangered Species Act that came into effect on January 27, 2025, included the listing of Eastern Red Bat, Hoary Bat and Silver-haired Bat as Endangered. Please revise the appendix to reflect the amendment and provide assessments and rationale for these species.	Comment remains outstanding. Please note at this time, further changes to the Endangered Species Act (ESA) have occurred and the SAR assessment should be revised based on the Species Conservation Act (SCA).
Glen Christie Quarry, Puslinch, Ontario, Natural Environment Monitoring Plan	
Section 1.0- Introduction	
As noted in the NEA, please confirm how the study area was defined. The report states that the study area extends slightly beyond the ZOI, please define 'slightly'. Based on the study area identified on Map 1 and the ZOI on Map 7, the study area is inside the ZOI south of the property, to the east of Hespeler Road. Please identify why the study area was not extended beyond the ZOI in this area.	Comment remains outstanding.
Section 2.0- Monitoring Plan Structure, Locations and Timelines	

Section 2.1- The report notes that an additional year of supplemental baseline monitoring will be completed; however, this should not be considered an additional year for studies not originally completed as part of the NEA. All of the studies identified in pre-dewatering are to have been completed as part of the NEA, with their results and potential impacts discussed and assessed within the NEA prior to moving on to pre-dewatering baseline studies.	Comment remains outstanding.
Section 2.3- The report notes that post-dewatering monitoring will track and anticipate recovery of the species as groundwater contributions to the ecological receptors resume. Please include a contingency for additional monitoring if groundwater levels and communities have not recovered or returned to baseline conditions within 6 years as anticipated.	Comment remains outstanding.
Sections 2.2, 2.3- Monitoring during the dewatering stage is proposed to occur every other year during the 10 year dewatering period and every other year during the proposed 6 year post-dewatering period. With the identification of floral and faunal species, as well as vegetation communities that are highly vulnerable to fluctuations in groundwater identified in the NEA, monitoring is to be completed annually to ensure impacts are identified early and mitigation employed immediately.	It is noted that annual monitoring has been included during the dewatering stage, however, monitoring frequency is decreased during the post-dewatering period. Justification should be provided for the reduced monitoring frequency, given that the vegetation communities identified in the NEA as being highly sensitive to changes in groundwater conditions may continue to be affected following cessation of dewatering. Annual monitoring should be maintained during the post-dewatering period until monitoring results demonstrate that conditions have remained stable relative to the baseline monitoring year. Where no changes to the identified vegetation communities or other indicators of impact are observed, consideration may be given to reducing the monitoring frequency to every two years.
Section 3.0- Monitoring Components	
Section 3.1- A review and analysis of the average wetness index for each vegetation plot, including all species observed, compared year to year, to determine any changes to the vegetation composition and wetness index should be included and discussed in the context of changes in groundwater level.	It is noted that threshold triggers have been included in the revised NEMP. These triggers should apply to comparisons between monitoring results and baseline conditions, rather than solely the previous monitoring year, as gradual changes may occur over multiple years and could otherwise be missed. Comment remains outstanding. Please include consideration of non-native/invasive species composition within the threshold triggers, including criteria for when mitigation/intervention will be initiated.
Section 3.1- The report notes that indicators of negative impact would include loss or reductions in abundance of sensitive species and increases in the number of species or proportional coverage of non-native/invasive species. Please include discussion pertaining to a threshold at which mitigation/intervention will be employed.	
Section 3.1- The report notes that plot-based vegetation surveys will be initiated during the pre-dewatering monitoring phase (e.g. between June and August). Please include verbiage noting that timing will be consistent and will specifically align with flowering periods for sensitive target species.	Comment remains outstanding.
Section 3.1- We agree that permanent stakes should be placed to mark the permanent vegetation monitoring plots. However, it is recommended that metal stakes are used to reduce the potential for tampering and rotting over the 17 year, or more, monitoring period.	Comment remains outstanding.
Section 3.1- Please include an inventory of all vegetation species present in monitoring plots to calculate FQI.	Comment remains outstanding. Further details on the Vegetation Plot Monitoring methodology should be provided.
Section 3.1- As non-native and invasive species were identified within the NEA, consideration for monitoring of invasive species is to be included. This includes identifying triggers for implementing mitigative actions (i.e. expansion into previously undisturbed areas).	Comment remains outstanding.

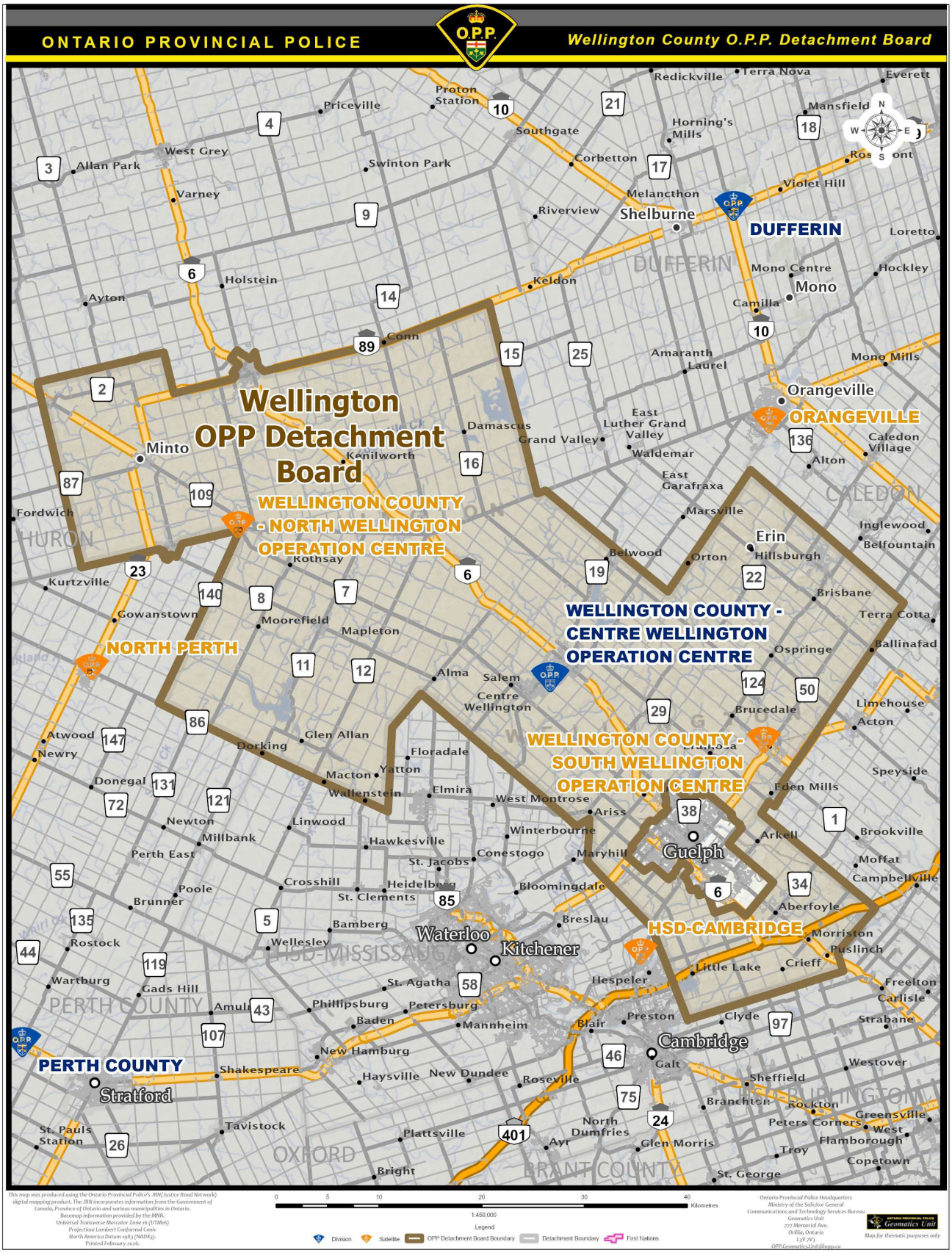
Section 3.1- The report notes excessive trampling as reasoning for completing vegetation plot monitoring every other year. Provided the vegetation plot monitoring is being completed by a single individual which is highly trained in botanical assessments, this should not be considered a constraint to annual monitoring.	Comment remains outstanding.
Section 3.1- Please include a summary of groundwater level changes identified by the implementation of piezometers discussed in the Hydrogeological Assessment (MTE, 2024). As several vegetation species highly sensitive to changes in groundwater levels were identified in the NEA, connections between the groundwater monitoring program and NEMP need to be drawn to fully understand the impacts of the proposed drawdown.	Comment remains outstanding.
Section 3.1- In relation to the above comment, piezometers should be installed within all wetland communities that are being proposed for vegetation plot monitoring.	Comment remains outstanding.
Section 3.2- Amphibian surveys completed per the Marsh Monitoring Protocol are required to be completed prior to determining monitoring locations. All habitats, including upland, are to be reviewed for vernal pools that could support ephemeral amphibian breeding.	It is recognized that anuran surveys have been included in the revised NEMP.
Section 3.2- Piezometers are to be located in wetlands with amphibian habitat and included on appropriate mapping.	Comment remains outstanding.
Section 3.2- The NEA notes that any surface water level drawdown caused by reduced groundwater inputs are expected to be slow, and it is unlikely that the pond will completely dry out. This should be included as a monitoring trigger.	Comment remains outstanding.
Section 3.3- The report notes that various other meadow marsh and shallow marsh wetland communities were mapped around the study area that could potentially be used by marsh birds. Marsh Breeding Bird studies are required to be completed as part of the NEA to identify suitable habitat to adequately determine monitoring locations.	Comment remains outstanding.
Section 3.3- Marsh Bird monitoring surveys are to occur annually.	Comment remains outstanding.
Section 3.4- Turtle overwintering and basking monitoring is to occur annually.	Comment remains outstanding.
Section 3.8- The report notes the completion of benthic macroinvertebrate sampling for the monitoring plan; however, baseline surveys were not completed as part of the NEA. Baseline surveys are required prior to the initiation of the monitoring plan.	Comment remains outstanding.
Section 3.8- Benthic macroinvertebrate monitoring surveys are to occur annually.	Comment remains outstanding.

Nowhere in the monitoring plan are redd surveys mentioned. As stated in section 8 of the NEA monitoring may include "characterizing the presence of Brook Trout, and quality assessment of Brook Trout spawning habitat and locations of redds". Given that the groundwater inputs to Brook Trout streams are threatened, redd surveys for all cool-cold water watercourses are necessary to assess whether spawning habitat is threatened.	Comment remains outstanding.
Section 4.0 Thresholds and Remedial Measures	
The objectives of the monitoring components are to identify changes that may result due to the proposed dewatering; however, no thresholds to determine level of impacts have been provided. Please identify thresholds based on baseline surveys that identify when intervention may be required to ensure protection of the existing natural features, significant species and their habitat. Baseline surveys for marsh breeding birds and anurans need to be adequately completed in order to determine thresholds.	It is noted that threshold triggers have been included in the revised NEMP. These triggers should apply to comparisons between monitoring results and baseline conditions, rather than solely the previous monitoring year, as gradual changes may occur over multiple years and could otherwise be missed. In addition, the results of the baseline monitoring surveys excluded from the original NEA submission should also be provided to validate the appropriateness of the proposed threshold triggers.
Spawning area reductions (number of redds) are to be considered as an ecological trigger that would prompt a mitigative response. Baseline surveys completed as part of the NEA are required to determine baseline conditions.	Comment remains outstanding.
Section 5.0- Reporting	
The report notes that it will be a stand-alone monitoring report; however, in order to provide a fulsome assessment of impacts the monitoring report must include a review of monitoring completed by other disciplines.	Comment remains outstanding.
The annual monitoring report is to be submitted to the Township of Puslinch Clerk and Wellington County for review.	Comment remains outstanding.
Maps	
Section 3.1 recommends vegetation monitoring plots in the Cattail Shallow Marsh (MAS2-1) in the southeast; however, that community does not contain the vegetation monitoring plot overlay on Map 2c. Please add the overlay for the MAS2-1 community.	Comment remains outstanding.
Please add the locations of all piezometers proposed for monitoring groundwater levels on the appropriate figures to ensure piezometers are placed to appropriately monitor surface water levels.	Comment remains outstanding.
Please include the locations for fish relocation on appropriate figures.	Comment remains outstanding.
Please identify that Redd survey monitoring will be completed for the length of Tributary #4 on Map 2a.	Comment remains outstanding.
Please include an additional AHP station at the upstream end of Tributary #4 on Map 2b.	Comment remains outstanding.



WELLINGTON COUNTY DETACHMENT

2025 DETACHMENT BOARD ANNUAL REPORT


ONTARIO PROVINCIAL POLICE
O.P.P.
Wellington County O.P.P. Detachment Board
Wellington OPP Detachment Board
WELLINGTON COUNTY - NORTH WELLINGTON OPERATION CENTRE
WELLINGTON COUNTY - CENTRE WELLINGTON OPERATION CENTRE
WELLINGTON COUNTY - SOUTH WELLINGTON OPERATION CENTRE
NORTH PERTH
DUFFERIN
ORANGEVILLE
HSD-CAMBRIDGE
PERTH COUNTY
Stratford
Guelph
Waterloo
Kitchener
Cambridge
Shelburne
Orangeville
Mono
Erin
Minto
Fordwich
Kurtzville
Gowanstown
Atwood
Newry
Donegal
Rostock
Wartburg
Gads Hill
Poole
Brunner
Perth East
Newton
Millbank
Linwood
Mapleton
Moorefield
Kothsay
Kenilworth
Dorking
Glen Allan
Floradale
Macton
Yatton
Wallenstein
Elmira
West Montrose
Ariss
Winterbourne
Hawkesville
Conestogo
St. Jacobs
Maryhill
Crosshill
Heidelberg
St. Clements
Bloomingdale
Breslau
Bamberg
Wellesley
St. Agatha
Phillipsburg
Petersburg
Baden
Mannheim
Blair
Preston
Hespeler
Little Lake
Crieff
Clyde
Galt
Sheffield
Branchton
Rockton
Greensville
Peters Corners
West
Flamborough
Troy
Copetown
St. George
Glen Morris
North Dumfries
Ayr
Plattsville
Bright
Tavistock
St. Pauls Station
New Hamburg
Shakespeare
Haysville
New Dundee
Roseville
Amaranth
Laurel
Damascus
Grand Valley
East Luther Grand Valley
Waldemar
East Garafraxa
Marsville
Belwood
Orton
Hillsburgh
Brisbane
Terra Cotta
Ospringe
Ballinafad
Salem
Alma
Centre Wellington
Brucedale
Eden Mills
Arkell
Aberfoyle
Morriston
Puslinch
Freelton
Carlisle
Strabane
Westover
Limehouse
Acton
Speyside
Brookville
Moffat
Campbellville
Inglewood
Belfountain
Caledon Village
Alton
Mono Mills
Mono Centre
Camilla
Hockley
Loretto
Violet Hill
Melancthon
Riverview
Keldon
Conn
Holstein
Ayton
Varney
Allan Park
West Grey
Swinton Park
Priceville
Proton Station
Southgate
Corbetton
Horning's Mills
Mansfield
Redickville
Terra Nova
Everett
Rosemont
HURON
CALEDON
DUFFERIN
HSD-MISSISSAUGA
PERTH COUNTY
OXFORD
BRANT COUNTY
BURLINGTON
401
This map was produced using the Ontario Provincial Police's JRN(Justice Road Network) digital mapping product. The JRN incorporates information from the Government of Canada, Province of Ontario and various municipalities in Ontario.
Basemap information provided by the MNR.
Universal Transverse Mercator Zone 16 (UTM16)
Projections Lambert Conformal Conic
North America Datum 1983 (NAD83).
Printed February 2026.
0 5 10 20 30 40 Kilometres
1:450,000
Legend
Division
Satellite
OPP Detachment Board Boundary
Detachment Boundary
First Nations
Ontario Provincial Police Headquarters
Ministry of the Solicitor General
Communications and Technology Services Bureau
Geomatics Unit
777 Memorial Ave.
Orillia, Ontario
L4V 3V3
OPP.Geomatics.Unit@opp.ca
Geomatics Unit
Map for thematic purposes only

2023-2025 STRATEGIC PLAN

Priorities and Commitments

PEOPLE

A healthy and resilient OPP

We will strive to support all members in achieving their professional and personal best.

WORK

A responsive and evolving OPP

We will empower our members to ensure the best possible policing services are delivered to Ontarians.

COMMUNITIES

A collaborative and progressive OPP

We will partner and build relationships with a shared vision for safety and well-being.

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Message from the Detachment Commander

I am pleased to present the Wellington County OPP Detachment 2025 Detachment Board Annual Report. This report includes crime, traffic enforcement and community well-being data, and highlights initiatives and successes from the past year. 2025 was the last year of the 2023-2025 Wellington County OPP Detachment Action Plan and this report will provide a final update and progress results from that plan.

In 2025,

- We continued to align traffic enforcement activity with collision data and provincial road safety priorities.
- We continued to leverage technology, including body worn cameras, in-car cameras, and Automated Licence Plate Recognition (ALPR) to support the collection of evidence, increase transparency and enhance public and officer safety.
- Public roadway updates were communicated through Municipal 511, improving the timely and efficient delivery of road safety information and awareness.
- Our Traffic Management Unit (TMU) conducted multiple commercial motor vehicle (CMV) blitzes, alongside the Ministry of Transportation (MTO) and other municipal partners. These inspections resulted in several vehicles being placed out of service due to identified safety concerns.
- Members participated in various courses and training opportunities, including the Breath Technician Course, Level 2 Collision Course, and motorized snow vehicle course. Our members assisted with the instruction of the Drug Recognition Expert and Standardized Field Sobriety courses.
- Our Offender Management and Apprehension Program (OMAP) maintained consistent enforcement activity and intensified compliance monitoring. As a result, over 330 warrants were executed, and proactive offender management strategies have been implemented.
- The Community Street Crime Unit (CSCU) assisted with numerous large projects and organized crime investigations resulting in the seizure of weapons, firearms and proceeds of crime.
- Due to an increase in property crime, we responded by conducting focused patrols in affected areas. As a result, several people were arrested and charged with property related offences stemming from break and enters and mischief.
- The Crime Unit made continued progress on several complex investigations, including death, attempted murder, kidnapping, sexual assault and fraud investigations.
- Plea agreements were reached in relation to a kidnapping incident that resulted in the victim's death. Five accused individuals entered guilty pleas to offences including manslaughter, assault with a weapon, kidnapping and accessory after the fact to manslaughter.
- We supported the development of our members and participated in ongoing training to maintain investigative excellence in areas such as search warrant preparation, Ontario Major Case Management, crisis negotiation, investigative interviewing, criminal investigation techniques, fraud and human trafficking investigations.

- Our Media Unit remained highly active, producing hundreds of public-safety communications and campaigns throughout the year including safe driving, school bus safety, winters storms, fraud prevention and public safety awareness.
- We partnered with community-based organizations through our Integrated Mobile Police and Crisis Team to develop/implement co-response models that enhance our ability to respond to mental health related calls.
- We continue to work with community-based organization such as Victim Services, the Canadian Mental Health Association, Wellington Guelph Drug Strategy, Wellington Health Care Alliance and Safe Communities Wellington County to better support our community by connecting them with local resources.
- We continued to engage with groups and organizations in our area to build relationships and promote community safety and well-being. We delivered several fraud presentations, back-to-school safety initiatives and conducted several School Bus Patroller training sessions. We focused on youth engagement through the Citizens Police Academy, Safe Kids Day, summer camp presentations and colouring contests. We also supported dozens of community events including fall fairs, Pride events, parades, charity events and farm shows.
- The Auxiliary Unit contributed 3978 volunteer hours dedicated to community events throughout Wellington County. 1200 hours were dedicated to assisting with vehicle and marine patrols. The unit also assisted with food and toy drives, car seat clinics, parades, festivals and bike rodeos.

In 2026, we will release our new 2026-2029 Wellington County OPP Detachment Action Plan. This is the first action plan developed under the *Community Safety and Policing Act* (CSPA). We are working closely with our Wellington County OPP Detachment Board and engaging with community members to ensure the needs of our communities are reflected in the commitments we make for the next four years.

Development of the 2026-2029 Wellington County OPP Detachment Action Plan will coincide with the creation of the 2026-2029 OPP Strategic Plan creating organizational alignment.

As we look ahead to emerging challenges and new opportunities in policing and community safety, our detachment members remain committed to our mission to serve our communities, protect our citizens, uphold the law, and preserve public safety.

Karen Medeiros
Detachment Commander
Wellington County OPP

Summary of Commitments

Through analysis and consultation, the following areas of focus were identified for the years 2023-2025.

Crime	Roadways, Waterways and Trails	Community Well-Being
Reduce the victimization from instances of violent crime including sexual violence in our communities. To address and prevent illicit drug crime in our communities. To address and prevent property crime including fraud. To address and prevent hate motivated crime.	Sustain a continuous and year-round focus on the causal factors of motorized vehicle collisions.	To identify co-response solutions for non-police related demands for service that impact police resourcing. To develop police-hospital transition protocols with relevant healthcare facilities. To streamline collision reporting. Engage youth in the community to form positive relationships.

2025 Crime Progress Results

Commitment	Progress Results
Reduce the victimization from instances of violent crime including sexual violence in our communities.	We continue to emphasize victim support through a trauma informed approach, timely referrals to community resources and the thorough and effective investigation of these offences.
To address and prevent illicit drug crime in our communities.	Reductions in drug possession and trafficking charges reflect sustained, targeted enforcement efforts focused on disrupting illicit drug activity and enhancing community safety.
To address and prevent property crime including fraud.	Expanded fraud education initiatives and increased community engagement reflect proactive prevention efforts. These initiatives, combined with community collaboration have reduced fraud incidents and mitigated property crime trends.
To address and prevent hate motivated crime.	Continued support of community events that advocate for respect, inclusion and equity. There were no reports of hate motivated crime in 2025.

2025 Roadways, Waterways and Trails Progress Results

Commitment	Progress Results
Sustain a continuous and year - round focus on the causal factors of motorized vehicle collisions.	Overall motor vehicle collision volumes remained relatively unchanged year to year; however, in response to an increase in fatal, including off-road collisions, enforcement and prevention efforts remain focused on high-risk casual factors.

2025 Community Well-Being Progress Results

Commitment	Progress Results
To identify co-response solutions for non-police related demands for service that impact police resourcing.	Co-response initiatives, including Integrated Mobile Police and Crisis Team (IMPACT) and Collision Reporting Centres (CRC), continue to connect individuals with appropriate supports while improving service delivery and supporting effective policing resources.
To develop police-hospital transition protocols with relevant healthcare facilities.	Current protocols in place and maintained with relevant healthcare facilities.
To streamline collision reporting.	Collision Reporting Clerks in our three detachment areas complete approximately 50% of our collision reports, saving hours of frontline response and increased service to the public.
Engage youth in the community to form positive relationships.	Citizens Police Academy, Safe Kids Day, summer camp presentations and bike rodeos highlighted increased awareness and safety with youth in the community.

Calls for Service

Table 1.1

All CAD Events*	Immediate Police Response Required**
41,500	11,169

* This represents all Computer Aided Dispatch (CAD) event types created for each detachment area. Not all CAD events are dispatched to a frontline OPP detachment officer. Some events may have been actioned by another OPP member, diverted to another unit, or deemed a non-OPP event. This does not include officer or detachment generated events that have not been reported through the PCC, or any online reporting events.

** This represents the total number of CAD events prioritized for an immediate police response, indicating the potential for extreme danger, catastrophic circumstances, injury, the threat of injury, death, and/or crime in progress.

Crime and Clearance

Violent Crimes **Table 2.1**

Offences	2023	2024	2025	Clearance Rate
01 - Homicide	1	0	1	100.00%
02 - Other Offences Causing Death	0	0	0	--
03 - Attempted Murder	0	0	0	--
04 - Sexual Offences	82	70	78	66.67%
05 - Assaults/Firearm Related Offences	209	237	257	82.88%
06 - Offences Resulting in the Deprivation of Freedom	7	2	1	100.00%
07 - Robbery	3	2	6	50.00%
08 - Other Offences Involving Violence or the Threat of Violence	140	159	182	50.55%
09 - Offences in Relation to Sexual Services	0	0	0	--
10 - Total Violent Crime	442	470	525	68.95%

Property Crimes **Table 2.2**

Offences	2023	2024	2025	Clearance Rate
01 - Arson	12	5	3	33.33%
02 - Break and Enter	119	139	120	10.00%
03 - Theft Over	183	205	185	3.24%
04 - Theft Under	401	480	449	16.70%
05 - Have Stolen Goods	18	15	20	85.00%
06 - Fraud	461	429	397	5.04%
07 - Mischief	262	211	270	15.56%
08 - Total Property Crime	1,456	1,484	1,444	11.98%

Other Criminal Code **Table 2.3**

Offences	2023	2024	2025	Clearance Rate
01 - Illegal Gaming and Betting	0	0	0	--
02 - Offensive Weapons - Careless use of firearms	24	28	17	64.71%
03 - Failure to Comply - Judicial Orders/Unlawfully at Large	203	230	238	82.77%
04 - Disturb the Peace	48	47	31	16.13%
05 - Child Pornography	10	6	1	0.00%
06 - Other Criminal Code (Ex. Traffic)	53	56	59	38.98%
07 - Total Other Criminal Code	338	367	346	68.21%

Drugs **Table 2.4**

Offences	2023	2024	2025	Clearance Rate
01 - CDSA Possession	22	20	9	100.00%
02 - CDSA Trafficking	11	14	12	58.33%
03 - CDSA Importation & Production	0	1	0	--
04 - Cannabis Possession	1	0	0	--
05 - Cannabis Distribution	1	0	0	--
06 - Cannabis Sale	0	1	0	--
07 - Cannabis Importation & Exportation	0	0	0	--
08 - Cannabis Production	1	1	0	--
09 - Other Cannabis Violations	0	0	1	0.00%
10 - Total Drugs	36	37	22	72.73%

Federal Statutes **Table 2.5**

Offences	2023	2024	2025	Clearance Rate
Federal Statutes	33	31	29	93.10%

Traffic Violations **Table 2.6**

Offences	2023	2024	2025	Clearance Rate
01 - Dangerous Operation	21	18	20	100.00%
02 - Flight from Peace Officer	25	24	19	26.32%
03 - Operation while Impaired/Low Blood Drug Concentration Violations	90	80	90	100.00%
04 - Failure or Refusal to Comply with Demand	8	3	5	100.00%
05 - Failure to Stop after Accident	8	20	13	23.08%
06 - Operation while Prohibited	11	14	11	100.00%
07 - Total	163	159	158	84.81%

Youth Crime **Table 2.7**

Disposition Type	2023	2024	2025
Bail	0	0	0
Conviction	20	13	6
Diversion	17	34	17
Non-Conviction	53	35	16
Not Accepted	1	0	1
POA Ticket	32	5	18
NULL	12	6	49
Total	135	93	107

Victim Referrals **Table 2.8**

Offences	2023	2024	2025
Sum of Offered	1309	1557	1827
Sum of Accepted	376	555	632
Sum of Total	1685	2112	2459
Sum of % Accepted	22.31%	26.28%	25.70%

Traffic and Road Safety

Motor Vehicle Collisions (MVC) by Type **Table 3.1**
(Includes roadway, off-road and motorized snow vehicle collisions)

Offences	2023	2024	2025
Fatal Injury Collisions	18	12	14
Non-Fatal Injury Collisions	250	276	281
Property Damage Only Collisions	1,721	1,926	1,889
Alcohol-Related Collisions	63	69	62
Animal-Related Collisions	350	369	285
Speed-Related Collisions	223	241	290
Inattentive-Related Collisions	183	175	170
Persons Killed	19	13	15
Persons Injured	367	423	426

Primary Causal Factors in Fatal MVCs on Roadways **Table 3.2**

Offences	2023	2024	2025
Fatal Roadway Collisions where Causal is Speed Related	3	1	4
Fatal Roadway Collisions where Causal is Alcohol/Drug Related	6	1	0
Persons Killed in Fatal Roadway Collisions where lack of Seatbelt/Helmet use is a Factor	3	3	5
Fatal Roadway Collisions where Causal is Inattentive Related	2	4	2
Fatal Roadway Collisions where Causal is Animal Related	0	0	0

Fatalities in Detachment Area **Table 3.3**

Fatality Type	Category	2023	2024	2025
Roadway	Fatal Incidents	18	10	13
Roadway	Persons Killed	19	11	14
Roadway	Alcohol/Drug Related Incidents	6	1	0
Marine	Fatal Incidents	0	0	0
Marine	Persons Killed	0	0	0
Marine	Alcohol/Drug Related Incidents	0	0	0
Off-Road Vehicle	Fatal Incidents	0	2	1
Off-Road Vehicle	Persons Killed	0	2	1
Off-Road Vehicle	Alcohol/Drug Related Incidents	0	1	1
Motorized Snow Vehicle	Fatal Incidents	0	0	0
Motorized Snow Vehicle	Persons Killed	0	0	0
Motorized Snow Vehicle	Alcohol/Drug Related Incidents	0	0	0

Big 4 **Table 3.4**

Offences	2023	2024	2025
Distracted (HTA 78.1)	76	111	150
Impaired (CCC 320.14 & 320.15)	232	230	246
Seatbelt (HTA 106)	315	630	726
Speeding (HTA 128)	3,424	4,331	2,472

Charges **Table 3.5**

Offences	2023	2024	2025
HTA	7,216	9,452	7,866
Criminal Code Traffic	361	374	362
Criminal Code Non-Traffic	1,423	1,495	1,332
LLCA	107	93	72
Controlled Drug and Substance Act	84	73	44
Federal Cannabis Act	4	3	2
Provincial Cannabis Act	64	79	39
Other	563	687	714

Policing Hours

The OPP has developed a Service Delivery Model (SDM) in response to several reviews and audit recommendations. The SDM is designed to:

- Promote officer wellness through balanced workloads
- Determine adequate staffing levels at each detachment
- Ensure the continued delivery of adequate and effective policing services in accordance with the *Community Safety and Policing Act (CSPA*)

To support SDM implementation, the OPP is undertaking a multi-year staffing strategy to address required increases in detachment personnel. This model supports the OPP's ability to:

- Respond effectively to increasing calls for service
- Maintain safe communities through proactive patrols and community engagement
- Meet municipal expectations for police visibility

To monitor progress and guide detachment-level planning, the OPP has established time allocation targets for provincial constables (Figure 1). These targets reflect how time should ideally be distributed by the end of the SDM staffing strategy.

The targets are based on a provincial average, and variations are expected between detachments due to differences in geography, operational structure, recruitment and leave of absence rates.

Detachments may face challenges in achieving these targets, but progress is expected as scheduling, data quality and strategic deployment continue to improve.

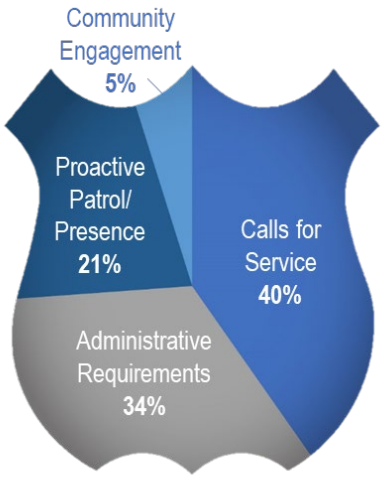


Figure 1: Service Delivery Model Provincial Target

Service Delivery Activity Allocations **Table 4.1**

Calls for Service	Administrative Requirements	Proactive Patrol	Community Engagement
40.9%	37.5%	18.4%	3.2%

Hours (Field Personnel) **Table 4.2**

	2023	2024	2025
TOTAL FRONTLINE HOURS	202,948	202,336	219,030

Endnotes

Tables 2.1, 2.2, 2.3, 2.4, 2.5, 2.6
Source: Niche Records Management System (RMS), (2026/02/24)

Note:

- Statistics Canada's Uniform Crime Reporting Survey was designed to measure the incidence of crime in Canadian society and its characteristics.
- Reported, Unfounded, Actual, Not Cleared, Cleared by Charge and Cleared Otherwise counts (2023, 2024 and 2025) and Clearance Rate for 2025 included.
- Actual counts and Clearance Rate (2023, 2024 and 2025) included.
- The most serious violation methodology (MSV) is used, which is the same as Statistics Canada's methodology. The MSV counts only the first of up to four offences per incident that occurred in the specific time range.
- First Nation population is not included.
- UCR Statistics Canada Verified (green checkmark) only.

Table 2.1 Violent Crimes
Corresponding Violation Description

01 Murder 1st Degree, Murder 2nd Degree, Manslaughter, Infanticide

02 Criminal Negligence Causing Death, Other Related Offences Causing Death

03 Attempted Murder, Conspire to Commit Murder

04 Sexual offence which occurred prior to January 4, 1983, Sexual Assault, Level 3, Aggravated, Sexual Assault, Level 2, Weapon or Bodily Harm, Sexual Assault, Level 1, Sexual Interference, Invitation to Sexual Touching, Sexual Exploitation, Sexual Exploitation of a Person with a Disability, Incest, Corrupting Morals of a Child, Making Sexually Explicit Material Available to Children, Parent or Guardian Procuring Sexual Activity, Householder Permitting Sexual Activity, Luring a Child via Computer, Agreement or Arrangement - Sexual Offence Against a Child, Bestiality - Commits, Compels Another Person, Bestiality in, Presence of, or Incites, a Child, Voyeurism, Non-Consensual Distribution of Intimate Images

05 Assault Level 3, Aggravated, Assault Level 2, Weapon/Bodily Harm, Assault Level 1, Unlawfully Causing Bodily Harm, Discharge Firearm with Intent, Using firearm/Imitation of Firearm in the Commission of an Offence, Pointing a Firearm, Assault, Peace-Public Officer, Assault Against Peace Officer with a Weapon or Causing Bodily Harm, Criminal Negligence Causing Bodily, Harm, Trap Likely to or Causing Bodily Harm, Other Assaults

06 Kidnapping, Forcible Confinement, Hostage Taking, Trafficking in Persons, Abduction Under 14, Not Parent/Guardian, Abduction Under 16, Removal of Children from Canada, Abduction Under 14 Contravening a Custody Order, Abduction Under 15 by Parent/Guardian

07 Robbery, Robbery to Steal Firearm

08 Extortion, Intimidation of a Justice System Participant or a Journalist, Intimidation of a Non-justice System Participant, Criminal Harassment, Indecent/Harassing Communications, Utter Threats to Person, Explosives Causing Death/Bodily Harm, Arson - Disregard for Human Life, Other Violations Against the Person, Failure to Comply with Safeguards (MAID), Forging/Destruction of Documents (MAID)

09 Obtaining Sexual Services for Consideration, Obtaining Sexual Services for Consideration from Person Under the Age of 18 Years, Material Benefit from Sexual Services, Material Benefit from Sexual Services Provided by Person Under the Age of 18 Years, Procuring, Procuring a Person Under the Age of 18 Years, Advertising Sexual Services

Table 2.2 Property Crimes
Corresponding Violation Description

01 Arson

02 Break & Enter, Break & Enter to Steal a Firearm, Break & Enter a Motor Vehicle (Firearm)

03 Theft over $5000, Theft over $5000 from a Motor Vehicle, Shoplifting over $5000, Motor Vehicle Theft

04 Theft $5000 or Under, Theft under $5000 from a Motor Vehicle, Shoplifting $5000 or Under

05 Trafficking in Stolen Goods over $5000, Possession of Stolen Goods over $5000, Trafficking in Stolen Goods $5000 and Under, Possession of Stolen Goods $5000 and Under

06 Fraud, Identity Theft, Identity Fraud

07 Mischief, Mischief to Cultural Property, Hate-motivated mischief relating to property used by identifiable group, Mischief Relating to War Memorials, Altering/Destroying/Removing a Vehicle Identification Number (VIN)

Table 2.3 Other Criminal Code
Corresponding Violation Description

01 Betting House, Gaming House, Other Violations Related to Gaming and Betting

02 Offensive Weapons: Explosives, Weapons Trafficking, Possession and Distribution of Computer Data (Firearm), Altering Cartridge Magazine, Weapons Possession Contrary to Order, Possession of Weapons, Unauthorized Importing/Exporting of Weapons, Firearms Documentation/Administration, Unsafe Storage of Firearms

03 Failure to Comply – Judicial Orders/Unlawfully at Large: bail violations, escape custody, fail to attend court, breach of probation

04 Disturb the Peace

05 Child Pornography: including making or distributing

06 Public Communications to Sell Sexual Services, Offences Related to Impeding Traffic to Buy or Sell Sexual Services, Counterfeiting, Indecent Acts, Voyeurism (Expired), Corrupting Morals, Lure child via Computer (Expired), Obstruct Public/Peace Officer, Trespass at Night, Threatening/Harassing Phone Calls (Expired), Utter Threats Against Property or Animals, Advocating Genocide, Public Incitement of Hatred, Promoting or Advertising Conversion Therapy, Unauthorized Recording of a Movie/Purpose of Sale, Rental, Commercial, Distribution, Offences Against Public Order (Part II CC), Property or Services for Terrorist Activities, Freezing of Property, Disclosure, Audit, Participate in Activity of Terrorist Group, Facilitate Terrorist Activity, Instruction/Commission of Act of Terrorism, Hoax – Terrorism, Advocating/Promoting Terrorism, Firearms and Other Offensive Weapons (Part III CC), Leave Canada to Participate in Activity of a Terrorist Group, Leave Canada to Facilitate Terrorist Activity, Leave Canada to Commit Offence for Terrorist Group, Leave Canada to Commit Offence that is Terrorist Activity, Harbour/Conceal Terrorist (Max = Life), Harbour/Conceal Terrorist (Max Does Not = Life), Harbour/Conceal Person Likely to Carry Out Terrorist Activity, Offences Against the Administration of Law and Justice (Part IV CC). Sexual Offences, Public Morals and Disorderly Conduct (Part V CC), Invasion of Privacy (Part VI CC), Failure to Comply with Regulations / Obligations for Medical Assistance in Dying (MAID), Other Offences Against the Person and Reputation, Offences Against the Rights of Property (Part IX CC), Fraudulent Transactions, Relating to Contracts and Trade (Part X CC), Offences Related to Currency, Proceeds of Crime (Part XII.2 CC), Attempts, Conspiracies, Accessories, Instruct Offence for Criminal Organization, Commit Offence for Criminal Organization, Participate in Activities of Criminal Organization, Recruitment of Members by a Criminal Organization, All Other Criminal Code (includes Part XII.1 CC)

Table 2.4 Drugs

Corresponding Violation Description

01 Possession – Heroin, Possession – Cocaine, Possession - Other Controlled Drugs and Substances Act, Possession - Methamphetamine (Crystal Meth), Possession - Methylenedioxyamphetamine (Ecstasy), Possession – Opioid (other than heroin)

02 Trafficking – Heroin, Trafficking – Cocaine, Trafficking - Other Controlled Drugs and Substances Act, Trafficking - Methamphetamine (Crystal Meth), Trafficking - Methylenedioxyamphetamine (Ecstasy), Trafficking – Opioid (other than heroin)

03 Import / Export – Heroin, Import / Export – Cocaine, Import / Export - Other Controlled Drugs and Substances Act, Import / Export - Methamphetamines (Crystal Meth), Import / Export - Methylenedioxyamphetamine (Ecstasy), Import/Export – Opioid (other than heroin), Production – Heroin, Production – Cocaine, Production - Other Controlled Drugs & Substances Act, Production - Methamphetamines (Crystal Meth), Production - Methylenedioxyamphetamine (Ecstasy), Production – Opioid (other than heroin), Possession, sale, etc., for use in production of or trafficking in substance

04 Possession of illicit or over 30g dried cannabis (or equivalent) by adult, Possession of over 5g dried cannabis (or equivalent) by youth, Possession of budding or flowering plants, or more than four cannabis plants, Possession of cannabis by organization

05 Distribution of illicit, over 30g dried cannabis (or equivalent), or to an organization, by adult, Distribution of cannabis to youth, by adult, Distribution of over 5g dried cannabis (or equivalent), or to an organization, by youth, Distribution of budding or flowering plants, or more than four cannabis plants, Distribution of cannabis by organization, Possession of cannabis for purpose of distributing

06 Sale of cannabis to adult, Sale of cannabis to youth, Sale of cannabis to an organization, Possession of cannabis for purpose of selling

07 Importation and exportation of cannabis, Possession of cannabis for purpose of exportation

08 Obtain, offer to obtain, alter or offer to alter cannabis, Cultivate, propagate or harvest cannabis by adult, Cultivate, propagate or harvest cannabis by youth or organization

09 Possess, produce, sell, distribute or import anything for use in production or distribution of illicit cannabis, Use of young person in the commission of a cannabis offence, Other Cannabis Act

Table 2.5 Federal Statutes

Corresponding Violation Description

Bankruptcy Act, Income Tax Act, Canada Shipping Act, Canada Health Act, Customs Act , Competition Act, Excise Act, Youth Criminal Justice Act (YCJA), Immigration and Refugee Protection Act, Human Trafficking (involving the use of abduction, fraud, deception or use of threat), Human Smuggling fewer than 10 persons, Human Smuggling 10 persons or more, Firearms Act, National Defence Act, Emergencies Act, Quarantine Act, Other Federal Statutes

Table 2.6 Traffic Violations
Corresponding Violation Description

01 Dangerous Operation Causing Death, Dangerous Operation Causing Bodily Harm, Dangerous Operation

02 Flight from Peace Officer

03 Operation - low blood drug concentration, Operation while impaired causing death (alcohol), Operation while impaired causing death (alcohol and drugs), Operation while impaired causing death (drugs), Operation while impaired causing death (unspecified), Operation while impaired causing bodily harm (alcohol), Operation while impaired causing bodily harm (alcohol and drugs), Operation while impaired causing bodily harm (drugs), Operation while impaired causing bodily harm (unspecified), Operation while impaired (alcohol), Operation while impaired (alcohol and drugs), Operation while impaired (drugs), Operation while impaired (unspecified)

04 Failure or refusal to comply with demand (alcohol), Failure or refusal to comply with demand (alcohol and drugs), Failure or refusal to comply with demand (drugs), Failure or Refusal to Comply with Demand (unspecified), Failure or refusal to comply with demand, accident resulting in bodily harm (alcohol), Failure or refusal to comply with demand, accident resulting in bodily harm (alcohol and drugs), Failure or refusal to comply with demand, accident resulting in bodily harm (drugs), Failure or refusal to comply with demand, accident resulting in bodily harm (unspecified), Failure or refusal to comply with demand, accident resulting in death (alcohol), Failure or refusal to comply with demand, accident resulting in death (alcohol and drugs), Failure or refusal to comply with demand, accident resulting in death (drugs), Failure or refusal to comply with demand, accident resulting in death (unspecified)

05 Failure to stop after accident resulting in death, Failure to stop after accident resulting in bodily harm, Failure to stop after accident, Operation while prohibited

06 Operation while Prohibited

Table 2.7 Youth Crime
Source: Niche Records Management System (RMS), (2026/03/06)

Note:

- Youth Charges by Disposition Type
- Only charges that have had a disposition type recorded in the OPP Niche RMS application are included.
- Youth charges without a disposition type are not included which may result in under stating the actual youth charges.
- “NULL” represents blanks, or where officers did not indicate the Disposition Type, however charges were applied.

Table 2.8 Victim Referrals
Source: Niche Records Management System (RMS), (2026/03/06)

Note:

- Number of Referrals to Victim Service Agencies

Table 3.1 Motor Vehicle Collisions (MVC) by Type

Source: Ontario Provincial Police, Collision Reporting System (CRS), (2026/02/24)

Note:

- Total Motor Vehicle Collisions (Fatal Injury, Non-Fatal Injury and Property Damage Only): Reportable Fatal Injury, Non-Fatal Injury and Property Damage Only Collisions entered into the eCRS for All Motorized Vehicles (MVC-Roadway, MSV- Snowmobile and ORV-Off Road Report Type) regardless of completion/approval status.
- Alcohol/Drug Related Collisions: Reportable MVC collisions where Alcohol/Drug Involved field indicated as Yes OR Contributing Factor scored as Ability Impaired (Alcohol or Drug) OR Driver Condition reported as Had Been Drinking or Ability Impaired.
- Animal Related Collisions: Reportable MVC collisions where Contributing Factor scored as Animal OR Wildlife Involved was an Animal OR Sequence of Events was an Animal.
- Speed Related Collisions: Reportable MVC collisions where Contributing Factor scored as Excessive Speed or Speed Too Fast For Conditions OR Driver Action reported as Exceeding Speed Limit or Speed Too Fast For Conditions.
- Inattentive Related Collisions: Reportable MVC collisions where Contributing Factor scored as Inattentive OR Driver Condition reported as Inattentive.
- Persons Killed or Injured: Number of Persons Injured or Killed in Reportable MVC collisions.

Table 3.2 Primary Causal Factors in Fatal MVCs on Roadways

Source: Ontario Provincial Police, Collision Reporting System (CRS), (2026/02/24)

Note:

- Fatal Roadway Collisions where Causal is Speed Related: Reportable Fatal Roadway Collisions where Contributing Factor scored as Excessive Speed or Speed Too Fast For Conditions OR Driver Action reported as Exceeding Speed Limit or Speed Too Fast For Conditions.
- Fatal Roadway Collisions where Causal is Alcohol/Drug Related: Reportable Fatal Roadway Collisions where Contributing Factor where Alcohol/Drug Involved field indicated as Yes OR Contributing Factor scored as Ability Impaired (Alcohol or Drug) OR Driver Condition reported as Had Been Drinking or Ability Impaired.
- Persons Killed in Fatal Roadway Collisions where lack of Seatbelt/Helmet use is a Factor: Persons Killed in Reportable Fatal Roadway Collisions where Victim is fatally injured AND a vehicle occupant AND where safety equipment reported to be not used but available.
- Fatal Roadway Collisions where Causal is Inattentive Related: Reportable Fatal Roadway Collisions where Contributing Factor scored as Inattentive OR Driver Condition reported as Inattentive.
- Fatal Roadway Collisions where Causal is Animal Related: Reportable Fatal Roadway Collisions where Contributing Factor scored as Animal OR Wildlife Involved was an Animal OR Sequence of Events was an Animal.

Table 3.3 Fatalities in Detachment Area

Source: Ontario Provincial Police, Collision Reporting System (CRS), (2026/02/24)

Note:

- Fatal Incidents: Reportable Fatal Collisions by Report Type (Roadway, Marine, Off-Road Vehicle, Motorized Snow Vehicle).
- Persons Killed: Number of Involved Persons where Injury is fatal by Report Type (Roadway, Marine, Off-Road Vehicle, Motorized Snow Vehicle).
- Alcohol/Drug Related Incidents: Reportable Fatal Collisions by Report Type (Roadway, Marine, Off-Road Vehicle, Motorized Snow Vehicle) where Alcohol/Drug Involved field indicated as Yes OR Contributing Factor scored as Ability Impaired (Alcohol or Drug) OR Driver Condition reported as Had Been Drinking or Ability Impaired.

Table 3.4 Big 4

Source: Niche Records Management System (RMS) & eTicket, (2026/02/24)

Note:

- Speeding (HTA 128): Charges are based on date charged. Speeding = HTA s.128 charges.
- Seatbelt (HTA 106): Charges are based on date charged. Seatbelt = HTA s.106 charges.
- Distracted (HTA 78.1): Charges are based on date charged. Distracted = HTA s.78.1 charges.
- Impaired (CCC 320.14 & 320.15): Charges are based on date charged. Impaired = CCC s.320.14 & 320.15 charges.

Table 3.5 Charges
Source: Niche Records Management System (RMS) & eTicket, (2026/02/24)

Note:

- HTA: Charges are based on date charged. Highway Traffic Act Statute charges.
- Criminal Code Traffic: Charges are based on date charged. Criminal Code Traffic (CCC s320.13, 320.14, 320.15, 320.16, 320.17 & 320.18) charges.
- Criminal Code Non-Traffic: Charges are based on date charged. All CCC charges not included in the Criminal Code Traffic section above.
- LLCA: Charges are based on date charged. Liquor Licence and Control Act charges.
- Federal Cannabis Act: Charges are based on date charged. Cannabis Act charges.
- Provincial Cannabis Act: Charges are based on date charged. Cannabis Control Act charges.
- Controlled Drug and Substance Act: Charges are based on date charged. Controlled Drug and Substance Act charges.
- Other: Charges are based on date charged. "Other" charges is comprised of CAIA, Other Provincial & Federal Offences not already captured in sections above.

Table 4.1 Service Delivery Activity Allocations
Source: Daily Activity Reporting (DAR) System
Date: January 12, 2026

Note: Activity allocation percentages are based on the total reported hours of detachment provincial constables performing duties within their home detachment location.

Table 4.2 Hours (Field Personnel)
Source: Daily Activity Reporting (DAR) System
Date: March 06, 2026

Note:

- Total reported hours, excluding paid duties.
- Includes Provincial Constable to Sergeant ranks only.
- Excludes First Nations badge numbers.
- Excludes administrative accounts and joint services accounts.
- Excludes incomplete DAR entries and those with errors.
- Excludes General Headquarters location codes.

CONTACT THE OPP

Know your location - be ready to describe the situation and your location. Look for addresses, landmarks and buildings that may help identify your location.

REACH THE OPP BY PHONE

- Call 9-1-1 if there is an immediate risk to someone's life or property
  - to stop or report a crime in progress
  - to report a fire
  - to report a life-threatening medical emergency
  - Don't hang up, stay on the line
- To report non-life-threatening incidents that require a police response, use the non-emergency line (1-888-310-1122) or go to opp.ca/reporting
- TTY 1-888-310-1133 or agent 511 for registered subscribers may be used for individuals in the Deaf, Hard of Hearing and Speech Impaired (DHHSI) community to contact police
- For all administrative inquiries or to schedule an appointment, find contact information for your local detachment at opp.ca/detachments

PROVIDE AN ANONYMOUS TIP

- Call Crime Stoppers at 1-800-222-8477 (TIPS) or visit www.crimestoppers.ca

REPORT AN INCIDENT ONLINE

- The OPP offers online reporting for minor, non-emergency occurrences in areas of OPP jurisdiction. opp.ca/reporting allows you to submit a report without visiting or calling.
- Use the online reporting tool for:
  - Theft Under $5,000
  - Mischief / Damage to Property Under $5,000
  - Mischief / Damage to Vehicle Under $5,000
  - Theft from Vehicle Under $5,000
  - Lost / Missing Property Under $5,000, including a licence plate(s) or validation sticker(s)
  - Driving Complaints

If you are reporting an emergency, call 9-1-1.

#KNOWWHENTOCALL

9-1-1 is for emergencies only: If there is an immediate risk to someone's life or property.

- ✔ a crime in progress
- ✔ a fire
- ✔ a life-threatening medical emergency

Dialed 9-1-1 accidentally? #Be911Ready. Don't hang up, stay on the line and speak with an OPP Communicator to confirm there's no emergency.

The misuse of 911 ties up emergency lines, communicators and officers, which can result in a slower response to a real emergency and risks the safety of people who may need urgent help.

It is against the law to call 9-1-1 as a joke. Prank 9-1-1 calls can be dangerous and waste valuable emergency resources.

DETACHMENT BOARD ANNUAL REPORT

2025

WELLINGTON COUNTY DETACHMENT

371 Charles Allan Way
FERGUS ,ON
NIM 2W3

Tel: 519-846-5930
Fax: 519-846-5460

Follow us on

Laura Emery

From: IESO Community Engagement <communityengagement@ieso.ca>
Sent: August 20, 2026 2:54 PM
To: IESO Community Engagement
Subject: South and Central Final Bulk Plan Now Available

Caution! This message was sent from outside your organization. Allow sender | Block sender | Report

An electricity plan that considers electricity demand and supply conditions over the next 20 years in a broad area encompassing regions across Southern and Central Ontario is now posted on the IESO website along with responses to submitted feedback.

The South and Central Bulk Plan was initiated in 2024 to assess transmission reinforcements required to enable the connection of small modular reactors near Darlington Nuclear Generating Station and expanded nuclear at the Bruce Power site, emerging demand across the Greater Toronto Area (GTA) and the Windsor–Hamilton corridor, the flow of electricity across multiple pathways, and the ability to connect to new large sources of demand that support economic development.

To manage costs and maintain flexibility, the IESO recommends a staged approach that can adapt as electricity demand, procurement outcomes, and policy direction evolve.

Early actions were advanced during the initial stages of the South and Central Bulk Plan due to the urgency of emerging needs. These included:

- A new transmission line from Bowmanville to the eastern GTA to connect small modular reactors and other electricity supply resources.
- Reconductoring a transmission line between Barrie and Orangeville.
- Corridor preservation studies for potential future transmission infrastructure.

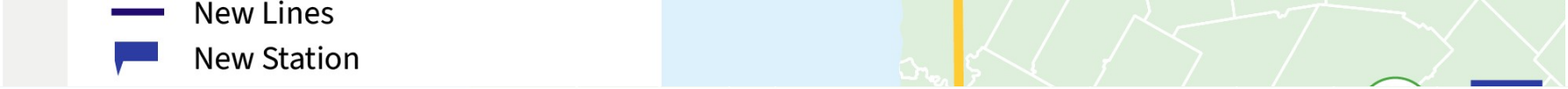
Implementation-ready actions are investments that should begin now to meet electricity needs by the early 2030s. Based on input from communities and stakeholders, the IESO recommends five new or upgraded stations in Milton, Barrie, Vaughan, Puslinch, and Guelph to support population growth, electrification, and economic development.

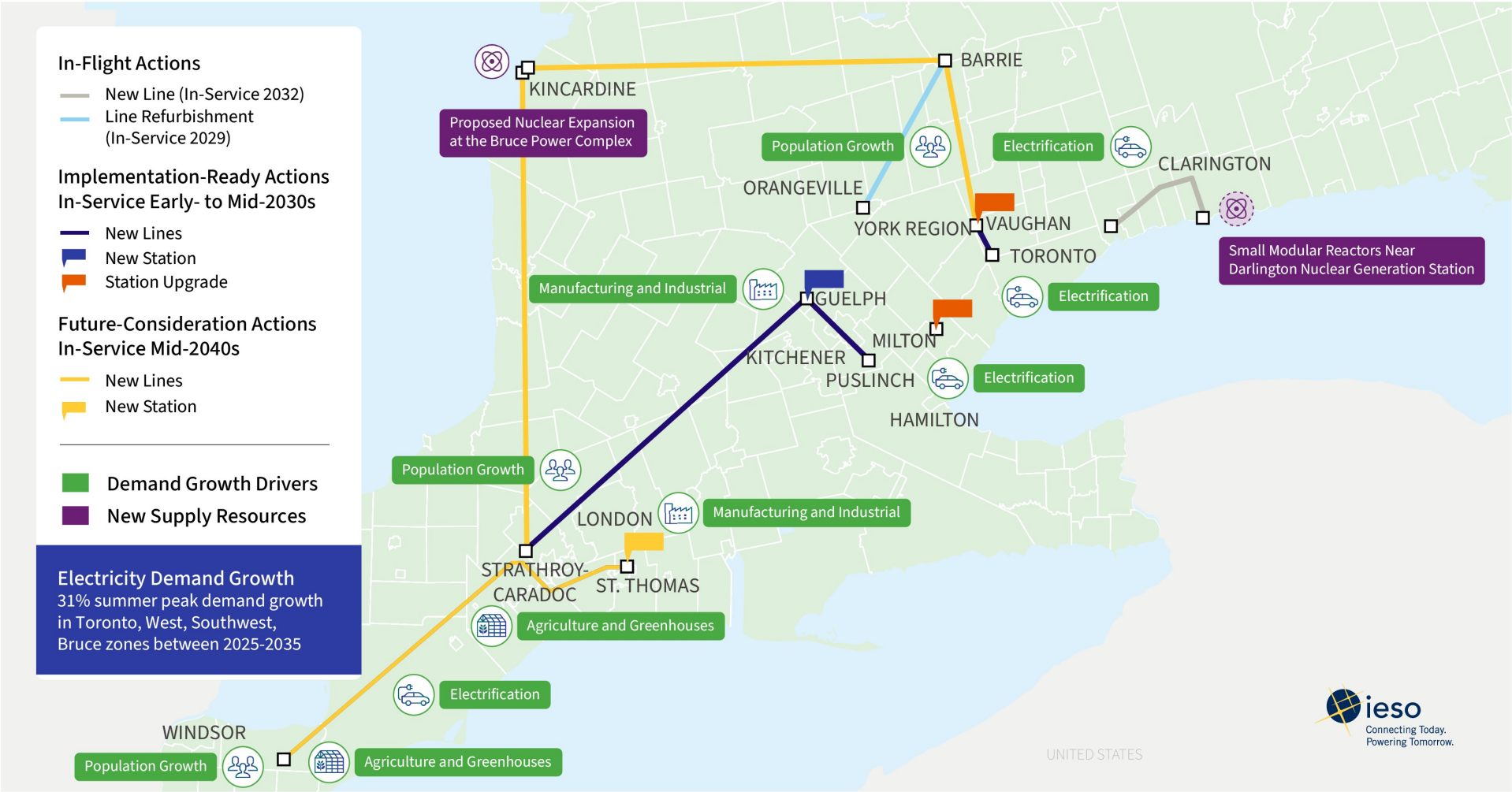
The IESO also recommends new transmission lines between Vaughan and Toronto, Strathroy-Caradoc and Guelph, and Guelph and Puslinch to increase system capacity, improve reliability, and enable new electricity supply. Given the long development timelines for transmission projects, these investments should move forward immediately, with in-service dates between 2030 and 2034.

Future-consideration actions help preserve the electricity system's ability to respond to longer-term growth and changing electricity system needs. These investments are not required immediately but may be needed to support future demand growth, new electricity supply, or evolving policy priorities. By advancing them only when needed, the IESO can maintain flexibility while managing costs for ratepayers.

For the South and Central Bulk Plan, these actions include a new transformer station in the London area, transmission infrastructure to enable the proposed Bruce C nuclear project, and a new transmission line between London and Lakeshore to support future growth in southwestern Ontario. The IESO will continue to monitor system needs and advance these investments as conditions evolve.

The diagram below provides an overview of the recommended actions to address the region's electricity needs. For more information, please refer to the final report or the backgrounder.





Transmission line routes are illustrative and not final. Demand drivers indicate general areas of potential growth.

Next Steps

A transmitter will be responsible for the design, construction, operation and maintenance of these recommendations, which includes engagement and the completion of the Environmental Assessment for Transmission Facilities. Once placed into service, the IESO will manage and direct the flow of electricity through this new infrastructure.

Your Participation Matters

The IESO consulted at key milestones to provide meaningful opportunities to provide feedback into this work. To ensure the plan reflects the needs of market participants, municipalities, stakeholders, Indigenous communities, customers, and the public, the IESO built awareness and understanding through a dedicated webpage, targeted discussions, public webinars and other communications. Input from these engagements informed the development of the report and shaped its final recommendations.

This concludes the South & Central Bulk Plan initiative. The IESO appreciates your participation and feedback throughout the development of the Plan. If you have any questions, please contact communityengagement@ieso.ca. To stay informed, subscribe to receive IESO updates.

Sincerely,

The IESO Regional and Community Engagement

This e-mail message and any files transmitted with it are intended only for the named recipient(s) above and may contain information that is privileged, confidential and/or exempt from disclosure under applicable law. If you are not the intended recipient(s), any dissemination, distribution or copying of this e-mail message or any files transmitted with it is strictly prohibited. If you have received this message in error, or are not the named recipient(s), please notify the sender immediately and delete this e-mail message.

Ontario Environmental Registry of Ontario

WHITE WOLF PROPERTY MANAGEMENT INC.

Instrument type: Permit to take water (/taxonomy/term/334)

ERO (Environmental Registry of Ontario) number	026-0893
Ministry reference number	1000460905
Notice type	Instrument
Act	Ontario Water Resources Act, R.S.O. 1990
Posted by	Ministry of the Environment, Conservation and Parks
Notice stage	Proposal
Proposal posted	August 28, 2026
Comment period	August 28, 2026 - September 27, 2026 (30 days) Open
Last updated	August 28, 2026

This consultation closes at 11:59 p.m. on:

September 27, 2026

Proposal summary

This proposal is for the renewal of Permit to Take Water No. (number) 4657-DLVP7F for White Wolf Property Management Inc. (incorporated) Water will be taken from one well, located in the Township of Puslinch, Ontario, for bottled water purposes.

Location details

Site address

101 Brock Road South
Puslinch, ON
Canada

Site location map

The location pin reflects the approximate area where environmental activity is taking place.

View this location on a map (https://maps.google.com/?q=43.46248,-80.149917)

Proponent(s)

WHITE WOLF PROPERTY MANAGEMENT INC.
485387 30th Sideroad
Shelburne, ON
L9V3N5
Canada

Proposal details

This proposal is for the renewal of Permit to Take Water No. (number) 4657-DLVP7F for White Wolf Property Management Inc. (incorporated) Water will be taken from one well, located in the Township of Puslinch, Ontario, for bottled water purposes. The renewal requests a reduction in the maximum taking, from 3,600,000 litres per day to 986,400 litres per day. Details of the water taking are as follows:

Application type – Renewal

Source Name: TW3-80

- Purpose: bottled water
- Maximum rate per minute (litres): 685
- Maximum number of hours of taking per day: 24
- Maximum volume per day (litres): 986,400
- Maximum number of days of taking per year: 365
- Earliest calendar date of taking (mm/dd (month/day)): 01 January
- Latest calendar date of taking (mm/dd (month/day)): 31 December
- Period of taking: 10 years

There are 3 categories of Permit to Take Water application:

- Category 1 applications are considered low-risk and are unlikely to pose unacceptable impacts
- Category 2 applications require a Qualified Person to undertake a scoped scientific evaluation to ensure the withdrawal of water does not result in unacceptable impacts or interference with other users. The evaluation should also demonstrate that the taking meets one of the Category 2 criteria
- Category 3 applications must submit a detailed hydrogeological study and/or surface water study prepared by a Qualified Person for ministry review. The study will evaluate the potential for unacceptable impacts resulting from the water taking

According to the application criteria presented in the Permit to Take Water application guide, the proposed water taking qualifies as a Category 3 application. Any proposals for groundwater or surface water takings that do not meet the Category 1 or Category 2 application criteria are considered to be Category 3 applications. For more information, refer to the Permit to Take Water application guide using the website link below: **Guide to Permit to take water application form | ontario.ca (https://www.ontario.ca/page/guide-permit-take-water-application-form)**

Supporting materials

Related links

General Information (https://www.ontario.ca/page/permits-take-water)

View materials in person

Some supporting materials may not be available online. If this is the case, you can request to view the materials in person.

Get in touch with the office listed below to find out if materials are available.

Client Services and Permissions Branch
40 St. Clair Avenue West
Floor 2
Toronto, ON
M4V 1M2
Canada

416-314-8001 or 1-800-461-6290

Comment

Let us know what you think of our proposal.

Have questions? Get in touch with the contact person below. Please include the ERO (Environmental Registry of Ontario) number for this notice in your email or letter to the contact.

Read our commenting and privacy policies. (/page/commenting-privacy)

Submit by mail

Client Services and Permissions Branch

Client Services and Permissions Branch
40 St. Clair Avenue West
Floor 2
Toronto, ON
M4V 1M2
Canada

Connect with us

Contact

Client Services and Permissions Branch

416-314-8001 or 1-800-461-6290

enviropermissions@ontario.ca

Justine Brotherston

From: Persaud, Ajay (He/Him) (MECP) <Ajay.Persaud@ontario.ca>
Sent: August 28, 2026 2:42 PM
To: Kyle Davis; Jennifer Adams; Scott Wilson, CAO; Source Water; rob.adams@erin.ca; Justine Brotherston; Courtenay Hoytfox
Subject: Notification of Permit to Take Water Application – Ref. No. 1000460905

Follow Up Flag: Follow up
Flag Status: Flagged

Caution! This message was sent from outside your organization. Allow sender | Block sender | Report

This E-mail message has been sent to you as a result of the requirements of Ontario's Water Taking and Transfer Regulation (O.Reg 387/04). The regulation requires that the Ministry of the Environment, Conservation and Parks notify municipalities and conservation authorities of applications for Permits to Take Water to withdraw water from locations within their jurisdiction.

Notification of Application for Permit to Take Water
Ministry Reference Number: 1000460905
Applicant: WHITE WOLF PROPERTY MANAGEMENT INC.

Location of Water Taking(s):
Well TW3-80, 101 Brock Road South, Lot 23, Concession 7, Geographic Township of Puslinch, Township of Puslinch, County of Wellington

Permit Type:
Renewal of Permit to Take Water No. 4657-DLVP7F

Length of the Taking:
10 years

Description:
This proposal is for the renewal of the Permit to Take Water No. 4657-DLVP7F for White Wolf Property Management Inc. Water will be taken from one (1) well, located in the Township of Puslinch, Ontario, for bottled water purposes. The renewal requests a reduction in the maximum taking, from 3,600,000 litres per day to 986,400 litres per day. Details of the water taking are as follows:

Application type – Renewal

Source Name: TW3-80
Purpose: Bottled water
Maximum rate per minute (Litres): 685
Maximum number of hours of taking per day: 24
Maximum volume per day (Litres): 986,400
Maximum number of days of taking per year: 365
Earliest calendar date of taking (mm/dd): 01 January
Latest calendar date of taking (mm/dd): 31 December
Period of taking: 10 Years

There are 3 categories of Permit to Take Water application:

- **Category 1** applications are considered low-risk and are unlikely to pose unacceptable impacts.

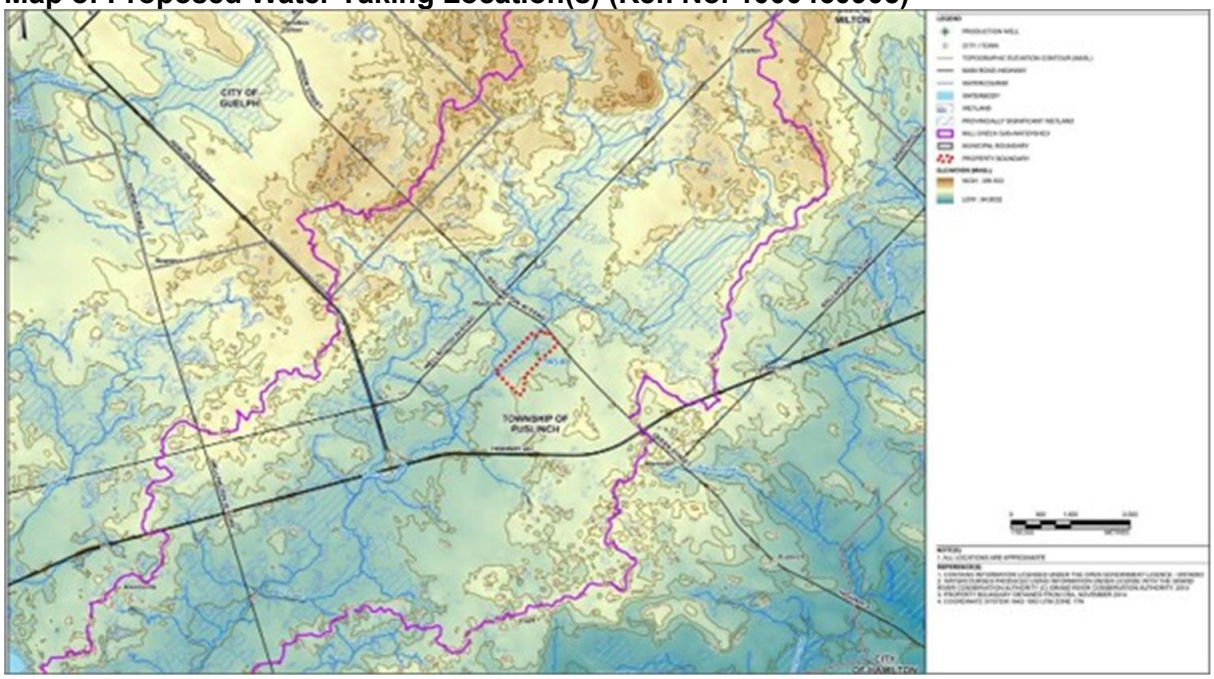
- **Category 2** applications require a Qualified Person to undertake a scoped scientific evaluation to ensure the withdrawal of water does not result in unacceptable impacts or interference with other users. The evaluation should also demonstrate that the taking meets one of the Category 2 criteria.
- **Category 3** applications must submit a detailed hydrogeological study and/or surface water study prepared by a Qualified Person for ministry review. The study will evaluate the potential for unacceptable impacts resulting from the water taking.

According to the application criteria presented in the Permit to Take Water application guide, the proposed water taking qualifies as a Category 3 application. Any proposals for groundwater or surface water takings that do not meet the Category 1 or Category 2 application criteria are considered to be Category 3 applications. For more information, refer to the Permit to Take Water application guide using the website link below:
Guide to Permit to take water application form | ontario.ca

Table A - Source information and Water Taking Amount Applied For:

	Source Name / Description	Source Type	Purpose Category	Specific Purpose	Activity	Max. Taken per minute	Max. No. of Hrs Taken per day	Max. volume per Day	Max. days in a year	Zone / Easting / Northing
1	TW3-80 (TW3-80)	Well	Manufacturing	Bottled water	Bottling	685	24	986,400	365	17 / 569053 / 4812797
							Total Taking	**986,400**		

Map of Proposed Water Taking Location(s) (Ref. No. 1000460905)



Supporting Documents:
Supporting documents submitted with this application are available upon request from the ministry contact identified below.

Comments should be directed to the following contact person:
Ajay Persaud
Environmental Scientist, Permit to Take Water Unit
Environmental Permissions Branch
Ministry of the Environment, Conservation and Parks
Floor 1, 135 St. Clair Avenue West

Toronto, Ontario M4V 1P5
Tel: (289) 200-0589
Email: ajay.persaud@ontario.ca

This E-mail message has been sent to you as a result of the requirements of Ontario Regulation 387/04. It is the responsibility of the municipality or Conservation Authority to determine the appropriate staff person to whom this notification should be forwarded. If you wish to have subsequent notification sent to a different person within your organization, please respond to this E-mail message with an alternate E-mail address and contact name. It is the responsibility of the municipality or conservation authority to ensure that any changes to the alternate E-mail address are reported to the ministry.

Please note that any comments, concerns, or questions must be received by the ministry within 30 days of the date of this message.

Ajay Persaud
Environmental Scientist, Permit to Take Water Unit | Environmental Permissions Branch
Ministry of the Environment, Conservation and Parks | Ontario Public Service
(289) 200-0589 | ajay.persaud@ontario.ca

Ontario

Hamilton Conservation Authority

A Healthy Watershed for Everyone

September 3, 2026

Via Email: jbrotherston@puslinch.ca

Mayor James Seeley and Members of Council
Township of Puslinch Office
7404 Wellington Road 34
Puslinch, Ontario
N0B 2J0

RE: Hamilton Conservation Authority – 2027 Draft Budget

Dear Mayor Seeley and Members of Council:

In accordance with *Conservation Authorities Act*, the HCA's draft 2027 budget, approved for consultation by the board of directors on September 3, 2026, is enclosed. This letter provides notice that HCA will be considering the final 2027 budget at the October Board of Directors meeting.

The draft budget, including the approved apportionment amounts for participating municipalities, has been provided to the City of Hamilton and the Township of Puslinch for review and comment. HCA has only two participating municipalities, with the City of Hamilton representing 99.24% of the municipal levy and the Township of Puslinch representing the remaining 0.76%.

HCA will consider any comments received prior to bringing the final budget forward for Board approval in October.

Sincerely,

[redacted]

Lisa Burnside
Chief Administrative Officer

Enclosure

Cc. Mary Hasan, Director, Finance and Treasurer, Township of Puslinch

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Hamilton Conservation Authority

2027 Draft Budget

2027 Draft Budgdet Approved for Circulation by

the HCA Board of Directors on

September 3, 2026

Hamilton Conservation Authority

Executive Summary

- The 2027 draft budget approved by the HCA Board of Directors contain details for HCA's planned operations and capital activities.
- It reflects a balanced budget that reflects a continuation of all programs and services and also addresses year-three priorities of HCA's Strategic Plan.
- The 2027 budget for HCA invests $23.1 million to protect natural spaces, enhance public accessibility, and support environmental initiatives across the watershed.
- The total budget of $23.1M is $18.3 million in operating and $4.8 million in capital.
- The operating budget contains a 3.7% increase to municipal levy (3.3% in 2026), and is balanced in part by significant self-generated revenue, with $1.8 million coming from our conservation areas.
- The Capital budget holds the $2 million block funding from the City of Hamilton, and is more than doubled through $2.55M from the Hamilton Conservation Foundation (grant funding through Heritage Green Community Trust) as well as $250K from HCA's Reserves.

Goals

Operating Budget:

- Support HCA's 2025-2029 Strategic plan and engage in year 3 priorities across the Plan's four strategic priority areas:
    - Water Resources Management
    - Organizational Excellence
    - Natural Heritage Conservation
    - Connecting People to Nature
- Operate on a cash neutral basis (break-even) – this requires maintaining and growing the funding revenues that come from non-levy sources, primarily the commercial operations at conservation areas and supplemented by the Hamilton Conservation Foundation, corporate, and government grants. The expenditure side of the equation is dominated by the cost of staff salaries, wages, and benefits.
- The 2027 budget reflects a maintenance budget approach, while HCA navigates organizational transition and the pending regional amalgamation. Approved Year 3 initiatives will be delivered within the available budget envelope, supported where appropriate by grants, donations and reserve funding.

Capital Budget:

- Balances strategic investment with the responsibility to maintain HCA's extensive network of infrastructure and assets .
- Of the total capital budget, 73% is directed to special projects and 27% to major maintenance.
- The development of the capital budget includes strategic initiatives initiated in the strategic plan, capital priorities identified in Asset Management Plan, and projects identified in Park master and management plans.
- Saltfleet Wetland Restoration: A significant component of the capital program is the continued investment in the Saltfleet Wetland Restoration Program. $2.8 million in grants and reserves will support construction of the third wetland at the Devil's Punchbowl and initiate design work for the fourth and final wetland.
- The special projects portion of the capital budget focuses on priority investments that advance HCA's strategic objectives, improve visitor amenities and protect key infrastructure, while also positioning some areas for future revenue opportunities. This includes work on projects such as Marina Investments and the first phase of the Christie Lake Causeway culvert replacement.
- Major maintenance accounts have been grouped into key areas of asset renewal and improvement.
- Planned work in 2027 includes building repairs and painting at various locations, the final phase of boardwalk replacement at Valens Lake, tar-and-chip work on internal roadways, and continued investment in wayfinding signage and master planning. This work represents the ongoing capital investment required to keep HCA's existing infrastructure safe, functional and accessible for staff and visitors.

2027 Draft Budget

Operating Budget (in 000's)

Division	Expenditures	Revenues	% Split	Revenue Description
Watershed Management Services	$ 3,592	$ 2,651		Levy
		941		Other Revenues
Conservation Areas Operations	6,830	-		Levy
		8,618		Other Revenues
Westfield Heritage Village	1,059	721		Levy
		338		Other Revenues
Central Support Services	6,893	2,040		Levy
		3,065		Other Revenues
Total		5,412	29.5%	Levy
		12,962	70.6%	Other Revenues
	$ 18,374	$ 18,374	100.0%	
Budget Surplus (Deficit)		$ -		

2026 Levy	$ 5,219
2027 Levy	5,412
Levy Increase	$ 193
% Increase	3.7%

Municipal Levy Apportionment

Municipal Levy	Levy	
Total Levy	$ 5,412,233	Including Westfield Heritage Village Levy
Less: Westfield Heritage Village	721,227	City of Hamilton only
Municipal Levy to Apportion	4,691,006	Levy to apportion to municipalities
City of Hamilton	99.24%	4,655,354
Township of Puslinch	0.76%	35,652
Total Municipal Levy		$ 4,691,006

Capital Budget (in 000's)

Capital	Expenditures	Revenues	
Special Projects	$ 3,500	$ 3,500	
Major Maintenance	1,300	1,300	
Total		2,000	Hamilton Capital Block Funding
		2,550	Hamilton Conservation Foundation
		250	HCA Reserves
	$ 4,800	$ 4,800	
Budget Surplus (Deficit)		$ -	

Consolidated Budget (in 000's)

Consolidated	Expenditures	Revenues
Operating	$ 18,374	$ 18,374
Capital	4,800	4,800
Total	$ 23,174	$ 23,174
Budget Surplus (Deficit)		$ -

2027 Divisional Summary (in 000's)

Watershed Management Services

Expenses		Revenues	
Staffing	$ 2,984	Municipal levy	$ 2,651
Contractors	319	Grants	404
Supplies	97	Permits, fees	290
Other	192	Other	247
Total	**$ 3,592**	**Total**	**$ 3,592**

Conservation Area Services

Expenses		Revenues	
Staffing	$ 3,998	Admissions	$ 3,814
Equipment	725	Camping	2,326
Utilities	458	Marina	1,656
Materials/supplies	369	Other	822
Other	1,280		
Total	**$ 6,830**	**Total**	**$ 8,618**

Westfield Heritage Village & Conservation Area

Expenses		Revenues	
Staffing	$ 662	Municipal levy	$ 721
Promotion	95	Events	129
Utilities	64	Admissions	87
Materials/supplies	57	School Programs	67
Other	181	Other	55
Total	**$ 1,059**	**Total**	**$ 1,059**

Central Support Services

Expenses		Revenues	
Staff	$ 4,904	Municipal levy	$ 2,040
Utilities	245	Equipment rental	1,455
Contractors	178	Management fees	618
Supplies	69	Transfer from Reserves	75
Other	1,497	Other	917
Total	**$ 6,893**	**Total**	**$ 5,105**

Capital & Major Maintenance

Expenses		Revenues	
Special Projects	$ 3,500	City of Hamilton Block Funding	$ 2,000
Major Maintenance	1,300	Hamilton Conservation Foundation	2,550
		HCA Reserves	250
Total	**$ 4,800**	**Total**	**$ 4,800**

THE CORPORATION OF THE TOWNSHIP OF PUSLINCH

BY-LAW NUMBER 2026-057

Being a by-law to appoint Members to the Wellington County Joint Municipal Election Compliance Audit Committee.

WHEREAS subsection 88.37 of the Municipal Elections Act, 1996, as amended requires Council to establish a Compliance Audit Committee;

AND WHEREAS the County of Wellington member Municipalities established a Joint Municipal Election Compliance Audit Committee for all municipalities in the County of Wellington;

AND WHEREAS Section 11 (2) of the *Municipal Act, S.O. 2001, c. 25,* authorizes a municipality to pass by-laws respecting the governance structure of the municipality and its local boards;

NOW THEREFORE the Council of the Corporation of the Township of Puslinch hereby enacts as follows:

1) That the following persons are hereby appointed to the Wellington County Joint Compliance Audit Committee from November 17, 2026 until the end of the term of Council in 2030 in accordance with the *Municipal Elections Act:*
    - Jim McQueen
    - Douglas Auld
    - Joseph Servos
    - John Daly
    - Troy McHarg
    - Lina Leeds

2) That this by-law shall repeal by-law 2026-041.

3) That this by-law shall come into force and effect on November 17, 2026.

READ A FIRST, SECOND AND THIRD TIME AND FINALLY PASSED THIS 16 DAY OF SEPTEMBER 2026.

_____
James Seeley, Mayor

_____
Justine Brotherston, Municipal Clerk

THE CORPORATION OF THE TOWNSHIP OF PUSLINCH

BY-LAW NO. 058-2026

Being a by-law to establish the rates of remuneration to Staff of the Corporation of the Township of Puslinch and to repeal By-law No. 076-2024.

WHEREAS the Council for the Corporation of the Township of Puslinch deems it appropriate to pass a by-law to establish the rates of remuneration to Staff of the Township; and

WHEREAS the *Municipal Act, 2001, S.O. 2001, c. 25*, as amended empowers Council to pass such a By-law regulating the appointment, duties and remuneration of Staff.

NOW THEREFORE the Corporation of the Township of Puslinch ("Township") hereby enacts as follows:

Remuneration:

1. The revised 2026 Salary Grid effective October 9, 2026 shall be as set out in Schedule A attached to this By-law.

2. The 2027 Salary Grid effective January 1, 2027 shall be as set out in Schedule B attached to this By-law.

3. The salary and wages in Schedule B of this by-law shall be automatically adjusted annually by the cost of living adjustment approved by Council for staff for each year.

4. The salary and wages in Schedule B of this by-law shall be automatically adjusted annually to the Ontario Minimum Wage as per the *Employment Standards Act*, as amended.

5. As stated in the Performance Appraisal Policy 2020-005, as amended, merit increases are based on performance and are not guaranteed. Apart from part-time Volunteer Firefighter positions, employees may receive a merit increase ranging from 0% to a maximum of 4% during their annual performance review. The merit increase is determined in accordance with performance indicators outlined in the Performance Appraisal Policy, as amended.

Vacation and Designated Holidays:

6. The following is the paid annual vacation for permanent full-time employees of the Township based on the number of years of service. Vacation entitlements shall be accrued in accordance with Township Policies and Procedures, as amended:

    (1) Two weeks after one year of service.
    (2) Three weeks after one year of service (for Department Heads only).
    (3) Three weeks after two years of service.
    (4) Four weeks after eight years of service.
    (5) Five weeks after fifteen years of service.
    (6) Six weeks after twenty-two years of service.

7. Permanent full-time employees may opt for performance-based vacation entitlement in lieu of a merit increase, contingent upon a successful annual performance appraisal. To be eligible for an additional 1.25 days of vacation per annual performance period, employees must meet all of the performance criteria in accordance with the Performance Appraisal Policy 2020-005, as amended. Performance-based vacation entitlement may be earned up to a maximum of

1.25 days per annual performance period, with a cumulative maximum of 10 days per employee throughout their employment with the Township. This performance-based vacation is in addition to the regular vacation entitlement outlined in Paragraph 6.

8. The following is the paid annual vacation for employees other than permanent full-time employees of the Township based on the number of years of service:

    (1) Two weeks (4%) paid vacation prior to five years of service.
    (2) Three weeks (6%) paid vacation after five years of service.

9. The vacation year begins January 1st to December 31st.

10. Vacation must be taken in the year earned or at the discretion of the Department Head. In the case of the Chief Administrative Officer, this is at the discretion of Council.

11. Designated Holidays are:

    (1) New Year's Day
    (2) Family Day
    (3) Good Friday
    (4) Easter Monday
    (5) Victoria Day
    (6) Canada Day
    (7) Civic Holiday
    (8) Labour Day
    (9) Thanksgiving Day
    (10) Remembrance Day
    (11) Christmas Day
    (12) Boxing Day

Benefits:

12. The Township will pay 100% of the premium costs to provide healthcare benefits for permanent full-time employees of the Township.

13. The Healthcare benefits provided to permanent full-time employees of the Township include the following:

    (1) Short Term Disability
    (2) Long Term Disability
    (3) Group Life Insurance
    (4) Accidental Death & Dismemberment
    (5) Extended Health Care
    (6) Hospital Semi-Private
    (7) Dental, Drug, Vision Care, Out of Province Coverage
    (8) Employee and Family Assistance Program (applicable to full-time and non-full-time employees)

14. The Township will pay 100% of the premium costs to provide the following benefits to Fire & Rescue Services personnel of the Township:

    (1) Basic Employee Life Insurance
    (2) Basic Spouse and Dependent Life Insurance
    (3) Accidental Death, Injury, Sickness & Dismemberment – On-Duty and Off-Duty
    (4) Employee and Family Assistance Program

15. OMERS Primary Pension Plan participation is in accordance with the Township's OMERS Participation By-law No. 065-2024, as amended. The Township will contribute to OMERS an amount equal to the required employee contribution.

16. The Township will continue to pay premiums for benefit coverage for a period of up to twelve months from the date of disability or at the discretion of Council, to a maximum of twenty-four months. Any individuals that are on Long Term Disability at the end of this period are no longer considered to be employees of the Township and will not be eligible to participate in any benefit plans unless premiums have been waived as part of such a plan.

17. The Township will continue to pay premiums for benefit coverage for pregnancy and parental leave as per the *Employment Standards Act, Ontario Regulation 286/01*.

18. Permanent full-time employees with ten or more continuous years of service with the Township, who retire within ten years of their normal OMERS retirement age, will be able to participate in the health benefits, with the exclusion of Accidental Death and Dismemberment and Long-Term Disability, provided under the healthcare benefit package at the time of retirement until the age of 65. This is only available to retirees who do not have access to current coverage elsewhere.

    Included as part of the health benefits package, regardless of coverage elsewhere, is a life insurance benefit in the amount of one times the annual basic wage at the time of retirement until the age of 65, rounded to the nearest $1,000.00.

    The employer will pay 50% of the cost of the premium.

Illness/Leave of Absence:

19. Full-time employees are entitled to eight working days of sick leave and/or personal/wellness leave for each calendar year. The entitlement shall be accrued in accordance with Township Policies and Procedures, as amended. The allowance of up to eight working days on an annual basis is not cumulative and is not eligible to be carried forward to the following calendar year.

20. Bereavement leave arising from the death of a spouse/companion or child will be granted with pay up to a maximum of five normally scheduled working days. Bereavement leave arising from the death in the immediate family, other than a spouse/companion or child, will be granted with pay up to maximum of three normally scheduled working days.

    Immediate family other than a spouse/companion or child shall include a parent-in-law, parent, sibling, sibling-in-law, grandparent, and grandchild.

21. Bereavement leave arising from the death of other family will be granted with pay up to a maximum of one normally scheduled working day.

22. An employee who is required to serve as a juror where a subpoena is issued will be granted a paid leave of absence. The employee shall be paid one-day's pay for the loss of each day of service provided that they report for work when not actually required for jury duty. Upon returning to work the employee will provide proof of such service.

23. Any other unpaid leave of absence will require approval from the Chief Administrative Officer and the Department Head. In the case of a Department Head, any unpaid leave of absence will require approval from the Chief Administrative Officer. In the case of the Chief Administrative Officer, any unpaid leave of absence will require approval from Council.

24. That By-law No. 076-2024 is hereby repealed.

25. That this By-law takes full force and effect October 9, 2026.

READ A FIRST, SECOND AND THIRD TIME AND FINALLY PASSED THIS 16th DAY OF SEPTEMBER, 2026.

_____
James Seeley, Mayor

_____
Justine Brotherston, Municipal Clerk

Schedule A

Township of Puslinch

Schedule A - 2026 Salary Grid

	20% between Minimum and Maximum	
Similar Value Group	**Minimum**	**Maximum**
13	$86.94	$105.04
11	$62.99	$76.10
10	$56.25	$67.96
9	$50.08	$60.50
8	$50.18	$60.63
7	$42.29	$51.09
6	$35.23	$42.56
5	$31.78	$38.39
4	$27.76	$33.54
3	$21.40	$25.85
2	$17.95	$21.69
1		

Notes:

$17.95 1. Ontario Minimum Wage effective October 1, 2026 is $17.95 per hour.

$0.00 2. Auxiliary Firefighter – This position does not have a rate of pay and is not eligible to participate in OMERS.

3. Part-time Volunteer Firefighter Administration Positions - Rates of pay for positions included in the salary grid will vary based on whether the volunteer firefighter elects to participate in OMERS.

The table below outlines the applicable rates of pay for part-time volunteer firefighters based on OMERS participation:

Position	Opt-In to OMERS	Opt-Out of OMERS
Captain	$38.99	$42.50
Acting Captain	$35.41	$38.60
Senior Firefighter (Leadership Development Stream)	$31.28	$34.10
Firefighter Class 1	$26.15	$28.50
Recruit Firefighter Class 2	$19.42	$21.17
Recruit Firefighter Class 3	$18.67	$20.35
Recruit Firefighter Class 4	$17.95	$19.57

Notes:

1. **Recruit Firefighter Class 4** – First Year: New members enter as Recruit Firefighter Class 4 and may advance after one (1) year of service to Firefighter Class 3 based on a successful annual performance appraisal, good standing, and attendance requirements.
2. **Recruit Firefighter Class 3** – Second Year: Members progress to Recruit Firefighter Class 3 and may advance after two (2) years of service to Firefighter Class 2 based on a successful annual performance appraisal, good standing, and attendance requirements.
3. **Recruit Firefighter Class 2** – Third Year: Members progress to Recruit Firefighter Class 2 and may advance after three (3) years of service to Firefighter Class 1 based on a successful annual performance appraisal, good standing, and attendance requirements.
4. **Firefighter Class 1**: Firefighter Class 1 is the fully qualified operational classification, with eligible members able to pursue the Senior Firefighter – Leadership Development Stream.
5. **Senior Firefighter – Leadership Development Stream:** Firefighter Class 1 members who demonstrate strong performance, attendance, experience, and leadership potential may enter a structured two-year development stream to obtain the training and operational experience required for future Acting Captain and Captain opportunities that become available, subject to maintaining good standing, successful annual performance appraisals, and continuing to meet or exceed all established attendance requirements.

Schedule B

Township of Puslinch

Schedule B - 2027 Salary Grid

	20% between Minimum and Maximum	
Similar Value Group	**Minimum**	**Maximum**
13	$89.20	$107.77
11	$64.63	$78.08
10	$57.71	$69.73
9	$51.38	$62.08
8	$51.48	$62.21
7	$43.39	$52.42
6	$36.15	$43.67
5	$32.61	$39.39
4	$28.48	$34.41
3	$21.96	$26.53
2	$18.42	$22.25
1		

Notes:

$17.95 1. Ontario Minimum Wage effective October 1, 2026 is $17.95 per hour.

$0.00 2. Auxiliary Firefighter – This position does not have a rate of pay and is not eligible to participate in OMERS.

3. Part-time Volunteer Firefighter Administration Positions - Rates of pay for positions included in the salary grid will vary based on whether the volunteer firefighter elects to participate in OMERS.

The table below outlines the applicable rates of pay for part-time volunteer firefighters based on OMERS participation:

Position	Opt-In to OMERS	Opt-Out of OMERS
Captain	$40.00	$43.61
Acting Captain	$36.33	$39.60
Senior Firefighter (Leadership Development Stream)	$32.10	$34.99
Firefighter Class 1	$26.83	$29.24
Recruit Firefighter Class 2	$19.93	$21.72
Recruit Firefighter Class 3	$19.16	$20.88
Recruit Firefighter Class 4	$18.42	$20.08

Notes:

1. **Recruit Firefighter Class 4** – First Year: New members enter as Recruit Firefighter Class 4 and may advance after one (1) year of service to Firefighter Class 3 based on a successful annual performance appraisal, good standing, and attendance requirements.
2. **Recruit Firefighter Class 3** – Second Year: Members progress to Recruit Firefighter Class 3 and may advance after two (2) years of service to Firefighter Class 2 based on a successful annual performance appraisal, good standing, and attendance requirements.
3. **Recruit Firefighter Class 2** – Third Year: Members progress to Recruit Firefighter Class 2 and may advance after three (3) years of service to Firefighter Class 1 based on a successful annual performance appraisal, good standing, and attendance requirements.
4. **Firefighter Class 1**: Firefighter Class 1 is the fully qualified operational classification, with eligible members able to pursue the Senior Firefighter – Leadership Development Stream.
5. **Senior Firefighter – Leadership Development Stream:** Firefighter Class 1 members who demonstrate strong performance, attendance, experience, and leadership potential may enter a structured two-year development stream to obtain the training and operational experience required for future Acting Captain and Captain opportunities that become available, subject to maintaining good standing, successful annual performance appraisals, and continuing to meet or exceed all established attendance requirements.

THE CORPORATION OF THE TOWNSHIP OF PUSLINCH

BY-LAW NUMBER 2026-059

Being a by-law to confirm the proceedings of the Council of the Corporation of the Township of Puslinch at its Council meeting held on September 16, 2026.

WHEREAS by Section 5 of the *Municipal Act, 2001, S.O. 2001, c.25* the powers of a municipal corporation are to be exercised by its Council;

AND WHEREAS by Section 5, Subsection (3) of the *Municipal Act,* a municipal power including a municipality's capacity, rights, powers and privileges under section 8, shall be exercised by by-law unless the municipality is specifically authorized to do otherwise;

AND WHEREAS it is deemed expedient that the proceedings of the Council of the Corporation of the Township of Puslinch at its Council meeting held on September 16, 2026, be confirmed and adopted by By-law;

NOW THEREFORE the Council of the Corporation of the Township of Puslinch hereby enacts as follows:

1) The action of the Council of the Corporation of the Township of Puslinch, in respect of each recommendation contained in the reports of the Committees and each motion and resolution passed and other action taken by the Council at said meeting are hereby adopted and confirmed.

2) The Head of Council and proper official of the Corporation are hereby authorized and directed to do all things necessary to give effect to the said action of the Council.

3) The Head of Council and the Clerk are hereby authorized and directed to execute all documents required by statute to be executed by them, as may be necessary in that behalf and the Clerk authorized and directed to affix the seal of the said Corporation to all such documents.

READ A FIRST, SECOND AND THIRD TIME AND FINALLY PASSED THIS 16th DAY OF SEPTEMBER 2026.

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James Seeley, Mayor

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Justine Brotherston, Municipal Clerk