A Shared Path to Grid Readiness

Closing Gaps Through Collaboration

A Discussion Paper ***by the***

Ontario Energy Collaborative ***Association*** **(OECA)**

Purpose

This paper supports shared understanding and collaboration across Ontario's energy system as electrification accelerates. It brings together publicly available information and practitioner insights to help municipalities, utilities, regulators, and policymakers consider system readiness, coordination, and long-term planning. The goal is to encourage constructive dialogue and early alignment as Ontario's energy institutions undertake upcoming planning and policy updates.

Figure 1 "System Pressures Overview", image generated by ChatGPT (OpenAI), 12 February 2026, using publicly available datasets and interpretive prompts synthesizing Ontario energy, regulatory and infrastructure sources (2022–2025)

Executive Summary

Ontario is entering a critical phase of its energy transition, as electrification of transportation, buildings, industry, and digital infrastructure advances concurrently. Provincial planning documents anticipate substantial growth in electricity demand and emphasize the need for long-term, coordinated planning.

This paper examines whether Ontario's energy system governance and delivery frameworks are positioned to support that transition. Its central observation is that while electrification objectives are broadly aligned across institutions, the assumptions related to capacity, timing, and financing are not yet consistently aligned across planning, regulatory, and implementation processes.

Electrification Transition

Ontario's electrification transition is already stressing infrastructure planning, as electric vehicles, heating conversion, industrial growth, and data centres add demand precisely where and when capacity is tight. This is exposing the need for coordinated system, market, and regulatory alignment.

Public planning materials indicate that electrification will increase peak electricity demand, particularly during winter conditions, and require sustained investment across generation, transmission, distribution, storage, and enabling systems. These impacts vary by location and customer class, creating uneven infrastructure requirements and delivery challenges.

The data included in this paper summarize illustrative medium- and high-adoption scenarios drawn from publicly available sources. It is intended to support comparison and discussion, not to serve as a forecast or policy target. The scenarios highlight how different adoption pathways affect peak demand, infrastructure requirements, and long-term capital needs.

Table 1a: Electrification Technical Needs

Domain	2035 Med. Adoption	2050 High Adoption	Structural Risk / Opportunity
Electrical Grid Summer Peak (GW) Current is assumed to be 25GW	35	45	Legacy planning benchmark misaligned with electrified winter system
Heating Transition Contribution to Winter Peak (GW)	65	120	System capacity shortfall risk
Transportation Contribution to Peak (GW)	5	30	Geographic feeder and transformer overload risk
Firm Long-Duration Storage Installed (GW)	1	1	Missing ~12-20GW for renewable growth
EV Fleet Storage (Peak Equivalent GW / Technical GWh)	2 GW / 7GWh	14 GW / 63 GWh	Latent distributed asset; currently a policy shortfall; conditional deferral if enabled
Stranded Low-Emissions Generation (GW)	5	5+	Estimated; non-dispatchable generators not currently counted

Generated by collating publicly available materials from Ontario's Energy for Generations plan (MEM, 2023–2024), Electricity Distributors Association publications (2023–2025), and Enbridge Gas Integrated Resource Plan and related filings (2023–2024). Medium Adoption is 50% heat pumps, 1M vehicles, High Adoption is 90% heat pumps and 9M vehicle.

Executive Summary

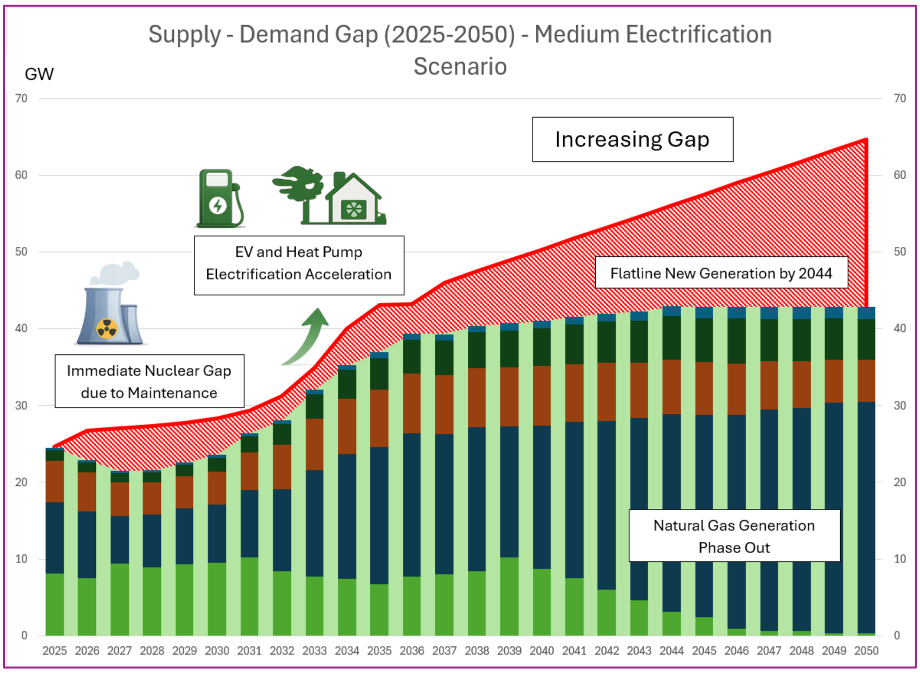
The costs associated with electrification extend beyond individual assets. They include long-lived infrastructure, system reinforcement, digital capabilities, and ongoing operations and maintenance. When planning, financing, and approval processes are not aligned, decision-makers face reduced cost visibility, longer timelines, and increased delivery risk and acceleration costs.

Table 1b: Electrification Scenario Funding Requirements ($B)

Domain	Medium Adoption	High Adoption	Structural Risk / Opportunity
Distribution Investment (10 yrs)	120	180	Capital intensity of electrification
Municipal and LDC Debt Servicing Capacity (/yr)	8	20	Current balance sheet constraint; limits funding runway
Total System Cost to 2050	435	830	Sequencing and lifecycle capital risk
Funded / Committed Capital	215	215	Financing misalignment
Unfunded Capital Gap	**220**	**615**	**Structural exposure to rate base and municipal borrowing limits**

Generated by collating publicly available materials from Ontario's Energy for Generations plan (MEM, 2023–2024), Electricity Distributors Association publications (2023–2025), and Enbridge Gas Integrated Resource Plan and related filings (2023–2024). Medium Adoption is 50% heat pumps, 1M vehicles, High Adoption is 90% heat pumps and 9M vehicle.

These challenges do not reflect a lack of available technologies or technical capability. Rather, they reflect the need for better alignment between institutions, processes, and information as electrification accelerates.



This discussion paper brings together publicly available planning materials, regulatory structures, municipal finance considerations, and practitioner observations to present a system-level perspective. It is offered as a foundation for shared understanding, collaborative problem-solving, and coordinated action across Ontario's energy sector.

Fig 2: Supply–Demand Gap Projection, image generated by ChatGPT (OpenAI), 12 February 2026, using publicly available Ontario electricity demand, capacity and planning outlook data (IESO 2023–2025; MEM 2023–2024) synthesized through interpretive prompts

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1. Electrification as System Transformation

Ontario is not merely adding new electrical loads to an existing grid, it is redefining the fundamental architecture of its energy system. Electrification is transforming end uses historically served by fossil fuels into electricity-dependent services, fundamentally altering load profiles, operational risks, capital requirements, and system governance relationships.

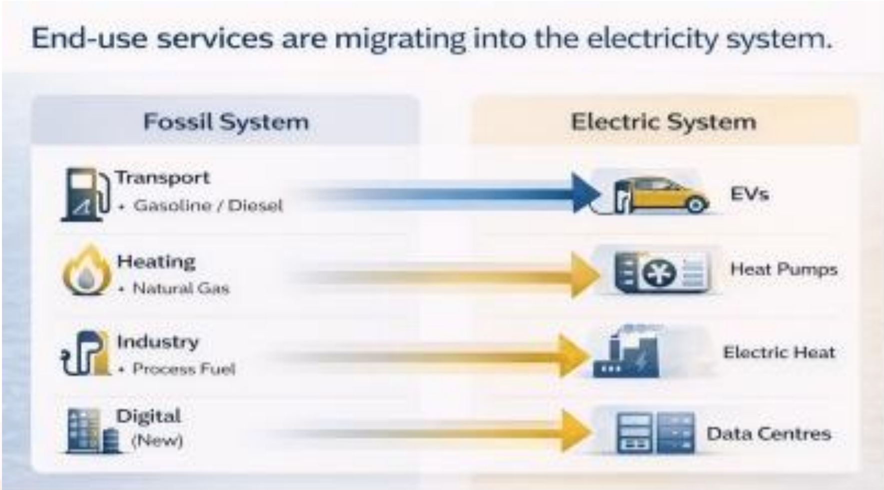


Fig 4: End-Use Electrification Shift, image generated by ChatGPT (OpenAI), 12 February 2026, using publicly available electrification, transportation, heating and industrial demand materials (NRCan 2023–2024; EPRI 2022–2023; IESO 2023–2024) synthesized

Provincial planning documents, including the IESO's Electricity Demand Outlook and the Ministry of Energy's Energy for Generations Integrated Energy Plan, project long-term electricity demand growth of approximately 60–75% by mid-century, driven primarily by electrification of transportation, buildings, and industry.

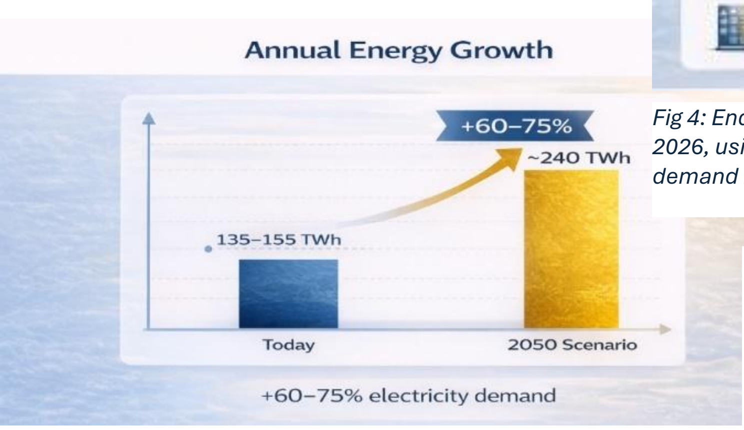


Fig 3: Annual Energy Growth to 2050

Ontario's annual electricity consumption has historically ranged between approximately 135 and 155 TWh. Long-term planning scenarios indicate potential growth toward 240 TWh by 2050 under high-electrification pathways. This growth is occurring alongside materially higher peak demand requirements.

Relative to Quebec's rather modest 200TWh needs, we believe that there is a mismatch. Electrification needs to be understood as a system-wide redesign challenge rather than a sequence of isolated projects.

1.1 Converging Drivers of Load Growth

1.1.1 Three structural forces are reshaping Ontario's electricity demand profile – Transportation Electrification, Thermal Electrification of Buildings

and Industrial Electrification and Digital Infrastructure. These drivers affect both annual energy consumption (TWh) and coincident peak demand (GW), with materially different implications for electricity and natural gas systems. The following are pragmatic statements about the various sectors to highlight their acknowledged realities, challenges, and initiatives.

Fig 5: EV Charging Infrastructure Scale, image generated by ChatGPT (OpenAI), 12 February 2026, using publicly available transportation electrification and infrastructure materials (Ontario Ministry of Transportation 2024; Metrolinx planning documents

1.1.2 Transportation Electrification

Transportation electrification is expanding rapidly across multiple segments, including:

- Private light-duty electric vehicles
- Municipal and commercial vehicle fleets
- Public transit systems
- Ports, logistics hubs, and intermodal facilities
- Medium- and heavy-duty freight

Ontario has approximately 9 million registered light-duty vehicles. Federal and provincial policy targets anticipate that 100% of new light-duty vehicle sales will be zero-emission by 2035. Ontario is publicly only anticipating 1M EVs in Ontario by 2030.
IESO and NRCan planning assumptions indicate that full electrification of the light-duty fleet would require approximately 25–35 TWh of incremental annual electricity consumption.

Typical charging infrastructure adds:

- Level-2 residential charging: 8-10 kW per vehicle.
- Public fast charging: 150–350+ kW per port
- Fleet depots: 3-10 MW per facility.
- Highway hubs: 5–30 MW per site (e.g.: ON Routes)

Unmanaged charging can materially increase evening and overnight system peaks, particularly in winter when coincident heating loads are present.

1.Electrification as System Transformation

1.1.3 Thermal Electrification of Buildings

Thermal electrification is accelerating through:

- Residential and commercial heat pumps
- Hybrid heating systems
- District energy networks
- Deep retrofits
- Electrified water heating

Fig 6: "Winter Electrification Load". Approximately 70% of Ontario households rely on natural gas fuels for heating.

IESO and NRCan modelling suggests that large-scale conversion to heat pumps could add 20–40 TWh of annual electricity demand by 2050.

Cold-climate heat pumps typically require:

- 2–5 kW per dwelling at moderate temperatures
- 5–10+ kW under extreme cold with resistance backup

IESO planning scenarios indicate that heating electrification could contribute 9 GW of incremental winter peak demand by 2035.

Thermal electrification therefore shifts peak demand from the natural gas system to the electricity system, increasing exposure to extreme weather conditions and correlated system stress.

1.1.4 Industrial Electrification and Digital Infrastructure

Industrial and institutional electrification is being driven by:

- EV and battery manufacturing
- Critical minerals processing
- Hydrogen electrolysis
- Advanced manufacturing
- Data centres and cloud infrastructure

These loads are characterized by high utilization factors, limited flexibility, and compressed connection timelines.

1. Electrification as System Transformation

1.1.5 Embedded Energy-to-Peak Translation Assumptions

Electrification planning requires explicit translation of annual energy growth (TWh) into coincident peak demand (GW).

For the purposes of this paper, the following reference assumptions are used, based on public planning studies and utility filings:

Table 2: Incremental Load Contribution by End Use

End-Use Category	Incremental Energy	Typical Load Factor	Implied Peak Contribution
EV Charging	30 TWh	20–35% (winter)	15 GW
Heat Pumps	60-120 TWh	10–15% (winter)	12 GW
Industry/Data	15 TWh	70–90% (steady load)	5 GW

Reference translation range:

- 1 GW of sustained coincident peak ≈ 6 TWh/year
- Winter electrification load factors are materially lower than summer industrial loads

These assumptions are indicative and subject to ongoing review. They are intended to provide a transparent basis for comparing energy growth, peak capacity requirements, and infrastructure needs across electricity and natural gas systems.

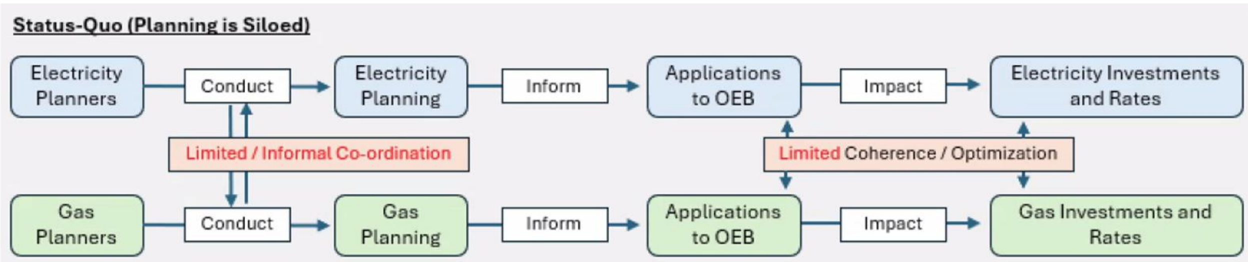


Fig 7: Status-Quo (Planning is Siloed), Ontario Energy Board (2026) Energy Planning 101, Gas-Electric Co-ordination Forum Staff Presentation Deck, 27 January 2026,

1. Electrification as System Transformation

1.2 System Implications of Electrification

Collectively, these drivers shift large volumes of energy consumption from fuels to electricity. They are spatially concentrated, sensitive to peak conditions, and increasingly correlated with extreme weather.

Implications include:

- Higher peak-to-average ratios
- Increased winter capacity risk
- Greater substation and feeder loading
- Expanded interdependence of system assets
- Increased localized congestion

Ontario's historical summer peak has ranged between 22 and 25 GW. IESO medium and high growth scenarios from the IESO project peaks of 35 GW by the early 2040s, with winter peaks potentially exceeding summer peaks under high heating electrification. We believe that these estimates are severely under calculated.

Distribution infrastructure is therefore driven primarily by coincident peak rather than annual energy throughput.

1.3 Historical Planning Context

Between 2005 and 2020, provincial electricity demand remained relatively flat, fluctuating within ±10%. Planning frameworks were optimized for:

- Stable demand
- 40–75-year asset lives with multiple renewals
- Gradual capital deployment
- Utility-specific programs
- Predictable rate recovery

Typical reinvestment rates are less than 2.5% of net book value annually. Electrification-driven growth now exceeds the design basis of these frameworks. We are talking about a 10-15% annual re-investment.

1. Electrification as System Transformation

1.4 Policy Ambition, System Value and Delivery Capacity

Ontario's electrification strategy is supported by multiple long-term public planning documents, including the Energy for Generations Integrated Energy Plan, IESO Pathways to Decarbonization studies, and regional infrastructure plans. Collectively, these sources imply a comprehensive transformation of generation, transmission, distribution, and system integration assets. Figure 1 is representative of the varying levels of coordination that exist today (OEB).

Fig 8: Overview of Electricity Planning, Ontario Energy Board (2026) Gas-Electric Co-ordination Forum Staff Presentation Deck, 27 January 2026, slide 9.

Publicly available scenarios indicate cumulative electricity-sector investment requirements on the order of \$375B–\$425B (nominal) between 2025 and 2050, including:

- New and refurbished generation capacity
- Major transmission corridors and reinforcements
- Substation and regional interface expansion
- Distribution system renewal and growth capacity
- Grid modernization and digital infrastructure
- Protection, control, and system integration assets

These figures represent total system value creation rather than incremental utility capital programs. They reflect the replacement and expansion of much of Ontario's legacy electricity infrastructure while simultaneously accommodating unprecedented new load growth.

However, delivery institutions remain organized around incremental, utility-level investment models developed for low-growth environments.

1.5 Historical and Implied Capital Deployment Rates

Over the past three decades, Ontario's electricity sector has deployed capital in relatively stable, cyclical patterns aligned with major generation projects and periodic grid renewal. Distribution and transmission investment, in particular, has followed gradual reinvestment trajectories.

The table below compares historical and implied future annualized investment levels using publicly reported capital plans, regulatory filings, and long-term outlooks.

Table 3: Historical and Projected Capital Deployment, table compiled by the author using publicly available Ontario electricity planning and capital investment materials (IESO 2022–2025; MEM 2023–2024; OEB 2024; Infrastructure Ontario 2024)

Period / Scenario	Generation, Transmission, and Distribution Investment	Approx. Annualized Value	Primary Drivers
1990–1999	Nuclear completion, grid expansion, renewal	$8B / year	Demand growth, refurbishment
2000–2009	Market restructuring, conservation, refurbishment	$7B / year	Market reform, efficiency
2010–2019	Green Energy Act, renewables, smart meters	$9B / year	Renewable buildout
2020–2024	Refurbishment cycle, resilience, modest growth	$10B / year	Nuclear renewal, resilience
2025–2035 (IEP)	Electrification acceleration	$16B / year	EVs, heating, industry
2035–2050 (High)	Net-zero pathways	$20B+ / year	Full system transformation

1. Electrification as System Transformation

Distribution-specific capital expenditures have historically represented approximately 25–35% of total sector investment, with annual deployment typically ranging between $2-3B prior to 2020 and rising toward $4B in recent rate applications.

Under high-electrification scenarios, implied distribution investment alone rises toward $8B annually by the 2030s, reflecting substation expansion, feeder reinforcement, protection upgrades, and digital systems.

Fig 9: Capital Deployment Trajectory, image generated by ChatGPT (OpenAI), 12 February 2026, using publicly available Ontario electricity investment and planning materials (IESO 2022–2025; MEM 2023–2024; OEB 2024; Infrastructure Ontario 2024) synthesized through interpretive prompts to illustrate historical averages.

1.5.1 Structural Clash in Planning Assumptions

Long-term provincial scenarios implicitly assume:

- Sustained multi-decade capital deployment at historically unprecedented levels
- Continuous access to low-cost debt and equity financing
- Stable political and regulatory support
- High public tolerance for rate and tax impacts
- Accelerated permitting and approvals

Utility planning & regulatory frameworks assume:

- Incremental reinvestment anchored to historical averages
- Gradual rate adjustments
- Conservative leverage limits
- Utility-specific risk containment
- Project-by-project approval processes
- Isolated geographical capacity impact

This divergence creates a structural clash between system-level transformation requirements and institution-level delivery capacity.

From a system perspective, electrification pathways treat large-scale investment as an engineering and optimization problem. From an institutional perspective, the same pathways represent cumulative balance-sheet exposure, ratepayer risk, and municipal fiscal pressure.

1. Electrification as System Transformation

The resulting tension is not primarily technical. It reflects incompatible assumptions about financing velocity, risk allocation, and governance scalability.

Without explicit mechanisms to reconcile these assumptions, capital deployment is likely to lag system requirements, increasing the probability of deferred connections, congestion, stranded assets, and affordability shocks.

1.5.2 Governance and Structural Fragmentation

Ontario's distribution system includes more than sixty municipally owned LDCs serving approximately 5.6 million customers. Rate bases range from under $50M to more than $2B, resulting in uneven financing capacity.

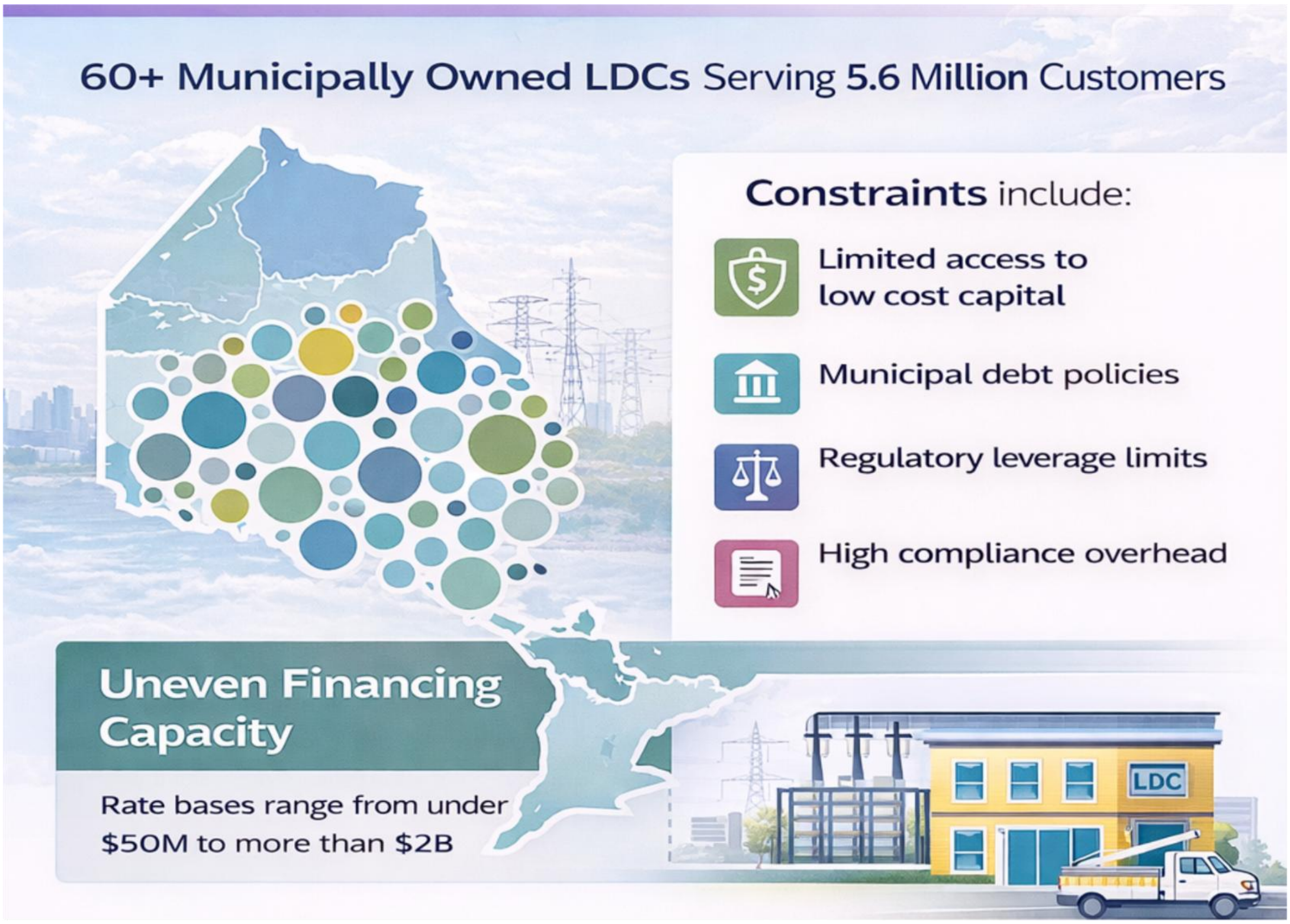


Fig 10: Uneven LDC Financing Capacity

1. Electrification as System Transformation

Ontario has an estimated 5 GW of distributed solar and several hundred MW of behind-the-meter storage. Most DERs are compensated through net metering, conservation, or pilot programs. Long-term flexibility contracts remain rare. DERs are therefore not yet dependable substitutes for conventional infrastructure in planning processes.

Public datasets include IESO regional plans, LDC hosting maps, and municipal forecasts, produced using inconsistent standards. Connection queues, transformer loading, and feeder utilization are rarely published in standardized formats.

This limits regional optimization and increases reactive investment.

1.5.3 Program Coordination and Institutional Scaling

Coordination initiatives include the Grid Innovation Fund, Regional Infrastructure Planning, and PowerShare. PowerShare participants serve more than 1.5 million customers and support:

- Shared analytics
- Hosting capacity tools
- Common data standards
- Regional constraint mapping
- Digital operations platforms

Participation remains voluntary, and no province-wide mechanism mandates coordinated deployment or cost sharing.

As a result, generation, transmission, distribution, and municipal growth planning continue to advance on partially independent tracks, increasing the risk of misalignment, duplication, and stranded investment.

1. Electrification as System Transformation

1.6 Institutional, Market, and Program Context

The electrification transition is unfolding within a complex institutional and market environment shaped by legacy governance structures and evolving coordination initiatives. Historically, Ontario's electricity system evolved incrementally or been relatively stable for the last 25 years. New demand was accommodated through periodic generation additions and localized distribution reinforcement. Today's transition is orders of magnitude different in scale, speed, and spatial concentration.

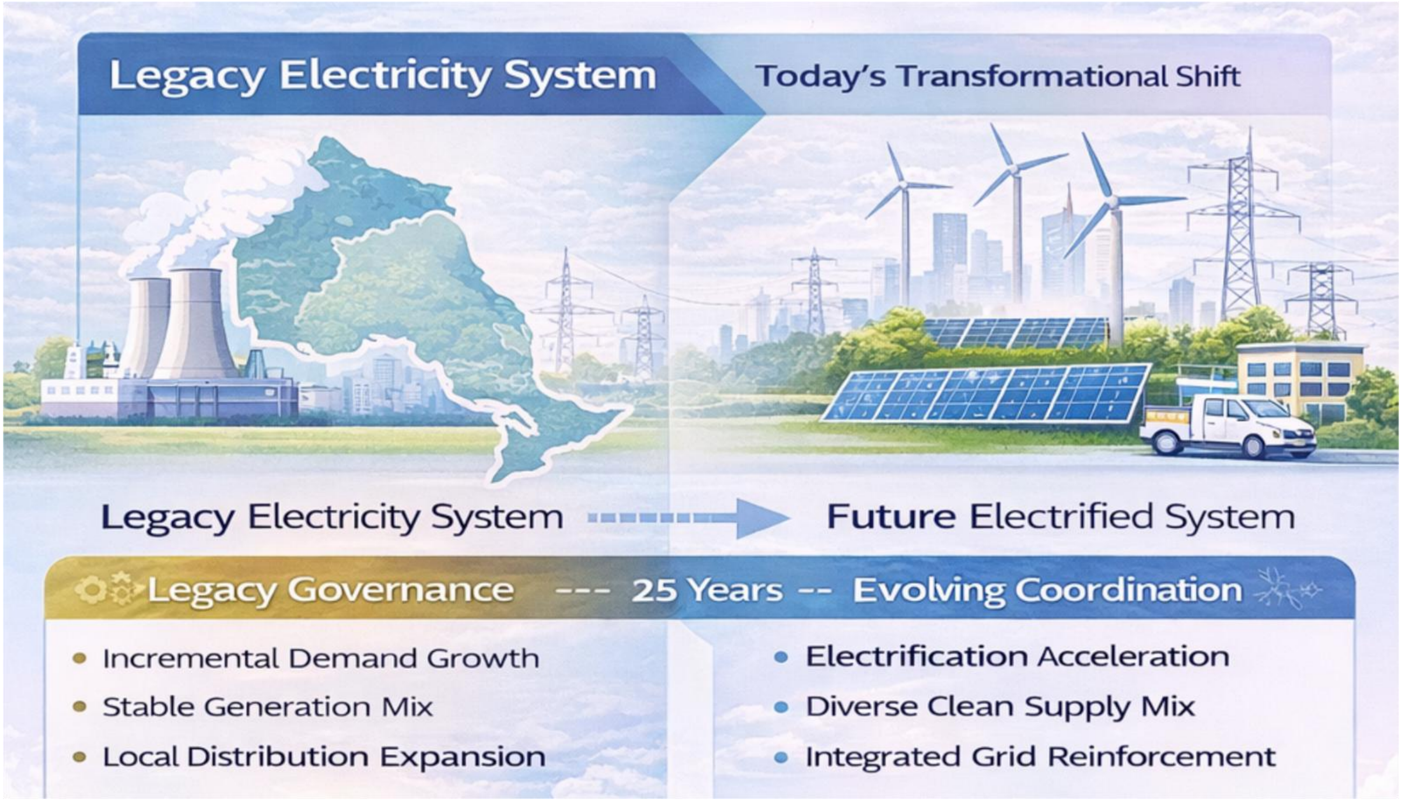


Fig 11: Legacy to Electrified System, image generated by ChatGPT (OpenAI), 12 February 2026, using publicly available Ontario electricity planning and policy materials (IESO 2022–2025; MEM 2023–2024; OEB 2024) synthesized through interpretive prompts to illustrate the shift from legacy governance and incremental growth to coordinated electrification and grid reinforcement.

2 . Peak Demand Constraint

Ontario's electrification pathway is increasingly constrained not by annual energy availability, but by coincident peak demand and the pace at which capacity can be delivered at the right locations. Transportation electrification, heating electrification, and residential load growth are converging in time and space, placing unprecedented pressure on distribution systems, sub-transmission interfaces, and regional supply.

Two load conversions dominate the peak challenge:

- **Heating fuels to electricity:** Space and water heating converts a winter-peaking thermal system (natural gas, oil, propane) into winter-peaking electrical capacity requirements, with performance (COP) and hybrid switching behaviour determining how much load remains electric during extreme events.
- **Transportation fuels to electricity:** EV charging concentrates demand into evening and workplace peaks.

The consequence is a capacity-led transition. Slight changes in coincidence and performance can produce large changes in required peak infrastructure. This section consolidates the key peak drivers, highlights why "TWh thinking" understates risk, and summarizes the distribution and enabling investments required to accommodate electrification.

2.1 Energy Growth Versus Peak Growth

Public discourse and policy documents frequently emphasize annual electricity consumption measured in terawatt-hours. Distribution and sub-transmission systems, however, are constrained primarily by coincident peak demand rather than annual averages.

Electrified heating and EV charging concentrate demand during winter cold snaps and evening residential peaks. These periods may occur only several dozen hours per year, yet they determine the required size of substations, feeders, transformers, protection systems, and regional interfaces.

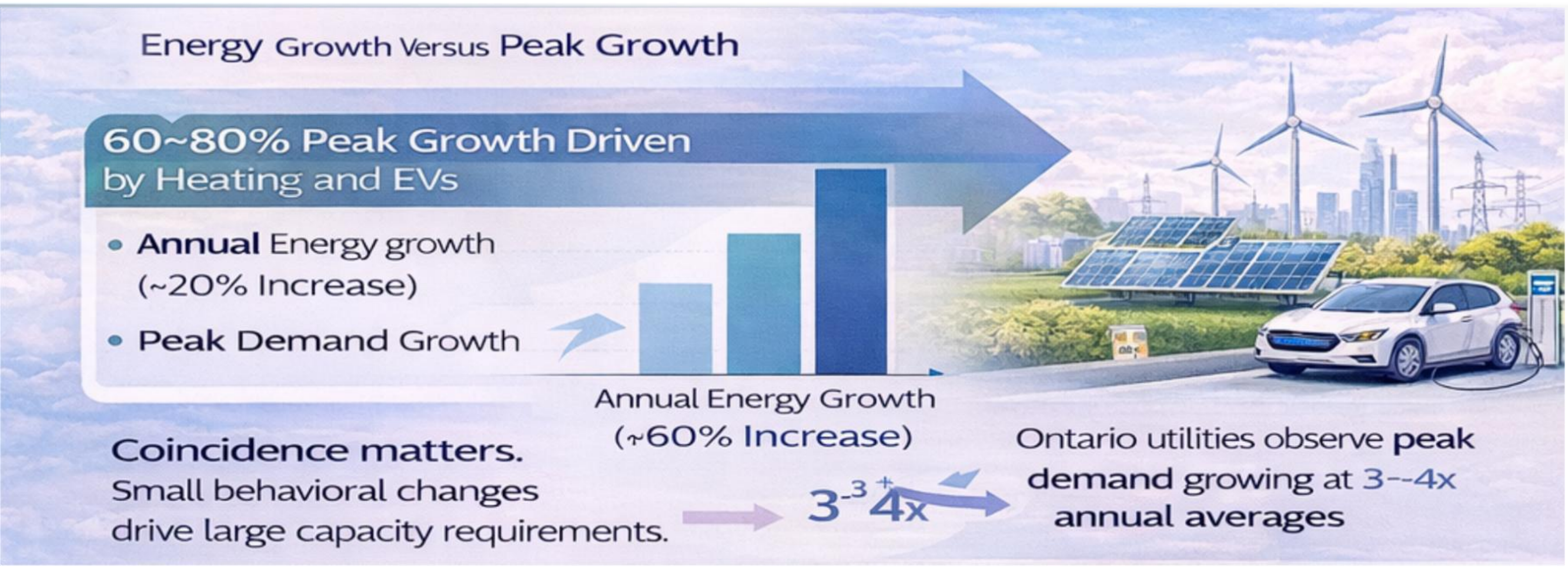


Fig 12: Energy vs. Peak Growth, image generated by ChatGPT (OpenAI), 12 February 2026, using publicly available Ontario demand outlook and electrification materials (IESO 2023–2025; NRCan 2023–2024; EPRI 2022–2023) synthesized through interpretive prompts to illustrate divergence between annual energy growth and peak demand growth driven by EVs and electrified heating.

Utility planning experience indicates that a 20% increase in annual energy consumption can translate into a 60–80% increase in peak capacity requirements when electrified heating and unmanaged charging are present.

As a result, energy-based growth projections systematically understate infrastructure needs unless explicitly translated into peak-capacity equivalents.

2.2 Heating Transition from Natural Gas and Peak System Reality

Ontario's decarbonization strategy increasingly relies on electrification of space and water heating. This transition represents one of the largest and least resolved structural risks in the current planning framework because it converts winter-peaking thermal demand from the natural gas system into winter-peaking electrical capacity requirements.

MEM analysis indicates that full displacement of natural gas heating implies peak thermal demand on the order of 121 GW during extreme winter conditions. When translated into electrical equivalents, even with high-efficiency heat pumps, this represents an unprecedented system burden. The IESO's 2025 Annual Planning Outlook forecasts net winter seasonal peak demand of approximately 23 GW in 2026, rising toward 37 GW by 2050, and identifies electrified heating as a principal driver of winter peaking.

2. Peak Demand Constraint

Fig 13: Winter Peak Implications, image generated by ChatGPT (OpenAI), 12 February 2026, using publicly available Ontario winter peak demand and electrification outlook materials (IESO 2024–2025; NRCan 2023–2024) synthesized through interpretive prompt.

No historical precedent exists for building, financing, or operating a system of this magnitude in Ontario.There is no realistic deployment scenario in which heat pumps alone can displace this load without massive parallel investments in generation, storage, transmission, and distribution capacity.

2.2.1 Translating Thermal Demand into Electrical Peak

Independent Canadian modelling estimates Ontario's buildings-sector peak demand (all fuels combined) at approximately 80 GW-thermal. IESO analysis indicates that natural gas supplies the majority of Ontario space heating energy and that space heating represents roughly 60% of total building energy use.

Translating heating demand into electrical peak requires explicit treatment of three interacting variables:

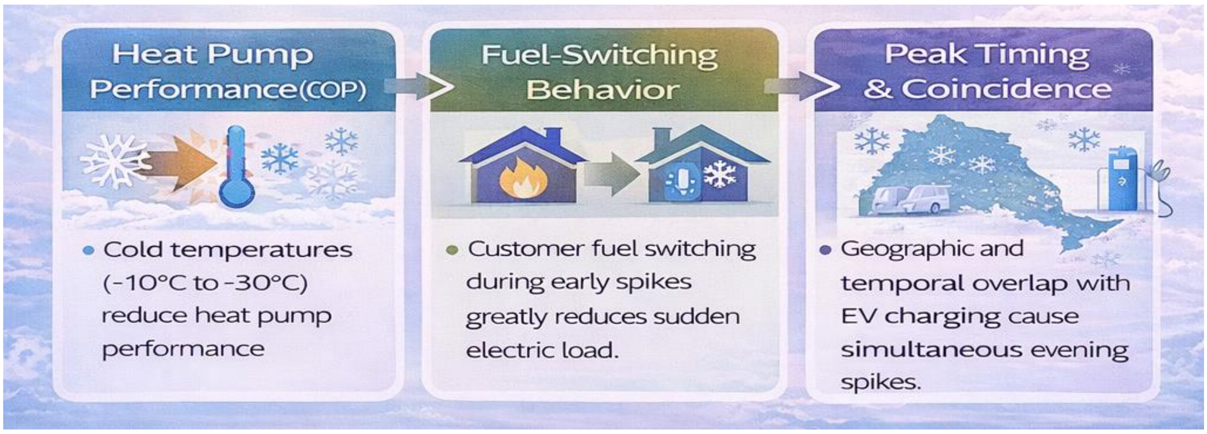


Fig 14: Peak Drivers and Coincidence, image generated by ChatGPT (OpenAI), 12 February 2026, using publicly available heat pump performance, fuel-switching and demand coincidence materials (NRCan 2023–2024; EPRI 2022–2023; IESO 2024–2025) synthesized through interpretive prompts

2. Peak Demand Constraint

For the purposes of this paper, the following reference assumptions are applied and are explicitly open for review:

Table 4: Heating Electrification Peak Parameters

Parameter	Reference Value	Rationale
Buildings-sector peak (all fuels)	80 GW-thermal	National energy system modelling
Heating share of buildings peak	75%	Space and water heating dominance
Fossil-fuel share of heating	80%	Residential and commercial averages
Effective peak electrification share	25%	Hybrid switching behaviour
Effective COP at peak	1.7	Cold-climate performance
Coincidence factor	0.88	Regional diversity

2.2.2 Diversity-Adjusted Peak Translation

Using the reference assumptions above, the implied thermal load shifting to electricity at peak:

$80 \times 0.75 \times 0.80 \times 0.25 = 12.0$ GW-thermal

Then the implied incremental electrical peak is approximately:

$(12.0 / 1.7) \times 0.88 \approx 6.2$ GW-electric

Under diversity-adjusted conditions, heating electrification increases Ontario's winter peak by approximately 6 GW.

A full-conversion stress case in which all heating remains electric at COP ≈ 1.6 implies an incremental winter peak of approximately 27 GW, illustrating the infeasibility of complete peak-hour displacement under current technology.

2. Peak Demand Constraint

2.2.3 Performance Degradation in Extreme Cold

Air-source heat pumps experience declining coefficients of performance as temperatures fall, increasing electrical input per unit of delivered heat.

Table 5: Heat Pump COP and Peak Impact, table compiled by the author using publicly available cold-climate heat pump performance data and modelling assumptions (NRCan 2023–2024)

Outdoor Temperature	Typical COP	Electrical Input per 10 kW Thermal Load	Relative Peak Impact
0°C	3.0	3.3 kW	Baseline
−10°C	2.2	4.5 kW	+35%
−20°C	1.7	5.9 kW	+80%
−25°C	1.4	7.1 kW	+115%

During extended cold events, many systems activate resistance backup or revert to fossil fuel operation in hybrid configurations, limiting achievable peak displacement.

2.2.4 Distribution System Enablement Requirement

Even partial heating electrification requires substantial local infrastructure reinforcement. Enabling high heat pump penetration typically involves:

- Service upgrades (from 100 A to 125A or 200 A)
- Transformer capacity increases of 30–60%
- Secondary and lateral conductor replacement
- Voltage regulation and protection upgrades
- Enhanced winter reliability standards

While provincial and federal incentives support customer-side equipment adoption, they do not compensate municipalities and municipally owned utilities for the distribution upgrades required to host the added load. End-to-end distribution enablement costs average approximately $10,000 per connected dwelling (utility pilot experience), excluding customer equipment and private electrical work.

2. Peak Demand Constraint

Planning assumptions applied in this paper:

Table 6: Residential Electrification Enablement Assumptions

Parameter	Reference Value	Rationale
Total Ontario households	~5.6 million	Customer base proxy
Baseline homes already upgraded	~20%	New builds and prior retrofits
Target heat pump penetration	75%	Policy-aligned objective
Net homes requiring upgrades	~55%	Target minus baseline
Average enablement cost	$10,000 / dwelling	Pilot/program experience

Implied distribution enablement obligation:

5.6M × 55% × $10,000 ≈ $31B

This obligation is largely unfunded and borne locally through rates, municipal balance sheets, or deferred investment in other assets.

2.2.5 Displaced Natural Gas as System Load and Enabling Investment

Electrification scenarios frequently treat natural gas displacement primarily as a carbon accounting exercise rather than a capacity planning problem. In practice, each unit of displaced gas demand implies incremental investment in:

- Firm generation capacity
- Transmission reinforcements
- Distribution capacity upgrades
- Protection and control systems
- Emergency and backup supply arrangements

Using the reference peak translation of 6 GW incremental winter demand, indicative enabling investments include:

2. Peak Demand Constraint

Table 7: Order-of-Magnitude System Cost by Layer

System Layer	Typical Unit Cost	Implied Investment
Firm Generation	~$2,500/kW	~$15B
Transmission	~$1,000/kW	~$6B
Distribution	~$1,500/kW	~$9B
System Integration	~$500/kW	~$3B
Total (Order of Magnitude)		**~$33B**

These values are consistent with aggregate EDA cost recovery envelopes observed in recent regulatory filings and illustrate that displaced gas volumes represent material balance-sheet exposure.

2.2.6 Hybrid Dependence and System Stability

In the medium term, Ontario will remain dependent on hybrid heating systems and residual gas infrastructure for system reliability.

A fully electric heating system without large-scale seasonal storage or retained gas backup would require extreme overbuilding of low-utilization assets, imposing substantial cost and reliability risks.

2.2.7 Non-Linear Gas-to-Electric Peak Offset Relationship

The relationship between gas displacement and electrical peak growth is strongly non-linear due to COP degradation, behavioural switching, and infrastructure constraints.

Table 8: Heat Pump Penetration and Winter Peak Interaction

Annual Heat Pump Penetration	Peak Electric Reliance	Incremental Winter Peak (GW)	Residual Gas Peak (GW-thermal)
20%	10%	2	38
40%	15%	3	34
60%	20%	4	31
75%	25%	6	28
90%	35%	9	23

2. Peak Demand Constraint

High annual penetration therefore does not translate into proportional peak displacement. Substantial gas-system capacity remains necessary even under aggressive electrification scenarios.

2.3 Interaction with EV and Residential Load (excludes Hydrogen)

Using available model information, we have estimated the coincident residential heating and EV charging under winter evening peak conditions. These scenarios highlight that transportation electrification materially amplifies residential peak demand when overlaid with heating loads.

These scenarios assume:

- Residential heat pump operation at degraded COP
- Partial reversion to backup fuels
- Evening EV charging coincidence of 30–40%, even when distributed over 6-8 hours
- Limited short-duration storage availability

Ontario currently has approximately 9 million registered light-duty vehicles. Provincial and federal policy targets imply more than 1 million EVs by 2030 (MEM) and long-term penetration approaching 60–70% of the fleet by 2050.

For planning purposes, this paper applies the following reference assumptions:

Table 9: EV Fleet and Winter Peak Assumptions, table compiled by the author using publicly available Ontario transportation electrification and demand outlook materials (IESO 2023–2025; NRCan 2023–2024; ICCT 2023; EPRI 2022–2023).

Parameter	2030 Reference	2050 Reference	Rationale
Total vehicle fleet	9.0 M	9.5 M	Modest population growth
EV penetration	~11%	~70%	Policy-aligned scenarios
Number of EVs	~1.0 M	~6.5 M	Derived
Average annual energy	2,800 kWh	3,000 kWh	Larger vehicles, winter losses
Residential charging share	70%	75%	Behavioural studies
Winter peak coincidence	35%	40%	Conservative planning
Average charging power	7 kW	7 kW	Level 2 dominance

Under these assumptions, coincident residential EV charging demand is:
2030 Scenario - 1.0 M × 70% × 35% × 7 kW ≈ 2 GW
2050 Scenario - 6.5 M × 75% × 40% × 7 kW ≈ 14 GW

These values represent incremental residential peak loads that are highly correlated with winter evening heating demand and low system flexibility periods. Appendix modelling indicates that when EV charging is superimposed on degraded heat pump performance and partial fuel switching, localized feeder and substation peaks increase by factors of 2.0 relative to pre-electrification baselines.

In high-growth corridors, combined heating and EV loads are projected to add 50–80% to winter evening peaks within a single asset life cycle, exceeding standard reinforcement thresholds and materially shortening replacement intervals.

At 2050 penetration levels, residential EV charging alone represents a peak demand category comparable in scale to Ontario's current industrial load base, yet it is distributed across millions of low-voltage connection points that were never designed for sustained multi-kilowatt coincident loading.

Without coordinated managed charging, thermal storage, and targeted distribution reinforcements, these compound loads will produce recurring localized overloads, accelerated asset degradation, voltage instability, and growing reliance on emergency operating measures.

2.4 Implications

Complete displacement of fossil heating at system peak is not technically or economically achievable under current performance envelopes. Hybridization and fuel-switching remain essential reliability mechanisms. At the same time, even partial electrification produces material peak growth and requires sustained multi-decade capital deployment across generation, transmission, and distribution systems.

2. Peak Demand Constraint

Planning frameworks that assume linear substitution between gas and electricity implicitly assume that technology, customer behaviour, financing capacity, permitting timelines, and political support will all evolve in parallel and without friction. In practice, each of these constraints evolves at different speeds and is governed by different institutions. Failure to recognize this misalignment risks systematic underestimation of peak-related investment needs, deferred connections, escalating congestion costs, and growing reliance on emergency operating measures. Over time, this erodes utility credit quality, destabilizes rate trajectories, and undermines public confidence in the electrification transition.

Heating electrification coincides with peak residential occupancy and unmanaged EV charging. These loads are not additive; they are multiplicative. Overlaying winter heating demand with EV penetration produces compound peaks that exceed most existing substation and feeder design assumptions.

Without coordinated thermal storage, managed charging, and hybrid system retention, distribution systems will face recurring overload conditions. This interaction is insufficiently reflected in current capital forecasts.

3 . Nuclear, Storage and the System Timing Mismatch

At the same time, industrial electrification, critical minerals mining, data centres, and transportation electrification are materializing during the 2026–2036 period. This creates a pronounced temporal mismatch between when reliable generation becomes available and when new demand must be served.

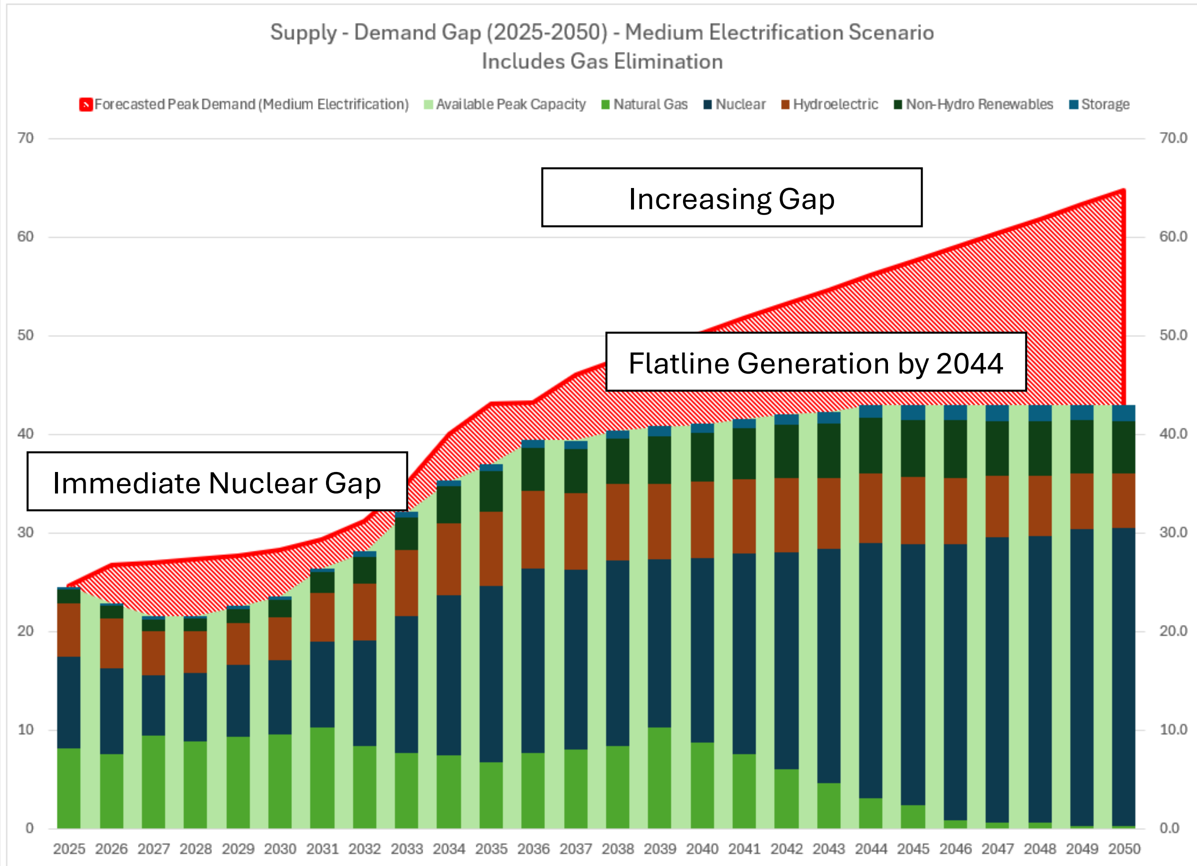


Fig 15: Medium Electrification Supply–Demand Gap, image generated by ChatGPT (OpenAI), 12 February 2026, extrapolated from Ontario's Energy for Generations Integrated Energy Plan (MEM 2023–2024) and publicly available IESO capacity outlook materials (2023–2025), synthesized through interpretive prompts to illustrate projected peak demand growth and available capacity under a medium electrification scenario.

Nuclear, Storage and the System Timing Mismatch

3.1 Near-Term Nuclear Capacity Gap

Ontario's nuclear refurbishment and expansion program is the foundation of long-term system reliability and decarbonization. However, refurbishment schedules at Darlington and Bruce, combined with the timing of proposed new-build projects, indicate that most incremental nuclear capacity will not be available until the mid-to-late 2030s and beyond.

As a result, the period of fastest electrification-driven load growth coincides with a prolonged interval of constrained baseload availability. This creates a structural capacity gap that must be bridged using interim resources.

3.1.1 Nuclear Investment Commitments and Delivery Timing

Ontario's nuclear program represents one of the largest infrastructure investment commitments in Canadian history. Recent infrastructure reporting places multiple Ontario nuclear projects among the highest-value projects nationally.

Table 10: Major Nuclear Investment Program Summary, (Canada's Top 100 Projects)

Major Project	Primary Purpose	Estimated Capital Cost	Principal Delivery Window
Pickering Life Extension	Extend legacy capacity	$26.8B	Late 2020s–2030s
Darlington New Nuclear	New large-scale capacity	$20.9B	Mid-2030s onward
Bruce Refurbishment Program	Life extension / update	$13.0B	2020s–2030s
Darlington Refurbishment	Life extension	$12.8B	2016–2026
Total Featured Investment		**~$73.5B**	

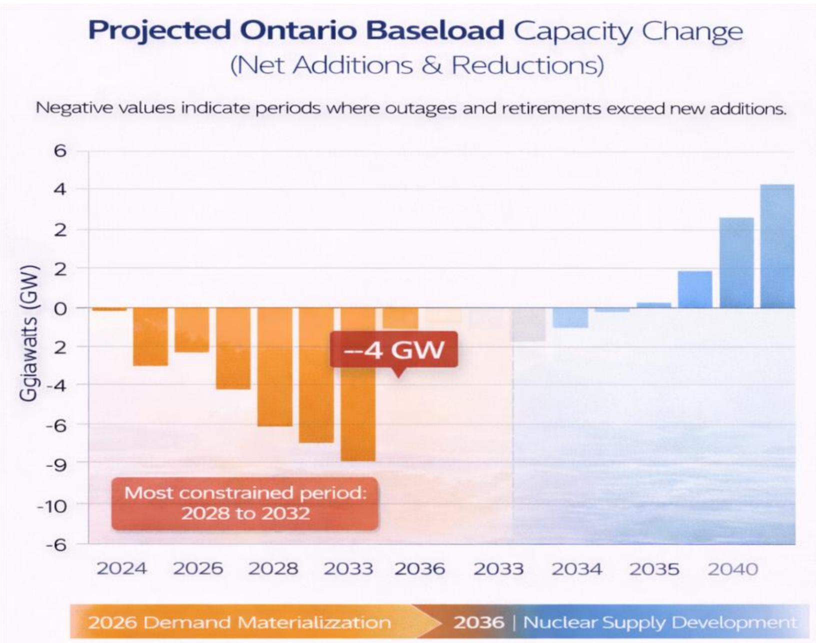
Despite the scale of these commitments, the timing of capacity delivery does not align with near-term electrification pressures. A large share of capital is deployed during refurbishment periods that temporarily reduce available output, while new capacity arrives only after the early-2030s.

3.1.2 Aggregated Nuclear Availability Profile

To illustrate system impacts, individual unit outages, life extensions, and new-build schedules are consolidated into representative planning periods.

Table 11: Nuclear Transition Capacity Profile

Period	Dominant System Events	Net Capacity Effect	Effective System Condition
2025–2028	Darlington refurbishments, early Bruce outages	−2.5 GW	Sustained shortfall
2028–2032	Bruce outages, Pickering retirements, LE outages	−4.0 GW	Deep capacity trough
2032–2035	Partial LE returns, early new-build ramp	+1.5 GW	Partial recovery
2035–2040	Bruce C / Wesleyville units enter service	+5.0 GW	Structural recovery
Post-2040	Continued large nuclear additions	+7.0 GW+	Long-term adequacy



Negative values indicate periods where outages and retirements exceed new additions.

The most constrained period occurs between 2028 and 2032, when effective baseload availability is reduced by approximately 4 GW.

Fig 16: Projected Baseload Capacity Change, image generated by ChatGPT (OpenAI), 12 February 2026, using publicly available Ontario nuclear refurbishment schedules, retirement timelines and new-build planning materials (Ontario Power Generation 2023– 2025; Ministry of Energy and Mines 2023–2024; IESO 2024–2025), synthesized through interpretive prompts to illustrate net baseload additions and reductions over time.

Nuclear, Storage and the System Timing Mismatch

Relative to a fully available fleet, the nuclear program produces the following sustained shortfalls during the critical electrification acceleration period.

Table 12: Average Nuclear Capacity Shortfall by Period

Period	Average Nuclear Shortfall
2025–2028	~2.5 GW
2028–2032	~4.0 GW
2032–2035	~2.5 GW

This trough coincides with rapid growth in heating electrification, EV adoption, and industrial load, materially increasing system balancing requirements.

3.1.3 Interim Replacement Through Gas Generation

The gas network that supplies incremental generation fuel is the same system that serves residential, commercial, and industrial heating loads.

Fig 17: Winter Demand and Gas Backstop

Nuclear, Storage and the System Timing Mismatch

As a result, interim reliance on gas generation reinforces gas-system dependence precisely during the period when hybrid and electrified heating adoption is expected to accelerate. Rather than freeing capacity for electrification, nuclear outages increase competition for winter gas deliverability.

Because large-scale nuclear additions are unavailable during this period, system adequacy must be maintained through dispatchable alternatives. In practice, this role is fulfilled primarily by:

- Existing combined-cycle and peaking gas facilities
- Incremental gas capacity additions
- Imports during favourable conditions
- Limited storage and demand response

Natural gas generation is the only resource capable of delivering sustained, dispatchable capacity at the required scale within the relevant timeframe. However, gas substitution is not electrically equivalent to nuclear output. Under peak conditions, gas-fired generation operates at approximately 40% thermal-to-electric efficiency. Replacing unavailable nuclear capacity therefore requires substantially higher upstream fuel throughput.

Period	Nuclear Shortfall (GW-electric)	Replacement Generation (GW-electric)	Required Gas Input (GW-thermal)
2025–2028	2.5	2.5	~6.2
2028–2032	4.0	4.0	~10.0
2032–2035	2.5	2.5	~6.2

During the deepest trough, the system requires approximately 10 GW of additional gas thermal input to replace unavailable nuclear output. This represents a sustained winter burden on the natural gas network.

3.1.4 Indicative Impact on Electrified Heating Potential

Using the diversity-adjusted heating conversion framework developed earlier in this paper, approximately 1 GW of firm electrical capacity supports ~170,000 fully electrified homes under winter peak conditions. The nuclear shortfalls are replaced through gas generation; a portion of winter gas capacity is redirected from heating to power production.

During the most constrained period, gas -system support for power generation competes with heating demand at a scale equivalent to roughly 700,000 fully electrified homes.

The implied effect is summarized below.

Table 13: Nuclear Shortfall and Gas Replacement Requirements

Period	Nuclear Shortfall	Gas Thermal Demand	Heating Capacity Displaced	Equivalent Homes Constrained
2025–2028	2.5 GW	~6.2 GW-thermal	High	~425,000
2028–2032	4.0 GW	~10.0 GW-thermal	Very High	~680,000
2032–2035	2.5 GW	~6.2 GW-thermal	High	~425,000

3.1.4 Requirement for Integrated Gas–Electric Capacity Assessment

Current provincial planning documents do not provide a consolidated, geographically resolved assessment of:

- Winter gas deliverability
- Power-sector fuel requirements during nuclear outages
- Hybrid heating trajectories
- Compressor station and line pack constraints
- Storage and contingency margins

Without this analysis, electrification pathways implicitly assume that winter gas capacity is unconstrained.
This assumption has not been validated.
A dedicated, integrated gas–electric capacity study is required to quantify:

- Where nuclear-related generation fuel demand overlaps with heating peaks
- Which regions face deliverability risk
- What reinforcements are required
- How associated costs should be allocated

3.1.5 System Interpretation

Ontario's nuclear program involves unprecedented capital investment and remains essential to long-term decarbonization and reliability. However, refurbishment and construction timelines create a structural capacity trough in the late 2020s and early 2030s.

This trough is planned to be bridged primarily by natural gas generation.
The current optimal (non-CHP) gas-to-electric conversion operates at approximately 40% efficiency, replacing unavailable nuclear output imposes a material thermal burden on the gas system and constrains the pace of heating electrification.

This dynamic does not reflect a failure of nuclear strategy. It reflects the physical reality of refurbishment cycles and construction lead times.

However, it establishes a binding near-term constraint: until new nuclear capacity enters service, electrification ambitions remain structurally dependent on gas-system capacity whose limits have not yet been fully quantified.

3.2 Current and Planned Storage Capacity

Energy storage is expected to play a central role in balancing variable renewable generation, winter peak demand, and delayed firm capacity additions. It must support reliability during extended cold-weather events, manage congestion, and enable high renewable penetration without excessive curtailment or overbuilding.

Nuclear, Storage and the System Timing Mismatch

MEM analysis highlights that renewable-heavy systems require substantial overcapacity and storage to maintain reliability. In practical terms, effective planning often assumes storage and generation capacity ratios approaching 3:1 in high-renewables scenarios.

This implies that for every 1 MW of firm peak demand to be supported by intermittent renewables, approximately 3 MW of combined renewable and storage capacity may be required.

Ontario currently operates approximately 175 MW of pumped storage at the Sir Adam Beck complex. The Ontario Pumped Storage Project, in pre-development, is proposed at approximately 1,000 MW and 11 GWh. Together, these assets would provide roughly 1.2 GW of long-duration storage power and 11 GWh of storage energy.
While significant in isolation, this scale remains modest in system context. It offsets only a small fraction of projected winter peak demand, provides hours rather than days of energy shifting, and does not address seasonal imbalances associated with heating electrification. Pumped storage therefore functions as a foundational asset rather than a comprehensive system solution.

Long-term storage and renewable requirements depend primarily on the depth of electrification adoption. For planning purposes, three internally consistent pathways are considered: limited uptake consistent with early policy trajectories, intermediate uptake aligned with mid-term targets, and full system electrification.

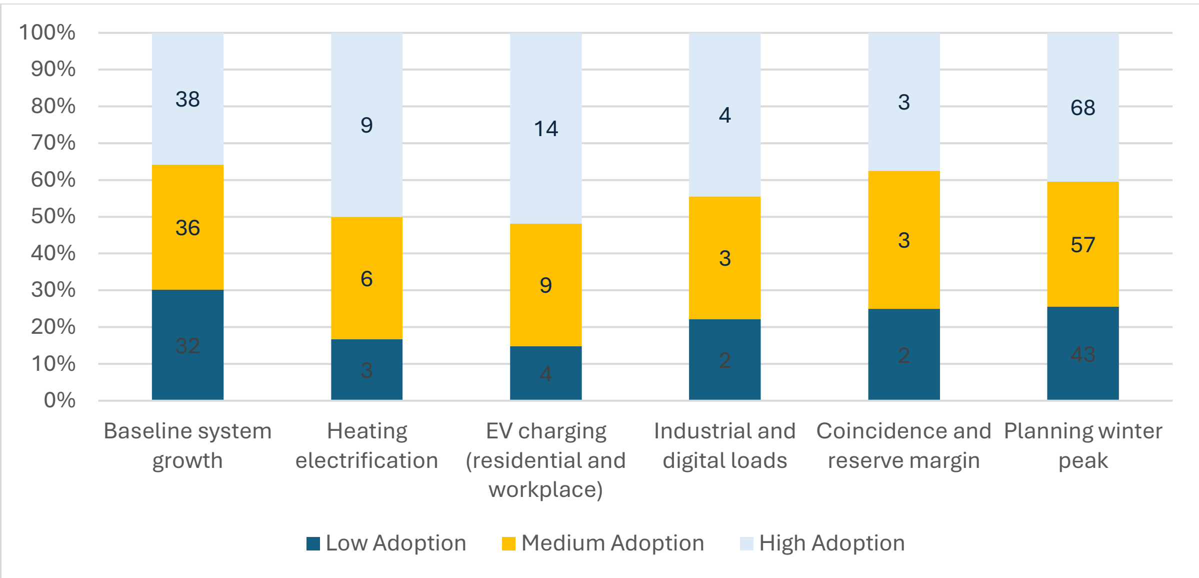
Nuclear, Storage and the System Timing Mismatch

The resulting winter peak profiles reflect combined growth in heating load, transportation electrification, industrial demand, and system reserve requirements.

Table 15: Winter Peak Composition by Adoption Scenario

Component	Low Adoption	Medium Adoption	High Adoption
Baseline system growth	32 GW	36 GW	38 GW
Heating electrification	3 GW	6 GW	9 GW
EV charging (residential and workplace)	4 GW	9 GW	14 GW
Industrial and digital loads	2 GW	3 GW	4 GW
Coincidence and reserve margin	2 GW	3 GW	3 GW
Planning winter peak	**43 GW**	**57 GW**	**68 GW**

Table 15: table and accompanying interpretive bar graph compiled by the author using publicly available Ontario demand outlook and electrification scenario materials (IESO 2023–2025; MEM 2023–2024; NRCan 2023–2024; EPRI 2022–2023), synthesized and visualized with the assistance of ChatGPT (OpenAI), 12 February 2026.



In all pathways, a substantial portion of peak demand continues to be supplied by firm and dispatchable resources, including nuclear, conventional hydro, imports, and retained thermal capacity. The remaining peak obligation must be met through variable renewable generation supported by storage.

Nuclear, Storage and the System Timing Mismatch

For planning purposes, the following shares are assumed:

Table 16: Peak Supply Composition by Electrification Pathway

Pathway	Peak Served by Firm Resources	Peak Served by Renewables and Storage
Low	70%	30%
Medium	55%	45%
High	40%	60%

Applying these shares yields the following system requirements for renewable and storage-backed capacity.

Table 17: VRE and Storage Requirements by Electrification Pathway

Pathway	Planning Peak	VRE + Storage Peak	Renewable Capacity	Storage Power	Storage Energy	Pumped Storage Credit	Net New Storage	Incremental System Cost
Low	43 GW	13 GW	18 GW	13 GW	52 GWh	1 GW / 11 GWh	12 GW / 41 GWh	~$60B
Medium	57 GW	26 GW	36 GW	26 GW	156 GWh	1 GW / 11 GWh	25 GW / 145 GWh	~$180B
High	68 GW	41 GW	58 GW	41 GW	328 GWh	1 GW / 11 GWh	40 GW / 317 GWh	~$360B

These values reflect the combined cost of renewable generation, storage systems, and associated integration infrastructure using conservative, escalated unit cost assumptions consistent with recent Ontario and comparable North American projects.

Several structural observations emerge. First, storage energy requirements increase more rapidly than storage power as electrification deepens. Reliability under winter conditions depends on sustained multi-hour and multi-day coverage rather than short-duration peak shaving.
Second, pumped storage provides meaningful foundational value but does not materially alter long-term system scale under medium and high adoption pathways.

Third, incremental system cost is driven increasingly by flexibility infrastructure rather than by energy production itself. As renewable penetration rises, storage, integration, and network reinforcement dominate capital requirements. Fourth, system cost grows non-linearly with adoption depth. Moving from medium to high electrification more than doubles required storage energy and approximately doubles total capital exposure.

Under higher adoption pathways, Ontario's long-term storage and renewable enablement requirements are therefore measured in tens of gigawatts and hundreds of gigawatt-hours, with capital implications exceeding $300B. Current and planned projects represent essential first steps, but they address only a limited fraction of the flexibility infrastructure required for full-system electrification.

The principal planning challenge is not the availability of renewable resources, but the financing, siting, and governance of the large-scale storage and integration assets required to make those resources reliably deliverable under winter peak conditions.

This gap illustrates the scale mismatch between present aspirations and long-term system needs.

3.2 Unlocking Stranded Generation

Northern and remote hydroelectric resources remain underutilized due to transmission and distribution bottlenecks. MEM documentation highlights that multiple northern corridor projects—including the Wawa–Porcupine line, North Shore Link, and Northeast Power Line—are expected to add approximately 900 MW of incremental transfer capacity by the late 2020s.

While material, this scale remains modest relative to system needs:

- 900 MW represents less than 2 per cent of projected mid-century peak demand.
- It offsets only a small fraction of electrified heating and industrial growth.
- It does not materially alter province-wide capacity constraints.

Nuclear, Storage and the System Timing Mismatch

Based on IESO and MEM projections, stranded and partially constrained northern hydro and renewable capacity is conservatively estimated at 6GW today, rising to 8GW by the 2030s without further network expansion. This includes curtailed hydro output, delayed project interconnections, and suppressed development due to congestion risk.

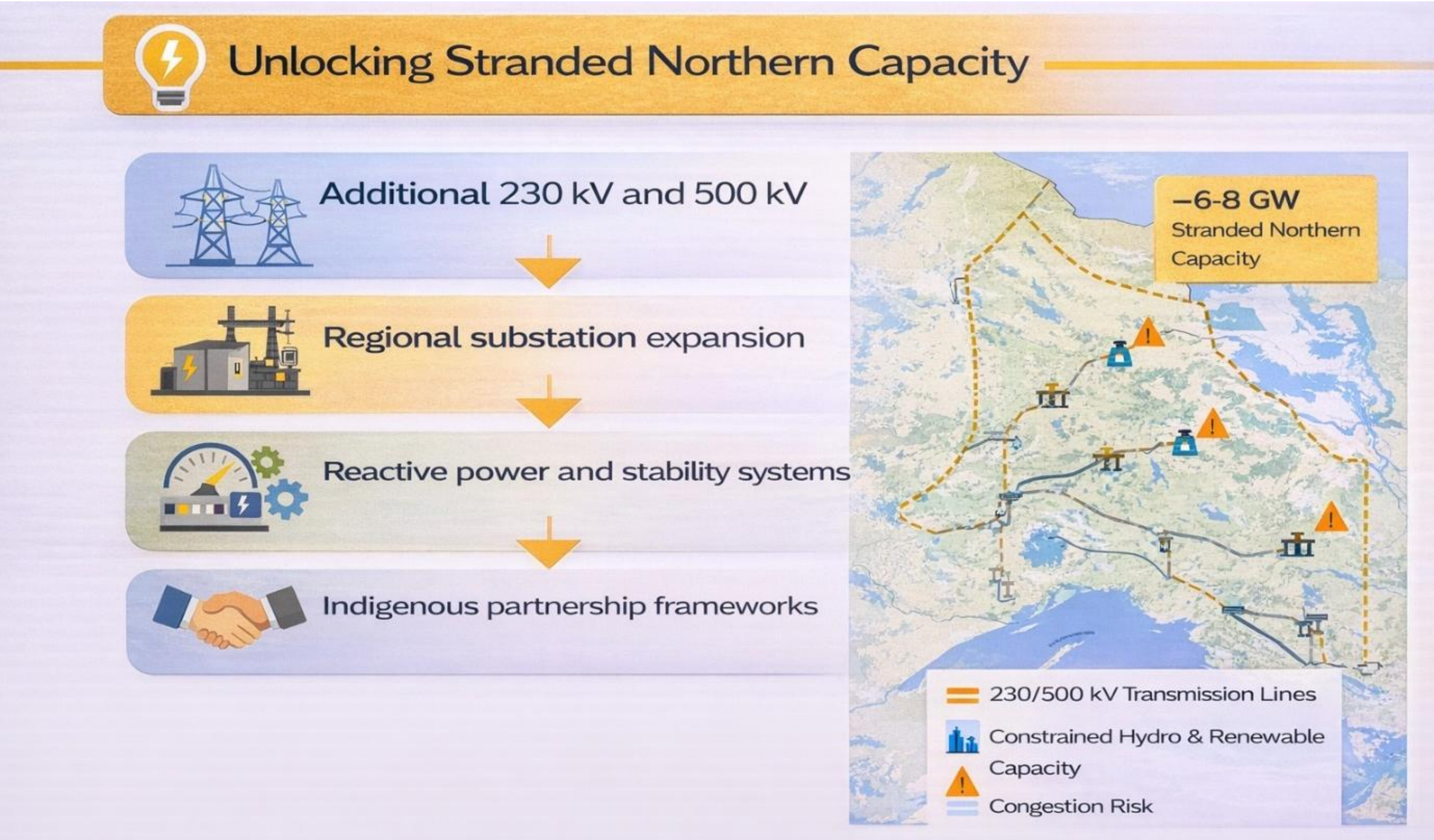


Fig 18: Unlocking Stranded Northern Capacity, Ontario Ministry of Energy and Mines (2023) Ontario's Energy for Generations Integrated Energy Plan, Toronto: Government of Ontario. Adapted from publicly released transmission and regional capacity materials/

Unlocking this capacity requires coordinated investments in local distribution to get them to the transmission lines. Fragmented planning and financing mechanisms have delayed these enabling investments. As a result, low-cost renewable potential remains stranded while higher-cost interim solutions are deployed elsewhere.

3.3. Asset Wear, and Lifecycle Trade-Offs

Reconductoring projects, such as the Orangeville–Barrie corridor, are promoted as cost-effective methods of increasing transfer capacity by upgrading existing rights-of-way. While reconductoring can increase thermal ratings by 30–40%, higher utilization shifts costs from deferred capital into accelerated wear, deferred maintenance (DM), and earlier renewal unless sustainment funding increases in parallel.

For this analysis, asset management is applied to the full electrified grid (generation, transmission, distribution, storage, digital systems, and control infrastructure), recognizing that a portion of assets may be privately owned but are ultimately recovered through consumer rates.

Deferred Maintenance (DM) and Facility Condition Index (FCI) Context

- Deferred Maintenance (DM): Accumulated sustainment and renewal work postponed beyond optimal timing.
- Facility Condition Index (FCI): DM backlog ÷ Replacement Asset Value (RAV).

For discussion purposes, this paper applies the following rounded system-wide reference values:

- Baseline system RAV (2025): $80B
- Incremental assets by 2035: +$120B (≈ $200B total)
- Incremental assets by 2050: +$370B (≈ $450B total)
- Current average FCI: ~0.08 (≈ 8% Assumed, this data point does not exist)

This implies an initial system-wide DM backlog of approximately $6B in the near term, rising materially if sustainment does not scale with asset growth. The municipalities are not preparing for this net increase in costs.

Nuclear, Storage and the System Timing Mismatch

The table below illustrates the relationship between sustainment intensity, DM recovery, and total lifecycle cost of ownership (TLCO) as the system expands.

Table 18: System Sustainment and Lifecycle Cost Trajectory

Period	System RAV	Sustainment (% of RAV)	Base Sustainment ($/yr)	DM Catch-Up ($/yr)	Total Sustainment ($/yr)	FCI Direction	TLCO Index
2025 Baseline	$80B	1.8% (current)	$1.4B	$0.0B	$1.4B	Deteriorating	108
2025 Stabilized	$80B	2.4%	$1.9B	$0.2B	$2.1B	Flat	100
2035 Electrification Buildout	$200B	2.7%	$5.4B	$0.6B	$6.0B	Improving	102
2050 Mature System	$450B	2.7%	$12.2B	$0.9B	$13.1B	Stable	102
Over-Maintained Case	$450B	3.2%	$14.4B	$0.9B	$15.3B	Diminishing Returns	105

Table compiled by the author using publicly available Ontario regulated asset base (RAV), asset management and lifecycle planning materials (OEB 2023–2024; IESO 2024–2025; Institute of Asset Management 2022; ASCE 2021)

Notes:

- DM catch-up assumes systematic retirement of backlog over ~15 years.
- Sustainment rates reflect higher utilization, denser power electronics, and climate-driven stress.

3.3.1. Lifecycle Implications of Reconductoring

At elevated loading levels, MEM analysis and industry experience indicate that reconductoring without commensurate structural and sustainment investment leads to:

- Accelerated conductor annealing and fatigue
- Increased insulator flashover and hardware failure
- Higher vegetation management and inspection frequency
- Shortened replacement cycles

Nuclear, Storage and the System Timing Mismatch

Absent movement up the maintenance J-curve, reconductoring programs can reduce effective asset life by 10–20%, increasing long-term system cost despite near-term capital savings.

3.3.2. System-Level TLCO Perspective

Fig 19: Lifecycle Implications of Reconductoring, image generated by ChatGPT (OpenAI), 12 February 2026, using publicly available Ontario transmission asset management and regulated asset base materials (OEB 2023–2024; IESO 2024–2025; Institute of Asset Management 2022), synthesized through interpretive prompts to illustrate lifecycle cost, RAV growth and sustainment planning interactions.

From a provincial perspective, reconductoring should be treated as a capacity bridge with embedded lifecycle obligations, not as avoided capital. Each incremental MW of capacity gained through higher utilization increases future sustainment and renewal requirements.

Optimizing Ontario's electrification pathway therefore requires explicit integration of the following into planning and rate-setting processes.

- Expanding RAV trajectories
- DM backlog management
- Sustainment funding envelopes
- Asset replacement timing

Failure to do so risks transferring short-term capital savings into long-term cost escalation borne by future ratepayers.

3.3.3. Planning and Transparency Gap (Outside of OEB Mandate)

Limited public disclosure of congestion patterns, curtailment volumes, interconnection constraints, and deliverability limits prevents systematic evaluation of how much capacity is liberated per dollar invested. As a result, infrastructure programs are optimized project-by-project rather than portfolio-wide, reducing capital efficiency and increasing the risk of parallel overbuilding of both generation and network assets.

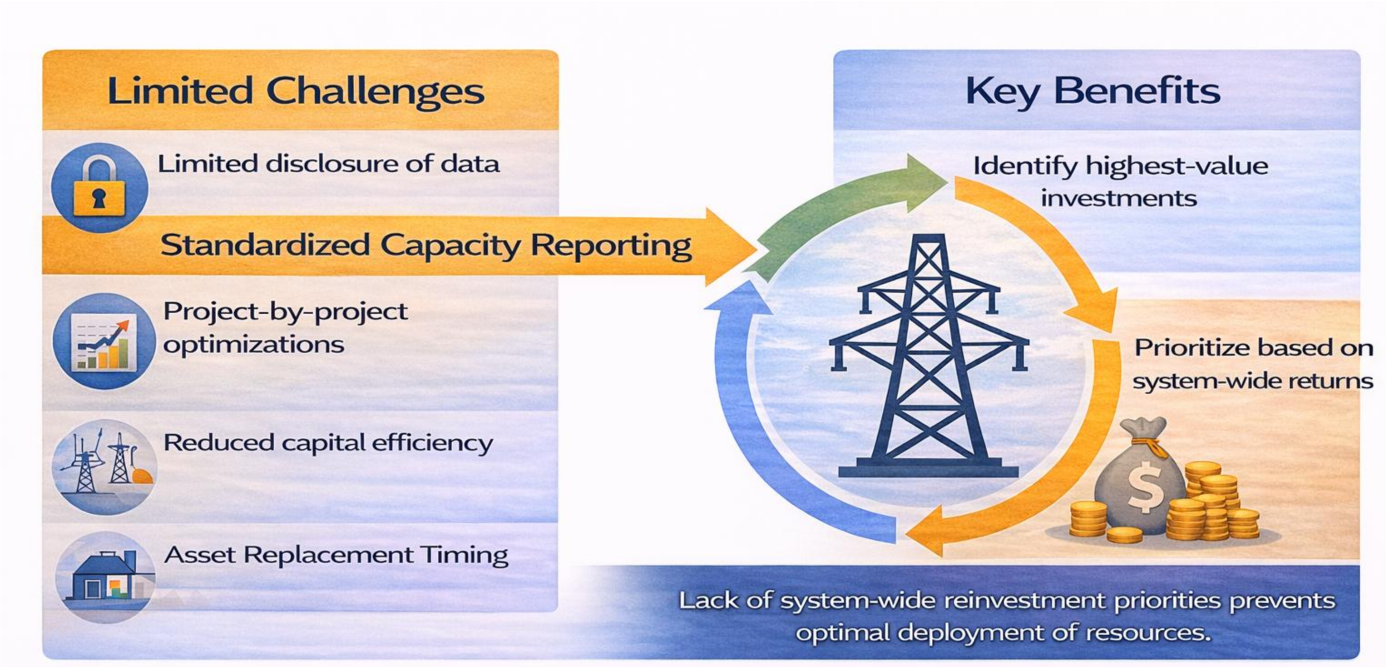


Fig 20: Standardized Capacity Practices - Challenges & Benefits, image generated by ChatGPT (OpenAI), 12 February 2026, to illustrate the benefits of standardized capacity reporting practices practices based on publicly available Ontario transmission asset management and investment priorities materials (IESO 2023-2024; OEB 2023-2024; Institute of Aset Management 2022).

Without standardized reporting of stranded capacity and de-stranding economics, Ontario lacks a mechanism to prioritize reinforcements based on system-wide return on capital rather than local necessity.

3.4. Capacity Unlocking Versus New Generation Economics

Unlocking stranded or underutilized generation requires coordinated investment in transmission, substations, protection systems, and distribution hosting capacity. Public filings and regional reinforcement projects indicate that these upgrades are rarely isolated; effective de-stranding typically involves multiple system layers.

Nuclear, Storage and the System Timing Mismatch

Recent Ontario and comparable North American projects suggest that the combined cost of transmission uprates, substation expansions, protection modernization, and hosting-capacity enhancements generally ranges between $0.8M and $1.5M per MW of reliably deliverable capacity unlocked. For planning purposes, this paper adopts a conservative reference value of approximately $1.2M per MW.

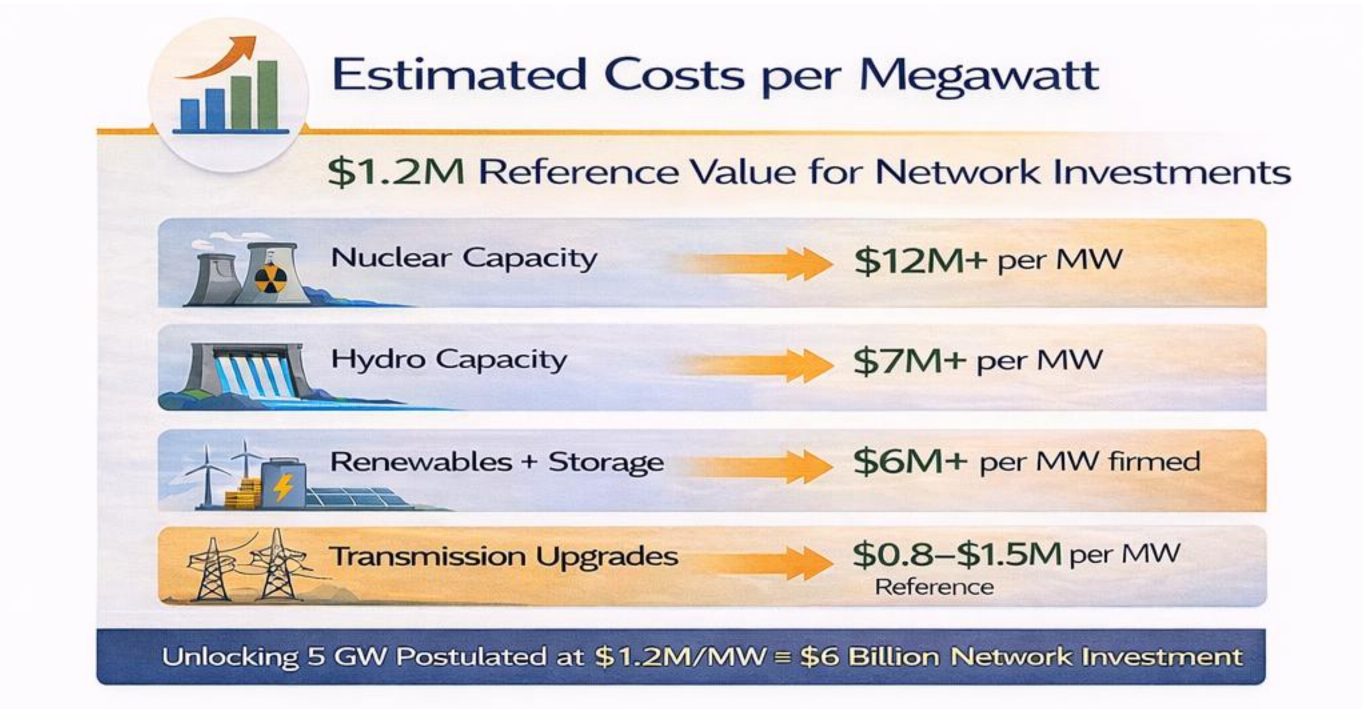


Fig 21: Estimated Costs per Megawatt, image generated by ChatGPT (OpenAI), 12 February 2026, using publicly available Ontario and North American generation, transmission and storage cost benchmarks (IESO 2023–2025; MEM 2023–2024; IRENA 2023; NERC 2023)

By comparison:

- New nuclear capacity ranges from $12M per MW
- Large hydro ranges from $7M per MW
- Utility-scale renewables plus storage exceed $6M per MW firmed

At this level, unlocking 5 GW of constrained generation implies approximately $6B in network investment, exclusive of generation capital.

Nuclear, Storage and the System Timing Mismatch

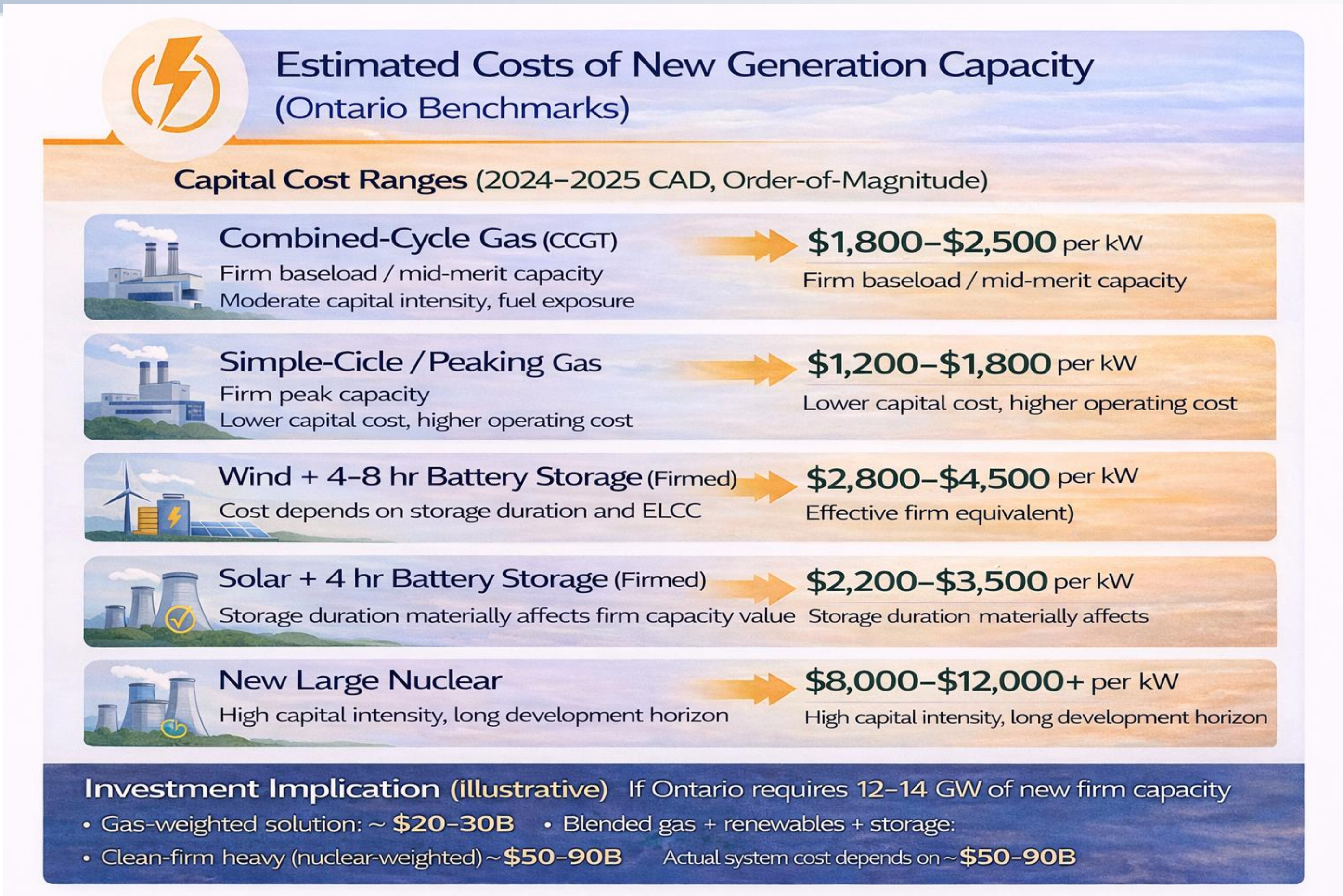


Fig 22: Est Costs of New Generation Capacity, image generated by ChatGPT (OpenAI), 12 February 2026, using publicly available Ontario and North American capital cost benchmarks for gas, nuclear, renewable and storage resources (IESO 2023–2025; MEM 2023–2024; IRENA 2023; NERC 2023; EPRI 2022–2023), synthesized through interpretive prompts to illustrate comparative per-kW capital cost ranges and indicative mid-century firm capacity investment envelopes.

In parallel, accelerated electrification requires substantial new firm and flexible generation capacity to be developed on compressed timelines. Public benchmarks for combined-cycle gas, peaking resources, storage-backed renewables, and firm clean capacity indicate all-in costs of $2,500–$3,000 per kW under accelerated procurement and construction conditions. Applying these benchmarks to the 12–14 GW of incremental capacity implied by high-electrification pathways yields an additional ~$36B in generation investment by mid-century.

Taken together, de-stranding and accelerated generation development imply more than $40B in incremental supply-side system costs that are rarely presented in consolidated planning documents. Limited transparency regarding congestion, curtailment, and deliverability prevents systematic optimization, reducing capital efficiency and increasing the risk of parallel overbuilding.

3.5. Market Nodes and System Value Creation, not just Transmission

Transmission capacity is more than a conduit for moving electrons. Well-designed corridors unlock market nodes, reduce congestion rents, improve price transparency and competitiveness, and enable regionally scalable industrial growth. In jurisdictions with constrained transmission, locational price differentials can persist, suppressing investment and distorting resource dispatch.
Transmission expands economic geography by enabling new delivery points and competitive market hubs that would otherwise be isolated by network bottlenecks.

Public infrastructure rankings show Ontario's transmission build-out is now earning national recognition. The 2026 *Top100 Infrastructure Projects* list includes a number of major Ontario energy initiatives, many of which hinge on transmission and network reinforcement to deliver system value at scale. Four energy projects alone represent a significant portion of the overall investment envelope, including refurbishment of nuclear generation and associated network integration needs.
In Ontario specifically:

- The Greenstone Transmission Line has been designated a priority project — a new 230 kV corridor that will strengthen northern connectivity and support economic development, including mineral processing and community electrification.
- The Welland-Thorold 230 kV project is advancing through regulatory approval, reinforcing capacity in the southwest and improving reliability for growth areas.

Nuclear, Storage and the System Timing Mismatch

By enabling critical minerals processing, hydrogen and electrolysis hubs, Indigenous-led generation projects, data centre siting, and remote community electrification, transmission upgrades unlock latent economic value far beyond simple power transfer. Without sustained corridor development and visibility into system constraints, these opportunities remain structurally constrained by bottlenecked interfaces and unpriced locational risk.

3.6. Integrated System Planning

The combined effects of limited storage, delayed nuclear, constrained hydro access, and partial transmission upgrades create a structurally fragile near-term system.

Bridging this period successfully requires:

- Accelerated long-duration storage deployment
- Multi-corridor transmission programs
- Integrated nuclear refurbishment coordination
- Expanded reconductoring with lifecycle safeguards
- Portfolio-level investment governance

Storage, transmission, and hydro unlocking must therefore be treated as core system infrastructure, not as an auxiliary measure.

Part II – Institutional Capacity

04	Financing and Balance Sheets
05	Municipal and Ratepayer
06	Governance Structure

4 . Financial and Utility Balance Sheet Capacity

This Part evaluates whether Ontario's current financial, municipal, and regulatory institutions are capable of delivering, governing, and sustaining the scale of investment implied by high-electrification pathways. It integrates utility balance sheets, municipal finance mechanisms, public infrastructure finance tools, ratepayer impacts, and approval processes into a consolidated institutional capacity framework.

4.1Regulated Utility Capital Formation

Ontario's electricity distribution sector currently sustains approximately $2.5B per year in regulated capital investment. This reflects the combined effect of:

- OEB-approved rate base growth
- Debt-to-equity constraints (typically 60:40)
- Ratepayer affordability limits
- Limited retained earnings
- Exposure to refinancing cycles

Over a five-year period, baseline capital deployment capacity is therefore approximately $12.5B, assuming stable interest rates and uninterrupted regulatory approvals. Transmission and large-system operators deploy an additional ~$2.5B annually, largely tied to refurbishment and incremental reinforcement programs.

Total baseline grid investment capacity (distribution + transmission): ~$5B/year.

4.2 Public Infrastructure Finance Instruments

Ontario utilities and municipalities increasingly rely on blended finance mechanisms to supplement regulated borrowing capacity. Key instruments include:

4. Financial and Utility Balance Sheet Capacity

Table 19: Types of Funding Available (Not Exhaustive)

Instrument	Typical Cost of Capital	Annual Ontario Envelope	Primary Use
Canada Infrastructure Bank (CIB)	~1.0%	~$1.5B	Grid, storage, transit electrification
Green Municipal Fund (GMF)	~2.0%	~$0.4B	Municipal energy systems
Grid Innovation Fund (GIF)	Grant / blended	~$0.3B	DER, automation, pilots
Provincial Infrastructure Bonds	~4.0%	Variable	Large system assets
Federal Climate Programs	Grant / blended	~$0.5B	Building, EV, storage

Collectively, these mechanisms currently provide ~$3.0B per year in low-cost or blended capital for energy infrastructure. These funds are material but remain small relative to electrification-driven system needs.

4.3 Integrated Capital Requirement (2025–2050)

Synthesizing Part I peak analysis, distribution enablement costs, system expansion, de-stranding, and lifecycle sustainment yields the following rounded investment envelope:

- Average required deployment: ~$17B/year over 25 years
- Current sustainable capacity (regulated + public finance): ~$8B/year
- Structural financing gap: ~$9B/year

4. Financial and Utility Balance Sheet Capacity

Table 20: Summarized Total Capital Requirement for Ontario

Asset Category	Lifecycle Cost to 2050
Distribution Enablement (HPs, EVs)	$31B
Distribution Expansion & Renewal	$120B
Transmission Reinforcement	$75B
Firm & Flexible Generation	$90B
Storage & Integration	$35B
Digital & Control Systems	$15B
Sustained Maintenance & Renewal	$60B
Total System Investment	**~$426B**

This table is rather conservative as it only reflects medium electrification. The total is enormous and needs to be handled together. A clear plan overlapping the different facets of our ambition would be the only way to that achieve it.

The February 2026 federal removal of the current mandated EV transition to fuel efficiency tightening as the timelines for the full conversion by 2035 were obviously flawed in many ways. That is not to put down the ambition but rather to help realign with reality. There are aspects of our ambition that may need to be rolled back as well, no to slow us down but to keep this sustainable in the long run. Accelerated bursts of construction are good but tend to require the same cyclical refurbishment, punting a problem down the line if not asset managed and planned appropriately.

4. Financial and Utility Balance Sheet Capacity

4.4 Long-Term Borrowing Dynamics

Ontario's electrification pathway requires sustained, multi-decade capital deployment well beyond historical utility and municipal borrowing patterns. Understanding long-term borrowing dynamics is therefore central to assessing institutional capacity and fiscal resilience. For reference, this paper applies the following baseline financial assumptions for system-wide infrastructure financing:

- Conventional regulated utility debt (market-based): 5.0%
- Public infrastructure banking / blended finance: 1.5–2.0%
- Blended system-wide cost of capital (current structure): ~3.8%
- Amortization period: 25 years
- Average net new borrowing requirement: $10B per year

These values reflect current Canadian market conditions and existing federal and provincial financing programs.

4.4.1 Annual Debt Service Under Alternative Financing Structures

Using standard annuity repayment profiles, the annual debt service associated with $10B of new borrowing differs materially depending on financing structure.

Table 21: Financing Structure and Debt Service Comparison

Financing Structure	Representative Rate	Annual Debt Service per $10B
Market-based utility debt	5.0%	~$0.71B
Public banking / blended finance	1.7%	~$0.49B
Current blended system average	3.8%	~$0.64B

The difference between conventional and blended public finance exceeds $200M per year per $10B tranche. Over multiple tranches, this differential becomes a major determinant of long-term affordability.

4. Financial and Utility Balance Sheet Capacity

Assuming $10B of net new borrowing annually over a decade:

Table 22: Ten-Year Debt Service Comparison by Financing Model

Financing Model	Annual Debt Service (Year 10)	Cumulative 10-Year Obligation
Market-based only	~$7.1B	~$42B
Blended public finance	~$4.9B	~$29B
Current blended mix	~$6.4B	~$38B

Access to low-cost public capital therefore reduces steady-state system debt service by $2.5B per year at scale. This reduction directly translates into lower rate pressure and improved balance-sheet resilience.

4.4.2 Role of Public Infrastructure Banking

Federal and provincial infrastructure banking mechanisms now form a critical component of grid financing:

- Canada Infrastructure Bank (CIB)
- Green Municipal Fund (GMF)
- Infrastructure Ontario
- Federal climate infrastructure programs
- Provincial credit enhancement facilities

These institutions typically provide:

- Long-duration loans (20–40 years)
- Interest rates near sovereign borrowing levels
- Flexible repayment structures
- Credit enhancement for smaller borrowers

For smaller municipalities and LDCs, access to these channels can reduce borrowing costs by 3 percentage points, often determining whether projects are financially viable.

However, these programs are currently under-scaled relative to electrification needs and are accessed on a project-by-project basis rather than as part of a coordinated financing platform.

4.4.3 Implications for Municipal Owners and Local Governments

Municipalities face electrification exposure through three channels:

- Direct utility borrowing
- Municipal guarantees
- Balance-sheet support for enablement infrastructure

For a typical mid-sized municipal utility undertaking $500M–$1B in electrification-related capital:

Table 23: Long-Term Debt Service Range by Financing Mode (25-Year Term)

Financing Mode	Annual Debt Service (25 yrs)
Market-only	$35M–$70M
Blended public finance	$24M–$48M

The difference is equivalent to multiple property tax points or major service programs. Without structured access to low-cost capital, municipalities are forced to:

- Defer infrastructure upgrades
- Compress investment schedules
- Increase local rates
- Crowd out housing, transit, and climate projects

4.4.4 Long-Term Impact on Rate Flexibility and Capital Headroom

As borrowing accumulates, debt service becomes a fixed system obligation that must be recovered before discretionary investment.

Under the reference case:

- Year 10 incremental debt service: ~$6.4B/year
- Year 20 incremental debt service: ~$11B/year
- Share of total electricity revenue devoted to debt: rising steadily
- High fixed debt loads reduce
- Capacity to respond to extreme weather
- Ability to accelerate priority corridors
- Flexibility to adopt new technologies
- Resilience to interest rate shocks

4. Financial and Utility Balance Sheet Capacity

This creates a structural risk of "financial lock-in," where past borrowing constrains future system evolution.

The scale of electrification requires a transition from opportunistic project finance to coordinated infrastructure banking.

Key elements include:

- Dedicated grid financing windows
- Portfolio-level credit enhancement
- Standardized eligibility for enablement assets
- Multi-utility borrowing platforms
- Integration with rate-setting processes

Without such coordination, low-cost capital remains fragmented, and overall system cost increases unnecessarily.

Fig 23: Long-Term Debt Burden of Ontario's Electricity Sector, image generated by ChatGPT (OpenAI), 12 February 2026, using publicly available Ontario electricity investment projections, regulated asset base trends and representative financing assumptions (IESO 2023–2025; MEM 2023–2024; OEB 2023–2024; DBRS Morningstar 2024), synthesized through interpretive prompts to illustrate projected debt service escalation under a reference financing case.

4.4.5 Interpretation for Municipal Decision-Makers

For municipal councils, boards, and finance committees, the central message is:
Electrification is not constrained primarily by engineering capacity.
It is constrained by financing architecture.
Access to low-cost, long-duration public capital is the difference between:

- Manageable, predictable rate evolution, and
- Persistent fiscal stress and service trade-offs.

Smaller and mid-sized municipalities are most exposed to this risk because they lack independent access to capital markets and portfolio diversification.
Ensuring systematic access to public infrastructure banking is therefore a prerequisite for equitable and durable electrification.

5 . Municipal Finance, Revenue and Ratepayer Exposure

5.1 Municipal Role in Grid Enablement

Municipalities act simultaneously as:

- Owners of LDCs
- Guarantors of utility debt
- Providers of servicing infrastructure
- Zoning and permitting authorities
- Rate stabilization agents

Electrification therefore expands municipal financial exposure well beyond traditional utility oversight.

5.2 Distribution Enablement Burden

As developed in Part I, residential electrification implies approximately $31B in local system upgrades.

This translates to an average municipal/LDC burden of:

- ~$1.2B/year (2025–2050)
- ~$225 per customer per year (system average)

Absent dedicated funding streams, these costs are recovered through distribution rates or municipal balance sheets.

5.3 Municipal Energy Enterprise Models

Several Ontario municipalities are piloting diversified energy platforms through LDC subsidiaries.

The Town of Oakville and Oakville Hydro Energy Services illustrate this model, with investments in:

- District energy systems
- Solar and storage
- EV charging networks
- Energy services contracting

These platforms generate:

- Stable non-rate revenue
- Carbon compliance credits
- Long-term service contracts

5. Municipal Finance, Revenue and Ratepayer Exposure

Indicative mature-system revenues: $10–25M/year per mid-sized municipality.

While promising, these models remain geographically limited and capital intensive.

5.4 Ratepayer Bill Integration Framework

Electrification costs are recovered through multiple channels.

Table 24: Electricity Bill Composition and Long-Term Trajectory

Bill Component	Current Average Share	Long-Term Trajectory
Energy Supply	35%	Declining
Transmission	10%	Rising
Distribution	25%	Rising
Capacity/System Charges	5%	Rising
Public Adjustments	25%	Policy-Dependent

Ontario currently allocates approximately $8B/year to electricity rebate and mitigation programs. These funds are not applied to asset renewal or system expansion.

Redirecting even 25% of this envelope would increase grid capital capacity by ~$2B/year.

5. Municipal Finance, Revenue and Ratepayer Exposure

5.5 Indicative Household Impact by System Average

Table 25 illustrates the expected impact of electrification on an average Ontario household electricity bill. The values are illustrative but align with projected capital expansion requirements and cost allocation trends across the province.

Under current conditions, the representative annual residential electricity bill of approximately $1,400 reflects a system where generation costs remain moderate and much of the legacy infrastructure is amortized. Distribution charges account for roughly $350, about one quarter of the total bill. Capacity and system-related charges are comparatively modest at approximately $70 per year.

In a post-electrification environment, the average annual bill increases to approximately $2,200. The increase is not primarily driven by energy supply costs. Instead, it reflects structural system changes.

Distribution costs rise from $350 to $650, driven by feeder upgrades, transformer replacements, substation expansion, and hosting capacity investments required to support electric vehicles, electrified heating, and growing digital loads. Capacity and system charges increase from $70 to $220, reflecting higher peak demand obligations and resource adequacy requirements.

Most of the incremental bill growth is therefore infrastructure and capacity driven rather than commodity driven. Electrification is capital intensive and network led.

From a policy perspective, long term affordability will depend less on marginal energy prices and more on how capital is deployed and financed. Financing structure, peak management, asset utilization, and coordination between gas and electric systems will materially influence rate outcomes.

Electrification is not only a supply challenge. It is fundamentally a capital allocation and system design challenge.

Table 25: Illustrative Residential Bill Impact under Electrification

Component	Current	Post-Electrification
Annual Bill	~$1,400	~$2,200
Distribution Share	~$350	~$650
Capacity/System Share	~$70	~$220

Impacts vary materially by region and growth profile.

6. Governance, Approval Pathways, and Institutional Throughput

Ontario's electrification transition is not constrained solely by engineering capacity or capital availability. It is equally constrained by the institutional structures through which infrastructure is planned, approved, financed, and governed. The speed, coherence, and accountability of these processes will materially determine whether projected investments can be delivered at the scale and pace required.

6.1 Multi-Layer Approval Architecture

Major electricity infrastructure projects in Ontario require coordinated approval across multiple institutions and jurisdictions, including:

- IESO needs assessments
- Regional and integrated resource planning
- Utility business case development
- Ontario Energy Board capital approval
- Rate recovery authorization
- Environmental permitting
- Indigenous consultation and accommodation
- Municipal servicing and land use agreements
- Provincial prioritization and funding alignment

Each stage is necessary and reflects legitimate public interest objectives. However, these processes are largely sequential rather than parallel, and are administered by separate authorities with distinct mandates and timelines.

As a result, end-to-end development timelines for major generation, transmission, and distribution projects commonly range from 6-12 years, even in high-priority corridors. These timelines are misaligned with current electrification-driven growth trajectories in transportation, housing, and industry.

Without procedural modernization and greater coordination, approval throughput itself becomes a binding system constraint.

6. Governance, Approval Pathways, and Institutional Throughput

6.2 Capital Prioritization and Portfolio Management

Current governance structures evaluate infrastructure projects primarily on an individual basis, rather than as components of integrated, multi-asset investment portfolios.

This limits the system's ability to:

- Optimize sequencing across generation, transmission, and distribution
- Evaluate trade-offs between centralized and distributed solutions
- Pool delivery and financing risk
- Reallocate capital as system conditions evolve
- Recycle capital through coordinated asset retirement and reinvestment

No provincial entity currently maintains a consolidated, system-wide investment pipeline with full lifecycle accountability across major asset classes. As a result, capital allocation decisions are fragmented across institutions, reducing overall efficiency and increasing exposure to stranded or underutilized assets.

In a capital program measured in hundreds of billions of dollars, the absence of portfolio-level governance represents a material structural weakness.

6.3 Change Implementation Pathway

Many of the reforms required to support electrification cannot be implemented within a single regulatory or policy domain. Effective change requires synchronized adjustments to:

- OEB filing and evidence requirements
- Municipal finance and debt regulations
- Provincial infrastructure and housing policy
- Federal funding eligibility criteria
- Indigenous partnership and equity participation frameworks

6. Governance, Approval Pathways, and Institutional Throughput

These systems evolved independently and are governed by different legislative, fiscal, and political constraints. In the absence of coordinated reform programs, institutional inertia becomes a significant delivery barrier.

Incremental adjustments within individual agencies are insufficient to resolve cross-system misalignments. Without deliberate change management and shared implementation roadmaps, well-intentioned policy objectives translate into prolonged execution delays.

6.4 Fiduciary and Stewardship Obligations

Utility boards, municipal councils, and regulators operate under fiduciary and stewardship obligations to:

- Preserve long-term asset value
- Maintain service reliability
- Protect customer affordability
- Manage intergenerational equity
- Ensure prudent financial management

High-electrification pathways materially increase the financial, operational, and reputational risk carried by these institutions. Decisions taken today will influence rate structures, debt profiles, and asset utilization for multiple decades.

This heightens the importance of transparent lifecycle accounting, standardized performance reporting, independent assurance mechanisms, and clearly articulated risk allocation frameworks. Without these safeguards, institutional decision-makers are exposed to growing uncertainty and accountability pressures.

6. Governance, Approval Pathways, and Institutional Throughput

6.5 Consolidated Financial Exposure and Governance Implications

The financial profile of Ontario's electrification transition amplifies the importance of governance and approval effectiveness. When system-wide investment requirements are consolidated, they reflect a sustained institutional and fiscal commitment extending well beyond typical planning cycles.

Consolidated Financial Indicators

Table 26: Lifecycle Investment Requirement and Financing Gap Summary

Category	Value
Total Lifecycle Investment (to 2050)	$426B
Average Annual Requirement	$17B
Current Sustainable Capacity	$8B
Annual Financing Gap	$9B
Cumulative New Debt (25 years)	$250B
Incremental Debt Service (Steady State)	$12B per year
Residential Enablement Cost	$31B
Annual Rebates (Non Capitalized)	$8B per year

These figures demonstrate that electrification is not a discrete infrastructure program but a permanent restructuring of Ontario's energy and municipal finance systems.

An annual financing gap of $9 billion, combined with cumulative new debt approaching $250 billion, places sustained pressure on approval processes, rate-setting frameworks, and political accountability structures. Delays, inefficiencies, and fragmented decision-making directly translate into higher system costs and increased public exposure.

In this context, governance reform is not an administrative refinement. It is a core system enabler. Approval pathways, capital prioritization mechanisms, and fiduciary oversight structures must evolve in parallel with technical and financial systems.

Without improvements in institutional throughput and portfolio governance, Ontario's electrification transition will remain vulnerable to escalating costs, prolonged delivery timelines, and declining public confidence, even where sufficient capital and technical capability exist.

Part III – Constraint into Opportunity

7. From Constraint to Opportunity

Ontario's electrification transition is ambitious, complex, and capital-intensive. The challenges identified in Parts I and II—including heating-driven winter peaks, financing gaps, governance fragmentation, and system integration risks—are substantial. Together, they signal that the province has reached a moment of strategic choice.

Electrification can proceed through incremental, reactive adjustments that compound cost and risk. Alternatively, it can be approached as a coordinated modernization program that aligns planning, finance, and governance across institutions. Current pressures therefore represent not only constraints, but catalysts for institutional renewal, improved coordination, and more disciplined public investment.

7.1 Integrated System Impacts and Investment Responsibilities

Electrification is now a whole-of-system capital program. The key question is not whether investment is needed, it is who secures the funds, how they are recovered, and how quickly delivery institutions can translate capital into capacity.

The table below consolidates the major investment domains, the lifecycle cost envelope developed to date in this paper, and the funding capacity contemplated to date using the blended "current institutional capacity" logic already established (regulated investment capacity plus low-cost / blended public finance tools). Residual costs are ultimately borne by end users through bills and/or taxation.

7. From Constraint to Opportunity

Table 27: Consolidated Investment and Funding Responsibilities (to 2050)

Major Investment Domain	Purpose	Lifecycle Cost	Funding Accounted	Unfunded / Gap	Parties That Must Secure Funds	Primary Cost Recovery Channel
Firm & Flexible Generation	Winter reliability, adequacy, dispatchable capacity	$90B	$35B	$55B	Generators, IESO procurement, Province (as needed)	Contracts → rates (and/or taxes)
Transmission Expansion & Reinforcement	Deliverability, congestion relief, new nodes	$75B	$40B	$35B	Transmitters, Province	Transmission rates
Distribution Enablement (HP/EV hosting)	Service upgrades, transformers, feeders, protection	$31B	$10B	$21B	LDCs, Municipal owners, Province (support/guarantees)	Distribution rates / local borrowing
Distribution Expansion & Renewal	Growth, replacement, resiliency hardening	$120B	$60B	$60B	LDCs, Municipal owners, Province	Distribution rates
Storage & System Integration	Peak shaping, firming, local constraints	$35B	$15B	$20B	IESO, utilities, private developers	Contracts → rates
Digital & Market Platforms	Visibility, control, coordination tools	$15B	$10B	$5B	IESO, utilities, Province (seed capital)	System charges
Market Structuring & Program Delivery	Settlement evolution, contracting frameworks, admin	$10B	$10B	$0B	OEB/IESO/Province	System charges / taxes
Sustained Maintenance & Renewal (TLCO)	Sustainment, DM catch-up, lifecycle integrity	$60B	$35B	$25B	Utilities, municipal owners, Province (rate smoothing)	Rates
TOTAL	**Fully built electrified grid (system view)**	**$436B**	**$215B**	**$221B**	**All parties above**	**End users (rates + taxes)**

Major Investment Domains and Funding Gap Allocation, table compiled by the author using publicly available Ontario electricity planning, capital investment and financing materials (IESO 2023–2025; MEM 2023–2024; OEB 2023–2024; Infrastructure Ontario 2024; Electricity Distributors Association 2023–2025)

7. From Constraint to Opportunity

The funding currently contemplated column represents our best effort at pulling together all current forecasts. This column represents what Ontario's current institutional stack is realistically positioned to carry without major structural change, based on:

- the baseline regulated deployment capacity (distribution + transmission),
- existing low-cost/blended capital channels (CIB/GMF/GIF and comparable vehicles),
- and current procurement practice scale.

Ontario is not facing "a funding gap" in the abstract. It is facing a delivery-capable capital gap: the portion of required investment that lacks a repeatable, bankable, and scalable path from need → approval → capital → construction → cost recovery.

7.2 Affordability, Public Acceptance, and Political Durability

Long-term success depends on whether households experience electrification as reliable, predictable, and economically fair. This is not primarily a communications issue. It is a system design requirement.

Based on the investment envelope developed in Parts I and II, the reference system-wide impact of electrification-related infrastructure is approximately $500 per customer per year in steady state. This reflects:

- ~$225 per year for distribution enablement and local reinforcement
- ~$275 per year for transmission, generation, storage, and system integration

Using current averages, this implies:

- Current average household electricity bill: $1,400 per year
- Electrification-adjusted long-term bill: $1,900 per year
- Net increase: $500 per year

This represents a permanent structural change in household energy costs rather than a temporary adjustment.

7. From Constraint to Opportunity

7.2.1 This Is Political Material in Today's Ontario

A sustained increase of this magnitude interacts directly with current socio-economic pressures:

- Housing affordability remains the dominant financial stressor for most households. Rising mortgage, rent, and property tax burdens reduce tolerance for additional fixed charges.
- Food and essential cost increases over the past five years have reduced public confidence in long-term "savings" narratives. Customers prioritize immediate affordability over distant benefits.
- Household debt service remains elevated. A predictable $40 per month increase competes directly with transportation, childcare, and insurance costs.

Regional disparities are widening. Customers in constrained or high-growth areas will experience higher costs earlier, creating perceived inequity. Perceived cross-subsidization remains sensitive. Households without EVs or heat pumps may view network upgrades as paying for others' technology choices. Small business and industrial customers face parallel increases. This affects competitiveness, employment, and local economic confidence. Institutional trust is fragile. Long reliance on pilots, temporary rebates, and shifting timelines has reduced confidence in delivery capacity.

7.2.2 Implications for Public Acceptance

Public support will not be sustained through mitigation programs alone. It depends on:

- Clear explanation of why costs are rising
- Transparent linkage between spending and local reliability
- Predictable multi-year rate trajectories
- Visible reinvestment in communities
- Credible evidence of institutional coordination

Affordability is therefore inseparable from governance quality. Stable expectations reduce financing risk, political volatility, and long-term system cost.

Without this stability, cost recovery becomes more expensive, slower, and more contested.

8. Reform Pathways

Ontario has demonstrated the technical feasibility of electrification, flexibility, and digital coordination. The central challenge is no longer proof of concept. It is institutional execution at scale.

The transition requires coordinated changes to financial treatment, planning practice, approval pathways, and operational integration. Partial alignment is no longer sufficient. The purpose of reform is to convert validated tools into repeatable system capacity.

This requires, predictable cost recovery, integrated peak planning, programmatic deployment, applied system analytics, and portfolio-level accountability.

Delay now increases congestion costs, financing premiums, and reactive investment.

8. Reform Pathways

Table 28: Implementation Pathways and Institutional Actions for Delivery

Pathway	What Must Change (Plain Language)	Who Must Move	What "Done" Looks Like (Observable Output)	Near-term Action
A. Standard financial treatment for non-wires and enablement	Make flexibility and enablement financeable and repeatable	OEB + IESO + utilities	A standard set of recovery templates and contract forms used across LDCs and IESO programs	Publish/approve 2–3 standard templates and use them immediately in priority corridors
B. Integrated winter reliability planning across electricity + fuels	Stop planning peaks in silos	IESO + Enbridge + Hydro One + TSSA	Joint winter peak framework that explicitly models hybrid switching, reliability, and emergency conditions	Stand up a joint winter planning cycle and publish the first integrated winter reliability view
C. Shift from pilots to rollout programs	Replace "one-off" demos with programmatic deployment	Province + IESO + OEB + LDCs	A defined deployment pipeline (MW enabled, assets upgraded) rather than "pilot outcomes"	Convert the top proven pilots into 2–4 rollout programs with annual targets
D. Use-case data utilization (not more reporting)	Turn existing pilot/operational data into planning intelligence	Utilities + IESO	Standard EV/heating load shape models derived from observed data	Issue a province-wide analytical pack based on existing datasets; embed in DSP/regional planning
E. EV mobility and workplace charging planning	Treat EV load as mobile; plan employment nodes and corridors	IESO + LDCs + municipalities + MTO	Employment-node hosting plans and corridor charging plans linked to capital budgets	Identify top employment clusters; begin staged upgrades + pricing/control pilots that become templates
F. Programmatic procurement for flexibility and storage	Procure capacity and locational relief as infrastructure	IESO + OEB	Contracts tied to performance in defined peak windows; MW delivered becomes bankable	Launch targeted procurements in constrained zones with performance settlement and bankable terms
G. Cost allocation clarity for beneficiaries	Stop defaulting enablement costs onto municipalities by accident	OEB + municipalities + LDCs	Clear beneficiary-pay rules for large loads and readiness reservations	Implement a simple readiness/capacity reservation approach for high-impact connections
H. Public co-investment to cut financing costs	Use low-cost capital to reduce bill volatility and accelerate build	Province + CIB/GMF + utilities	A scaled co-investment platform with repeatable eligibility and performance covenants	Expand low-cost capital use for repeatable asset classes (automation, enablement, storage)
I. Sequencing discipline (deliverability first)	Build "where it unlocks capacity" first	IESO + Hydro One + LDCs	Published sequencing plan tied to MW enabled and congestion relief	Publish a 3-year "deliverability-first" build list aligned to peak corridors
J. Accountability without paralysis	Governance that enables fast correction rather than slow consensus	All institutions	Clear targets, public progress measures, course-correction authority	Adopt annual scorecards: MW enabled, connections cleared, congestion reduced, renewal rate maintained

8. Reform Pathways

8.1 Imperfect but Rapid Action

Ontario's institutions have been cautious in pursuing system-wide change. This caution was appropriate during early validation phases. It is now a constraint. Further delay in pursuit of perfect alignment will materially increase long-term cost and risk. Large infrastructure transitions do not succeed by eliminating error. They succeed by detecting and correcting error quickly.

A delivery-oriented posture requires accepting that:

- Some investments will be sequenced imperfectly
- Some cost-recovery mechanisms will require revision
- Some programs will underperform
- Some technologies will not scale as expected
- These outcomes are unavoidable

The governing question is therefore not whether mistakes will occur. It is whether institutions are structured to learn and adapt before constraints become structural.

A practical operating stance is:

- implement standardized templates quickly,
- deploy proven solutions in priority corridors,
- measure performance in real time,
- adjust recovery and procurement rules rapidly,
- scale what performs,
- and retire what does not.

8. Reform Pathways

Targeting "mostly right" at system level is economically superior to waiting for theoretical optimization. The cost of delayed action is compounding congestion, higher financing costs, deferred connections, and emergency operating measures. These costs are largely irreversible.

Disciplined speed is therefore a form of prudence. It reduces total lifecycle cost, preserves institutional credibility, and protects intergenerational equity.

8.2 Different Paths in Other Provinces

Provincial electrification strategies in Canada are diverging in their implied system scale, capital intensity, and institutional burden. Comparative analysis indicates that long-term outcomes are shaped not only by resource endowments, but by how demand, land use, and industrial development are integrated into infrastructure planning.

Recent modelling by Québec and emerging experience in British Columbia illustrate that high-electrification outcomes are not singular in design. System size, peak exposure, and financing burden are strongly influenced by institutional choices made early in the transition. Ontario's modelled pathways sit between these approaches, reflecting both structural constraints and policy choices.

8. Reform Pathways

Table 29: Comparative Demand and Capacity Pathways (2050 Reference Case)

Dimension	Québec – Sobriety	Québec – High Demand	BC (Current Path)	Ontario – Sobriety (Modelled)	Ontario – Current Trajectory
Population (M)	9.5	9.5	6.5	18.0	18.0
Manufacturing Index (2023=1.0)	0.9	1.3	1.1	1.2	1.5
System Scale Factor	1.0	1.4	1.3	2.2	2.7
Annual Demand (TWh)	235	345	210	380	460
New Supply Required (TWh)	111	221	140	155	215
New Domestic Generation (TWh)	35	120	95	70	140
Winter Peak (GW)	32	44	29	45	55
Storage Requirement (GW)	8	18	10	15	25
Transmission Intensity	Moderate	High	High (Corridors)	High	Very High
Distribution Reinforcement	Moderate	High	Moderate	High	Very High
Capital Intensity Index	0.7	1.2	1.0	1.0	1.4
Long-Term Rate Pressure	Low–Moderate	High	Moderate	Moderate	High

Comparative Provincial Electrification Pathways, table compiled by the author using publicly available provincial energy planning and outlook materials (Hydro-Québec 2023–2024; Régie de l'énergie du Québec 2023; BC Hydro Integrated Resource Planning materials 2023–2024; IESO 2023–2025; MEM 2023–2024)

8.2.1 Québec, British Columbia, and Ontario: Three System Archetypes

Québec's sobriety pathway limits system expansion by shaping demand upstream. Efficiency, land-use planning, and industrial optimization are treated as system resources rather than secondary policy objectives.

Structural features include:

- Integration of urban densification and transport planning into energy forecasting
- Systematic industrial efficiency and process optimization
- Freight modal shifts and logistics coordination
- Building standards that limit peak heating demand

These measures reduce both annual consumption and winter peak exposure before major infrastructure is committed. The system evolves primarily through renewal and targeted expansion rather than wholesale reconstruction.

As a result:

- New generation requirements remain limited
- Storage and transmission expansion is moderated
- Capital intensity remains comparatively low
- Long-term rate pressure is contained

Québec's experience demonstrates that decarbonization outcomes are extremely sensitive to early demand-shaping choices. System size is not an automatic consequence of electrification; it is a planning outcome.

8.2.2 Cross-Provincial Coordination as a Strategic Opportunity

The comparative analysis highlights that no province can fully optimize its electrification pathway in isolation. Québec's demand-structured system produces surplus clean energy and flexible capacity that can support neighbouring jurisdictions. British Columbia's hydro reservoirs provide seasonal balancing potential. Ontario's scale creates opportunities for market depth, technology deployment, and system innovation.

8. Reform Pathways

However, current interprovincial coordination remains limited and largely opportunistic. Enhanced collaboration could unlock material system value through:

- Coordinated capacity planning and reserve sharing
- Expanded firm interprovincial transmission
- Joint storage and balancing strategies
- Harmonized market and settlement frameworks
- Shared data and forecasting platforms
- Coordinated industrial siting and corridor development

Without such coordination, provinces are incentivized to overbuild independently, duplicating assets and increasing aggregate system costs. With coordination, Canada's major electricity systems can function as a partially integrated clean-energy platform, reducing peak exposure, improving capital efficiency, and strengthening reliability.

Taken together, provincial comparisons demonstrate that durable electrification depends not only on technological deployment, but on disciplined control of system scale. Jurisdictions that integrate demand, land use, and industrial policy into infrastructure planning consistently achieve lower capital intensity and greater institutional resilience. Those that do not face escalating costs, tighter delivery constraints, and declining financial flexibility.

9. Final Observations

Electrification represents one of the most significant infrastructure and economic development opportunities in Ontario’s modern history. Previous generations successfully delivered hydroelectric systems, nuclear fleets, urban transit, and continental-scale transmission networks under equally demanding conditions.

Today’s transition benefits from stronger institutions, deeper capital markets, advanced engineering capabilities, and unprecedented analytical tools. With coordinated leadership, transparent economics, and disciplined investment, Ontario is well positioned to succeed.

The challenges identified in this paper define the work ahead. They also illuminate a clear path forward: collaborative planning, smart financing, and sustained public trust.

The elephant in the room is now clearly visible. The opportunity lies in transforming it into a foundation for a more resilient, competitive, and inclusive energy system—built with confidence, foresight, and shared purpose.

Appendices

Appendices

This appendix is written so a municipal CFO, LDC planner, or provincial policy team can reproduce the math. It expands the earlier "headline" numbers into:

- low / medium / high electrification scenarios,
- explicit conversions from *Energy for Generations* (EfG) planning signals,
- stacked borrowing and debt-service math,
- and sensitivity tables for interest rates, amortization, timelines, and non-wires deferral.
- Debt-service uses level-payment amortization.
- References for all publicly available material.

Appendices

A0. Inputs and Assumptions

A0.1 EfG-derived Quantities

These are used as anchor points for conversion and scale checks:

- EV adoption: EfG states that by 2030 there will be more than one million EVs on Ontario's roads.
- LT2 procurement: EfG indicates LT2 is seeking up to 14 TWh/year of new energy, described as ~6,000 MW of "capacity equivalent," plus ~1,600 MW of additional capacity resources.
- Installed capacity growth: EfG indicates installed capacity could rise from ~37,200 MW today to 65,000+ MW by 2050.
- Pumped storage: EfG describes advancing pre-development of a pumped storage project up to ~1,000 MW.
- Northern transfer unlocks: EfG describes northern transmission projects that together can add up to ~900 MW of incremental transfer capacity.

A0.2 Assumptions – Open for Debate

These are intentionally transparent and adjustable:

- Baseline winter peak today: 24 GW (used for scale only).
- Heating peak thermal demand under full displacement: 121 GW (th) (from the MEM notes you provided).
- Heat pump COP under design conditions: 3.0.
- Heat pump COP during extreme cold: 1.3–1.8 (degradation + backup resistance contribution).
- Home L2 charging power: 7 kW (typical)
- EV coincidence during winter peak window (unmanaged): 20–40%
- Renewables to Storage ratio up to 3:1 (nameplate renewables+storage+enabling capacity per 1 MW firm peak contribution).

Appendices

A1. EfG Conversions (Energy ↔ Average Power ↔ Planning Meaning)

A1.1 LT2: 14 TWh/year converted to average MW

Step 1: Convert annual energy to average power

- 14 TWh/year = 14,000,000 MWh/year
- Average MW = 14,000,000 / 8,760 = **~1,598 MW average**

Step 2: Interpret the "~6,000 MW capacity equivalent" statement

If 6,000 MW produces 14 TWh/year, the implied capacity factor is:

- CF = 1,598 / 6,000 = **~26.6%**

Planning meaning: "6,000 MW equivalent" is a nameplate framing. Reliability planning is still governed by coincidence with peak and deliverability.

A1.2 Installed capacity growth: 37,200 MW to 65,000+ MW

- ΔCapacity = 65,000 − 37,200 = **27,800 MW** additional nameplate installed capacity

Planning meaning: 27.8 GW of nameplate does not imply 27.8 GW of firm winter peak capability, especially if a significant share is variable.

A2. Heating Electrification: Converting Thermal Peaks into Electrical Peaks

EfG's demand growth framing is often **interpreted through annual energy. Heating electrification breaks that framing: it is fundamentally a peak capacity problem**.

A2.1 Core conversion

Let:

- Q_peak = peak thermal heating demand (GW_th)
- COP_peak = coefficient of performance at peak conditions
- E_peak = electrical input required (GW_e)

Then:

- **E_peak = Q_peak / COP_peak**

A2.2 Electrical peak equivalents for 121 GW heating peak

Using Q_peak = 121 GW_th:

Peak COP assumption	Electrical peak required (GW_e)	Interpretation
3.0	40.3	best-case, mild conditions
2.5	48.4	common planning COP
2.0	60.5	cold-weather degradation
1.5	80.7	extreme cold + backup contribution
1.3	93.1	stress case

Key point: even if average seasonal COP is strong, the grid must be sized for **the peak COP**.

A2.3 Partial displacement scenarios (low / medium / high)

Let f = fraction of peak heating demand that is actually displaced from natural gas in the scenario horizon.

- $E_{peak,scenario} = f \times (Q_{peak} / COP_{peak})$

Using COP_{peak} = 1.5 (winter stress planning) and Q_{peak} = 121 GW_{th}:

Scenario	f (heating displaced)	Heating-driven electrical peak (GW_e)
Low	25%	20.2
Medium	50%	40.4
High	75%	60.5

Even the medium case produces a heating-driven peak layer comparable to or greater than Ontario's entire current system peak.

Appendices

A3. EV Electrification: Energy is Manageable; Peak Is Not

EfG indicates >1M EVs by 2030. Energy is not the main constraint; coincidence is.

A3.1 Annual energy estimate (order-of-magnitude)

Assume:

- kWh/EV-year = 3,000

Then 1,000,000 EVs add:

- 3.0 TWh/year (matches the scale used in the main paper).

A3.2 Peak coincidence estimate

Let:

- N = number of EVs
- P = average charging power during the coincident window (kW)
- c = coincidence fraction (0–1)

Peak power (GW) ≈ N × P × c / 1,000,000

Using N = 1,000,000 and P = 10 kW:

Coincidence (c)	EV peaks add (GW)
0.20	1.4
0.30	2.1
0.40	2.8

Planning meaning: Without managed charging, EVs can add 5 GW in the same winter peak windows when heating stress occurs.

Appendices

A4. Compound Peak Overlay (Heating + EV + Base)

This is the practical issue for LDCs: peaks stack locally.

Illustrative overlay (not a forecast):

- Base winter peak: 25 GW
- EV layer: 2 GW (30% coincidence)
- Heating layer: 40 GW (50% displacement at COP_peak 1.5)

Compound peak ≈ 25 + 2 + 40 = 67 GW

Interpretation: EfG's "~75% energy growth by mid-century" does not communicate the peak reality that local infrastructure must be designed for.

A5. Storage Scaling: Why 1,000 MW Is Material but Not Sufficient

EfG references a proposed pumped storage project up to ~1,000 MW.

A5.1 Power scale comparison

Reference quantity	Value	What 1,000 MW represents
Today's peak (scale check)	~25 GW	~4%
Illustrative compound peak	~67 GW	~1.5%
Heating layer alone (medium example)	~40 GW	~2.5%

A5.2 Energy duration

Pumped storage "MW" is discharging power; the grid value also depends on duration (MWh).

- If a 1,000 MW facility provided 8 hours, it would be 8,000 MWh (8 GWh).
- Heating-driven stress events can persist for days.

Implication: Without long-duration/seasonal balancing (or retained hybrid backup), the system must overbuild capacity for rare peaks.

Appendices

A6. Transmission Unlocking and Stranded Hydro: Deliverability Has a Cost

EfG identifies northern transmission projects that collectively add **up to ~900 MW** of transfer capacity.

A6.1 Why "900 MW unlocked" does not equal "900 MW available at the meter"

Unlocking deliverable capacity typically requires:

- corridors + stations,
- protection upgrades,
- reactive power/stability equipment,
- interconnection capacity and system reinforcement.

These enabling costs can be substantial and are often not visible in public "project budget" summaries.

A6.2 Stranded capacity estimate (planning-order)

Based on the MEM notes and common congestion/curtailment patterns, a conservative working range used in the paper is:

- ~5 GW stranded today, rising to ~7 GW by the 2030s without further expansion.

Important: This is a planning estimate to bound the discussion. A proper value requires publishing capacity maps + curtailment + interconnection queues (a key recommendation).

A6.3 Enabling cost adder (de-stranding premium)

To reflect the "additional cost to de-strand," this appendix explicitly carries an enabling line item in scenario totals (see A8). The core point is:

- Stranded generation is not free capacity.
- Making it deliverable adds incremental capital that must be financed.

A7. Reconductoring: Capacity Bridge, not a Free Lunch

EfG highlights reconductoring (e.g., Orangeville–Barrie) as a way to make better use of existing rights-of-way.

A practical lifecycle view must account for:

- thermal fatigue and loading effects,
- tower/insulator mechanical margins,
- protection/monitoring modernization,
- increased maintenance/inspection.

Planning takeaway: reconductoring can be excellent value, but aggressive utilization can increase lifecycle O&M and may shorten remaining life unless structural upgrades are bundled.

Appendices

A8. Capital Requirement Scenarios

Because your feedback is correct: the earlier appendix did not reflect the full manipulation needed to compare “EfG system intent” to “municipal/LDC finance reality.” The scenario tables below make the buckets explicit.

We separate capital into three buckets because each has different governance and financing pathways:

- Distribution system upgrades (LDC capex)
- Enabling / de-stranding investments (transmission, substations, protection, interconnection, reinforcement)
- Storage & integration (utility-scale storage, grid-forming equipment, control systems, integration)

Five-year planning envelopes

Scenario	Distribution (B$)	Enabling / de-stranding (B$)	Storage & integration (B$)	Total required T (B$)
Low	80	5	10	95
Medium	120	10	20	150
High	160	20	40	220

These totals are designed to be consistent with the paper’s argument: once enabling and storage are explicitly priced, the “distribution-only” story understates the all-in system burden.

Appendices

A9. Baseline Capital Capacity and Funding Gap

Baseline sector capacity used in the paper:

- Current LDC capital investment ≈ **$2.5B/year**
- Over 5 years: **B = 12.5B**

Gap definition:

- **G = max (T – B, 0)**

Scenario	T (B$)	B (B$)	Gap G (B$)	Annual incremental borrowing I = G/5 (B$/yr)
Low	95	12.5	82.5	16.5
Medium	150	12.5	137.5	27.5
High	220	12.5	207.5	41.5

Appendices

A10. Debt Service (ADF) and Year-5 Stacked Debt Service

A10.1 Debt service factor

ADF formula

- ADF = r(1+r) ^n / ((1+r) ^n – 1)

Annual debt service

- DS = P × ADF

ADF table

Amortization	4%	5%	6%	7%
20 years	7.36%	8.02%	8.72%	9.44%
30 years	5.78%	6.51%	7.26%	8.06%
40 years	5.05%	5.83%	6.65%	7.50%

A10.3 Stacked debt service

If borrowing is spread evenly across five years, then by Year 5 there are five equal tranches outstanding.

Define:

- G = total gap financed by debt over the horizon (B$)
- H = horizon (years) (here, 5)
- I = annual borrowing = G / H (B$/yr)
- ADF = annual debt service factor (from A10.2)

Then:

- Debt service per tranche (annual payment) = I × ADF
- Year-5 stacked annual debt service (five tranches) = H × I × ADF
- Since H × I = G, a compact form is:
  - DS_year5 = G × ADF
    (valid when tranches are equal and we are at Year H)

Compute DS_year5 for each scenario (30-year amortization) Using ADF (30y) from A10.2:

- 4% → 5.78%
- 5% → 6.51%
- 6% → 7.26%
- 7% → 8.06%

Recall gaps from A9:

- Low: G = 82.5B
- Medium: G = 137.5B
- High: G = 207.5B

Now compute DS_year5 = G × ADF:

Scenario	DS_year5 @ 4% (B$/yr)	DS_year5 @ 5% (B$/yr)	DS_year5 @ 6% (B$/yr)	DS_year5 @ 7% (B$/yr)
Low (G=82.5)	4.77	5.37	5.99	6.65
Medium (G=137.5)	7.95	8.94	9.99	11.08
High (G=207.5)	12.00	13.50	15.07	16.72

Appendices

Worked example (Medium scenario @ 5%, 30-year)

1. Gap financed: G = 137.5B
2. ADF (5%, 30y) = 6.51% = 0.0651
3. DS_year5 = 137.5 × 0.0651 = 8.95B/year
   (rounding explains 8.94 vs 8.95)

Interpretation: By Year 5, if the gap is debt-financed and amortized over 30 years at 5%, the electrification-driven *incremental* annual payment obligation is roughly $9B/year, *before* any further increases from higher rates, accelerated schedules, or additional enabling investments beyond the scenario bucket.

Compare 20-year vs 30-year amortization (rate shock vs total cost)
Using ADF (20y) from A10.2:

- 4% → 7.36%
- 5% → 8.02%
- 6% → 8.72%
- 7% → 9.44%

Medium scenario (G=137.5B):

Amortization	4%	5%	6%	7%
20 years	10.12	11.03	11.99	12.98
30 years	7.95	8.94	9.99	11.08

Meaning: Longer amortization reduces near-term rate pressure (annual payments) but increases total interest paid over the life of the debt. Municipal and LDC affordability debates tend to focus on annual bill impacts, which makes the amortization choice politically and regulatorily material.

What DS_year5 is (and is not)

- DS_year5 is **not** total provincial electricity-system cost.
- DS_year5 is **not** total municipal/LDC debt service.
- DS_year5 is the **incremental annual payment obligation** created by the *gap-financed portion* of electrification-driven capital under the stated scenario and financing terms.

It is, however, the right metric for:

- rate shock risk and bill impact framing
- municipal Annual Repayment Limit pressure
- credit rating stress testing
- affordability constraints for provincial and local leaders

A11. Non-Wire / GIF Deferral Sensitivity

Non-wires solutions, managed charging, thermal storage, and scaled GIF replication can defer a portion of wires capex. This is a deferral, not elimination.
Stress test: 20% deferral of the gap-financed portion

For the medium scenario:

- T = 150B, B = 12.5B, G = 137.5B
- Deferral = 0.20×137.5B = 27.5B
- Revised gap G_eff = 137.5 − 27.5 = 110.0B

Year-5 DS (5%, 30y):

- DS_year5 ≈ 5 × (110/5) × 6.51% = ~7.15B/year

Interpretation: Deferral helps meaningfully but does not close the gap.

A12. Timeline Sensitivity (5 vs 10 vs 15 Years)

Spreading the gap over more years reduces annual borrowing intensity but increases delivery risk when load growth is front-loaded.

For the medium scenario gap (G = 137.5B):

Horizon	Annual incremental borrowing (B$/yr)	Directional implication
5 years	27.5	highest near-term rate shock
10 years	13.75	lower shock, longer program
15 years	9.17	lowest shock, highest timing risk

Appendices

A.13 Captured Nuclear Fleet Refurbishment Plan

Bucket	Item	MW (Full)	Energy (TWh/yr)	Outage Start	Outage End	Ramp Start	Full MW By
Refurb outage	Darlington G2	**-935**	—	2016	2020	—	—
Refurb outage	Darlington G3	**-935**	—	2019	2023	—	—
Refurb outage	Darlington G1	**-935**	—	2021	2024	—	—
Refurb outage	Darlington G4	**-935**	—	2022	2026	—	—
Refurb outage	Bruce G6	**-750**	—	2020	2024	—	—
Refurb outage	Bruce G3	**-750**	—	2022	2026	—	—
Refurb outage	Bruce G4	**-750**	—	2024	2027	—	—
Refurb outage	Bruce G5	**-750**	—	2026	2030	—	—
Refurb outage	Bruce G7	**-750**	—	2028	2032	—	—
Refurb outage	Bruce G8	**-750**	—	2030	2034	—	—
Refurb outage	Pickering G5	**-515**	—	2027	2030	—	—
Refurb outage	Pickering G6	**-515**	—	2027	2032	—	—
Refurb outage	Pickering G7	**-515**	—	2027	2033	—	—
Refurb outage	Pickering G8	**-515**	—	2027	2034	—	—
Life extension	Bruce Unit 1 LE (outage)	**-1000**	—	2029	2031	—	—
Life extension	Bruce Unit 1 LE (return/uprate)	**1300**	—	—	—	2031	2033
Life extension	Bruce Unit 2 LE (outage)	**-1000**	—	2030	2032	—	—
Life extension	Bruce Unit 2 LE (return/uprate)	**1300**	—	—	—	2032	2034
New large nuclear	Bruce New Unit 1	**1200**	—	~2031	—	2031	2033
New large nuclear	Bruce New Unit 2	**1200**	—	~2032	—	2032	2034
New large nuclear	Bruce New Unit 3	**1200**	—	~2033	—	2033	2035
New large nuclear	Bruce New Unit 4	**1200**	—	~2034	—	2034	2036
New large nuclear	Wesleyville New Unit 1	**1200**	—	~2033	—	2033	2035
New large nuclear	Wesleyville New Unit 2	**1200**	—	~2034	—	2034	2036
New large nuclear	Wesleyville New Unit 3	**1200**	—	~2035	—	2035	2037
New large nuclear	Wesleyville New Unit 4	**1200**	—	~2036	—	2036	2038
LT2 intake	LT2 Window 1 (Capacity)	**600**	—	**2025 Q4**	**2030 Q2**	2030	2032

Bucket	Item	MW (Full)	Energy (TWh/yr)	Outage Start	Outage End	Ramp Start	Full MW By
LT2 intake	LT2 Window 1 (Energy)	—	**3**	**2025 Q4**	**2030 Q2**	2030	2032
LT2 intake	LT2 Window 2	**400**	**+1 to +3**	**2026 Q3**	**2031 Q2**	2031	2033
LT2 intake	LT2 Window 3	**300**	**+2 to +4**	**2027 Q3**	**2032 Q2**	2032	2034
LT2 intake	LT2 Window 4	**300**	**+2 to +4**	**2028 Q3**	**2033 Q2**	2033	2035
LT3 intake (scenario placeholder)	LT3 Window 1	**600**	3	*(assume)* 2030 Q4	*(assume)* 2035 Q2	2035	2037
LT3 intake (scenario placeholder)	LT3 Window 2	**400**	+1 to +3	*(assume)* 2031 Q3	*(assume)* 2036 Q2	2036	2038
LT3 intake (scenario placeholder)	LT3 Window 3	**300**	+2 to +4	*(assume)* 2032 Q3	*(assume)* 2037 Q2	2037	2039
LT3 intake (scenario placeholder)	LT3 Window 4	**300**	+2 to +4	*(assume)* 2033 Q3	*(assume)* 2038 Q2	2038	2040
LT4 intake (scenario placeholder)	LT4 Window 1	**600**	3	*(assume)* 2035 Q4	*(assume)* 2040 Q2	2040	2042
LT4 intake (scenario placeholder)	LT4 Window 2	**400**	+1 to +3	*(assume)* 2036 Q3	*(assume)* 2041 Q2	2041	2043
LT4 intake (scenario placeholder)	LT4 Window 3	**300**	+2 to +4	*(assume)* 2037 Q3	*(assume)* 2042 Q2	2042	2044
LT4 intake (scenario placeholder)	LT4 Window 4	**300**	+2 to +4	*(assume)* 2038 Q3	*(assume)* 2043 Q2	2043	2045

Appendices

A.14 Quebec and Ontario Comparative Grid (From Hydro Quebec numbers)

Comparative Demand and Supply Pathways (2050 Reference Case, LeDevoir Jan 31, 2026)

Dimension	Québec – Sobriety Path	Québec – High-Demand Path	Ontario – Sobriety Path (Modeled)	Ontario – Current Trajectory
Population (2050)	~9.5 M	~9.5 M	~18.0 M	~18.0 M
Manufacturing Output Index (2023=1.0)	0.9	1.3	1.2	1.5
Relative System Scale Factor*	1.0	1.4	2.2	2.7
Policy Orientation	Demand restraint + electrification	Industrial growth	Managed electrification	Supply-led electrification
Structural Demand Management	High	Low	High	Low
Annual Electricity Demand (TWh/yr)	235	345	380	460
New Electricity Supply (TWh/yr)	111	221	155	215
New Domestic Generation (TWh/yr)	35	120	70	140
Imports / Interties (TWh/yr)	33	20	30	15
Efficiency & Demand Reduction (TWh/yr)	43	25	55	25
Winter Peak Demand (GW)	32	44	45	55
Heating Electrification Share	Moderate	High	Managed	High
EV Penetration (Fleet)	High, Managed	Very High	High, Managed	Very High
Storage Requirement (GW eq.)	8	18	15	25
Transmission Expansion Intensity	Moderate	High	High	Very High
Distribution Reinforcement	Moderate	High	High	Very High
Capital Intensity Index**	0.7	1.2	1.0	1.4
Long-Term Rate Pressure	Low–Moderate	High	Moderate	High

Appendices

Notes on Multipliers

* **Relative System Scale Factor**

This reflects combined effects of:

- Population size
- Industrial intensity
- Data centre / digital load
- Export orientation

Formula (simplified for planning use):

Scale Factor ≈ (Population Ratio × 0.6) + (Manufacturing Index × 0.4)

Using current projections:

- Ontario population ≈ 1.9× Québec
- Ontario manufacturing ≈ 1.3–1.5× Québec

Result:

- Ontario requires ~2.2× infrastructure under sobriety
- ~2.7× under supply-led growth

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