PWU Compendium

Tab 1

Appendix B Incremental Capital Module Whitby Smart Grid & Sustainable Brooklin, Pages 41-42 of 56

4.1.2. Sustainable Brooklin

Elexicon identified 4 alternatives with respect to the Sustainable Brooklin Project:

1. Extend feeders from Whitby TS DESN 1 to serve the North Brooklin area, with funding through this ICM, and with the WSG enabling DER integration capability (**preferred**);
2. Proceed with system enhancement by extending the feeders from Whitby TS DESN 1 to serve the North Brooklin area with developers paying a capital contribution as per the DSC, with the extension of the duration of capital contribution period from 5 years to 15 years;
3. Build a new TS to serve the North Brooklin area, funded by Elexicon's existing rates; and,
4. Utilize existing 44kV feeders to the North Brooklin area, funded by Elexicon's existing rates.

Elexicon determined that the prudent option is to proceed with the proposed Brooklin Line from Whitby TS to North Brooklin, funded via this ICM application, while the WSG enables DER integration capabilities for anticipated DER uptake in North Brooklin.

Option 1 is the preferred option for Sustainable Brooklin. Participation by the Developers in the design of Elexicon's distribution system to facilitate the development of a DER-and-EV-Ready community is a highly innovative and unique opportunity. Electing this option would result in over 10,000 concentrated residential units which could have been future-proofed for DERs and EVs, being constructed status quo; meaning future uptake of these technologies would require costly retrofits paid for by customers.

Option 2 was rejected as suboptimal for two reasons. First, absent the DSC section 3.2 exemption, the Developers would otherwise be required to pay a capital contribution for construction of the Brooklin Line and the developers would no longer be willing to commit to invest in building DER and EV ready homes across all of North Brooklin. This will likely result in lower DER and EV penetration rates, and may be a lost opportunity for Elexicon, the OEB and other LDCs to observe and gather information about the ICM Projects to defer or avoid future material capital expenditures through greater uptake of DERs.

Option 3 was rejected for two reasons. First, development and construction of a TS takes considerable time (measured in years), especially given the supply chain issues that have resulted from COVID-19, and would not bring capacity in time to serve the immediate need for power to facilitate the construction of new homes and businesses in the Brooklin area. Second, a new TS is not the most cost-effective option for ratepayers when compared with the Brooklin Line. Elexicon has capacity available at Whitby TS DESN 1 that can be brought to the Brooklin area via the Brooklin Line, which is approximately half the cost of a new TS.

Option 4 was also rejected. Naturally, one of the immediate options evaluated by Elexicon was to provide capacity from existing assets proximate to North Brooklin; namely existing 44kV feeders in the area. Typically, Elexicon reserves 44kV feeder capacity for commercial and industrial customers that do not require a substation step-down to 13.8kV as residential customers do. In this case, while capacity does exist on local 44kV feeders today, this capacity has already been reserved for known commercial and industrial load under development south of the 407 highway. This option was dismissed and not subject to detailed costing as it is not technically feasible.

Tab 2

Appendix B-2 Sustainable Brooklin Business Case, Pages 18-26 of 37

4. Project Alternatives

4.1. Alternative Descriptions and Comparative Analysis

Option	1	2	3	4
Scenario Description	Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area, with funding through this ICM, and with the Whitby Smart Grid project enabling DER integration capability	Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area with the developer paying a capital contribution as per the DSC, with the extension of the duration of Capital Contribution period from 5	Build a new TS to serve the North Brooklin area using Elexicon's existing rate base	Utilize existing 44kV feeders to the North Brooklin area using Elexicon's existing rate base.

Option	**1**	**2**	**3**	**4**
		years to 15 years.		
Project Scope	Elexicon will install two new 27.6kV feeders and the associated assets that will connect the Brooklin development to the Whitby TS.	This is the same as Option 1 with the difference that the developer would provide a capital contribution but rather than the normal 5-year contribution period, it would be extended to 15 years.	A brand new TS would be built to serve the additional capacity from the Brooklin development. This would be funded through the existing rate base.	Utilize existing capacity on the two 44kV feeders at Whitby TS that are typically used for commercial and industrial loads and step down the 13.8kV to serve the residential load. This would be funded through the existing rate base.

Option	**1**	**2**	**3**	**4**
Total Gross Capex	$26.6 MM	$35.5 MM[9]	~$50 MM	N/A
Project Pros	This solution provides a connection that meets the developer's timeline. The two new 27.6kV feeders can directly supply the development, when compared to option 4 where the voltage would have to be stepped down from 44kV to 13.8kV. In addition, the two 27.6kV feeders have a combined	Developer must pay a capital contribution, therefore reducing the impact of the cost on the rates.	N/A	N/A

[9] It would be expected that the Capital Contribution would be cover the full amount.

Option	1	2	3	4
	capacity that matches the anticipated capacity from the North Brooklin development. Through the project, Elexicon can maximize DER and EV uptake in an expanding community, avoiding costly DER or EV retrofits post-construction. This solution and the associated funding will allow developers to			

Option	**1**	**2**	**3**	**4**
	fund and construct DER ready homes, thus reducing costs for customers.			
Project Cons	An exemption from DSC 3.2 requirements is needed to allow the developers to be exempt from paying a capital contribution. The rationale and justification for this is included in section 5 of this ICM application.	If the developer must make a capital contribution, even extended out to 15 years, it is likely they will not build DER and EV ready homes. Given the high and increasing cost of residential development and construction, the developers	This is not the preferred option as building a new TS station is a costly and timely undertaking. A new TS typically take a minimum of 5 years to build. To meet the timings of the Brooklin developers, the TS would need be	This is not the preferred option. Though the two feeders currently have capacity, they are planned for a known commercial and industrial load south of the 407 highway. Elexicon's planning

Option	1	2	3	4
		would be otherwise unlikely to assume the business risk of constructing DER-and-EV-ready homes in North Brooklin. This outcome is highly sub-optimal, as the costs and challenges of DER and EV retrofits are significantly greater than inclusion of these technologies at the design and construction phases.	completed by the end of 2023 which is not possible in the current market. In addition, the cost of the delivering a new TS station is the equivalent of Elexicon typical annual capital budget. If existing rate base were to be used, this would mean Elexicon would have to defer and cancel a considerable number of discretionary	practice is to typically reserve the 44kV feeders for commercial and industrial load as no stepdown of the voltage is required. Residential customers are typically fed off either a 13.6kV or 27.6kV system. If a 44kV feeder is used, it would require conversion to 13.8kV which is a costly

Option	1	2	3	4
		Failing to incorporate these technologies into front-end development will result in a community of North Brooklin that has low or average levels of DER and EV uptake.	projects to be able to deliver this project. This is unfeasible and would put at risk the safety and reliability of Elexicon's system.	process as a new substation would have to be installed in addition to other associated equipment. Y implementing a 27.6kV feeder, this negates the need to have a substation to step down the voltage further.
Project Economics	The cost is the lowest capital cost and will deliver many benefits for customers now	Whilst the cost of project overall will be similar to the preferred option, this option will not deliver the	The cost of a new substation is around $5MM higher than the preferred option and will	This option has not been costed as it is not a technically feasible option to

Option	1	2	3	4
	and in the future.	objective of building DER ready homes that can be integrated into Elexicon's system. This would therefore have a detrimental impact on enabling a Grid of the Future.	not enable the benefits of the proposed development in the required timelines.	proceed with for costing.
Customer Feedback	Elexicon has engaged with a coordinated group of Developers whose development lands in North Brooklin are largely contiguous. To accomplish the objectives of Sustainable Brooklin, Elexicon must enable a level of project certainty sufficient to secure Developer commitments prior to near-and-mid-term construction of new homes. Appendix B-6 includes the letters of support where the Brooklin Developers and Town of Whitby support for the project can be found.			
Other Constraining Factors	The developer has a timeline of delivering the 1st phase of homes by Q3, 2023, and as	Approval of a change to capital contributions would have to be sought, which	A new TS takes a minimum of five years to build which does not meet	It is Elexicon's planning practice to allocate 44kV feeder

Option	**1**	**2**	**3**	**4**
	such Elexicon needs to install a solution that meets this timeline.	has typically been rejected in the past by the OEB. If the developer must pay a capital contribution, they will not build DER and EV ready properties.	the timeline of the developer.	capacity to commercial and industrial growth. This might lead to capacity constraints in the future and put system contingency at risk if Brooklin residential development is served by the 44kV.
Preferred Alternative	**X**			

4.2. Rationale for Preferred Alternative & Consequences of Inaction

Tab 3

Interrogatory Staff-32

Elexicon Energy Inc.

Answer to Interrogatory from

OEB Staff

Interrogatory STAFF-32:

Distribution System Code Exemption

Ref. 1: Appendix B-2 Sustainable Brooklin Business Case, pp. 18-25 of 37

On p. 19 of Appendix B-2 Elexicon describes the same "Project Scope" for the Brooklin Line under Option 1 (DSC exemption) and Option 2 (no DSC exemption), i.e., "…two new 27.6kV feeders and the associated assets that will connect the Brooklin development to the Whitby TS". On p. 20 of Appendix B-2, Elexicon identifies the "Total Gross Capex" of the Brooklin Line as $26.6 million for Option 1 and $35.5 million for Option 2.

a) Section 3.2.4 of the DSC states that a customer's contribution "shall be equal to that customer's share of the difference between the present value of the projected capital costs and on-going maintenance costs for the facilities and the present value of the projected revenue for distribution services provided by those facilities". Please explain why 'Total Gross Capex' is higher for Option 2 than for Option 1.

On p. 25 of Appendix B-2, Elexicon states in relation to Option 2 (no DSC exemption) that "Approval of a change to capital contributions would have to be sought, which has typically been rejected in the past by the OEB."

b) Please confirm that the "change" referred to is "the extension of the duration of Capital Contribution period from 5 years to 15 years" as stated under 'Option 2' on pp. 18-19 of Appendix B-2.

Response:

a) This is an error. The cost in Option 2 would be the same as Option 1, $26.6 million.

b) Yes, that is correct.

Tab 4

Appendix B-4 METSCO Forecast,

Page 24 of 35

6 Non-Wires Alternatives

Non-wires alternatives for capacity upgrades including customer rooftop solar and the combination of rooftop solar with a battery energy storage system ("BESS"). Specifically, the new developments in North Brooklin will include rough-ins enabling customers to install rooftop solar and BESS if they choose to (and electric vehicles, although vehicle-to-grid capacity relief is not explored in this report). Assumptions made for specifications and performance of the rooftop solar panels and battery storage are listed below.

Assumptions:

1. Nameplate rating of rooftop solar panel: 10 kW.
2. Nameplate rating of battery storage: 10 kWh.
3. Firm capacity of rooftop solar without BESS in summer: 33%.
4. Firm capacity of rooftop solar without BESS in winter: 0%.
5. Firm capacity of rooftop solar with BESS (summer and winter): 100%.

Since the Brooklin Low Scenario is the most conservative of the three, the non-wires alternatives are evaluated based on this scenario to assess feasibility. The total Distributed Energy Resource ("DER") capacity required was calculated for one-year, three-year and five-year periods and used in conjunction with the above assumptions to determine the DER penetration required among the North Brooklin developments to defer the excess load.

Table 15 shows the estimated DER penetration required for deferral based on the number of DER connections required and total expected customers from new Brooklin development for the given time periods. Three options of rooftop solar only, rooftop solar with BESS, and mix of 50% rooftop solar only and 50% rooftop solar with BESS.

Table 15: DER Penetration Required for Excess Load Deferral – Brooklin Low Scenario

	DER Penetration Required (% and # of units)		
Deferral Period	Rooftop Solar	50-50 Mixed Infrastructure	Rooftop Solar with BESS
1-Year	36% - 3294 units	18% - 1647 units	12% -1098 units
3-Year	N/A	58% - 6158 units	39% - 4105 units
5-Year	N/A	79% - 9146 units	53% - 6098 units

Rooftop solar alone cannot reliably defer capacity constraints beyond one year since it is not dispatchable without an associated BESS. The mix of 50% rooftop solar and 50% rooftop solar with BESS can possibly defer investment for three years but the 79% penetration needed for a five-year deferral is not reasonable to expect. Rooftop solar with BESS across the system provides the greatest potential to defer investment across each deferral period.

Since these DERs are customer-owned, Elexicon has no control over their implementation and will need to monitor installation trends in the future. Deferral of future capacity investment needs in the area can

Tab 5

Ontario's Distributed Energy Resources (DER) Potential Study, Section 6 excerpt

Pages 57 to 74 of 90

Ontario's Distributed Energy Resources (DER) Potential Study

Volume I: Results & Recommendations

September 28, 2022

Prepared for:

ieso
Connecting Today.
Powering Tomorrow.

6. Achievable Potential

The achievable potential represents the expected contribution of DERs towards Ontario's system needs over the next decade, considering real-world factors that influence the uptake of these technologies (e.g. customer economics, technology familiarity, etc.).

Similar to the market-wide economic potential, the achievable potential assessment applies all DERs to the system - simultaneously capturing the interactive effects and competition among measures. Moreover, all measures that present a viable value proposition to a potential DER investor or customer are included in the achievable potential assessment, regardless of whether they pass the TRC cost-effectiveness screen. As a result, the achievable potential results yield a more diverse mix of measures. A detailed description of the achievable potential modeling approach is described in **Appendix E. Achievable Potential Methodology.**

The achievable potential explores the degree to which DERs can contribute to system needs, as well as the mix of DERs that would be expected to be installed system wide over the next 10 years. **The achievable potential results are expressed primarily in terms of DER contribution to system capacity (GW) by 2032, with the magnitude of the system capacity needs being driven by the summer peak demand event in each year.** The system capacity contribution for a given DER is defined as the average capacity contribution, or demand reduction, that the DER can contribute over a four-hour summer peak demand event window. Additional metrics related to other DER value streams are included where relevant, and detailed results with additional metrics (e.g. nameplate capacity, winter peak demand reductions, energy generation (kWh) contributions, avoided carbon emissions, etc.) can be found in the appendices. Interpretation of the achievable potential results should take into consideration the caveats outlined in the call-out box.

ACHIEVABLE POTENTIAL CONSIDERATIONS

- To avoid double-counting, **existing DERs are excluded from the achievable potential**. We used the APO's reacquisition scenario as a basis for existing DERs, assuming that they will continue to operate after the end of their contractual lifetime.
- The achievable potential **is based on the adoption of DERs (including adoption driven by NEM, rates, or the Industrial Conservation Initiative[42]) and the participation of those DERs in the IAMs, which are driven by the actual revenues and benefits available to customers under each scenario, as opposed to the system value identified in the economic potential.**
- Achievable potential is **not exclusively a subset of economic potential** as some DERs may still offer customers a value proposition regardless of their system TRC (e.g. BTM Solar).
- **BTM solar resources are assumed to be primarily compensated through net-metering**, and not direct market participation.
- **DR measures are modeled as an aggregated market resource** with the assumption that aggregators would provide customers with a participation / performance incentive equivalent to a percentage of the market revenues received, varying by scenario.

[42] The Industrial Conservation Initiative (ICI) program incentivizes eligible industrial and commercial customers to reduce their demand during peak periods. Customers who participate in the ICI pay a Global Adjustment based on their percentage contribution to the top five peak hours over a 12-month period.

6.1 Summary

Figure 6-1 highlights the forecasted summer system capacity that DERs are expected to contribute to by 2032. Under BAU, DERs are projected to contribute to 1.3 GW of summer capacity by 2032 (equivalent to a 5% reduction in the projected summer peak demand), which represents 7 GW of DER nameplate capacity.[43] Considering the assumed market, technology and policy changes under BAU+, DERs are forecasted to contribute to 2.2 GW of capacity by 2032 (equivalent to a 7% reduction in the projected system peak demand), and under the Accelerated scenario DERs are projected to contribute 4.3 GW (equivalent to a 14% reduction in the forecasted summer peak).

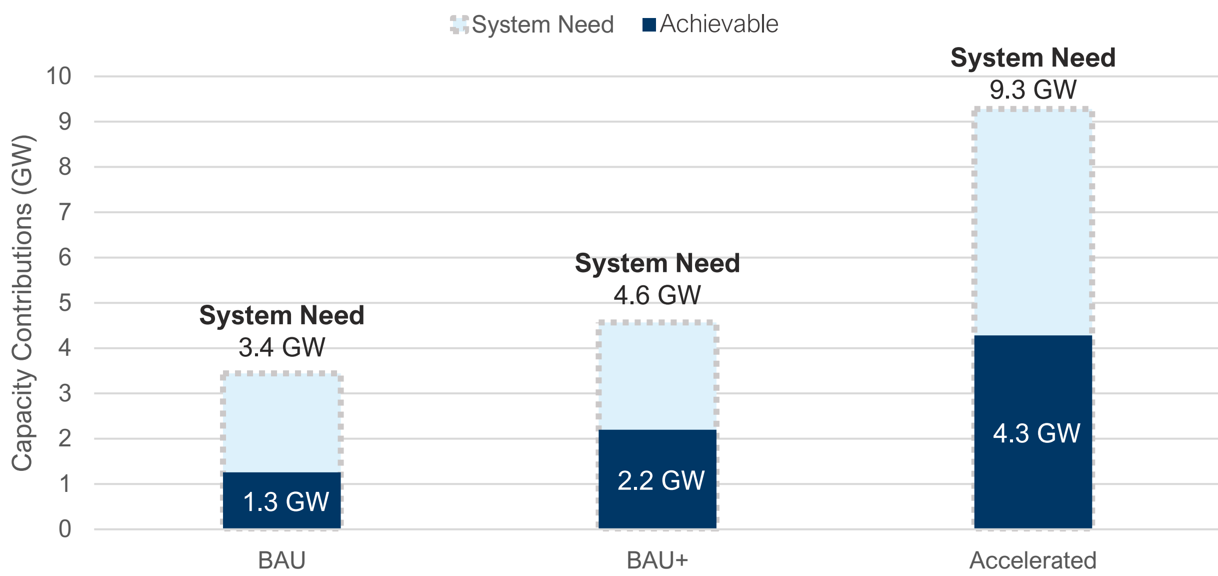
DER nameplate capacity increases to 13 GW and 25 GW in 2032 under the BAU+ and Accelerated scenario respectively. Similar to the trends observed in the Technical and Economic potentials, the DER potentials to contribute to winter peak capacity needs are somewhat lower than the summer potentials, as is illustrated in Figure 6-1, reflecting the lower winter peak coincidence factor of a few key DERs - most notably solar PV.

Overall, the findings indicate that under the modeled achievable scenarios, DERs offer the potential to provide 39%-62% of Ontario's incremental summer capacity needs over the next decade. These results represent 23%-31% of the market-wide economic potential. The differential between the economic and achievable potential is a factor of customer economics, DER barriers, market opportunities and IESO market rules that influence the adoption of DERs in the province.

As indicated above, the achievable results are notably lower than the economic potential results due to a range of factors captured in the modeling. First, the achievable potential is driven by customer/developer financial returns, and in many cases, DERs that prove cost-effective from an electricity system perspective do not offer sufficient returns to be attractive to a large number of DER providers. Thus, opportunities to increase returns to potential DER providers can notably increase the achievable potential, as is observed through the growth in potential from the BAU to the Accelerated scenarios as energy and capacity prices increase. Moreover, while not explicitly assessed here, opportunities to reduce DER market barriers by increasing awareness, removing building code restrictions, or reducing DER procurement or market participation complexities, can lead to increased achievable potentials. Stated another way, the spread between the economic and achievable DER potential is driven largely by the distributed nature of the resources, and the need to influence many decision points to encourage widespread adoption and participation of DERs in providing system services.

[43] DERs have an associated coincidence factor (CF) which represents the expected portion of the nameplate capacity that will produce power during system peak load events. Since these CFs are typically less than 1.0, the DER nameplate capacities are typically larger than their capacity contributions.

Figure 6-1: Achievable Capacity Contribution from DERs by Scenario in 2032



As shown in Figure 6-2 the identified achievable potential can also contribute to meeting Ontario's emerging winter system peak needs. Specifically, DERs are forecasted to contribute between 1 GW – 3.6 GW of winter capacity by 2032, representing 4% to 9% of the forecasted winter peak demand for that timeframe.

Figure 6-2: Achievable Winter Capacity Contribution from DERs by Scenario in 2032

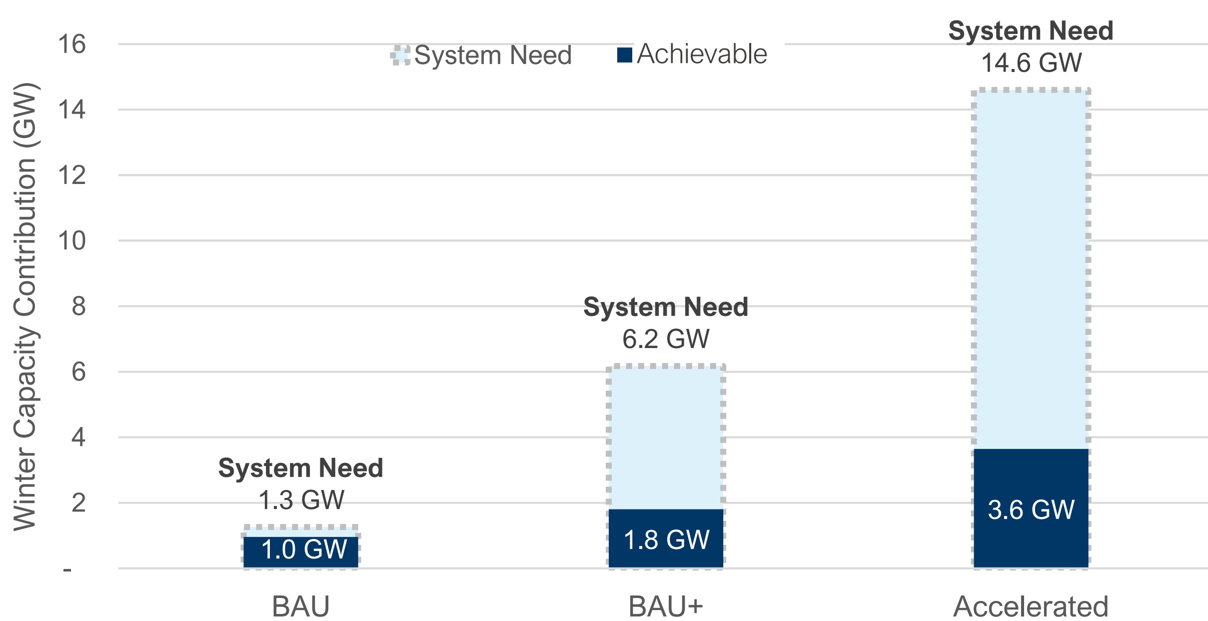


Figure 6-3 and Table 6-1 below provide the resulting mix of DERs forecasted in the achievable scenarios. The achievable DER mix can be seen to differ from the market-wide economic potential DER mix in the following ways:

- The majority of the achievable potential comes from DR opportunities, which are forecasted to contribute 0.92 – 1.53 GW of capacity by 2032. However, the DR measure achievable potential is limited by the forecasted adoption of applicable equipment (i.e. heat pumps and electric vehicles) as well as the corresponding market participation that can be expected based on the available market revenues in each scenario. Specific details on how and where DR measure adoption and participation are impacted by customer economics and market barriers is provided in the following sections.

- Despite the significant economic potential observed for FTM resources, only limited capacity of FTM solar is observed under the achievable scenarios because the current energy market value and compensation available for FTM resources are insufficient to drive significant developer investment under the BAU and BAU+ scenarios. They do become extremely economically attractive in the later years of the Accelerated scenario, but the results show a lag in the development of the full FTM resource potential due to the diffusion curves applied in the model that account for the time it takes the industry to recognize and develop emerging and distributed opportunities. Conversely, little to no FTM battery storage achievable potential is observed in any scenario due to the local distribution company non-coincident peak demand charges applied to FTM storage resources in Ontario, which undermine the business case for prospective FTM storage developers.
- BTM resources make a notable contribution to the achievable potential in all scenarios (contributing 0.31 – 2.25 GW of capacity), despite only being cost-effective under the BAU+ and Accelerated measure-level economic potential assessment. This is largely attributable to the current compensation mechanisms for BTM solar (e.g. net-metering, ICI) and non-financial drivers (e.g. resiliency, environmental benefits) that support the value proposition for customers to adopt BTM solar and storage.

Figure 6-3: Achievable Seasonal System Capacity Contributions by Scenario and Resource Type in 2032

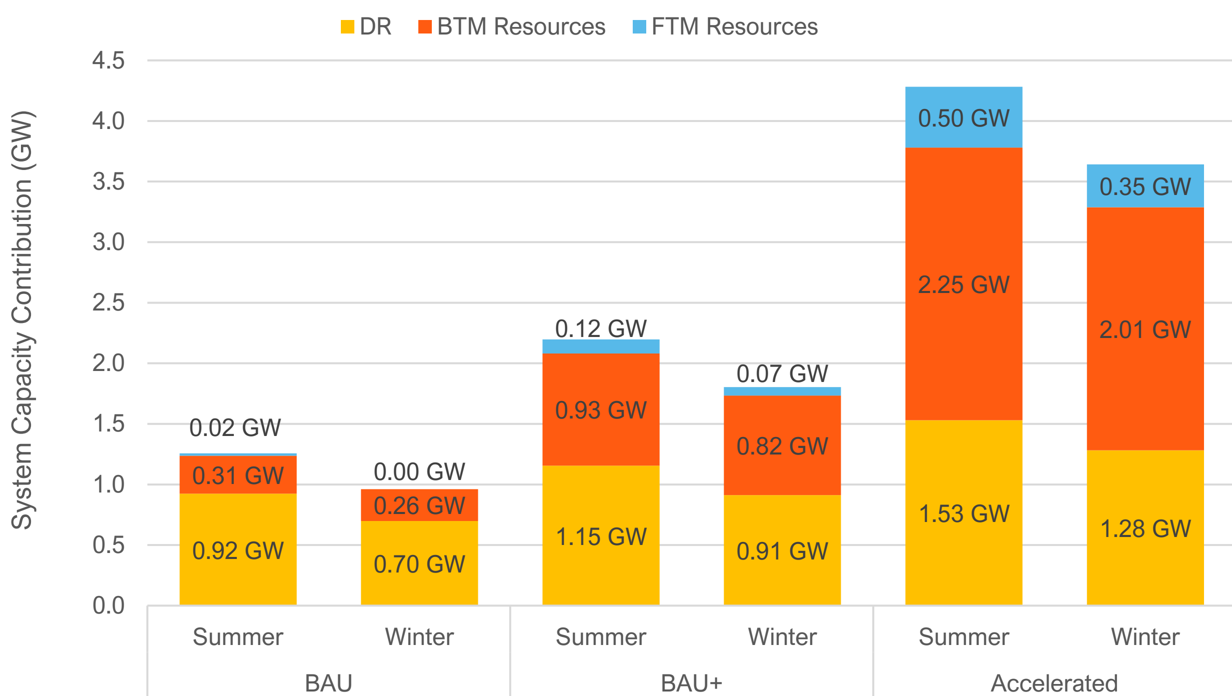


Table 6-1: Achievable Capacity Reductions by Resource Type and Year

	Summer Capacity Reductions (MW)			Winter Capacity Reductions (MW)		
	2023	2027	2032	2023	2027	2032
BAU	614	770	1,257	510	610	961
DR	545	664	924	444	522	699
BTM Resources	67	98	313	66	88	262
FTM Resources	3	8	20	-	-	-
BAU+	692	1,026	2,197	540	812	1,804
DR	597	756	1,155	485	597	912
BTM Resources	81	206	926	55	185	822
FTM Resources	14	64	116	-	30	70
Accelerated	894	1,652	4,282	552	1,357	3,642
DR	692	942	1,530	495	765	1,282
BTM Resources	115	491	2,251	11	439	2,005
FTM Resources	87	219	501	46	154	355

Figure 6-4 and Figure 6-5 provide the energy generation results for the achievable DER mix in 2032 under each scenario, as compared to the forecasted system needs. Overall, these results illustrate the extensive growth in energy needs expected in Ontario over the coming decade, driven by market growth along with the electrification of transportation, space heating and industry. In each scenario the achievable potentials make up just a small fraction of the forecasted incremental energy needs (5% - 10%). However, the economic potentials presented in Figure 6-5 are much higher, representing 20% of the projected need under the BAU scenario, over 50% under the BAU+, and 100% of the needs in the Accelerated scenario. While this demonstrates the impact of higher energy prices in the Accelerated scenario to support FTM and BTM solar generation economics, the remaining discrepancy between the achievable and economic potentials underlines the challenges of actually building the needed generation facilities in the absence of planned direct procurement.

Overall, these results show that energy becomes the main driver of benefits for DERs under the Accelerated scenario (as shown later in Figure 6-7). While the relative gap between achievable and economic potential is the most pronounced in this scenario, it should be noted that the avoided costs of energy rise steeply in the last 3 to 4 years of the study period, and the model's diffusion curves would predict a lag in the adoption of FTM/BTM solar in response to the improved economics. Thus, decisions to procure solar capacity in the preceding years would help to raise the achievable potentials in advance of the steeply growing needs in the later years of the study period.

Another aspect that should be considered is the seasonal energy needs, which were not assessed in the model. It would be expected that heating electrification would drive increasing winter energy needs, with solar generating more energy in the summer, and FTM small scale hydro generating more in the winter. Moreover, the study capped FTM solar technical nameplate capacity at 37 GW, which limits total annual solar production to 65 TWh - all of which proves cost-effective in 2032. Further analysis would be needed to determine how these DERs could fit into a resource adequacy plan for Ontario, considering hourly, daily, and seasonal needs.

Figure 6-4: Achievable Annual Energy Generation vs Incremental System Needs (2032)

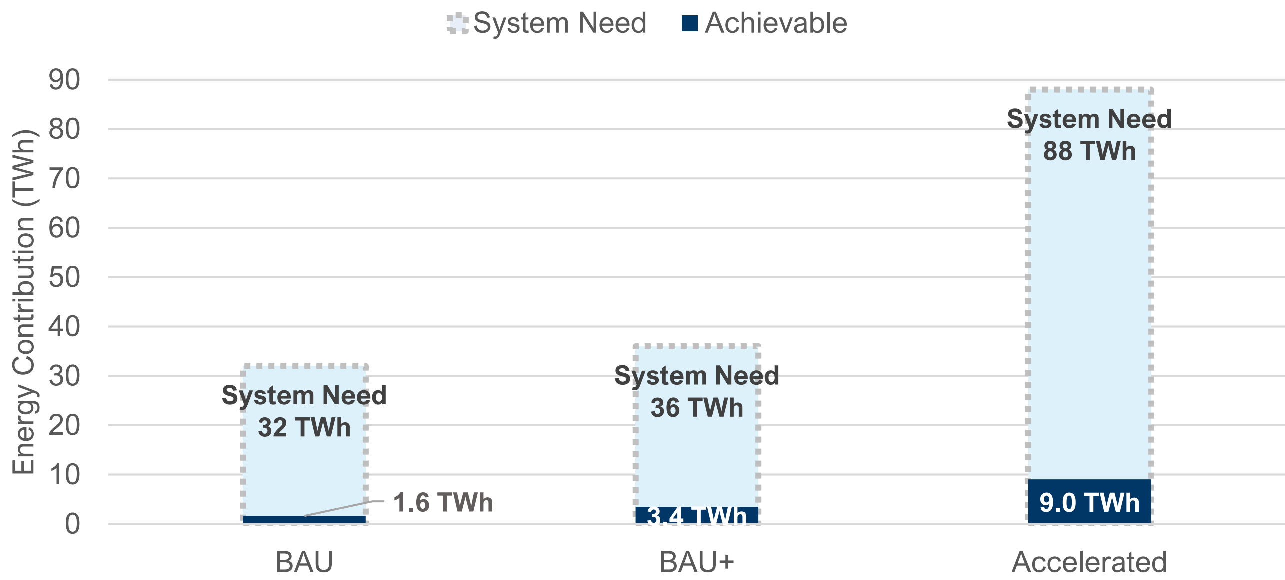


Figure 6-5: Annual Achievable and Economic Potential for Energy Generation by Scenario in 2032

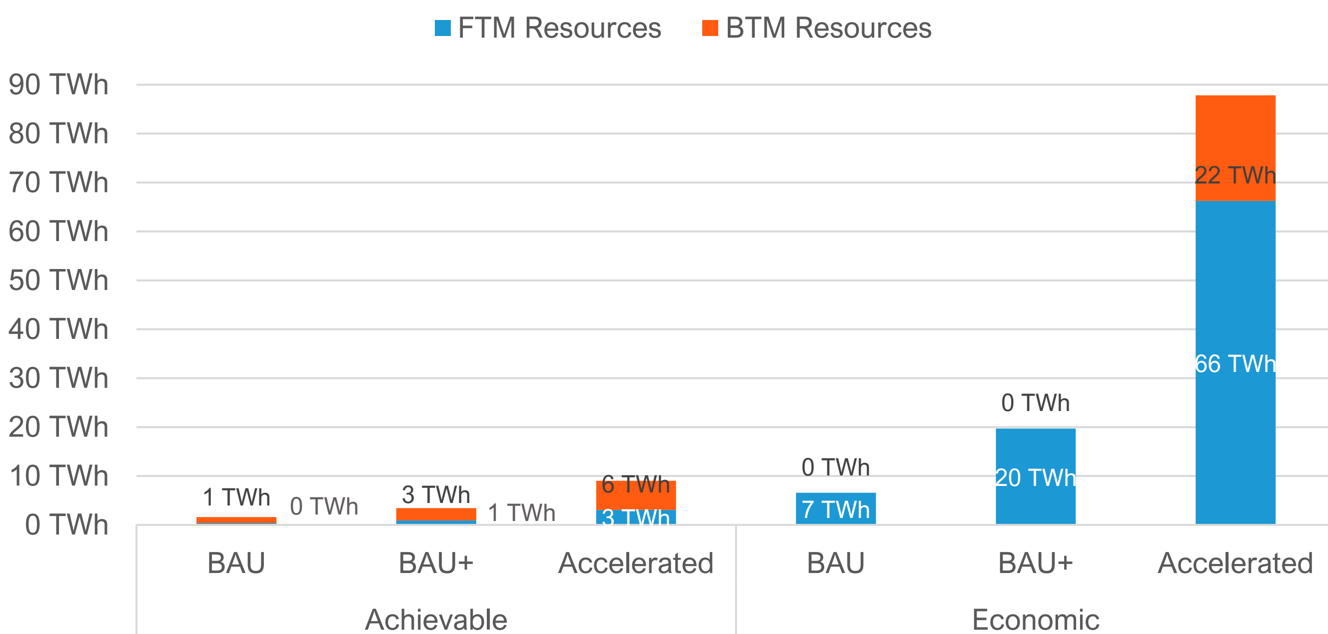


Figure 6-6 below provides a breakdown of the proportion of achievable DER potential that can provide each grid service to the system. As per the economic potential results, under all scenarios, the majority of DERs are capable of providing 5-minute dispatchability, OR, RC and capacity benefits. Moreover, only a small fraction can provide energy benefits, once again limited to the solar PV measures in all scenarios, and small-scale hydro under the Accelerated scenario. A majority of DERs are not event/call constrained (i.e. they can be called 20 times per year or more).

Figure 6-6: Portion of Achievable Potential Nameplate Capacity Capable of Providing Various Grid Services

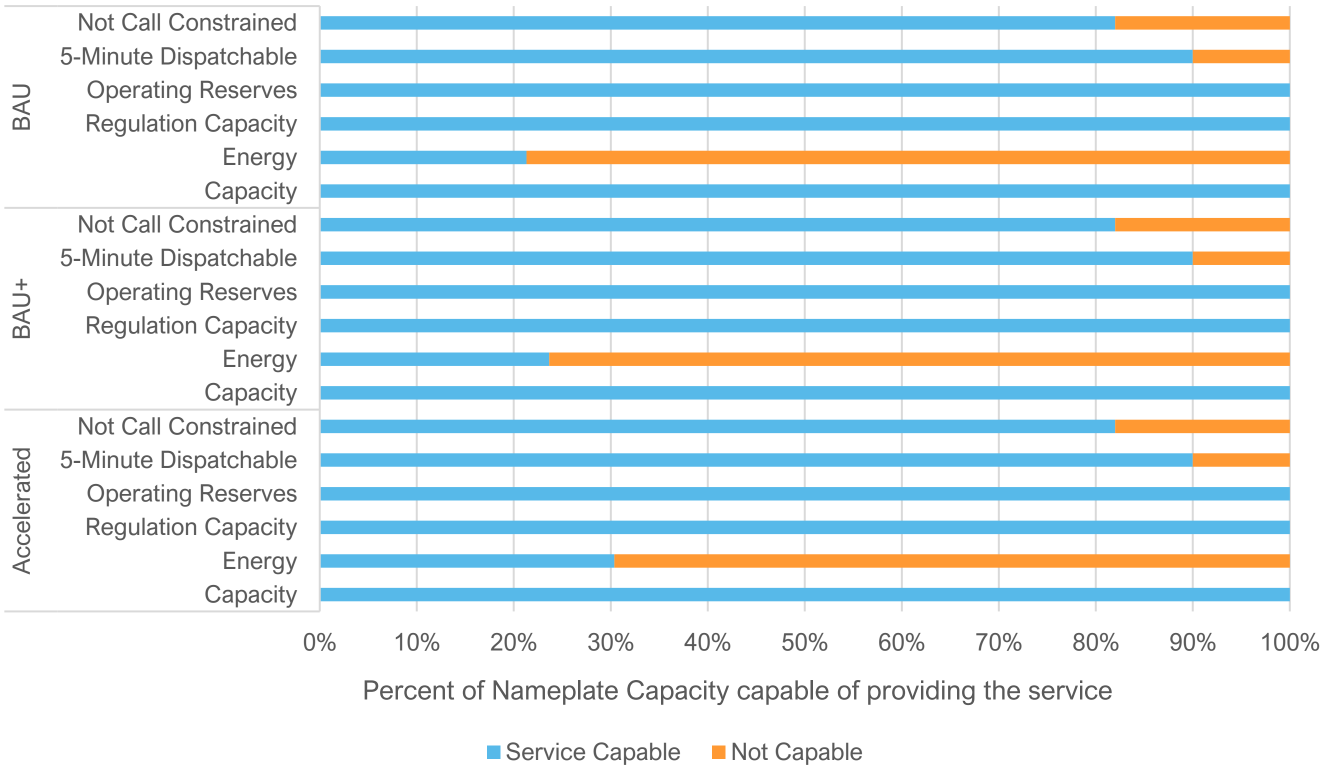


Figure 6-7 and Table 6-2 show the achievable lifetime net benefits by grid service and scenario. Overall, under the BAU and BAU+ scenarios, the results clearly show the importance of the capacity benefits offered by DERs in supporting their cost-effectiveness. However, under the Accelerated scenario, the energy benefits expand to become the most important grid service from a lifetime benefits perspective. This is due to the rapidly increasing energy avoided costs under the Accelerated scenario, along with the carbon emissions benefits (which are captured within the energy benefits in this analysis). The Accelerated scenario reveals a significant rise in net benefits stemming from adopted DERs, which exceed $42B by 2032. These benefits are derived from the assessed avoided costs, which assume highly constrained electricity supply under the Accelerated scenario, causing energy avoided costs to rise nearly seven-fold over the BAU+ scenario by 2040.[44]

[44] As noted in Chapter 5, coherent, real-world planning and integration could help to mitigate these extremely high avoided costs. However, given that many of the DERs become highly cost-effective under the Accelerated scenario, accounting for energy price feedback mechanisms between supply and avoided costs would not be expected to significantly reduce the overall achievable potential for DERs in this scenario.

Figure 6-7: Lifetime Benefits and Costs associated with the Achievable Potential (2032)

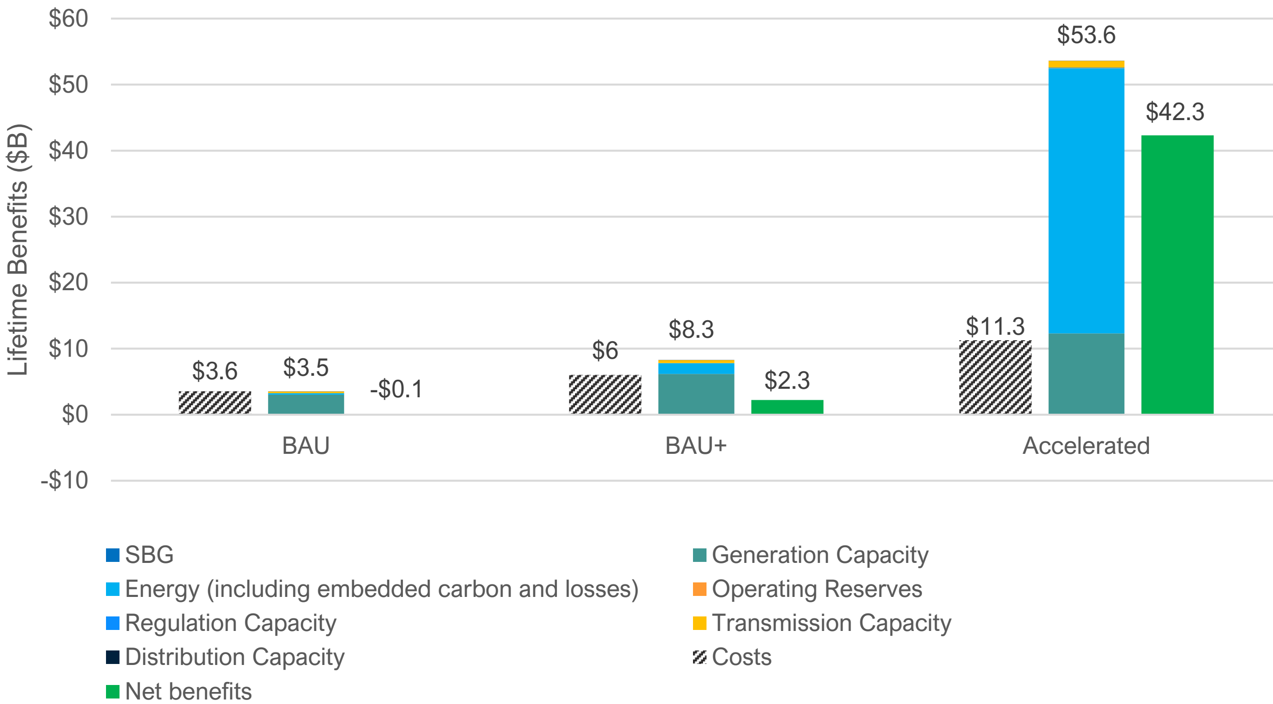


Table 6-2: Lifetime Benefits and Costs Associated with the Achievable Potential

Market Service	BAU	BAU+	Accelerated
Benefits	$3.5 B	$8.3 B	$53.6 B
SBG	$1.85 M	$0	$0
Generation Capacity	$3.0 B	$6.2 B	$12.3 B
Energy (including embedded carbon and losses)	$265.6 M	$1.6 B	$40.2 B
Operating Reserves	$49,539	$23.6 M	$68.7 M
Regulation Capacity	$0	$0	$8.4 M
Transmission Capacity	$238.6 M	$430.4 M	$1.0 B
Distribution Capacity	$2.5 M	$4.9 M	$9.5 M
Total Costs	$3.6 B	$6.0 B	$11.3 B
Net Benefits	-$0.1 B	$2.3 B	$42.3 B
Lifetime GHG Emissions reductions ($CO_{2\,eq}$) (Annual 2032 value)	0.9 Mt (57 kt)	1.8 Mt (122 kt)	4.8 Mt (321 kt)

GHG EMISSIONS REDUCTIONS FROM DERS

DERs can play a vital role in reducing GHG emissions related to energy use in Ontario. To put the assessed carbon benefits into perspective, in 2019 Ontario's electricity sector accounted for 3.3

megatonnes (Mt) of CO_2(eq), and thus the annual DER carbon reduction benefits in 2032 would represent a 2-10% reduction in GHG emissions compared to this baseline.

This study attributed two key opportunities for DERs to reduce emissions, which are captured in the quantification of DER benefits:

- For generating DERs, such as solar PV and small-scale hydro, benefits are quantified based on the energy production from these resources that directly displaces the high-carbon content electricity from gas-fired generation facilities.
- DR and storage measures can theoretically shift consumption from times when high-emitting resources are on the margin to times when lower-emitting resources are on the margin, but with storage incurring a roundtrip efficiency penalty that could somewhat hamper the overall carbon benefits and actually result in net-positive emissions. For all scenarios, in the latter years of this study due to high load growth, gas generation appeared on the margin nearly 100% of the time. Such conditions significantly limited the carbon-abatement opportunities of DR, and resulted in a net increase in emissions as a result of storage. Under a counterfactual hypothetical circumstance where the marginal generating resources alternated between gas and non-emitting generation (such as renewables or nuclear), DR and battery storage would have resulted in significantly more emissions reductions.

This study did not estimate the *net* GHG reductions from electrification

Under the BAU+ and Accelerated scenarios, higher levels of heating electrification and electric vehicle adoption would logically lead to net GHG emissions reductions as fossil fuel usage is displaced by largely clean electricity. While the overall GHG benefits (accounting for GHG reductions from fossil fuel use occurring outside of the electricity sector) was not included in this study, the contribution of DERs to Ontario's electricity system would help to enable such electrification.

Table 6-3 below provides the annual and lifetime GHG emissions benefits by measure group and achievable scenario. Only measure groups that provide some GHG impacts are presented under each scenario, and as was noted above in the economic potential discussion, the GHG impacts of DR measures that do not include any form of energy storage were not assessed in the model. As with the economic potential results, Storage and Back-up Generation both lead to increases in GHG emissions, due to round-trip efficiency losses and fossil fuel consumption, respectively. In the achievable scenarios, Water Heating measures do lead to GHG emissions reductions due to a shifting in the timing of their impacts, and increased uptake relative to the economic scenarios. Measure by measure GHG emissions impacts by year can be found in the MS Excel tables included in Appendix G – Detailed Results.

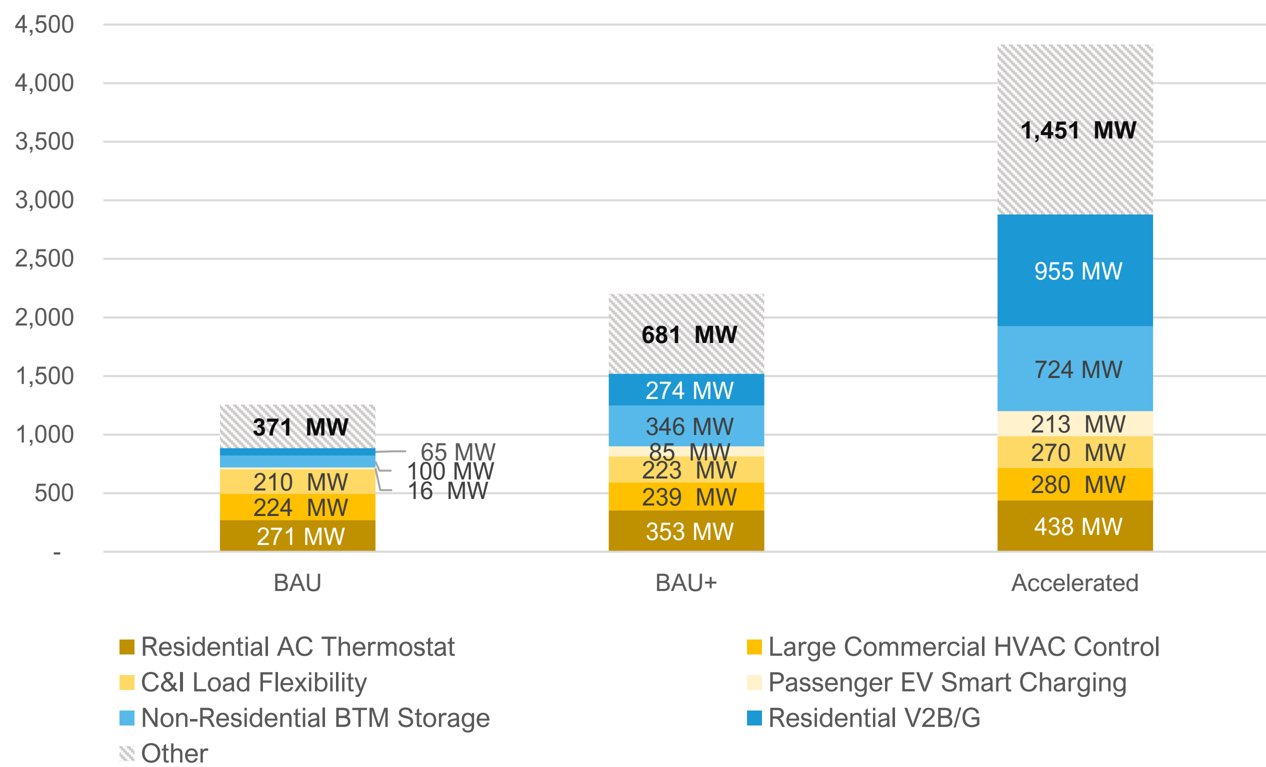
Table 6-3: Achievable GHG Reduction by Measure Group and Year

	Annual GHG Reduction (tonnes CO2 eq)			Lifetime GHG Reduction (tonnes CO2 eq)
	2023	**2027**	**2032**	**2032**
BAU	906	13,064	57,450	850,342
Backup Generation	-1,030	-1,067	-1,134	-17,103
Distributed Generation	2,559	15,094	60,464	882,214
EV Fleet Charging	4	9	18	137
HVAC DR	22	15	19	151
Passenger EV Charging	7	7	9	69
Storage	-671	-1,024	-2,032	-15,962
V2B/G	11	27	97	755
Water Heating	1	1	1	5
BAU+	10,484	42,221	122,057	1,817,626
Backup Generation	-1,127	-1,166	-1,238	-18,675
Distributed Generation	12,448	45,273	128,834	1,879,788
EV Fleet Charging	5	14	31	244
HVAC DR	55	74	157	1,227
Other Load Flexibility	0	0	0	1
Passenger EV Charging	11	18	91	706
Storage	-915	-2,064	-6,235	-48,938
V2B/G	0	66	405	3,160
Water Heating	1	0	2	14
Accelerated	23,588	94,676	320,562	4,789,858
Backup Generation	-1,311	-1,356	-1,440	-21,724
Distributed Generation	26,346	99,306	338,362	4,940,116
EV Fleet Charging	10	24	46	357
HVAC DR	29	95	211	1,652
Other Load Flexibility	0	0	3	23
Passenger EV Charging	38	80	220	1,717
Storage	-1,530	-3,804	-18,252	-143,324
V2B/G	0	325	1,402	10,936
Water Heating	2	1	2	18

Figure 6-8: Achievable Summer System Capacity Contributions from Top 6 DER Measures (2032) below shows a measure-level breakdown of the forecasted achievable potential, identifying the six DER types comprising the bulk of the achievable capacity. Specifically, residential AC thermostats represent a significant opportunity of 271 – 438 MW of summer peak reduction potential, with Large Commercial HVAC DR measures

contributing another 224 – 280 MW of potential. This growth is likely a by-product of the increased prevalence of smart thermostats in the market over time as well as higher market participation accessibility and revenues, which result in cost-effective opportunities emerging over the study period. The growth in residential HVAC DR is particularly notable given that no residential HVAC DR is observed in the capacity auction today. Non-residential BTM storage also represent a large portion of the identified achievable potential, contributing between 100 MW to 724 MW of capacity. With the forecasted increase in EV uptake under the BAU+ and Accelerated scenarios, up to 955 MW of V2B/G potential, and 213 MW of smart charging potential is projected by 2032. The "Other" category captures the contribution of all other DER measures considered in the study, such as BTM solar, FTM solar, FTM storage and non-HVAC residential DR.

Figure 6-8: Achievable Summer System Capacity Contributions from Top 6 DER Measures (2032) [45]



6.2 DR Potential

As shown in Figure 6-9, the capacity contributions from DR measures are expected to grow over the study period, reaching from 0.9 GW to 1.5 GW of Summer peak capacity contributions by 2032:

- Nearly half of the forecasted achievable DR potential is expected to come from **HVAC DR** consistently across the study period. Under BAU and BAU+, a little over 50% of the HVAC DR opportunities are expected to come from the residential sector, enabled through the increased penetration of smart thermostats; this increases to nearly 70% under the Accelerated scenario. Commercial DR measures represent the majority of the remaining DR potential, with the industrial measure offering 8 - 15% of the total potential. Despite the reduction in HVAC DR technical potential between BAU and BAU+ (as heat

[45] C&I Load Flexibility includes Other Commercial Flexibility and Industrial Flexibility measures.

pumps displace less efficient ACs), the contribution of HVAC DR increases from 380 MW to 490 MW under the BAU+ scenarios due to higher participation incentives stemming from the increased market revenues for DR measures, resulting from higher overall capacity benefit values under the BAU+ scenario. Similarly, under the Accelerated scenario, the further increase in incentives result in the highest HVAC DR achievable potentials.

- **EV smart charging** represents a high growth area, with up to 252 MW of capacity contributions by 2032 under the Accelerated scenario from passenger and fleet EV charging opportunities. The potential particularly increases in the latter part of the decade as EV uptake in the province surges. Relative to commercial fleets, passenger EV charging opportunities have higher system capacity contributions (enabled by the prevalence of controls through onboard EV telematics) and higher propensity to participate in managed charging initiatives.
- Beyond HVAC and EV charging, the remaining capacity contributions from DR are distributed among **water heating, commercial lighting controls and other end-uses**. In particular, a large portion of the "other flexibility" represents segment-specific DER opportunities in the commercial and industrial sector.

Figure 6-9: Achievable System Capacity Contributions from DR Resources

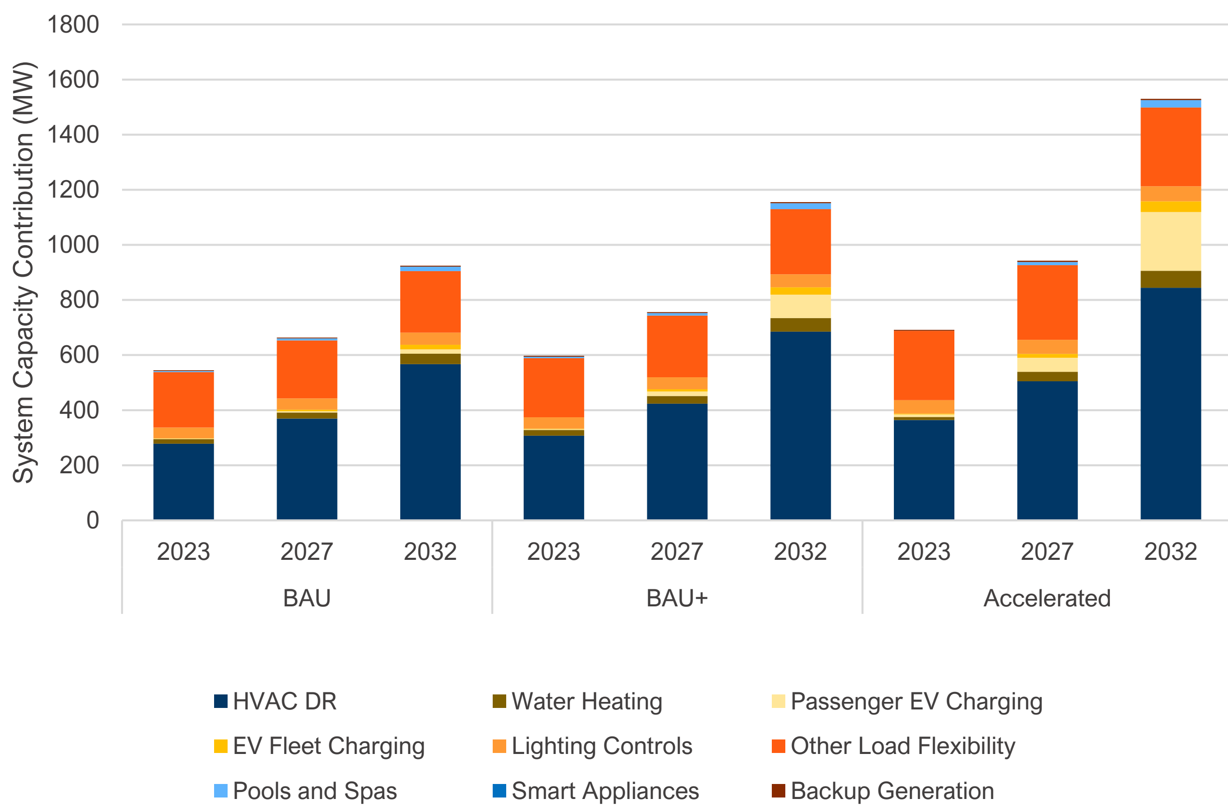


Table 6-4: Achievable Seasonal System Capacity Contributions from DR Resources

	System Summer Capacity Contribution (MW)								
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
Residential	**75**	**144**	**336**	**100**	**202**	**523**	**111**	**284**	**783**
HVAC DR	59	115	273	77	154	374	96	194	489
Other Load Flexibility	1	1	1	2	2	2	2	2	3
Water Heating	10	15	30	13	20	41	3	25	52
Passenger EV Charging	2	5	16	3	17	85	10	51	213
Pools and Spas	4	7	16	5	10	21	-	12	27
Commercial	**322**	**367**	**429**	**339**	**391**	**462**	**387**	**458**	**539**
HVAC DR	219	254	294	230	270	311	268	311	356
Lighting Controls	39	41	44	42	44	47	49	51	55
Other Load Flexibility	52	56	63	55	59	65	55	68	76
EV Fleet Charging	1	5	17	2	8	27	3	14	39
Water Heating	7	7	7	8	8	8	8	9	9
Backup Generation	3	3	3	3	4	4	4	4	4
Industrial	**148**	**153**	**159**	**158**	**163**	**170**	**193**	**200**	**207**

	System Winter Capacity Contribution (MW)								
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
Residential	**57**	**106**	**240**	**77**	**156**	**421**	**17**	**237**	**697**
HVAC DR	35	69	156	46	92	224	13	117	309
Other Load Flexibility	1	1	1	2	2	2	2	3	3
Water Heating	15	23	47	20	30	64	0	39	80
Passenger EV Charging	2	7	21	4	22	111	1	67	280
Pools and Spas	4	7	15	5	9	20	-	12	26
Commercial	**238**	**262**	**299**	**250**	**277**	**320**	**284**	**328**	**377**
HVAC DR	95	106	120	97	110	124	113	128	142
Lighting Controls	68	72	77	73	77	83	87	92	98
Other Load Flexibility	59	64	72	62	67	75	65	78	88
EV Fleet Charging	1	5	14	1	6	20	2	10	28
Water Heating	12	12	12	13	13	14	13	15	16
Backup Generation	3	3	3	3	4	4	4	4	4
Industrial	**149**	**154**	**160**	**159**	**164**	**171**	**194**	**200**	**208**

6.3 BTM Resources

As highlighted earlier, BTM resource capacity (summer) represents 0.31 GW – 2.25 GW of achievable potential in 2032 (which reflects 1.4 – 9.0 GW of nameplate capacity):

- Despite limited uptake forecasted in early years of the study period, between 1 GW and 4.9 GW (nameplate) of new **BTM solar** are forecasted to be deployed in Ontario by 2032. However, the deployed BTM solar capacity is only expected to contribute 50 to 246 MW towards capacity needs due to low - and declining - coincidence with system peak for new solar additions. The achievable potential primarily consists of residential and small commercial BTM solar deployments that are enabled by the favorable business case available to net-metering customers with assumed access to TOU rates.[46]
- 178 MW of **BTM storage** capacity is forecasted under BAU, increasing to 485 MW under BAU+, and 962 MW under Accelerated. Under all scenarios, BTM storage adoption is concentrated among commercial and industrial customers due to benefit streams from demand charge management and ICI participation resulting in favourable economics. Beyond bill management, benefits from capacity contributions are the key market value stream driving uptake in the BAU and BAU+ scenario. However, under Accelerated, higher arbitrage opportunities create significant new revenue opportunities. Despite the lack of a solid business case, some residential BTM storage capacity is observed, with 34 – 144 MW forecasted by 2032, likely driven by a combination of financial motivations as well as other non-energy benefits (e.g. resiliency). The majority of the deployed BTM storage capacity is expected later in the study period (2027 onwards) as technology costs decline.
- 84 MW of capacity contribution are expected from **V2B/G** under BAU, increasing to 337 MW under BAU+ and reaching 1,043 MW in the Accelerated scenario as a result of increased passenger and fleet EV penetration.

Figure 6-10, Table 6-5 and Table 6-6 highlight the achievable installed nameplate capacity for key BTM resources and the corresponding system capacity contributions.

[46] Presently, it is common practice for LDCs to remove net-metering participants from the TOU rate structure and instead place them on the tiered rate structure.

Figure 6-10: Achievable Summer System Capacity Contribution from BTM Resources

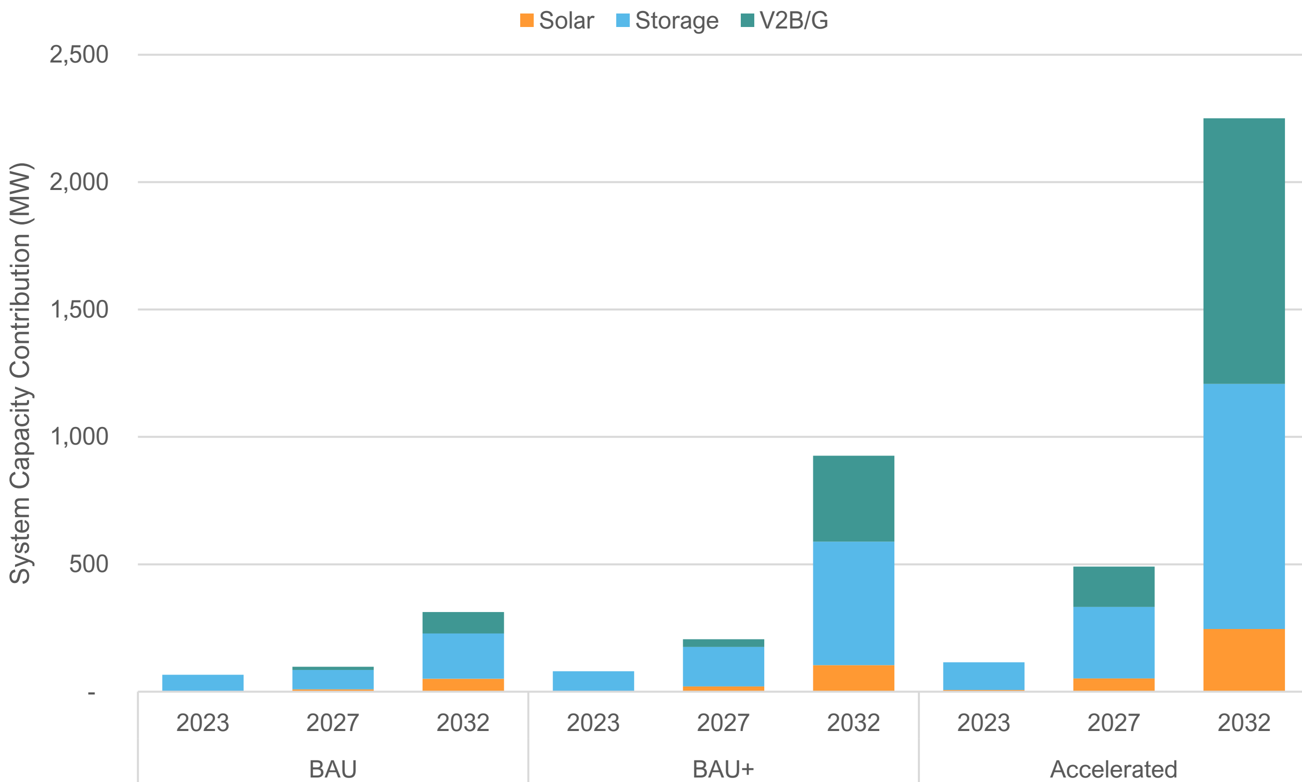


Table 6-5: Achievable Installed BTM Nameplate Capacity

	Installed Nameplate Capacity (MW)								
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
Residential	**7**	**178**	**771**	**19**	**268**	**1,098**	**66**	**512**	**1,853**
BTM Solar	5	169	737	14	247	1,027	56	471	1,709
BTM Storage	2	9	34	5	21	71	10	41	144
V2B/G	0	30	196	0	74	821	0	451	2,863
Commercial	**46**	**65**	**366**	**69**	**258**	**1,300**	**147**	**687**	**2,966**
BTM Solar	2	18	266	16	150	954	72	483	2,242
BTM Storage	44	47	100	54	108	346	75	204	724
V2B/G	0	7	56	0	17	188	0	23	264
Industrial	**20**	**20**	**47**	**20**	**43**	**160**	**33**	**119**	**1,069**
BTM Solar	-	-	3	-	17	92	10	83	975
BTM Storage	20	20	44	20	26	68	23	36	94

Table 6-6: Achievable Seasonal System Capacity Contribution from BTM Resources

System Capacity Summer Contribution (MW)									
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
Residential	**2**	**18**	**71**	**6**	**33**	**123**	**13**	**65**	**231**
BTM Solar	0	9	37	1	13	52	3	24	87
BTM Storage	2	9	34	5	21	71	10	41	144
V2B/G	0	10	65	0	25	274	0	150	955
Commercial	**44**	**48**	**113**	**55**	**115**	**393**	**79**	**228**	**835**
BTM Solar	0	1	13	1	7	47	4	24	111
BTM Storage	44	47	100	54	108	346	75	204	724
V2B/G	0	2	19	0	6	63	0	8	88
Industrial	**20**	**20**	**44**	**20**	**27**	**72**	**24**	**40**	**142**
BTM Solar	-	-	0	-	1	5	0	4	48
BTM Storage	20	20	44	20	26	68	23	36	94

System Capacity Winter Contribution (MW)									
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
Residential	**2**	**19**	**99**	**1**	**45**	**345**	**1**	**191**	**1,099**
BTM Solar	-	-	-	-	-	-	-	-	-
BTM Storage	2	9	34	1	21	71	1	41	144
V2B/G	0	10	65	0	25	274	0	150	955
Commercial	**44**	**49**	**118**	**34**	**114**	**409**	**7**	**211**	**812**
BTM Solar	-	-	-	-	-	-	-	-	-
BTM Storage	44	47	100	34	108	346	7	204	724
V2B/G	-	2	19	-	6	63	-	8	88
Industrial	**20**	**20**	**44**	**20**	**26**	**68**	**2**	**36**	**94**
BTM Solar	-	-	-	-	-	-	-	-	-
BTM Storage	20	20	44	20	26	68	2	36	94

6.4 FTM Resources

As highlighted earlier and shown below in Figure 6-11, Table 6-7 and Table 6-8, FTM Resources are forecasted to have a limited contribution under the modeled achievable potential scenarios:

- Limited uptake of **FTM solar** is observed under BAU, with 210 MW of installed capacity contributing to 20 MW of system capacity needs. Increased energy prices coupled with cost declines modeled under the BAU+ and Accelerated scenarios result in up to 500 MW and 1,630 MW of installed capacity respectively, contributing to 46 MW to 151 MW of peak capacity respectively. However, the potential remains significantly lower than that identified in the economic potential due to market barriers to adoption, primarily the relatively low compensation available compared to system costs.
- Under BAU, no **FTM battery storage** capacity is observed due to the unfavourable economics for investors. This is largely due to the demand charges FTM storage resources are subjected to in Ontario, which diminish the business case. Under BAU+ however, 70 MW of deployed capacity are observed in the second half of the study, resulting in an equal magnitude of capacity contributions by 2032. Under the Accelerated scenario, substantially more FTM storage is observed, reaching 340 MW of capacity by 2032.
- Across the BAU and BAU+ scenarios, no new small-scale hydro capacity is forecasted in the market over the next decade. However, the notable increase in energy prices observed under the Accelerated scenario results in 20 MW (nameplate capacity) of new small-scale hydro deployments.

Figure 6-11: Achievable System Capacity Summer Contribution from FTM Resources

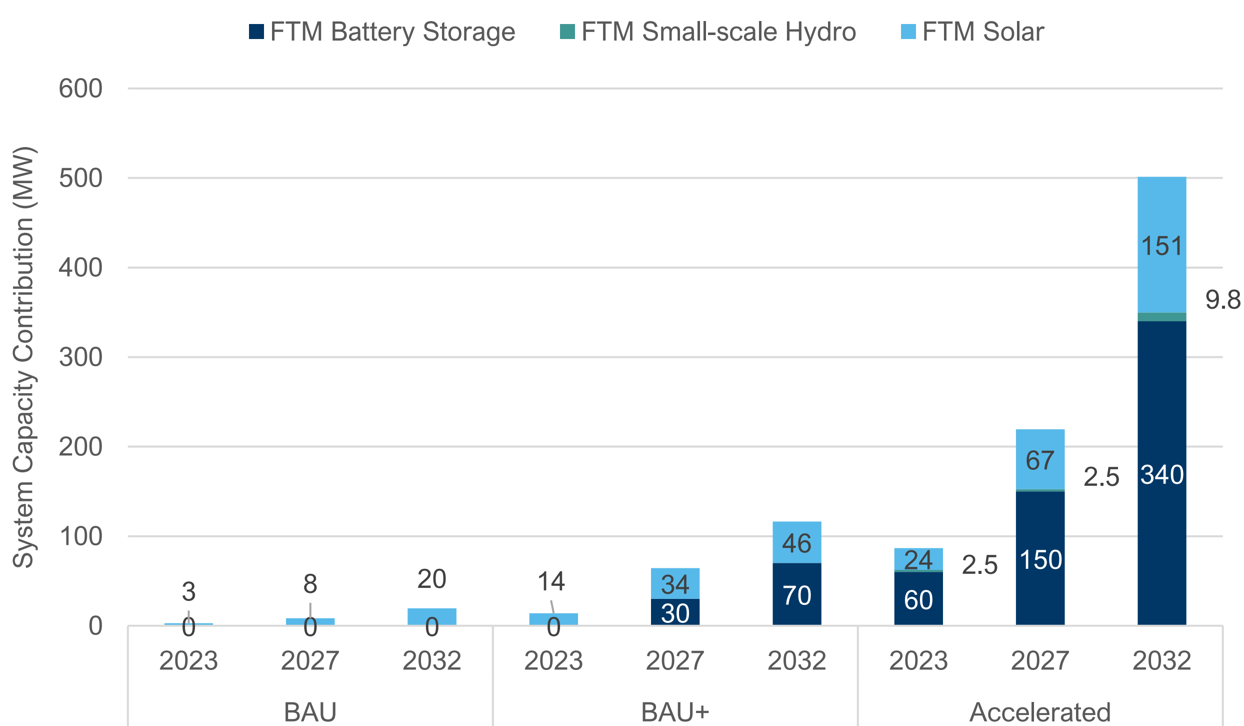


Table 6-7: Achievable Installed FTM Capacity

	Installed Nameplate Capacity (MW)								
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
FTM Battery Storage	-	-	-	-	30	70	60	150	340
FTM Small-scale Hydro	-	-	-	-	-	-	5	5	20
FTM Solar	30	90	210	150	370	500	260	720	1,630

Table 6-8: Achievable Seasonal System Capacity Contribution from FTM Resources

	Achievable System Capacity Summer Contribution (MW)								
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
FTM Battery Storage	-	-	-	-	30	70	60	150	340
FTM Small-scale Hydro	-	-	-	-	-	-	2	2	10
FTM Solar	3	8	20	14	34	46	24	67	151

	Achievable System Capacity Winter Contribution (MW)								
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
FTM Battery Storage	-	-	-	-	30	70	42	150	340
FTM Small-scale Hydro	-	-	-	-	-	-	4	4	15
FTM Solar	-	-	-	-	-	-	-	-	-

<u>Tab 6</u>

Appendix B-1 - Whitby Smart Grid Business Case, Page 33 of 67

In addition, for a high-DER future, VVO will be required to help manage voltage levels. Research studies have projected that a 1.5-3% of demand reduction is typically expected by implementing VVM tool. In the Whitby case, the lines are short, and the voltage profile is flat so the slightly more optimistic range of 2-3% is viable. This is a savings on the Customer Bill and a commensurate reduction in the LDC Cost of Power.

The following list provides a summary of the typical industry expected benefits of VVO implementation[9]:

- Energy Reduction: 2-3% based on a 5% source voltage reduction
- Peak Reduction: 2-3% based on a 5% source voltage reduction
- System Losses Reduction: <0.1%
- Greenhouse Gas Reduction

Taking the potential energy reduction of 3%, the below table highlights the potential equivalent greenhouse gas emissions reductions. The analysis has taken the total energy usage for 2021 for the Whitby Rate Zone, and then for each year increased this by the same ratio as indicated in the load forecast to calculate each years Total Energy Usage (kWH) for the 2022-2041 period. A report[10] published by The Atmospheric Fund (TAF) in 2021 developed energy savings emission factors from IESO published data and their own methodology suggested use of a Marginal Emissions Factor (MEF) to quantify GHG savings from energy efficiency savings. This enables the calculation of the TCO2e GHG savings. Using the MEF the calculated GHG savings, over the 20 year forecast period and based on a 3% annual energy usage savings, is 202,977 TCO2e. The below table 16 shows the annual GHG savings from 2022-2041:

[9] Appendix B-5
[10] 20211116_TAF_Emissions-Factors-Guidelines

Tab 7

Undertaking JT1.22

Elexicon Energy Inc.

Answer to Undertaking from

OEB Staff

Undertaking JT1.22:

TO UPDATE TABLE 1,PAGE 11 OF APPENDIX B TO REFLECT THE 2022 TOTAL COST OF POWER IN THE SAME MANNER AS WAS DONE WITH THE CURRENT TABLE 1, INCLUDING THE COST-OF-CAPITAL PARAMETERS FOR THE ICM, TO UPDATE THAT WITH THE 2023 COST-OF-CAPITAL PARAMETERS, THE FINALIZED OEB COST-OF-CAPITAL PARAMETERS, AND, TO THE EXTENT POSSIBLE, ALSO DO THAT WITH THE EXCEL FILE THAT WAS PROVIDED. AND ALSO TO LOOK AT THE RELIABILITY WORKSHEET WITHIN THE STAFF WHITBY SMART GRID WORKBOOK AND SEE IT CAN BE APPLIED TO THE UPDATED TABLE 1.

Response:

The updated Table 1, page 11 of Appendix B, included below reflects the following updated values which are highlighted in yellow:

1. Elexicon's unaudited total Cost of Power for the Whitby Rate Zone as of December 31, 2022 of approximately $112 MM.
2. Whitby Smart Grid ("WSG") Additional ICM Revenue from the OEB ICM Excel model provided in undertaking JT1.15 of $4.477 MM, and
3. Updated Operating Efficiencies from WSG to include the cost of truck assets provided in undertaking JT1.1 of $0.05 MM.

As a result of the above updates, the net benefit of the WSG to Whitby Rate Zone ("WRZ") customers has been reduced from $0.673 MM to $0.433 MM per year. Elexicon did not include an update to the Cost of Capital parameters for the purpose of this response as requested. The OEB's ICM policy requires the use of a distributors most recently approved cost of capital parameters; updating of these parameters to match the OEB's 2023 Cost of Capital parameters would be inconsistent with OEB policy.

In addition to the updated Table 1 requested in this undertaking, Elexicon has included the following additional tables related to benefit calculations that were produced during the interrogatory and technical conference proceeding steps:

1. Updated Interrogatory ED-01 Table 1 – 20 Year NPV Whitby Smart Grid Benefit Calculation
2. Updated Interrogatory ED-01 Table 4 – 20 Year NPV Benefits From Sustainable Brooklin and Whitby Smart Grid
3. Updated Undertaking JT1.5 - NPV Whitby Smart Grid Based on Time Period Equal to Average Lifetime of the Equipment

Updated Table 1 – Annual Net Benefit of WSG to WRZ Customers

Table 1 – Annual Net Benefit of WSG to WRZ Customers

Customer Annual Benefit Summary		
(All Dollars Listed in Thousands CAD)		
2022 Cost of Power (WRZ)	$	112,198
Projected % Energy Savings from WSG		3.00%
Total Purchased Power Savings from WSG (A)	$	3,366
ICM Additional Revenue (B)	$	4,477
Additional OM&A Expenses (C)	$	324
Operating Efficiencies from WSG (D)	$	48
Sub-Total of Savings (E = A-B-C+D)	$	(1,387)
Projected VoLL Benefit from Reliability (F)	$	1,820
Annual Net Benefit to WSG Customers (G = E+F)	$	433

<u>Updated Interrogatory ED-01 Table 1 – 20 Year NPV Whitby Smart Grid Benefit Calculation</u>

Table 2 – 20 Year NPV Whitby Smart Grid Benefit Calculation

Customer 20yr NPV Benefit Summary (5% Discount)		
(All Dollars Listed in Thousands CAD)		
Total Purchased Power Savings from WSG	$	49,363
ICM Additional Revenue	$	45,739
Additional OM&A Expenses	$	4,747
Operating Efficiencies from WSG	$	700
Sub-Total of Savings	-$	423
Projected VoLL Benefit from Reliability	$	26,689
NPV of Net Benefits (20 years) to WSG Customers	$	26,266

<u>Updated Undertaking JT1.5 - NPV Whitby Smart Grid Based on Time Period Equal to Average Lifetime of the Equipment</u>

Table 3 - NPV Benefit Calculation of Whitby Smart Grid Based Using Time Period Equal to Average Lifetime of the Equipment of 27 Years

Customer 27yr NPV Benefit Summary (5% Discount)		
(All Dollars Listed in Thousands CAD)		
Total Purchased Power Savings from WSG	$	60,903
ICM Additional Revenue	$	50,425
Additional OM&A Expenses	$	5,857
Operating Efficiencies from WSG	$	864
Sub-Total of Savings	$	5,485
Projected VoLL Benefit from Reliability	$	32,928
NPV of Net Benefits (27 years) to WSG Customers	$	38,413

Tab 8

Interrogatory SEC-20

Elexicon Energy Inc.

Answer to Interrogatory from

School Energy Coalition

Interrogatory SEC-20:

With respect to Customer Engagement, Elexicon states that in its 2020 survey, customers support investing in grid management technologies. What were customers told about the cost of such investments?

Response:

Elexicon Energy ("Elexicon") has leveraged its 2021 Distribution System Plan customer engagement effort to identify customer needs and preferences to inform the development of the ICM Projects and this application. The Customer Engagement Report is found in Appendix B-7.

Elexicon has relied on this Customer Engagement Report as support for customers' preference to modernize the electricity grid, and increase resilience to storms and severe weather events. In the 2021 Customer Engagement Report, customers stated a preference for value for money, which, as demonstrated in Table 1 of Elexicon's application, the Whitby Smart Grid is expected to deliver a net benefit of $0.673MM to Elexicon's customers.