Feedback Form

Distributed Energy Resources (DER) Potential Study – September 30, 2022

Feedback Provided by:

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The Independent Electricity System Operator (IESO) is seeking feedback and welcoming questions in relation to the Ontario DER Potential Study, which was published in-full on September 30, 2022.

The final study materials (the main report, the supplemental methodology/assumptions report, MS Excel Appendices, and updated results presentation), can be found on the DER Potential Study webpage.

Please provide any feedback and questions by October 28, 2022 to engagement@ieso.ca. Please use subject header: *DER Potential Study*.

To promote transparency, submitted feedback will be posted on the DER Potential Study webpage unless the sender requests otherwise.

The IESO will consider this feedback in the organization's future work, including but not limited to DER integration. The IESO will publish a document responding to feedback, and with support of the project consultants, respond to any technical questions relating to the study.

Thank you in advance for your contribution.

Takeaways, Recommendations, and Additional Analysis

Does the report highlight the most relevant results and takeaways from the study?

What other results or messages from this study are of high importance?

The report highlights key findings of the study. Other results or messages from the study of high importance are as follows:

Electrification, particularly at the rates described in the BAU+ and Accelerated scenarios, will require more generation. The gap between economic and achievable potentials underscores how much policy and regulatory work needs to be done to unlock more achievable potential from existing non-wires alternative (NWA) technologies. NWAs would help to defer T&D investments and could contribute to conservation efforts to address the energy supply gap. Considerations of supply chain constraints should be included in such an NWA policymaking process, because availability of equipment from vendors and increasing average wait times for key items (e.g. lead time for transformer delivery in the U.S. is currently 12-18 months, up from the longstanding three-month average, according to the American Public Power Association) will impact the eventual implementation of these policies—and consequently the closing of the economic-achievable gap that said policies would be intended to achieve.

Residential and fleet EV charging and V2B/G/X is very prominent in this study—particularly in the gap between residential V2B/G/X's economic potential for summer peak reductions (Table 5-4) and achievable potentials for summer system capacity contributions (Fig. 6-8), as well as the energy it contributes to the Accelerated scenario (955 MW).

Scenario	Economic potential, MW (Table 5-4)	Achievable potential, MW (Fig. 6-8)	% Achievable
BAU	1,204	65	5%
BAU+	3,910	274	7%
Accelerated	11,067	955	9%

This finding necessitates addressing—and removing—regulatory barriers regarding compensation of charging infrastructure. LDCs in Ontario do not have the regulatory approval or mandate from the Ontario Energy Board (OEB) to invest in EV infrastructure. Section 71 of the OEB Act limits distributors' business activity to distributing energy, with three exceptions: promoting conservation and energy efficiency, electricity load management, or the promotion of cleaner energy sources, including renewables. EV chargers do not fall under any of the three exceptions. While EV chargers could be enabled with demand response controls, dynamic load management cannot be realized with current one-way power flows. Although Section 71 allows for distributors' affiliates to own and operate EV charging infrastructure, there is not yet a strong business case for public EV charging. Several utilities have conducted the analysis and found that utilization of public chargers need to be at a much higher rate to cover maintenance and installation costs.

To harness more of the economic potential of V2B/G/X DERs identified in the study, the OEB would need to update its policies, codes, and guidance to include two-way power flows. Enabling V2G would require additional distribution infrastructure investment and planning to enable two-way power flows, since the current system is designed for one-way power flows.

In addition to accommodating two-way power flows, distribution planning and related upgrades should include a level of flexibility to future-proof forthcoming load increases due to electrification of the economy in addition to transportation (e.g., building stock, industrial processes).

To plan distribution infrastructure upgrades in support of domestic charging for their customers and the V2G DERs envisioned by the study, LDCs will benefit from greater awareness of EV uptake in their respective service areas and the locations of the EV charging sites that consumers prefer.

The study’s reference to “alternative datasets” regarding EV locations is accurate and of high importance. Interagency cooperation between MTO and MOE would facilitate knowledge transfer, allowing LDCs to properly plan for system upgrades in support of this increased load.

Ontario’s LDCs have been operating and planning distribution infrastructure for decades, but they require reasonable load estimates to fulfil expectations and targets from all levels of government (i.e. net-zero commitments, federal ZEV mandate, etc.). For example, LDCs would benefit from OEB guidance on whether to use load forecasts or actual load data. This would impact the customer experience and EV uptake, in terms of whether customers would need to wait to use their EV after purchasing, if there are additional distribution infrastructure upgrades required at their cost, or if they must rely solely on public charging infrastructure.

Do the recommendations capture appropriate actions to acquire the DER potential revealed in the study? Based on the study results, are there other actions that should be considered?	The study's four recommendations capture the appropriate actions. **Continue with DER MVDP** – further to the EDA's comments submitted on October 11, 2022 re: DER MVDP, "distributors should also be permitted to participate in this DER design as they are currently able to participate in IESO markets and could do so with experience. Distributors have existing relationships with DERs, and if DERs wish to participate through distributors, they should not be limited in their ability to do so. Distributors have a mandate to provide customers with choice and to service them reliably." **Develop Tailored DER Programs and Procurements** – LDCs are proud of their success and positive relationships with customers in Ontario, which have been developed and nurtured over decades through ongoing engagement and education. The study rightly recognizes the important role of LDC participation and LDC-led enablement pathways for many DER measures, as well as the "enabling non-market participation pathways such as CDM initiatives for customer-facing programs." LDCs successfully and cost-effectively delivered CDM programs to over 5 million residential, commercial, industrial, and institutional customers throughout Ontario for over a decade. The 2015-2020 Conservation First Framework (CFF), delivered by LDCs with centralized funding from the IESO, was the most cost-effective CDM framework in Ontario's history. A February 2022 poll conducted by Campaign Research found that 85% of Ontarians interested in energy efficiency and conservation programs for residents and business preferred that their local hydro utility design and deliver such programs in their communities. **Develop T&D Compensation Frameworks** – the study recognizes that the IESO should coordinate closely with LDCs among its stakeholders on NWA frameworks and compensation approaches for DERs. In fact, LDCs have the capacity and experience to unlock the economic potential of DERs into achievable potential through the aggregation of BTM storage potential. The York Region NWA Pilot being delivered by Alectra Utilities is demonstrating that LDCs could support bulk system needs with DERs, which consequently reduce transmission burden. The IESO and Alectra will be reporting on the Pilot's findings in Q2 2023. These important results would contribute to the development of DER compensation frameworks. **Align telemetry and metering requirements with expected resource contribution** – the study rightly recognizes that metering can be a barrier to entry by emphasizing the need to ensure visibility while avoiding imposing significant and prohibitive cost burdens. Further investigation should be conducted to ensure barriers to entry are minimized or eliminated. Since telemetry and metering costs can be detrimental to a project's economics, i) IESO-specified metering requirements should be consistent with Measurement Canada, and ii) telemetry requirements

should be shown to be necessary for the provision of service under *most* situations.

Other actions that should be considered:

System planning should support LDC investments, particularly regarding EV infrastructure – LDCs face obstacles (described below) in providing customers with domestic and public EV charging infrastructure. Updating compensation frameworks for DERs—and prioritizing EV-related DERs in doing so—would be central to deploying adequate infrastructure to support the federal government's 2035 ZEV mandate.

The OEB is silent on whether LDCs should anticipate their customers' EV uptake by ensuring distribution system upgrades in advance, or if LDCs should be reactive to customer demand for EV charging, risking underservice. Currently LDCs are unable to rate base their EV infrastructure investments, in either a "make-ready" or an "owner-operator" approach. The "make-ready" approach has an LDC investing in the electrical infrastructure and upgrades necessary at the site, while a site host is responsible for the procurement, installation, and ownership of the charging station itself. The "owner-operator" approach has an LDC investing in all the electrical equipment and infrastructure upgrades, as well as the station itself. Both approaches would require LDCs to rate base their investments in EV infrastructure.

In the context of domestic EV charging for passenger and fleet vehicles, another obstacle to EV infrastructure planning is LDCs' lack of visibility of EV registration locations to facilitate distribution planning. Further, for EV charging to realize and harness the V2G/B/X potentials identified in the study, updates to the OEB's policies, codes and guidance would need to meaningfully address two-way power flows.

In addition to domestic charging, LDCs also have a role to play in public EV charging infrastructure along highway corridors and in community clusters. Project developers, including those in the private sector that are not LDCs, have a hard time making the business case for EV charging infrastructure projects. Public charging infrastructure is often funded by automakers as a loss-leader to market and sell EVs. Instead of thinking about public EV charging infrastructure as an evolution of the traditional gas service station, it may be more informative for policymakers and project developers to consider it from the perspective of public transit, where the service (EV charging, akin to transit ridership) is generally not financially viable with only its fare revenues and requires financial support from governments.

Building on the work completed in this study, are there other areas of analysis that should be considered or undertaken that can provide meaningful insights for the IESO and others in the sector?	Suggested areas for further analysis include: Gap analysis of economic vs. achievable potentials (including supply chain constraints) of DER measures selected in the study, and consideration of policy measures to unlock more economic potential into achievable potential of the same. Analysis of telemetry and metering requirements' impact on project economics to ensure those requirements are not a barrier to entry. Analysis of energy storage locations to examine their impact on storage potential (which is vastly different depending on where it is added to the system) and alignment with capacity constrained areas.

General Comments/Feedback

Harnessing a variety of DERs (e.g., HVAC DR, BTM storage, V2B/G/X, FTM storage, preparing for residential and fleet charging programs) into a DERMS platform where some LDCs could orchestrate devices to serve as a virtual power plant (VPP) is a cost-effective alternative to investing in traditional poles and wires, and brings value to local as well as bulk system needs. LDCs have a unique knowledge and understanding of program design, due to their longstanding customer relationships. They should have a primary role in business development for DR and DER programmatic opportunities.

Many LDCs are very interested in DR as a system resource and have experience in residential and commercial HVAC DR programs. To maximize benefits, customers (residential, commercial, industrial) should be able respond to calls from LDCs and be compensated accordingly, without having to choose participation in one program over another.

LDCs need to be very involved in programs that curtail load as it impacts their ability to manage their distribution systems safely and efficiently. Short-term and long-term system planning requires this knowledge. Curtailing load would enable further program development more widespread adoption of NWAs.

The study's BAU+ and Accelerated scenarios anticipate high levels of electrification in transportation as well as in other sectors of the economy. Consequently, there will be increased demand on distributors' systems. System planning needs to support distributor investments to facilitate this transition, including and particularly those relating to EV infrastructure investments, DERs, NWAs and two-way power flows.

Questions Relating to this Study

Does the study consider time to market for components needed in the listed DER measures, e.g., batteries?

Does the study differentiate between LDC or third-party owned FTM infrastructure, e.g., storage?

Does the study allow other ways for BTM measures (besides BTM solar, per Vol. 1, page 57) to participate outside of a net-metering basis?

The study assumes the system operator will be able to access these DERs. Does the study contemplate if it will be able to connect to these DERs, particularly if they sit behind distribution constraints? What changes will be required to utility processes and operations in coordinating this?