September 2, 2022

**VIA RESS**

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge St., Suite 2700
Toronto, ON M4P 1E4

Dear Ms. Marconi:

**Re: Framework for Energy Innovation ("FEI") (EB-2021-0118)**

On May 10, 2021, the Ontario Energy Board ("OEB") issued a letter setting out the priority workstreams for the FEI consultation and announcing the creation of the FEI Working Group ("FEIWG"). As outlined in the letter, the main priorities of the FEIWG were to:

- investigate and support utilities' use of DERs they do not own as alternatives to traditional solutions to meet distribution needs; and
- ensure that utilities' planning is appropriately informed by DER penetration and forecasts.[1]

On June 30, 2022, the FEIWG delivered a report ("the Report") to the OEB detailing the work done to date and provided recommendations for next steps the OEB should take to foster the integration of DERs in the energy sector. Accompanying the report were reports from three subgroups: the Benefit Cost Analysis ("BCA") subgroup, the Utility Incentive ("UI") subgroup, and the DER Integration ("DERI") subgroup. The OEB made these reports public on July 6, 2022, accompanied by a letter inviting stakeholders to comment on the Report to assist the OEB in determining its next steps in this consultation.

Alectra Utilities ("Alectra") participated on the FEIWG, as well as the UI subgroup. Alectra views this initiative as an important step to move forward with a framework for DERs in Ontario.

In the OEB's November 2021 Mandate Letter from the Minister of Energy, the Minister outlined that:

> *The OEB should continue to prioritize its work facilitating and enabling innovation and adoption of new technologies….*[2]

In Alectra's view, this consultation is central to enabling innovation and the adoption of new

[1] Framework for Energy Innovation, May 10, 2021, Appendix A (FEI Working Group and Workstreams)
[2] Mandate Letter from the Minister of Energy, November 15, 2021, p. 2 (MOE Mandate Letter)

technologies, and as such, should continue to move forward in a timely manner. Work on DER policy and integration has been ongoing for some time. Moving forward will require foresight and leadership.

Ontario is facing a looming resource adequacy issue as well as unprecedented demand growth coming from two broad areas: the electrification of vehicles, and de-carbonization, including the electrification of homes, buildings, and processes. DERs should be a prominent feature for addressing current and anticipated supply shortfalls. These issues directly impact the business of distribution and will impact planning activity in the near to medium term in order to properly facilitate and execute DER integration.

Enabling DER adoption and integration and facilitating innovation will require review and amendments to market structures and regulatory perspectives. These require sufficient scope for review, and consequently the scope for consultation moving forward should focus on elements beyond simply DERs that utilities do not own. Specifically, the scope of subsequent review should not be constrained by DERs that utilities do not own and should necessarily expand to include fundamental issues such as the role of utilities and remuneration, which will be key to fostering sector evolution. Many of these issues emerged when the OEB first initiated the Utility Remuneration and Responding to DERs policy initiative in 2019, and much on these issues yet remains to be done.

The OEB has issued specific questions pertaining to areas of focus and is seeking input from stakeholders. Alectra's responses to these questions are presented below.

**Input on Areas of Focus**

*General*

***1. What is the relative priority of the issues and next steps identified by the FEIWG?***

The FEIWG presented seven recommended next steps, as indicated in the report:

1. Provide further guidance on the role of distributors and the expectations of them;
2. Actively engage in the broader energy sector policy development activities;
3. Establish an initial framework and template for benefit cost analysis;
4. Remove DER disincentives including cost recovery uncertainties;
5. Establish an initial DER incentives policy including testing possible incentive structures;
6. Establish an initial policy for the sharing of information between LDCs, DER providers, and customers to support distribution planning and operations;
7. Develop regulatory reporting requirements for DERs, including RRR filings, applications, and other reporting.[3]

[3] Framework for Energy Innovation Working Group - Report to the OEB, June 30, 2022, p.17-19 (FEIWG Report)

Alectra agrees that these are all important items upon which the OEB should engage stakeholders and provide further, detailed direction.

In Alectra's view, the most important among these recommendations is that the OEB provide guidance on the role of distributors. As identified in the FEIWG Report, this issue in particular was a cross-cutting theme that arose in each of the Subgroup reports.[4] It is the only recommendation that necessarily impacts all of the others, and as a result, it must be considered and resolved early on in policy development. For example, it would not make sense to remove cost uncertainties or establish parameters around information sharing without detailing explicitly what activities distributors should (or shouldn't) undertake. As indicated in the Report, this is important because it clarifies the relationship between third-party DER providers and customers, and also serves to inform what modifications to the planning and operation of utility systems may need to take place. This issue is also central to much of the work being undertaken by the Independent Electricity System Operator ("IESO"), and consequently, it aligns well with Recommendation #2 - *actively engaging the broader energy sector policy development activities.*

Establishing the role and expectations for distributors should also include clear guidance on cost recovery conditions for investments utilities will need to make to prepare distribution grids for further DER integration.[5] Such a review should result in clear and binding OEB guidance on cost recovery expectations for these items.

Once the role of distributors has been examined, it will be possible to undertake the establishment of an appropriate benefit/cost framework, removing DER disincentives including cost recovery[6], and an incentive framework for DERs that distributors do not own (Recommendations #3, 4, and 5). As detailed in the FEIWG Recommendation #3:

> "D*istributors would benefit from a formal template that implements the appropriate benefit cost analysis in a way consistent with the framework policy the OEB determines*".[7]

Without a prior determination of the changing role of utilities (if any) it can't be known where incentives will be needed, let alone, which are appropriate in the circumstances.

With the accountabilities, expectations, and framework established, the OEB should then consider what information should be shared as between different parties to support planning and operations (Recommendation #6). Concurrently, the OEB could also consider what information should be

[4] Framework for Energy Innovation Working Group Report, June 30, 2022, p.14. (FEIWG Report)
[5] For example, greater DER integration may require investment or upgrades to certain infrastructure, such as transformers, stations, or feeder capacity for hosting DERS, Advanced Metering Infrastructure, SCADA systems, or operating systems, such as Distributed Energy Resource Management Systems ("DERMS"), among others.
[6] For clarity: cost recovery here refers to costs required to implement DERs, including the opportunity costs for utilities, which is distinct from cost recovery for make-ready investments required to host DERs across the distribution network.
[7] Framework for Energy Innovation Working Group Report, June 30, 2022, p.18. (FEIWG Report)

shared through RRR filings, Applications, and other reporting, such as Distribution System Plans ("DSPs") and Scorecards. As indicated in Recommendation #7, this information should be identified where it will assist the OEB regarding the impact of DERs on utility load, costs, forecasting, planning or other aspects of the utility's business.[8]

*Developing a BCA Framework*

***2. What is the appropriate scope of a BCA Framework? In other words, should a narrow or broad set of benefits and costs be considered with respect to deployment of DERs as alternatives to traditional solutions to meet electricity distribution system needs?***

In Alectra's view, the scope of a BCA framework should include a broad set of benefits and costs with respect to the deployment of DERs. As previously discussed, it will first be necessary to understand what role utilities are expected to play in order to determine how they will approach opportunity identification and analyses. Alectra believes that the identification and evaluation of DER opportunities should consider the full stream of benefits and costs each opportunity entails. As specified in the BCA Report, an appropriate framework would entail the identification of all benefits, costs and impacts associated with the items articulated in Table 3-1 of that Report and would also ensure the avoidance of double counting benefits.

In Alectra's view, however, a BCA framework cannot be completed without first addressing what the analysis is intended to address. In particular, if the evaluation is constrained to simply looking at distribution benefits and costs, then it is likely that there will be missed opportunities to provide cost effective energy solutions for Ontario's ratepayers, resulting in higher than necessary customer bills. The BCA Working Group contemplated this in section 4.1 of their Report with regard to the limitations of adopting a Distribution System Test.[9] In Alectra's view, the framework for evaluation should consider whole energy system benefits, and the OEB should articulate how costs will flow between different sector participants in order to achieve maximum benefits – for example, through settlements with the IESO or as between transmitters and distributors. As indicated in the BCA report (Appendix 1):

> *A focus on distribution customer impacts will lead a decision-maker to select a sub-optimal solution whenever a solution that results in the greatest energy system benefits entails a net cost for the implementing distributor's customers. If a solution achieves benefits for the customers of other distributors that cannot be recouped from those other customers, the two approaches can lead to different outcomes. This is significant because, for instance, the province-wide avoided generation capacity costs arising from reduced peak load are often greater than the avoided distribution system costs.*[10]

Further, the BCA report also points out that market and regulatory structures in Ontario have evolved such that the benefits of DERs cannot always be properly monetized and the mechanisms to ensure

[8] Framework for Energy Innovation Working Group Report, June 30, 2022, p.19. (FEIWG Report)
[9] Benefit Cost Analysis Subgroup Report, June 8, 2022, p.19 (BCA Report)
[10] Benefit Cost Analysis Subgroup Report, June 8, 2022, p.17 (BCA Report)

that costs always follow benefits do not exist.[11] A myopic and siloed view constrained to only distribution benefits in a market design where costs are not appropriately apportioned to beneficiaries are the main obstacles to enabling innovation and the adoption of new technologies. In other words, the path to innovation and evolution lies in addressing market structures or regulatory reforms.

Distributional fairness and the assignment of benefits and costs can be dealt with through policy options and market structure; lost opportunities or sub-optimal projects can bear costs (or lost benefits) for decades.[12] In order to find a resolution, the market and regulatory structures in Ontario should be revisited, revised, and revamped, rather than simply maintaining the *status quo*, which inherently prevents value creation for Ontario's ratepayers. Such review should aim to maximize the benefits of DER integration, while eliminating cross subsidization and ensuring that beneficiaries pay.

*Developing and implementing utility incentives*

***3. How might the OEB remove disincentives for utilities to adopt DER solutions?***

Alectra fundamentally agrees with the point made in the UI Subgroup report that cost recovery mechanisms, if not dealt with or left to uncertainty, can be a disincentive itself:

> *While not technically incentives, cost recovery mechanisms can, if they are incomplete, or delayed, or include any component of risk, represent disincentives and thus barriers to utility support of DERs.*[13]

Alectra envisions that there are two categories of cost for the successful integration of DERs. First, for DER integration to move forward meaningfully, it will be necessary for utilities to begin investing in and implementing certain infrastructure. This base infrastructure will be necessary to accommodate the integration of all DERs, no matter who owns them or how they are evaluated or used. For example:

- System capacity will need to be evaluated at the transmission, feeder, and station levels to ensure that reliability can be maintained or enhanced through the use of DERs, and to ensure that feeders have the capacity to host DERs;
- Advanced Metering and SCADA systems will be necessary for facilitating enhanced information flows to enable two-way power flow and optimized operations;
- Distribution Energy Resource Management Systems ("DERMS") may be required to apply enhanced algorithmic logic to operating systems considering resource capabilities, constraints, locational issues, etc.;

[11] Benefit Cost Analysis Subgroup Report, June 8, 2022, p.17 (BCA Report)
[12] Benefit Cost Analysis Subgroup Report, June 8, 2022, p.21 (BCA Report)
[13] Utility Incentives Subgroup Report, June 8, 2022, p.6 (UI Report)

- Cyber security and data privacy will also likely require further investment in order to deal with the increased amount of data that utilities will be managing within their systems; and
- More sophisticated financial settlement and transactive energy systems will be required to support the increasingly complex relationship between customers, DER providers and utilities.

Second, it will also be necessary to understand the costs the utility will be required to undertake to evaluate and implement DER solutions. For example, procurement of third-party DER services will entail information sharing, engineering studies, and an assessment of alternatives (at a minimum). Alectra believes that clear and binding guidance on the expanded use of utility owned DERs should also be assessed by the OEB. This will then necessitate a review of how the costs related to evaluating, acquiring, and implementing such solutions will be assessed.

Simply put, in Alectra's view, the steps towards removing disincentives for utilities to adopt DER solutions include the following:

- Direction regarding the expectations of utilities are and how DERs are expected to be used;
- Assess what types of costs will be necessary to facilitate the expectations;
- Provide binding guidance around how costs will be evaluated and assessed;
- Understand what barriers must be overcome to reach the desired goals.

In the existing structure, a lack of vision and understanding for these issues is the most significant barrier in Ontario. At present, market players and customers don't know how to proceed, what outcomes are sought and how they can or should evaluate risks and investment planning. Until these issues are directly addressed, enabling innovation and new technologies will continue to be stifled.

***4. Is providing incentives to distributors to facilitate adoption of DER solutions (i.e., non-wires alternatives) appropriate? Under what circumstances?***

Alectra believes that a complete understanding of distributor roles is required before this question can be fundamentally addressed. Considering only the instance where DERs are deployed in circumstances where the utilities do not own them, it is entirely reasonable that incentives to facilitate adoption of DER solutions makes sense. This is so, because, as indicated in the UI subgroup report, procured DER services will be non-capital in nature, therefore impacting utility earnings, resulting in a natural disincentive for utilities to actively identify and pursue opportunities.[14]

Creating incentives that produce agnosticism between traditional and non-traditional alternatives will assist in this regard. It follows then, that the first goal is to clearly articulate the objective so that the disincentive may be understood and an equal and offsetting positive incentive can be applied, where it makes sense to do so. Also, as articulated in the UI paper, getting the incentive right is the key to

[14] Utility Incentives Subgroup Report, June 8, 2022, p.5 (UI Report)

ensuring the optimal solutions are identified and implemented so as to achieve maximum benefits that correspond with the objective.[15]

***5. If incentives are appropriate, how should the OEB select/develop the form of incentive that should be available? A) Are there options the Incentive Subgroup did not identify that should be considered?***

The UI Subgroup appropriately identified a wide spectrum of incentives for the OEB's consideration. Alectra does not believe that there are any options not identified by the UI Subgroup. The report laid out the alternatives, with appropriate discussion of issues, and the strengths and weaknesses for each of the alternatives.

Consistent with the comments above with respect to the relative priority of issues, the OEB should consult further on this topic once it has been determined what utilities are expected to achieve. This might entail considering broader remuneration issues (for example, clear policy and binding guidance around utility ownership of cost-effective DER solutions). In the meantime, for DERs that the utility does not own, it is appropriate that utilities would earn an incentive for identifying and implementing solutions that produce system benefits, in order to offset any disincentives. As articulated in the UI Subgroup report, the capitalization of non-utility owned assets would most directly address the disincentive in this situation.[16]

Alectra believes that the OEB should select and develop the form of incentive that best achieves the objectives sought. For example, the objective (in Alectra's view) should be to actively pursue DER solutions that lead to system wide benefits. The current business model works well for poles and wires solutions; thus, it can work well for non-wires solutions as well, if this is a core utility function. Therefore, the capitalization of DER assets likely makes the most sense. The end product (i.e., the delivery of electrons) doesn't change, nor do the fundamentals for operations and maintenance, grid management, and customer service. As indicated in the UI report:

> *Utility Compensation. Utilities may prefer capitalizing DER expenditures because that generates profits consistent with their existing business model. It is possible that the barrier to DERs is lower in this situation, since the utility comparison is between competing capital costs, and the only difference is that one could be cheaper than the other. In other words, this fits within the traditional perspective for system planning.*[17]

The UI report lays out appropriate evaluation criteria for the OEB to consider as it assesses how to develop incentive structures. Specifically, the report lays out the following items as important criteria:

- Effectiveness of the incentive, including their ability to influence utility behaviour;
- Cost to customers, and specifically to participating and non-participating customers;
- Consequences, both intended and unintended;

[15] Utility Incentives Subgroup Report, June 8, 2022, p.12 (UI Report)
[16] Utility Incentives Subgroup Report, June 8, 2022, p.15 (UI Report)
[17] Utility Incentives Subgroup Report, June 8, 2022, p.17 (UI Report)

- Complexity (or simplicity) of incentive formats and structures.[18]

Alectra does not support non-financial tools or obligations, as they do not produce positive incentives and could have other unintended consequences, such as negative business risk and credit evaluation impacts. Given the importance of policy outcomes related to decarbonization, electrification, and the expected near term penetration of electric vehicles, Alectra does not think it would be prudent to create such obligations. Rather, in Alectra's view, it would be far more productive to engage the sector and develop the right framework to achieve the desired objectives.

*Ensuring distribution planning is informed by DER adoption*

***6. What should the OEB consider when setting expectations to ensure distributors appropriately consider DER adoption when planning and operating their systems (e.g., industry guidance, additional filing requirements for Distribution System Plans, new requirements for reporting and sharing information)?***

The first task is to clearly articulate the expectations and objectives for distributors. This is critical to determining how the sector will, could, or should evolve. With this guidance, consideration can be given to how planning and reporting requirements will need to develop.

In the near term, the OEB should begin consulting on and provide binding guidance to distributors with respect to DER enabling investments. For example, as more DERs are installed involving two-way power flows, distribution operations will be more complex and require new capabilities. For example, the development of new techniques for more granular forecasting and operating controls may be necessary to ensure both enhanced reliability and enhanced asset optimization. Fundamental to enabling these enhanced capabilities will also require certain infrastructure to be in place, as expressed in Alectra's response to Question 3 above.

The DERI Subgroup Report articulated additional recommendations that Alectra agrees are a good starting place for further OEB consideration or consultation:

- Collaborative planning across all levels (provincial and municipal governments, IESO, transmission and distribution) to establish requirements and solutions;
- the provision of information for both planning and operating purposes;
- a method for ascertaining when DERs are a cost-effective alternative for meeting system needs; and,
- mechanisms for the electricity sector to recover the costs of DER solutions and DER-related investments from the beneficiaries, including compensating DERs for any services they provide to the distribution system.[19]

[18] Utility Incentives Subgroup Report, June 8, 2022, p.13-14 (UI Report)
[19] DER Integration Subgroup Report, June 8, 2022, p.4-5 (DERI Report)

**Conclusion**

In closing, Alectra would like to reiterate the importance of these issues as the sector addresses evolution that enables innovation, technology, and enhanced customer choice and value. The *Advisory Committee on Innovation – Report to the Chair of the OEB*, issued on November 22, 2018, identified a number of actions the OEB should take to support sector innovation which remain applicable to this particular consultation. In particular, the following recommendations continue to remain relevant:

> *"provide a transparent and level playing field by clarifying expectations and requirements regarding obligations between parties and towards customers*"; and
>
> *"remove disincentives to innovative solutions by changing how utilities are remunerated and introducing more systematic methods of valuation and pricing*".[20]

The first step in this regard should be clarifying the role of, and expectations for, distributors so that market players can move forward confidently, bringing greater value to Ontario's ratepayers.

Alectra appreciates the opportunity to provide these comments for the OEB's consideration. Should you have any questions, please do not hesitate to contact the undersigned.

Yours truly,

Christine E. Long
Vice President, Regulatory Affairs
Alectra Utilities Corporation

[20] Advisory Committee on Innovation – Report to the Chair of the OEB, November 22, 2018, p.1 (Advisory Committee Report)