Framework for Energy Innovation Working Group

REPORT TO THE OEB

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FRAMEWORK FOR ENERGY INNOVATION WORKING GROUP

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Introduction

Through the Framework for Energy Innovation (FEI) consultation, the Ontario Energy Board (OEB) is seeking to provide increased regulatory clarity in the treatment of innovative energy services technologies and approaches, and support the deployment and adoption of novel, cost-effective solutions in electricity and gas services by utilities and other sector participants in ways that enhance value for consumers. The Framework for Energy Innovation Working Group (FEIWG) was formed to address two specific workstreams defined by the OEB to respond to the most pressing issues in this area and lay the foundations for future work. These two specific workstreams are:

1. **DER Usage:** "*to investigate and support utilities' use of DERs they do not own as alternatives to traditional solutions to meet distribution system needs*."
2. **DER Integration:** "*to ensure that utilities' planning is appropriately informed by DER penetration and forecasts*."[1]

We were tasked with *"identifying options, developing proposals, and preparing written recommendations"*[2] for the OEB to consider with respect to these priority workstreams. This report captures our discussions on these topics and offers recommendations to assist the OEB in its deliberations in furtherance of its objectives.

The energy sector is undergoing a significant transition that has implications for virtually every facet of how energy service is provided, including how such services are regulated. The OEB has indicated that it is taking an incremental approach and addressing issues in a stepwise fashion.[3] We understand this approach to be in recognition of the broad scope and complexity of issues under consideration, as well as uncertainty about the future and the pace of change. In line with such an approach, we read our Terms of Reference (TOR) as reflecting an intent to provide a manageable scope of work that would help the sector make meaningful, near-term progress and lay the foundation for subsequent steps. This had advantages and disadvantages, as detailed below.

Over the course of our discussions, it became clear that even the relatively narrow scope we were given was open to divergent interpretations, and was challenging to address without discussing issues that, while out of scope, are intrinsically related and important to the topics under consideration. We were deliberate in our efforts to stay within scope, but also believe it is important to situate our recommendations within the broader context.

[1] FEIWG Terms of Reference, May 26, 2021, page 5 (Framework for Energy Innovation (FEI) - Terms of Reference (oeb.ca)).
[2] FEIWG Terms of Reference, May 26, 2021, page 1 (Framework for Energy Innovation (FEI) - Terms of Reference (oeb.ca)).
[3] OEB's March 23, 2021 Letter, page 2.

Natural Gas

The working group considered issues pertaining to DER usage and integration from an electricity sector perspective, or a generic perspective, but rarely from a purely natural gas sector perspective.

Natural gas was generally discussed in three contexts:

- Acknowledging the importance of breaking down energy silos including those between natural gas and electricity planning.
- The extent, if any, to which current regulatory requirements for natural gas utilities may be instructive for the electricity sector or vice versa.
- Referencing the Natural Gas IRP proceeding (EB-2020-0091), which addressed similar issues this group was tasked with exploring, but specifically for the natural gas sector. We agreed that, to facilitate integration of natural gas and electricity planning, some degree of policy consistency may be helpful but is not always necessary or desirable given the different situations of the two sectors.

For instance, the degree of change occurring in the energy sector may be calling into question the continued appropriateness of the current distribution utility[4] role and rate-regulation framework. We were not asked to consider these fundamental issues, but they were of necessity a recurring theme in our discussions. Similarly, as we carried out the tasks at hand, we recognized that the landscape continues to change. Since the FEI Working Group was convened in May 2021, Ontario's anticipated supply needs have changed, including forecast increased future demand[5] heightening interest in, and increasing efforts to accelerate, DER adoption and address DER integration challenges. Considering this, we agreed that the OEB must maintain momentum in its efforts to adapt the regulatory framework as the sector evolves and DER adoption grows, recognizing that thoughtfully developing and implementing new approaches takes time and, along the way, some issues may require urgent attention. The sector should prepare for a high-DER penetration future before it is upon us.

This is the report of the FEI Working Group, which we have all approved. The OEB purposefully assembled a working group of diverse and informed stakeholders. This diversity resulted in fertile discussions. This report reflects our collective description of what we discussed and the issues we addressed. Although we have sought general consensus, there may be one or more members of the working group that would oppose some of the options, issues and/or next steps included in this report. While more work remains to be done, we hope that this report informs the OEB in determining appropriate next steps, and we have developed some recommendations in that respect.

[4] Throughout this report the terms "utility" and "distributor" are used interchangeably.
[5] The IESO's Annual Planning Outlook Report forecasts increased electricity demand that, due to a variety of factors including the electrification of transportation and economic growth, rises rapidly in the early 2030s. (Annual Planning Outlook Report, December 2021)

This report is organized as follows:

- First, we provide an overview of our process and activities over the past year.
- After that, we provide summaries of the key points identified by the subgroups which we mandated to explore the main topics reflected in our TOR. These summaries should be read in conjunction with the full subgroup reports (Appendices A, B and C) to get a complete picture.
- Our report then provides observations on the overarching and cross-cutting issues that emerged from the subgroups' work and our own discussions.
- Finally, we attempt to frame next steps that the OEB can consider as its work to understand and respond to the energy transition continues.

The FEIWG understands the OEB intends to publish this report for broader stakeholder comment.

Developing our Advice to the OEB

This section provides an overview of the steps we took to carry out the tasks in our TOR, which is attached to this report as Appendix D.

We took on the tasks set out in our TOR in sequence. First, we nominated three administrative co-chairs – Sarah Griffiths (Enel, a DER solution provider), Ian Mondrow (AMPCO & IGUA, utility customers) and Andrew Sasso (Toronto Hydro, an OEB regulated electricity distributor) – who, along with OEB staff, planned and chaired working group meetings to support the group in achieving its objectives. We developed a workplan which was revamped around the halfway point and periodically refined as work progressed. The working group met 21 times over the past year.[6] Collectively, the subgroups met 37 times.

The FEIWG gathered information and expertise from among its membership and supplemented that with additional expertise as required. Additionally, the subgroups leveraged industry documents such as the National Standard Practice Manual for DERs.[7] While our dialogue was informed by various presentations and documents referenced in our reports, it is important to recognize this was not a process designed to develop, receive, or test evidence on each issue. There is a general view that, to be sound and robust, policy should be evidence-based[8], a view which is reflected in our recommended next steps.

In early meetings, we received a series of presentations from FEIWG members and guests, including OEB staff leading related consultations and expert consultants retained by the OEB to support the FEI consultation; London Economics International LLC and ICF. These presentations[9] helped us to develop an understanding of how DERs can create value for consumers (individually and collectively), how they may be used to meet system needs, issues that must be addressed to advance the cost-effective use and integration of DERs, and the roles and interests of different stakeholders and sector participants. This stage was important for level-setting and providing everyone with a common set of background information, thus providing a basis for subsequent discussion.

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[6] FEIWG meeting materials and all other OEB documentation pertaining to this consultation is available at: https://engagewithus.oeb.ca/fei

[7] *"The National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources provides a comprehensive framework for cost-effectiveness assessment of DERs. The manual offers a set of policy-neutral, non-biased, and economically-sound principles, concepts, and methodologies to support single- and multi-DER benefit-cost analysis."* National Standard Practice Manual, August 2020

[8] "Evidence based" means based on facts that are properly validated, for example as is the case in a hearing (though there may be other ways to obtain such evidence). While there is agreement that expediency in development of DERs policy is desirable, it should not come at the expense of a sound policy development process that provides appropriate evidence on which that policy can be properly built.

[9] Many presentations included information about other jurisdictions, not all of which have energy sector structures, and/or economic, political, or geographic circumstances, which are directly relevant to Ontario. These presentations assisted in revealing DER integration issues that may exist because of the structure of Ontario's energy sector.

Next, we developed a working definition of DERs and a set of use cases to inform discussion on the three key topics set out in our TOR; i) a Benefit-Cost Assessment framework for measuring benefits and costs of DER solutions; ii) utility incentives to adopt DER solutions; and iii) DER information distributors need to plan and operate their systems.

Working Definition of DER

For the purposes of our work, we considered a DER to include any resource, whether in front of or behind the meter, which could provide an alternative to traditional utility solutions to meet distribution system needs or which could have a material positive or negative impact on the distribution system.

In developing a working definition, we considered several existing definitions (for example, from the IESO[10] and the National Standard Practice Manual for DERs[11]), each of which was developed within a specific context. Ultimately, we agreed to a working definition that was sufficient to anchor our discussions but purposefully broad so as not to exclude discussion of any resource that could impact distribution systems. It was agreed that any definition of DERs will be contextual in nature. This definition was intended to be specific to our work and was not formulated for use in different contexts.

With assistance from ICF, we developed and discussed six use cases that illustrate how DERs could be used as non-wires alternatives (NWAs). The use cases serve as illustrative examples and were not intended to capture all possible DER solutions. The inclusion or exclusion of certain DER solutions should not be construed as a comment on the feasibility, cost-effectiveness, or relative value of certain solutions in Ontario. Like the presentations we received, developing the use cases helped us gain an understanding of the types of DER solutions that can be implemented to meet distribution system needs. The use cases were intended to support subsequent discussions by providing scenarios against which specific ideas or options could be tested. While they were not ultimately used in support of any specific analyses because we generally did not compare or attempt to reach consensus on preferred options, the BCA subgroup relied on the use cases to develop examples of the outcomes of different BCA tests. The use cases are set out in Figure 1.

[10] *"DERs are electricity producing resources or controllable loads that are connected to a local distribution system or connected to a host facility within the local distribution system. DERs can include solar panels, combined heat and power plants, electricity storage, small natural gas-fuelled generators, electric vehicles and controllable loads. These resources are typically smaller in scale than the traditional generation facilities that serve most of Ontario demand."* – IESO (Distributed Energy Resources (ieso.ca)).

[11] The NSPM defines a DER as: *"resources located on the distribution system that are generally sited close to or at customers' facilities. DERs include EE, DR, DG, DS, EVs, and increased electrification of buildings. DERs can be either on the host or customer side of the utility interconnection point (i.e., behind the meter) or on the utility side (i.e., in front of the meter). DERs are mostly associated with the electricity system and can provide all or some of host customers' immediate power needs and/or support the utility system by reducing demand and/or providing supply to meet energy, capacity or ancillary services (time and location) needs of the electric grid."* – National Standard Practice Manual, August 2020

Figure 1: FEIWG Use Cases

Use Case #1: Industrial Demand Response to Provide Distribution Capacity

On feeder lines where more commercial/industrial capacity is requested, demand response that reduces existing customers' load can free up capacity for new customers if it provides for consistent power quality and reliable supply for the anticipated duration and timing. Industrial demand response controls installed at key customer sites and configured to be both remotely monitored and dispatchable could be used to avoid costly feeder upgrades. These solutions are mature, scalable, and cost-effective.

Use Case #2: Electric Vehicles to Provide Reliability

Where improved reliability is needed, EVs are close to load and could be dispatched to provide energy to customers who are islanded during an outage. EV capabilities for reliability needs depends on the number of EVs, location, available storage, and capabilities for using on-board batteries as a critical load power supply. EVs are highly scalable, potentially dispatchable, and can be deployed at relatively low cost via incentive programs.

Use Case #3: Solar PV and Storage Projects to Provide Resilience

A section of a 44 kV distribution feeder has multiple, significant outages from catastrophic tree failures and contacts. Dispatchable DERs can improve resilience by providing short-term energy to the area during storm season (May – October) and when high winds are forecasted. With information about the specific energy needs and potential interconnection points, third party developers can install solar PV and storage to deliver energy when needed, while also generating solar energy for local/community supply when not needed for resilience.

Use Case #4: Market-Based DR Aggregation to Provide Capacity

Where localized, short term capacity constraints are forecasted a market-based approach to aggregated demand response from the residential and small commercial sectors could alleviate the expected constraint. This solution would leverage a combination of third-party platforms and appropriate incentives to shift and/or modify loads in sufficient volumes to address the capacity issues, enabling continued overall load growth without costly line and equipment upgrades.

Use Case #5: DER Portfolio Approach to Provide Distribution Capacity

Service areas experiencing rapid growth will have capacity constraints for overall load and demand peaks. A portfolio of DER technologies could be deployed to reduce and/or modify both existing and new customer loads to defer adding significant new capacity in the affected service territory. The aggregated solution could potentially include energy efficiency, demand response, BTM solar, combined heat and power, managed EV charging, and other technologies.

Use Case #6: Solar PV Equipped with Smart Inverters to Address Power Quality

In areas with significant solar PV adoption by residential and commercial customers, the typical load profile served by specific substations changes. Smart inverters installed with these solar PV systems can help address power quality issues that arise on the local network, avoid substation upgrades and delay transformer replacements. Providing interconnection, technical, and operational guidance for customers as they plan for and install their solar PV systems could unlock the potential for DER-based solutions to these localized power quality issues.

Following the development of the working definition and use cases, the FEIWG established subgroups to work through, in greater depth, the three tasks in our TOR:

- **The Benefit Cost Analysis (BCA) Subgroup** was tasked with defining an approach to measure the benefits and costs of DER solutions as alternatives to traditional distribution investments.
- **The Utility Incentive (UI) Subgroup** was asked to explore appropriate incentives for utilities to adopt DERs for distribution uses that do not require equity investment by the utility.
- **The DER Integration (DERI) Subgroup** was convened to identify information about DERs that distributors require to plan and operate their systems effectively.

The membership of each subgroup was purposefully chosen to include representation of each of the perspectives of utilities, customers, DER solution providers and DER advocates. Each subgroup developed a report capturing discussion by its members of the issues assigned to them by the working group. The subgroups updated the working group members along the way and sought feedback to inform their discussions and the development of their reports. The subgroup reports are filed along with this report as appendices. Each of these subgroup reports provide considered, in depth discussion of one of the main topics in the FEIWG's TOR. We refer the OEB and interested readers to these subgroup reports for detailed discussion of these topics. Like this report, the subgroup reports reflect a collaborative effort to document the subgroups' discussions, including input provided to the subgroups from the FEIWG. Those reports may not fully reflect the views of all FEIWG or subgroup members on a given issue.

Electricity Distributor Diversity

There are 60 electricity distributors in Ontario. In our discussions, we tried to remain mindful of the different nature and implications of DER integration in densely populated urban centres and remote First Nation communities (and everything in between). DER use cases and integration challenges will be different, as will be the benefits depending on the service area in which they are deployed. The current capability of disparate distributors to integrate and plan for DERs also varies.

The Work of the Subgroups

This section provides a summary of each of the three subgroup reports but is not a replacement for reviewing those reports directly to get a more comprehensive and nuanced analysis of each subgroup's discussion and recommendations.

The BCA Subgroup

We tasked the BCA Subgroup with "*Defining an approach to measure the benefits of the DER use cases relative to costs and assess the value of DERs relative to traditional distribution investments*."[12]

The BCA Subgroup identified five components for a BCA Framework to define such an approach:

1. **Purpose and use:** identifies when a BCA is required and the BCA's intended use.
2. **Information requirements:** lists the impacts that should be considered for assessment in a BCA.
3. **Cost-effectiveness test:** sets out how the BCA impact assessments will be used to inform the decision on which solution should be deployed by the distributor, all other planning considerations being equal.
4. **Standardized methods:** provides standard methods, assumptions, and tools for carrying out assessments.
5. **Reporting requirements:** establishes the format for reporting BCAs.

> **DERs and Indigenous Communities**
>
> Concurrent with the energy transition, Ontario is seeing increasing Indigenous economic participation in the energy sector, particularly among communities that have been underserved or experience on-going reliability challenges where DER solutions may be appropriate.

The BCA Subgroup considered the BCA within the context of a distributor's planning process because the output of a BCA would be one of the factors that would inform a distributor's planning decisions between DERs and traditional distribution investments. Similarly, the BCA Subgroup considered the BCA Framework in the context of guidance that would be provided by the OEB to distributors to explain how the OEB would review, for example, a distribution system plan (DSP).

The BCA Subgroup's discussions uncovered a fundamental difference of opinion regarding the appropriate scope of considerations for decisions regarding DER and traditional solutions funded through distribution rates.

[12] FEIWG Terms of Reference, May 26, 2021, page 5 (Framework for Energy Innovation (FEI) - Terms of Reference (oeb.ca)).

As a starting point, it was agreed that the benefits and costs of DERs are often much broader than traditional distribution investments and can include impacts to the whole energy system (i.e., capacity, energy, reliability improvements, avoided bulk delivery, and potentially additional ancillary services).

If costs follow benefits, there are no concerns with how cost-effectiveness would be reviewed by the OEB. In this situation, the benefits relating to resource or transmission services would be paid by the benefiting ratepayers, and the social benefits would be paid by society. There would be no concerns about distributional fairness, price signals or jurisdiction.

However, in Ontario's reality, costs do not always follow benefits, and this can impact the implementation of DERs depending on the approach that is taken. Including all energy system or societal benefits in a cost-effectiveness test used by a distributor would promote the selection of options that would, respectively, lower overall Ontario energy bills (using an energy system approach) and maximize overall net benefits (using a societal approach). Distribution ratepayers might potentially pay for a DER, through distribution rates, based on benefits that do not exist within the distribution system or do not accrue to the implementing distributor's customers. This could generate a net cost to the implementing distributor's customers for a project, even if it results in lower energy bills for electricity customers as a whole on average.

The BCA Subgroup offered measures of cost-effectiveness for the OEB to consider[13] and recommended that the OEB provide direction on the scope of BCA to be applied for decision making regarding distributor deployment of DERs in the alternative to traditional distribution system solutions.

The UI Subgroup

We tasked the UI Subgroup with "*Developing appropriate incentives for distributors to adopt DERs for distribution uses that do not require equity investment by the utility*."[14]

The UI Subgroup prefaced its discussion by acknowledging that changes happening in the electricity and natural gas distribution sectors are calling into question the continuing appropriateness of the utility remuneration paradigm, in use for many years. However, the UI Subgroup acknowledged that a reconsideration of the utility compensation model, and/or the roles and responsibilities of distributors, is outside of the FEIWG's scope. The UI Subgroup's Report therefore identified various forms of incentives that could be adopted within the OEB's current rate-setting paradigm and discussed the benefits and drawbacks of each option.

The options identified include some which are already in use in Ontario or other jurisdictions, such as shared savings mechanisms, which are a relatively common feature of demand side management frameworks, as well as more novel or emerging approaches, such as scorecard-based financial incentives, earned when certain predetermined performance targets are achieved. In choosing an approach or combination of approaches for incenting distributors to

[13] See Table 4-1 on page 17 of the Report of the BCA Subgroup
[14] FEIWG Terms of Reference, May 26, 2021, page 5 (Framework for Energy Innovation (FEI) - Terms of Reference (oeb.ca)).

adopt non-utility owned DER solutions, the UI Subgroup suggested that the OEB consider factors such as the effectiveness of the incentive, the cost to customers, intended and unintended consequences of different approaches, and regulatory simplicity.

The UI Subgroup also discussed the importance of considering the utility's costs associated with adopting DER solutions and ensuring that any disincentives for DER solutions are addressed before further financial incentives are considered. Adopting DER solutions in place of traditional wires and poles investments may give rise to new costs associated with, for example, new planning or procurement activities or providing incentives to DER solution providers contracted to provide services to the distribution system (e.g., capacity, reliability, power quality, etc.). If recovery of these costs is incomplete, delayed, or includes undue risk because current cost recovery approaches do not adequately account for DER-related activities, this could present a disincentive for utilities to adopt DER solutions. The subgroup concluded that issues related to appropriate recovery of a utility's costs associated with adopting DER solutions and any disincentives for DER solutions should be addressed.

DERI Subgroup

The DERI Subgroup was tasked with "*identifying information distributors require regarding existing DERs to effectively operate and make future system plans*"[15] and provided a report that identifies, at a high-level, why distributors need information about DERs, what information they should consider, and how such information might be collected.[16]

The DERI Subgroup agreed that distributors need information about DERs to understand how the system is and will be used in order to, among other things, identify and plan for current and future system needs and, at the right time, make the business case for enabling investments. It was observed that DER information will also help utilities evolve planning and operations as DER penetration, and the resulting need for more active system management and asset optimization, grows. Finally, it was noted that utilities will need information to identify NWAs and NPAs (non-pipeline alternatives). This includes understanding where and how non-utility owned DERs can be used to meet system needs, carrying out BCAs, and developing internal processes to procure and manage non-utility owned DER solutions.

With respect to what information is needed, three main categories were identified: forecasts of DER adoption, DER usage data, and market relevant information to enable the use of DERs as NWAs or NPAs.

Distributors need information about future DER adoption to inform planning decisions. However, synthesizing information from different sources to paint a complete picture will be a challenge. There is value in a common forecast and/or set of planning assumptions but information must

[15] FEIWG Terms of Reference, May 26, 2021, page 5 (Framework for Energy Innovation (FEI) - Terms of Reference (oeb.ca)).

[16] Unlike the BCA and UI subgroups which focused on the use of DERs as NWA's alternatives to meet distribution system needs, the DERI Subgroup was tasked with considering information distributors require to account for DER adoption broadly (i.e., DERs adopted by consumers for their own purpose and those deployed to provide services to IESO administered markers, as well as DERs used as NWAs to meet distribution system needs).

also be sufficiently granular and specific to a distributor's service area to inform planning decisions in a meaningful way.

With respect to DER usage data, distributors need information about how DERs connected to their systems are being used by customers. Some DERs are, or appear from the system's perspective, akin to a variable load, and existing methods used to monitor changes in load patterns over time for planning and operations purposes may be sufficient for these DERs. Other DERs will directly interact with the system, for example by injecting supply, and distributors will require more information and visibility of these resources.

Finally, with respect to information needed about DERs looking to provide services to the distribution system (as NWAs or NPAs), distributors will need information about the presence and availability of these resources to provide such services, to factor these solutions into their system plans. The flow of information must go both ways. The market requires information about distributors' needs so that solutions can be offered. Although information distributors should provide to the market to facilitate DER use and adoption was outside the scope of the DERI Subgroup's TOR, the Subgroup found it difficult to discuss the information distributors need, in isolation from the information distributors should provide. To enable NWAs, market relevant information – that is, price, quantity, term, and location – must be exchanged between distributors and third-party providers or customers. In establishing regulatory requirements for the information exchange, the OEB should have regard for the cost of collecting information versus the benefit of having it, privacy and commercial sensitivity, and standardization.

In addition to a number of specific recommended actions, the DERI Subgroup suggested the OEB should clarify its expectations of distributors in relation to DER integration, so that distributors can determine what information they have or need to deliver on those expectations.

Cross-Cutting Issues

Although focused on different topics, there was a great deal of common ground covered in the subgroup's discussions. This section describes the issues that were encountered by all three subgroups.

Role of Distributors

The subgroups identified the need to clarify the role of distributors in an evolving sector.

The BCA Subgroup raised the question of whether a distributor should have a role in considering the cost and benefit impacts of its DERs decisions on the electricity system as a whole or should only consider the impacts on its own distribution customers.

The UI Subgroup suggested that in order to "*assist in identifying what changes are needed to unshackle utilities and allow them to meet the needs of customers using more DERs*"[17] the OEB should identify what utility actions that can affect DER implementation are currently or prospectively required, allowed, or prohibited.

Similarly, the DERI Subgroup noted that to "*facilitate the greater enablement of non-utility owned DERs reconsidering the role, responsibilities, and activities of distributors may be warranted*."[18] They also recommended that the OEB make its expectations of distributors clear with respect to DER integration.

Uncertainty about the future role of distributors sometimes impeded the FEIWG's and subgroups' discussions. It may not be possible, or necessary, to determine the role of distributors definitively or exhaustively in an evolving sector. Indeed, decisions about some activities are already being made on a case-by case basis.[19] However, in providing guidance on BCAs, utility incentives and integration of DERs, the OEB will have to make certain assumptions about the current roles of the distributor and making those assumptions express would be of assistance to the sector.

The FEIWG did identify an important distinction between ***deciding*** the role of distributors, and expressly ***assuming*** a specific role of distributors for the purpose of developing DER policies. Many members believe that, as the sector is evolving, the role of distributors may also evolve, and may do so in ways that are not fully predictable today. However, most members agree that,

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[17] Report of the Incentives Subgroup, p 26
[18] DER Integration Subgroup: Report to the FEI Working Group, p 5
[19] Examples include: (1) Decision and Order on Toronto Hydro's application for 2020-2024 distribution rates (EB-2018-0165) which approved, among other things, rate recovery of a local demand response segment of the Stations Expansion program and the use of in front of the meter storage to meet distribution system needs.
(2) OEB Staff Bulletin (July 7, 2016) stating that Electric Vehicle Charging Services are not a distribution activity, do not constitute retailing electricity and does not generally fall under OEB oversight.
(3) OEB Staff Bulletin (August 6, 2020) providing guidance in respect of a set of circumstances in which the ownership and operation of behind-the-meter (BTM) energy storage assets may be considered a distribution activity for the purposes of section 71(1) of the *Ontario Energy Board Act, 1998*.

for the purpose of determining policy guidance, the OEB must have a clear picture in its mind of what distributor role is assumed in that guidance. That assumption may then change over time, and the policy guidance may change with it.

Planning Integration and Coordination

The challenge of integrating DERs and realizing their full range of potential benefits to meet Ontario energy needs, in an electricity system where supply, transmission and distribution are separate functions and where gas and electricity planning are undertaken largely separately, was also a cross-cutting theme.

For the BCA Subgroup, this issue manifested in part as a coordination challenge. That subgroup noted that the benefits and costs of DERs are often much broader than traditional distribution investments and can include impacts to the whole energy system in addition to the distribution system (i.e., capacity, energy, reliability improvements, avoided transmission, and potentially a number of ancillary services). The BCA subgroup also noted that Ontario does not have a single entity responsible for planning, procuring and operating all energy system services which adds complexity and co-ordination challenges for securing DERs that can provide multiple services to the energy system.

The UI Subgroup suggested the OEB may wish to consider whether "planning that focuses on building and managing the utility distribution system, as opposed to starting with the needs of the customers and working backwards to the available solutions" will be sufficient as the sector evolves.

The DERI Subgroup discussed the need for changes to current planning approaches to identify and implement NWAs and to cost-effectively integrate DERs adopted for other reasons (e.g. to meet consumer needs or provide services to the IESO). The DERI Subgroup also identified the need to coordinate natural gas and electricity system asset plans and operation.

The FEIWG recommends that the distributors (natural gas and electricity), transmitters and IESO co-ordinate planning and forecasting in the energy sector. The FEIWG recognized that through improved OEB guidance in relation to BCAs, utility incentives and integration of DERs distributors, transmitters, and the IESO will be aided in coordinating and integrating their planning.

Alignment and Coordination with the Natural Gas Sector

Although discussions largely focused on the electricity sector, linkages with, and the applicability of different issues to, the natural gas sector were considered by all subgroups.

Throughout this process the FEIWG and its subgroups remained conscious that the OEB has made an initial decision on many issues related to the adoption of NPAs (the equivalent of NWAs) for gas distribution.[20] The decision discussed incentives to adopt NPAs and information

[20] EB-2020-0091, Enbridge Gas Inc. Integrated Resource Planning Proposal, Decision with Reasons, July 22, 2021

to be filed about opportunities for NPAs. The IRP Technical Working Group directed by that decision is currently addressing the details of an IRP framework, including a BCA approach. Coordinated planning between the natural gas and electricity sectors is an important goal, but structural and technological differences between them may call for distinct approaches. It was helpful and important to consider natural gas in our discussions, even if we determined not to seek to solve for issues specific to natural gas, but rather to defer to the separate gas IRP Technical Working Group forum.

The need for more integration between gas and electricity planning was discussed on numerous occasions. Natural gas and electricity utilities may need to consider one another's system plans to optimize their respective assets. These issues were also identified by the Regional Planning Process Advisory Group in its recommendations to the OEB.[21]

Coordination of DER Initiatives Across the Sector

The OEB and IESO are carrying out numerous DER-related initiatives. We recognize that this is necessary because it is not practical, perhaps not even possible, to address all DER-related issues in a single overarching forum. However, it would be best that these efforts lead to a cohesive, rational framework for DER integration, rather than result in a host of new, uncoordinated, and potentially inconsistent regulatory requirements. This could create unnecessary barriers to, and result in incremental and avoidable costs of, DER deployment.

As a result, the need for improved coordination of DER initiatives and a shared vision for how DERs will be integrated in Ontario to the benefit of consumers is reflected in our recommended next steps.

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[21] "The RPPAG therefore anticipates the need for improved coordination between Natural Gas Planning and Electricity Regional Planning may increase in the future for reasons that also includes the following:

- To avoid planning for the same energy need. For example, the IESO and Enbridge assume different levels of electrification resulting in over- or under-planning.
- To avoid unintended consequences between the two systems. For example, if Enbridge plans for NPA investments using electric powered heat pumps, regional planning should be informed and incorporate the increased load growth, including informing Enbridge if the electricity grid can accommodate the additional load within the timelines that the NPA investment must be deployed. If electric grid investments are required, the associated costs and benefits should be provided to Enbridge so they can be taken into consideration."

Recommended Next Steps

To assist the OEB in its efforts to keep up with the energy transition and achieve its goals for the FEI consultation – *"to contribute to increased regulatory clarity in the treatment of innovative technologies and approaches"* and to *"further support the deployment and adoption of novel, cost effective solutions in ways that enhance value for consumers*"[22] – we are pleased to recommend the following next steps.

The next steps listed are deliberately not prioritized, because the sector is already evolving, and the role of the OEB will necessarily be both proactive and reactive.

The steps to be taken may be in some cases sequential, and in other cases parallel activities. The level of urgency of each of these steps is a matter of debate, and the importance of each step may depend on policy decisions with respect to other steps. We recognize the suggested activities below cannot be undertaken all at once.

We also agree that, as noted at the outset of this report, things are changing. The energy sector is undergoing a significant transition. Definitive, ongoing guidance from the OEB on the issues which we have raised and reflected in this report, and the steps that we have suggested be taken, would assist the sector and support the deployment and adoption of novel, cost-effective solutions in ways that enhance value for consumers.

The Subgroup reports have provided detailed recommendations on actions that could or should be taken by the OEB. The following summary highlights some of the key takeaways from the work of this Working Group as a whole:

1. ***Provide Further Guidance on the Role of Distributors and the Expectations of Them.*** While the evolution of the sector may mean that longer term changes to the role, responsibilities and activities of distributors cannot, and perhaps should not, be determined and implemented immediately, distributors would benefit from guidance on what is expected from them in the short term. This includes things such as their relationship to third party DER providers and customers, and modifications to the planning and operation of their systems to reflect changes in the broader energy marketplace in which distributors operate. Like all guidance in these areas, this may change over time, but for right now distributors need assistance in determining practical things like how to modify the development of their next Distribution System Plan to be consistent with OEB expectations.

2. ***Actively Engage in the Broader Energy Sector Policy Development Activities.*** The changes to the energy sector are being discussed, and policy changes are being made, by the OEB, IESO, government ministries and agencies at multiple levels, and by many non-governmental organizations. The OEB can play a valuable role by actively engaging in the many initiatives of those other bodies currently underway, and those coming in the

[22] FEIWG Terms of Reference, May 26, 2021, page 1 ([Framework for Energy Innovation (FEI) - Terms of Reference (oeb.ca)]).

near term (including and expanding its engagement with IESO). Examples include continuing active coordination with the IESO, providing a forum, and establishing a communications hub to ensure that stakeholders, including regulated utilities, have regular and consistent information on the evolution of the sector and the policy changes being proposed or implemented by the various actors.

3. ***Establish an Initial Framework and Template for Benefit Cost Analysis.*** Developing the Framework involves policy decisions on what information on benefits and on costs should be included, and for what purposes. It may involve distinguishing between factors that are used for decision-making purposes versus other purposes. Distributors would also benefit from a formal, OEB-developed template that implements the appropriate benefit cost analysis in a way consistent with the framework policy the OEB determines.

4. ***Remove DER Disincentives including Cost Recovery Uncertainties.*** Separate from consideration of any positive incentives for distributors, it is important that the OEB ensure that DER-related disincentives and cost recovery uncertainties are removed. This would require a rigorous identification of those disincentives and uncertainties, and policy determinations by the OEB as to which of those, if any, are appropriate utility risks, and which should be adjusted or ameliorated to assist distributors and encourage the evolution of the sector.

5. ***Establish an Initial DER Incentives Policy including Testing Possible Incentive Structures.*** The Report of the UI Subgroup provides a list of potential financial and non-financial incentives for distributors to encourage DERs, and criteria for analyzing those incentives. The OEB should first make a general policy decision as to the extent, if any, to which positive incentives are appropriate. The next step would be to test any incentives that fit within that policy against actual use cases to determine the real-world consequences. This could be done by modeling, by pilot projects, or through utility applications.

6. ***Establish an Initial Policy for the Sharing of Information between LDCs, DER Providers, and Customers to support distribution planning and operations.*** LDCs, DER providers, and customers each have information that would be of value to the others. Both the nature of that information, and the needs of the parties, will evolve over time. At least initially, regulated utilities would be assisted in incorporating DERs into their planning and operations if the OEB established a transitional policy for information sharing (including with respect to pilots) in all directions, stipulating the types of information to be shared, and the timing and method of sharing (including among LDCs). While Green Button may provide some information sharing, more will be required, particularly by distributors.

7. ***Develop Regulatory Reporting Requirements for DERs, including RRR Filings, Applications, and other OEB Reporting.*** Key to the OEB staying on top of the changes taking place in the energy marketplace relating to DERs will be the information that it receives. The two main information flows – RRR filings, and Applications – should be revised so that the OEB has initial information on the impact of DERs on load, customer requirements, costs, forecasting, planning, and other aspects of the regulated utility's business. Distributors would be assisted if the OEB took a proactive approach to these information expectations.

As covered earlier in our report, and specifically in relation to DER planning and implementation, we also acknowledged the importance of breaking down energy silos including those between natural gas and electricity planning, as reflected in the OEB's recent acceptance of the Regional Planning Process Advisory Group's recommendation to enhance the coordination of other planning processes with regional planning. More work in this area is warranted.

The OEB should remain open to utilities developing and seeking approvals for DERs in the interim. Major distributors are in the process of preparing rebasing applications now. Although it is preferable to provide guidance to utilities as soon as possible and to make decisions on distributor applications based on pre-existing policy, the time required for ongoing development of policy ideally should not result in lost opportunities to pursue cost-effective non-wires alternatives or appropriately plan for customer-driven DERs.