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Framework for Energy Innovation

Report of the DER Integration Subgroup

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Submitted to:
The Framework for Energy Innovation Working Group

Submitted by:
The DER Integration Subgroup

Contents

1 Introduction

The Framework for Energy Innovation Working Group (FEIWG) established the DER Integration (DERI) Subgroup to identify information about DERs distributors need to plan and operate their systems effectively. The members of the Subgroup are:

- Spencer Gill, Hydro One (Lead)
- Marc Brouillette, Canadian Manufacturers and Exporters and Ontario Chambers of Commerce
- Cara-Lynne Wade, Enbridge
- Utilia Amaral, Energy Storage Canada
- Darren McCrank, EPCOR
- Nimal Weeratunga, Enwin
- Adam White, Powerconsumer

The work of the Subgroup was assisted by OEB Staff Rachel Anderson and Andrew Brinn.

This is the Report of the DERI Subgroup to the FEIWG. The views expressed in this Report are intended to reflect the discussions of the members of the Subgroup. The Report may not represent views of the individual organizations represented in the group and does not represent the views of the OEB or OEB Staff.

The FEIWG and its subgroups are tasked with considering the electricity and natural gas sectors; therefore, the DERI Subgroup discussed their task within the context of both sectors. That said, because of the non-vertically integrated structure of the electricity sector as well as some technological differences, certain information gaps and challenges required specific electric DER discussion. Also, the OEB has made an initial decision on matters pertaining to non-pipe alternatives (NPAs) for gas distribution in EB-2020-0091, Integrated Resource Planning Proposal, Decision and Order, July 22, 2021. This Report assumes that Enbridge will implement DERs/IRPAs consistent with that decision, unless and until the OEB establishes new parameters for gas IRP. Coming out of this decision, the OEB is now leading a natural gas IRP Technical Working Group (TWG). The IRP TWG's first priorities are the selection and implementation of IRP pilot projects, as well as consideration of enhancements or additional guidance in using the Discounted Cash-Flow-plus economic evaluation methodology. Within the natural gas IRP Framework Decision, the OEB has outlined which supply side and demand side alternatives, or DERs in the context of the FEIWG's work, are permitted. Information requirements to support NPAs are being implicitly addressed in this process.

Throughout the Report, we have called out the relevance of certain discussions to natural gas, as applicable. In addition, this Report discusses how considering both the electricity and natural gas sectors when integrating DERs will ensure the optimization of assets. This Report is organized as follows:

- Section 2 sets out the contextual issues considered by the Subgroup
- Section 3 discusses why information is needed and how it will be used.
- Section 4 identifies distributors' information needs and how it might be obtained, if not already available.

- Section 5 discusses information related to natural gas distributors and the need for more integration between natural gas and electricity planning.
- Section 6 sets out factors the OEB should consider when establishing requirements to collect new information.
- Section 7 identifies actions the OEB can take in the near term to begin addressing the information gaps identified in this Report, as well as issues that arose in the Subgroup's discussions which were determined to be out of scope but warrant consideration as work to facilitate innovation and integrate DERs progresses.

In the near-term, the Subgroup believes *the OEB should clarify its expectation of distributors with respect to DER integration and require distributors to explain how DER adoption has been factored into their system plans, and what information was considered to help inform the OEB's assessment of the prudence of those plans*.

2 Context

Various factors are driving the need for distributors to address DER integration.[1] Distributors may be asked to proactively consider how to efficiently and cost-effectively accommodate DERs that are being adopted by all types of customers – from large, sophisticated industrial and commercial customers installing generation and storage systems, to residential customers with smart thermostats, smart EV chargers, and increasing home automation. Customers may be adopting DERs (a) to meet their individual needs, (b) to participate in IESO markets, or (c) in response to public policy objectives (such as municipal and federal net-zero goals, including heat and transportation decarbonization).

The OEB expects distributors to consider how to use existing and new, non-utility owned[2] DERs as non-wires alternatives (NWAs) or non-pipe alternatives (NPAs) to meet distribution system needs.[3] DERs can be used to provide services to the distribution system such as capacity, power quality, reliability, and resilience. In the future, new or existing DERs, as NWAs or NPAs, have the potential to become an integral element of distribution systems and need to be considered in the planning process.[4] DERs may entail benefits and impacts beyond the distribution system where a DER may be installed, with implications across the entire system.

Integrating and using DERs without compromising safety, reliability, resiliency, quality of service, and energy security requires changing the way things are currently done, which may need to be enabled through changes to the existing regulatory framework. DER integration requires:

- 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,

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[1] The FEIWG adopted a broad 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."

DER integration may therefore include not only distributed generation, storage, demand response resources, and energy efficiency, but also, heat and transportation electrification (e.g., EV chargers whether or not they are used for demand response) because they can materially impact the distribution system.

[2] The Terms of Reference for the FEIWG focuses on enabling use of non-utility owned DERs as NWAs or NPAs. In the future, there may be a role for utility-owned DERs but, in accordance with the TOR, this Report focuses on information requirements related to non-utility owned DERs used as NWAs/NPAs.

[3] See 2021 Conservation and Demand Management Guidelines for Electricity Distributors, Filing Requirements for Electricity Distribution Rate Applications (Chapter 5: Distribution System Plan), FEI DER Usage workstream, IRP Proposal Decision and Order (EB-2020-0091).

[4] Recent OEB decisions have affirmed the importance of adequately considering NWAs or NPAs in system planning. See Decisions and Orders filed under EB-2021-0107, EB-2020-0192 and EB-2020-0293.

- 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.[5]

As the list above suggests, Subgroup members acknowledged that fostering greater collection and sharing of information, on its own, is not sufficient to enable and realize the potential benefits of DER integration. To facilitate the greater enablement of non-utility owned DERs, reconsidering the role, responsibilities, and activities of distributors may be warranted. More integrated planning is also needed, which will require changes to current approaches; however, such considerations are outside the scope and mandate of both the DERI Subgroup and the FEIWG. The Subgroup believes that considering these issues is an important next step to be undertaken by the OEB.

Consistent with its Terms of Reference, the DERI Subgroup has discussed the types of information distributors need to effectively operate and make future system plans. This includes information to:

- Understand how customers are using, and will use, the distributor's system;
- help distributors evolve their planning processes or operations to deal with DERs in the future; and,
- identify NWAs and NPAs.

The remainder of this Report discusses what information is needed, how it would be used, what information is needed, and how it may be collected.

[5] The OEB's decision in EB-2020-0091 (IRP Proposal Decision and Order) established such mechanisms for gas distributors.

3 Why information is needed and how it will be used

This section summarizes the discussions regarding information needs and how it will be used from three perspectives set out in the DERI Subgroup's Terms of Reference:

- Understand how the system is and will be used.
- Evolve planning and operations.
- Identify Non-Wires Alternatives.

3.1 Understand how the system is and will be used

Information about current and future system use will be used to:

- **Identify and plan for current and future system needs:** Information about current and anticipated DER adoption, including new load arising from heat and transportation electrification, can be integrated with information about current asset capacity and reliability limits to identify potential capacity constraints and reliability issues. Expected DER penetration should inform distributors' plans to serve future load growth.

- **Make the business case for, and appropriately time, enabling investments:** Closely monitoring the pace of DER adoption will help distributors determine the right time to make enabling investments, such as monitoring and control capabilities, upstream system capacity upgrades to manage EV load growth, and voltage control devices where DER penetration may impact line voltages.

- **Justify spending proposals in rate applications:** Information about DER adoption and future system use will be relevant to assessing the prudence of distributors' capital plans and proposed operating, maintenance and administration (OM&A) spending. There would be additional OM&A spending in assessing and managing the expected increase in DER connection applications. Distribution real time system operations is an operating cost, and is expected to increase to accommodate DER integration, and potentially manage those resources in real time.

- **Inform load forecasts (annual and peak) which underpin distribution rates:** At the current pace of adoption, DERs are not having a material impact on load forecasts. Distributors will need to monitor the pace of DER adoption to identify whether a manual adjustment is required to account for exponential DER adoption not reflected in historical data used in current models.

- **Maintain appropriate alignment with government policy and other exogenous factors**: Policy regarding the energy system is rapidly evolving in response to climate objectives, carbon pricing, municipal concerns over the ongoing use of natural gas, the cost of electricity and the impacts on rate payers and taxpayers, and other environmental concerns. These can all point to priorities regarding the optimal use of distribution assets, the nature of DERs that can contribute to that, and the extent of integration between the natural gas system and electricity system. As governments subsidize the transition to EVs through EV charging infrastructure grant programs or vehicle rebates to support decarbonization, electricity distributors will need to prepare the electricity grid to manage this transition supported by policy.

3.2 Evolve planning and operations

DERs have placed new demands on distribution planning and operations. Distributors need greater visibility and control of their systems and the DERs connected to them. Decentralized resources and diffuse benefits are driving the need for greater coordination between provincial, regional, and local electricity system planning. The IESO is asking distributors to develop greater interoperability with the transmission system to facilitate greater DER participation in wholesale markets.[6] Decarbonization efforts across all levels of government are underscoring the need for more integration of electricity and natural gas system planning.

With all of this in mind, information about DERs will be used to:

- **Develop new DER-related planning assumptions and update long-standing planning assumptions about load:** Distributors have developed assumptions about load that inform planning decisions, such as what size equipment to install for a new sub-division. As DER penetration grows, existing assumptions about load may need to change, and new DER-related assumptions may be required. For example, EV charging behaviour may change assumptions around load diversification and residential load profiles. Assumptions will be developed and refined over time as DER adoption increases and new behaviour patterns emerge.

- **Inform adjustments to current planning "rules" (potentially including those imposed by the transmitter):** With more information about how widespread DER adoption impacts distribution systems, current technical requirements can be updated. Examples include transformer station short circuit and thermal capacity allocation, load-to-generation ratios, and hosting capacity of feeders.

- **Inform the appropriateness of distributors' planning approaches and timelines:** Information about the pace of DER adoption and the differing lead times of DER and conventional wires or pipes solutions can inform changes to planning. The gas sector is moving towards a 10-year asset management plan that is refreshed on a more frequent cycle. During their discussions, FEIWG members have asked whether a five-year distribution planning cycle is too long, given the pace of change. This is also an important consideration for integrating natural gas and electricity system planning.

- **Transition planning and operational approaches consistent with the role of distributors:** As more DERs are connected, a model centered on active system

[6] According to the IESO's Transmission-Distribution Coordination Working Group (TDWG) webpage, the TDWG is focused on supporting "both transmission and distribution level reliability, transmission-distribution (T-D) coordination processes are needed to better integrate DERs in wholesale system and market operations. The IESO, Local Distribution Companies (LDCs), and DER participants will need to share information in a timely manner and ensure there is sufficient awareness (e.g., with respect to outages, limits on DERs, and dispatch of DERs, etc.) among the parties. If distribution services are also sought from DERs, then T-D coordination processes will also be needed to ensure there are no conflicting instructions, double counting, or other unintended consequences."

management instead of "passive system operation and a fit-and-forget approach to connecting new system users"[7] may be required to optimize infrastructure and control costs. Information about the impacts of widespread DER adoption on load behaviour and the distribution system can inform this transition. It can also inform the appropriate role of distributors, which the FEIWG and its subgroups have identified as a fundamental question to be addressed.

3.3 Identify NWAs and NPAs

DERs have the potential to provide benefits throughout the energy system. Using DERs for NWAs or NPAs at the distribution level is one layer of the overall value stack that needs to be enabled. To support their adoption, information will be used to:

- **Understand where and how non-utility owned DERs can be used to meet system needs:** The use cases developed by the FEIWG provide examples of how certain DERs can address certain distribution system needs. Information is required to identify real-world opportunities for NWAs or NPAs.

- **Carry out a Benefit Cost Assessment of DER solutions:** The BCA Subgroup Report discussed the potential level of effort required to quantify the costs and benefits of a DER solution and carry out a BCA. They suggested that the OEB develop tools and inputs to make it easier and promote consistency. The information requirements to carry out a comprehensive BCA are significant and should be standardized as much as possible.[8]

- **Increase distributors' confidence that non-utility owned solutions can be relied upon to perform as required:** Distributors are accountable for providing safe, reliable energy service to consumers. Uncertainties related to leveraging non-utility owned assets (e.g., lack of distributor control, no mechanism to compensate DER solution providers) may impact distributors' confidence that such assets will perform as required. Distributors need to have the same confidence in non-utility owned assets or solutions as they do in their own wires or pipes solutions. Information about the real-world performance of these solutions is one means of overcoming this confidence gap.

- **Develop internal processes to procure and manage non-utility owned DER solutions:** The processes for planning and operating traditional wires or pipes solutions are well established. Information about how DERs can provide services to electricity and gas distribution systems, including planning requirements and operational data, will inform the internal mechanics of distributors' reliance on non-utility owned DER solutions to meet system needs.

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[7] See "Utility of the Future" Massachusetts Institute of Technology. (2016), pp., 46

[8] The BCA Subgroup's Report developed a BCA approach that is applicable to electricity distributors; however, the IRP Technical Working Group established its own BCA Subgroup to look at developing a BCA or BCA framework for Ontario's natural gas distributors to consider DERs. The DERI Subgroup recognized that information requirements for a BCA framework for gas distributors may include similar needs or requirements, but it did not discuss whether such requirements should be standardized for gas distributors, since it is more appropriate for the IRP Working Group to make such determinations.

- **Develop standard approaches for electricity distributors to compensate non-utility owned DERs for the services they provide to the distribution system:** Establishing revenue streams for benefits that are not currently monetizable will contribute to the overall DER "value stack" and support the viability of DER projects for electricity distributors, similar to what has been approved for NPAs within the natural gas sector.

- **Set incentives for distributors to adopt NWAs:** The Utility Incentive Subgroup Report identified options to incent the adoption of NWAs. Some would require new information to implement. For example, if the OEB were to adopt a performance-based incentive, information would be needed to set appropriate performance targets and verify whether they have been achieved.[9]

[9] With respect to natural gas, the DERI Subgroup acknowledged the OEB has made an initial decision on incentive mechanisms in EB-2020-0091 (IRP Proposal Decision and Order) and this Report assumes that Enbridge will implement DERs/IRPAs consistent with that decision; however, the Subgroup also acknowledged that similar information requirements discussed in this Report may nonetheless support the OEB's decision-making in approving such incentives for gas distributors.

4 What information is needed and how it can be obtained

The following identifies, at a high-level, the information distributors need to understand how the system will be used, evolve forecasting, planning and operations, as well as how such information could be collected. This information falls into three broad categories:

- DER Adoption
- DER Usage Data
- DERs as NWAs and NPAs

4.1 DER adoption

Distributors need information about DER adoption occurring within their service areas and the expected pace and nature of DER adoption over the next 5, 10, and 20 years. There are a variety of potential sources for this information. A key challenge for distributors will be synthesizing and filtering it so that it is sufficiently granular, relevant to their service areas, and useable from a planning perspective. Unlike forecasting load, distributors do not have much experience forecasting DER adoption, nor are there common or best practices to rely on. It will take time for these scenario planning capabilities to be developed by the sector as a whole. *Ensuring distributors are considering available information about DER adoption, identifying information gaps, and supporting a shared understanding of the probable future state should be a near-term priority for the OEB.*

Natural gas and electricity distributors should consider the following information:

- **IESO forecasts and the underlying data**: The Reliability Outlook, the Annual Planning Outlook, Integrated Regional Resource Plans and Regional Infrastructure Plans, are available on the IESO's website and can be used to contextualize distributor planning and forecasting.[10] Information exchanged by distributors and transmitters as part of Regional Planning processes, but not necessarily publicly available, is also useful contextual data. Understanding the prospects for electrification should also inform natural gas system planning.

- **Municipal energy and decarbonization plans:** The City of Toronto's Transform TO Net Zero Strategy, Ottawa's Energy Evolution: Ottawa's Community Energy Transition Strategy, and Thunder Bay's Net-Zero Strategy are examples of publicly available plans which should inform both natural gas and electricity distributors' understanding of how their systems will be used in the years ahead.

- **Assumptions and inputs for integrated natural gas and electricity planning:** As discussed further in section 5, more integration of natural gas and electricity system planning is required, including exchanging information and relying on common inputs and assumptions.

[10] The OEB recently accepted recommendations from the Regional Planning Process Advisory Group which included, among other things, a recommendation to add an obligation to the IESO's licence to make planning information available to interested stakeholders.

- **Large customer energy use and DER adoption:** direct engagement with larger customers to understand their energy needs (e.g., do you plan to expand, significantly alter, or switch from gas to electricity for your operations?) and plans for DER use (e.g., are you planning to install battery storage or electrify your fleet?) is already a common practice among electricity and natural gas distributors. Although customers are required to share certain information (e.g., via connection agreements and conditions of service), these mechanisms will not help distributors plan very far ahead and, following the point in time when that information is collected, customers are free to use energy and their DERs as they see fit. Distributors will need to continue to nurture relationships with their customers to encourage voluntary disclosure of information that is helpful to system planning and operations.

- **Low-volume energy use and DER adoption:** EV charging is such a significant load that electricity distributors are seeking more visibility of residential energy use than they have needed in the past; however, since this is private customer information, electricity distributors may have to rely on a variety of means for gaining visibility of residential DER adoption. Examples include developing capabilities to analyze smart meter data for distinctive load profiles to identify EV adoption; encouraging customers to voluntarily disclose an EV purchase by explaining why it is important for the distributor to know, and/or working with the ESA or local electricians to get notification of EV charger installations as they occur. Some electricity distributors are already using some of these approaches.[11]

- **Rate designs and the incentives they provide for DER adoption:** The design of rate programs has been the impetus for DER adoption in Ontario, specifically the Industrial Conservation Initiative (ICI) and Net Metering programs. As these or other programs evolve, the implications on user adoption can vary. For example, the recent provincial government shift of the cost of renewables to the tax base changed the incentive of the ICI. Similarly, the future reliance on natural gas-fired generation will increase the hourly Ontario electricity price and reduce the global adjustment, altering the value of the ICI. Forward looking guidance on such implications would be helpful to distribution planning.

4.2 DER usage data

Distributors need real-world data about how DERs connected to their systems are being used. In this context, the type and size of the DER is important. Information needed about sophisticated commercial and industrial customers with large capacity DERs will be different from the information needed about a residential customer with an EV charger and a smart thermostat. This includes, but is not limited to:

- **Storage and EV charging patterns:** From an electricity distributor's point of view, these are additional loads. For planning purposes, existing metering infrastructure and data collection methods used to monitor load may be sufficient for electricity distributors to identify the impacts of storage and EV charging behaviour, as well as assess the sufficiency of existing infrastructure and operational measures required to maintain

[11] See EnWin invitation to customers to disclose information about residential EV chargers.

reliability and power quality. Electricity distributors need to understand where EVs are being adopted to identify when existing transformer capacity will need to be upgraded to accommodate them. Managed charging (e.g., demand response) can give electricity distributors the ability to optimize schedules for upgrading equipment.

- **Generation and storage injection outputs/timing:** As a matter of safety and reliability, distributors need to know when resources will inject/are injecting into their systems. For DERs over a certain size, electricity distributors collect this information through the connection process[12] and it is factored into distributor operations to varying degrees.

- **Load factor with and without DERs:** This information provides an indication to the distributor about the current penetration level of DERs and their contribution to electricity distributors' system peak. Some relevant information is already collected by electricity distributors and reported to the OEB annually under current Reporting and Recordkeeping Requirements (RRR) for embedded generation.[13] The Subgroup, however, acknowledged this requirement may not capture all DERs with the potential to impact load factor, including EVs, demand response and DER aggregators and updates to the RRR may therefore be necessary.

Some of this information is already collected by distributors whether through the connection process, smart metering, or system monitoring. In some cases, distributors need to take steps to develop the internal capabilities to make use of this information beyond its original purposes. For example, smart meter data, currently only used for billing, would need to be inputted into SCADA or DERM systems to inform operations. For operations purposes, information is required on a near real-time basis and the main gap to be filled is not identifying the information required, but rather, developing the internal tools to collect, interpret, and act on the information in real-time, which involves automation and computing intelligence. In the near-term, distributors should start considering the data they already collect with respect to DER usage, consider what steps need to be taken to fill any gaps, and make better use of that data for planning and/or operations purposes.

4.3 DERs as NWAs and NPAs

More information will be needed from DER solution providers seeking to provide services to distributors than required from those merely seeking to connect. If distributors are going to use non-utility owned DERs for NWAs and NPAs, they require information about the available solutions, and the market requires information about distributors' needs so that solutions can be offered. Information that distributors should provide to the market to facilitate DER use and adoption is outside the scope of this Subgroup's Terms of Reference. The Subgroup, however, found it difficult to discuss the information distributors need in isolation from the information distributors should provide. To enable NWAs and NPAs, market relevant information – that is, price, quantity, and term – must be exchanged.

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[12] The OEB's DER Connections Review is assessing current requirements to identify barriers to the connection of DERs and, where appropriate, standardize and improve the connection process. Recent code amendments include templated forms for collecting information through the connection process.
[13] See S. 2.1.5.5 of the Electricity Record Keeping Reporting Requirements

How this information is exchanged depends on how distributors will procure these services, through procurements, programs, or local markets. Information about need, solutions, price, and term is exchanged through RFP processes and resulting contracts or service agreements ensure that information needed to verify delivery of the service is provided. In the case of a demand response program to meet system needs, information is gathered through the program enrolment process and devices are used to exchange information for the duration of the program (i.e., send and respond to signals to curtail demand, as well as verify demand was curtailed). If distributors become local market operators, information would be collected through market registration, bid/offer processes, and other mechanisms.

Regardless of the method, the information that must be exchanged remains the same:

Information Distributors Require	Information DER Solution Providers Require
What distribution system needs can DERs solve?	What distribution system needs can DERs solve?
What is the availability of existing DER resources to provide services to the distribution system? **How much capacity is available to provide services?** **When is it available? When is it not available because it is committed to providing another service?** **How long will the resource be in place for the distributor's use?**	How much capacity does the distribution system need? When is the capacity needed (under what circumstances)? How much notice will be given? How long will the service be needed for (how long will this revenue stream exist)?
What is the value of the service to the distributor/distribution system? **What is the DER solution provider's cost of the providing the service?**	What is the value of the service to the distributor/distribution system? What is the DER solution provider's cost of the providing the service?
Did the DER perform as required to realize the expected benefits?	N/A

4.3.1 DERs providing services to multiple entities

The BCA Subgroup Report acknowledges that much of the potential value of DERs for electricity distributors lies in their ability to provide services throughout the electricity system. In Ontario, where electricity supply, transmission, and distribution are separate functions, coordination is required to realize the benefits of DERs. The IESO has a consultation underway to review transmission and distribution interoperability that, among other things, is expected to consider the exchange of information between distributors and transmitters.

Some DERs also have the potential to provide services to electricity and gas distributors.[14] *The OEB should consider options for facilitating the exchange of information between electricity and natural gas distributors necessary for evaluating solutions that benefit both systems.* Integration between electricity and gas sectors is discussed in greater detail in section 5.

4.3.2 Pilot results

Ontario distributors have engaged in numerous pilots to test the ability of DERs to provide NWAs and different operational arrangements for these solutions. *The results of the pilots can be instructive for all distributors and should be consolidated and shared.*

[14] Examples include but are not limited to hydrogen electrolyzers that can produce cleaner supply for the natural gas system and act as a system peak-management resource for the electricity system, joint demand response programs, and hybrid-heating solutions that leverage the electricity distribution system to reduce annual gas usage and gas infrastructure to provide reliable and resilient winter peak service.

5 Information considerations for natural gas and electricity planning integration

Meeting climate change and decarbonization policies in the most cost-effective and resilient way will require us to look at natural gas and electricity systems more holistically and break down planning silos. The Subgroup noted that by looking at the systems together, there could be both electric and gas alternatives/DERs identified that benefit customers and meet policy objectives. An example of integration between natural gas and electricity is joint demand response programs carried out in partnership by natural gas and electricity distributors to provide a streamlined customer experience and benefits to both systems.

Coordination of gas and electricity planning will require collaboration and information sharing between gas and electricity distributors, and input gathering from stakeholders. This may include but is not limited to gas and electricity distributors selecting common planning assumptions, alignment of planning horizons, and joint consumer engagement. A review of the planning process considerations is required before specific information requirements can be usefully identified and meaningfully addressed. The need for further integration between the electricity and natural gas sectors to optimize assets and cost-effectively meet decarbonization goals is an important issue that warrants further exploration.

6 Reporting requirements and considerations when deciding to collect information

The Terms of Reference tasked the DERI Subgroup with proposing reporting requirements, including identifying how the OEB presently receives information about DER integration and any gaps to be filled.

The OEB presently receives information about DER integration in a few ways:

- **Distribution System Plans filed to support rate applications:** The OEB's Filing Requirements require distributors to describe how CDM has been taken into consideration in their planning processes, including the use of energy efficiency, demand response, or energy storage as alternatives to traditional infrastructure to meet system needs.[15] *The OEB should consider updating the Filing Requirements to include its expectations related to DER integration and require distributors to explain how DER adoption has been factored into their system planning*.

- **Reporting and Recordkeeping Requirements:** Distributors currently report information about net metering and embedded generation, renewable connections, and load factor with and without embedded generation.[16] The Subgroup did not identify specific new items that should be included in the RRR but notes that information about storage and DER aggregators and/or distributor aggregation of DERs (such as EV charging, dual fuel home heating, demand response, etc.) are gaps that may need to be considered. Any further information collected through the RRR should have a clear purpose and the benefit of having it should outweigh the cost of collecting it.

- **The Innovation Sandbox:** Several distributors have brought forward proposals related to DER use and integration and received guidance from the OEB's Innovation Sandbox. The Sandbox has minimal information requirements by design. As part of Sandbox 2.0 the OEB will be publishing more information about the proposals submitted to the Sandbox and the guidance or response provided by OEB staff.

The Subgroup also discussed factors the OEB should consider when making determinations about information that should be collected.

- **Cost versus benefit:** The OEB should weigh the costs and administrative burden of collecting information against the benefits of having it for planning and operating distribution systems. Collecting unnecessary information and duplication of effort (e.g., DER proponents providing similar information to IESO and distributors) should be minimized.

    - **Make use of existing data:** Related to the cost and benefit of collecting new information, is first considering whether information already collected can be used for a new purpose (e.g., using AMI data for operational purposes as well as billing), and whether information collected by one party may be useful to others (e.g., sharing the results of DER pilots undertaken by distributors).

[15] See the OEB's Filing Requirements for Electricity Distribution Rate Applications - 2022 Edition for 2023 Rate Applications, Chapter 5 – Distribution System Plan

[16] See S. 2 of the Electricity Record Keeping Reporting Requirements

- **Validating the need for data:** Some information is necessary for distributors to have to ensure the safe and reliable operation of distribution system. Some information is important to have to promote optimal asset use and cost control. Some information is nice to have but potentially not worth the cost and effort of collecting it. When establishing new data collection requirements, the purpose and value of collecting the data must be clear.

- **Who pays:** There is a cost to collecting new information and the OEB should consider who should bear those costs based on why the information is being collected and who benefits from it.

- **Commercial sensitivity:** When it is necessary to collect commercially sensitive and proprietary information, appropriate safeguards must be established. Before establishing any requirements, the OEB should expect that distributors have considered whether alternative, non-sensitive information is sufficient to inform planning and operations.

- **Cybersecurity:** The Subgroup did not discuss cybersecurity in detail but acknowledged that with greater integration and information exchange between distributors and DER solution providers, as well as transmitters and the IESO, comes heightened cybersecurity risk. Cybersecurity must not be an afterthought when establishing information requirements.

- **Privacy:** Distributors already collect personal consumer information and adhere to rules for safeguarding it. Data collected about DERs can include private or sensitive consumer information. The OEB should assess whether existing rules and requirements with respect to the collection and use of personal consumer information are sufficient as more DER-related information is collected.

- **Standardization:** To improve the usability of information collected, data requirements should be standardized across distributors and DER solution providers.

- **Jurisdictional analysis**: In determining how to meet information needs, consideration should be given to what information is available in other jurisdictions outside Ontario, including but not limited to pilot results, ISO forecasts and planning initiatives, and other reporting requirements.

- **Information sharing:** Distributors should consider opportunities to share data and lessons learned. Such an approach may afford the opportunity to gain perspective on DER adoption, usage, and benefits across the province, rather than limiting such analysis to distributors' service area. Collaboration may also result in a more efficient process for gathering and analyzing data.

7 Next Steps

Throughout its discussions the Subgroup identified some next steps the OEB may wish to consider. The next steps are organized into three categories of steps that can be taken to:

- Collect or make use of the DER information distributors need for planning and operations (i.e., directly related to this Subgroup's Terms of Reference).
- Address information requirements related to the work of other FEIWG Subgroups.
- Consider issues that arose in this Subgroup's discussions but are out of scope.

7.1 Next steps for collecting and making use of DER information

- **Expectations for distributors regarding DER integration:** Distributors connect DERs upon request, subject to system constraints, which could be considered a "reactionary" approach to enabling DERs. A proactive "enabling" approach may be necessary to maximize benefits of DERs and integrate them most cost-effectively. The OEB should provide clear guidance on what distributors are expected to do vis-à-vis DER integration so that distributors can determine what information they have or need to deliver on those expectations.
    - Ensuring distributors are considering available information about DER adoption, identifying information gaps, and supporting a shared understanding of the probable future state should be a near-term priority for the OEB.
    - The OEB should consider updating the Filing Requirements to include its expectations related to DER integration and require distributors to explain how DER adoption has been factored into their system planning.

- **Safeguarding information:** The OEB should assess whether existing rules and requirements with respect to the collection and use of personal consumer information are sufficient as more DER-related information is collected.

- **Sharing information and learnings:** The OEB should require that results of the various DER-related pilots, which can be instructive for all distributors, be consolidated and shared.

7.2 Next steps related to other FEIWG Subgroups

- **Support DER services to the distribution system:** Consider what regulatory guidance or mechanisms (e.g., code/rule changes) may be needed to enable distributors to compensate DERs for the services they provide to the distribution system when being used as NWAs.

- **Common indicators:** Support the development of a common set of indicators related to, for example, capacity, load, and reliability, to assist in the identification of opportunities for non-utility owned DERs to meet distribution system needs.

- **Distribution data catalogue:** Distributors have information that may not be used to its full potential (whether by utilities or by the market). The IESO publishes a data catalogue as an appendix to its Market Rules that lists the data the IESO collects and identifies which data is published (sensitive data is kept confidential). A distribution data catalogue would support transparency and enable the sector to maximize the use of the information already collected.

7.3 Next steps related to out-of-scope issues

- **Planning integration:** Consider approaches to mitigate natural gas and electricity sector planning silos and foster more coordination to optimize asset use and cost-effectively achieve decarbonization goals. The subject of DERs should feature prominently in the regional planning process and the scope of the plans to help establish DER related opportunities, performance value, and expectations.

- **Cost responsibility:** Determining how the costs of DER integration and enabling investments will be allocated (including whether such costs should only be allocated to customers adopting DERs, sometimes referred to as “host” or “participating” customers, or from all distribution customers) will inform distributors’ decisions about DER integration.