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Request IR-1:

The application notes the following:

...Reduce manual operational DER management effort through process automation; Improve operational awareness through centralized visibility and control of DERs; Standardize management of a multi-vendor, multi-protocol, multi-integration, DER fleet; Establish a framework and operational procedures to support future DER integration...

...NS Power's DCC operators currently have limited real-time visibility and control of DERs on the distribution system and the operational processes which enable DER dispatch are decentralized and manual...

The project includes the selection of a platform which will provide centralized visibility and

allow for orchestration of DER dispatch through integration with NS Power's Operational Technology (OT), utility owned DERs, and aggregators.

...DERs, such as rooftop solar, battery storage systems, electric vehicles, smart thermostats, and other grid-edge or customer-sited technologies are increasingly becoming an active part of Nova Scotia's electricity grid. Currently, DCC operators have no visibility into the DERs in the distribution system and dispatch of available DERs is enabled by decentralized, manual processes.

...and helps ensure DERs can be integrated with the system as active, controllable resources rather than passive connections.

... creating localized impacts that cannot be identified by grid operators without a DERMS platform

...This project advances the DER orchestration strategy set out in the DERIR which is intended to allow for coordination of DER behaviour to help avoid grid constraints.

Board staff understand that any distributed energy resources (DERs) referenced in the utility's application would have been connected to the grid only after an interconnection agreement was carried out with the utility. For any material capacity,

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1 the associated interconnection costs are the responsibility of the interconnection
2 customer. Board staff also understand that the utility should be aware of the feeder
3 and substation to which any significant DERs are connected and should also submit
4 its day-ahead power-production forecast, along with any other forecasts required by
5 the Distribution Control Centre. Board staff further understand that some
6 substations to which these DERs are connected may have RTUs capable of providing
7 their online status if required, notwithstanding any additional programming that may
8 be necessary.

9
10 (a) Using the list of DERs referenced in the application such as rooftop solar, battery
11 storage systems, electric vehicles and smart thermostats, and using a hypothetical
12 example, please explain the current manual dispatch process and the future dispatch
13 capability enabled by this technology installation.

14
15 (b) Please also explain what the utility is trying to dispatch.

16
17 (c) Please confirm whether this proposed project is intended solely for utility-owned
18 DERs and aggregators.

19
20 (d) Please explain what an aggregator means in the context of DERs.

21
22 (e) Please provide a list of all utility-owned DERs and aggregators associated with this
23 project, including each resource's capacity, type, location, and the substation to which
24 it is currently connected.

25
26 (f) Please provide a list of the locations where this technology will be installed.

27
28 (g) Using a hypothetical example, select a few different types of DERs referenced in item
29 1d) above and explain how the proposed technology will ensure that these DERs can

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1 **be integrated into the system as active, controllable resources rather than passive**
2 **connections.**

3
4 **(h) Please quantify the current cost associated with DERs as passive connections and the**
5 **corresponding benefit to ratepayers of integrating DERs as controllable resources.**

6
7 **(i) Please explain how this technology will enable DER behaviour to help avoid grid**
8 **constraints using a specific example, and please quantify the corresponding benefit to**
9 **ratepayers associated with removing these constraints.**

10
11 Response IR-1:

12
13 NS Power agrees that its existing interconnection and distribution records identify the location and
14 characteristics of DERs that are subject to an interconnection review, and that telemetry or SCADA
15 information is available for resources subject to applicable interconnection review and/or
16 monitored system locations. NS Power maintains records of connectivity that identify the
17 distribution-system connection point of these resources. These existing capabilities, however, do
18 not provide the Distribution Control Centre (DCC) with a consolidated, real-time view of
19 individual DER availability, output, operating status, or controllable capability across the
20 distribution system.

21
22 Interconnection records are primarily static records identifying the characteristics and connection
23 point of a resource. Substation RTUs generally provide aggregate feeder or station measurements
24 and do not identify the contribution or available capability of individual DERs. Similarly, forecasts
25 and site-level telemetry apply only to certain resources and do not provide a common operational
26 interface for coordinating multiple DER types, vendors, and aggregators. A significant amount of
27 the DER growth in Nova Scotia is expected to occur through smaller customer-sited resources,
28 such as rooftop solar, battery storage, electric vehicle charging, and other distributed technologies,
29 which are generally not individually forecast or telemetered. In addition, following amendments

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1 to the *Electricity Act* in 2022, self-generation and storage installations up to 27 kW may be installed
2 without participation in NS Power's interconnection review process.

3
4 The proposed DERMS project does not replace NS Power's interconnection, SCADA, forecasting,
5 or substation-monitoring processes. It provides the operational layer required to consolidate
6 available DER information, associate participating DER capability with distribution-system
7 location and conditions, and coordinate eligible resources through integrations with utility-owned
8 assets and aggregator platforms. The project establishes a scalable capability to support the
9 coordinated integration of increasing levels of DERs as adoption grows.

10
11 (a) DER-related operational activity is currently administered outside of the DCC primary
12 operating environment. As stated in the application, DCC operators have limited real-time
13 visibility and control of DERs on the distribution system, and the operational processes
14 which enable DER dispatch are decentralized and manual. Information relating to DER
15 capability, availability, and performance resides in separate systems, including vendor
16 platforms, program administration systems, customer program records, and third-party
17 aggregator portals. DERs are managed through a combination of vendor-specific
18 platforms, customer program systems, and manual processes, with no grid-aware
19 coordination layer between those systems and distribution operations.

20
21 Coordination therefore depends on activities not currently automated, including direct
22 communication with administrators, collection of data for identification of event windows,
23 manual retrieval of asset data for performance review, and manual reconciliation of
24 program data with distribution records.

25
26 Current State

27
28 NS Power's residential battery energy storage fleet is a representative example of the
29 current manual process. These are utility-owned assets deployed under the Smart Grid

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1 Nova Scotia (SGNS) project that have been retained by the Company, and the coordination
2 sequence for an event described below is performed by NS Power staff using vendor tools.

- 3
- 4 • Staff assess weather forecasts, anticipated system conditions, expected daily
5 dispatch, and reserve margins to determine whether an event is warranted and when
6 it should begin and end. This assessment is performed manually and is not informed
7 by a consolidated view of fleet availability at the time the decision is made.
 - 8 • Once an event is determined, staff log into the vendor portal or use vendor-provided
9 tools to manually create the event and define its start and end times. There is no
10 interface between this activity and the DCC's operating environment.
 - 11 • Staff review individual asset health and state of charge to confirm that participating
12 units can deliver the expected response. That review must also confirm that the
13 event will not draw state of charge below the minimum reserved for customer
14 premises backup and resilience. Customers whose devices report alarms or errors
15 are identified and contacted individually.
 - 16 • During the event, manual monitoring is required to determine whether control
17 signals were received and acted upon. Operators do not observe the fleet's response
18 in an operational context alongside distribution system conditions.
 - 19 • Following the event, performance data is downloaded and analyzed after the fact.
20 Customers whose devices unexpectedly did not participate are contacted
21 individually to determine the cause. Opt-out rates are tracked separately.
- 22

23 The same process would similarly apply across other DER classes. For net metered rooftop
24 solar and customer-sited battery storage not enrolled in a program, NS Power is currently
25 aware of connectivity and location records but has no operational visibility of real-time
26 output or state of charge. For electric vehicle charging, NS Power currently has no
27 operational visibility of charging behaviour. These resources operate autonomously in
28 response to customer preference, local settings, and site conditions.

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1 DER coordination today is therefore manual, sequential, retrospective, and conducted
2 through various vendor-specific tools which are not integrated with distribution operations.
3 While this option for DER management may remain effective while adoption rates are low,
4 a robust and automated system for the operational management of DERs is needed to
5 support the increasing adoption of DERs in a manner which allows NS Power to identify
6 and proactively address potential distribution system impacts which may result from
7 increased DER penetration.

8
9 Hypothetical Future State

10
11 The DERMS platform will consolidate DER information into a single operational
12 environment which will be integrated with NS Power's existing operational technology
13 systems, providing the grid-aware coordination layer which does not exist today. Returning
14 to the utility-owned residential battery fleet example, the existing manual process will see
15 the following improvements as a result of this project:

- 16
- 17 • The platform will continuously monitor asset health, communications status, and
18 state of charge across the fleet, and provide alerts on deviation. Readiness for
19 dispatch will be an automated standing operational condition rather than a manual
20 pre-event verification exercise.
 - 21 • The DERMS platform will maintain awareness of DER asset attributes, including
22 the state of charge reserved for customer premises backup, and can prepare
23 participating systems in advance so that available capacity is positioned when
24 required without encroaching on the customer's reserved minimum.
 - 25 • Because participating resources will be represented with their location on the
26 distribution system, capacity can be allocated to a system-wide objective or directed
27 to a localized specific area including substation, feeder, sub-feeder, etc. Where
28 operating objectives compete, the DERMS platform will support prioritization and
29 allocation of available capability between them.
-

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- The event is initiated and tracked through an integrated interface, and response is observed alongside distribution system conditions as it occurs rather than established afterward, allowing execution and response to occur in the operational environment.
- Performance reporting and identification of non-participating resources will be produced by the DERMs platform, replacing post-event download and manual reconciliation.

NS Power demonstrated the underlying mechanics of the proposed future state under SGNS. Dispatch events were issued to fleets of residential batteries, commercial batteries, electric vehicle chargers, and building management systems through the pilot platform, and resource response was measured. The SGNS project also demonstrated automated, condition-driven dispatch, in which the platform monitored a system input and generated dispatch events without operator scheduling.

- (b) NS Power is not seeking to directly control individual customer devices through this project. The DERMs platform implemented through this project will give NS Power the ability to dispatch DER capability that has been made available for grid purposes through utility-owned assets or through customer participation in a program administered by an aggregator or program operator.

In this context, “dispatch” means requesting, coordinating, or adjusting DER capability that is available to NS Power in accordance with the applicable ownership or program arrangements in support of operating objectives.

- (c) Confirmed. The initial implementation of the DERMs platform through this project is focused on utility-owned DER assets and integration with DER aggregators. The project does not involve establishing direct operational control of individual customer-owned DERs. Where customer-owned resources are visible to or coordinated through the DERMS

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platform, this will occur through the aggregator or program construct in which the customer has voluntarily enrolled.

- (d) An aggregator is an entity that coordinates multiple, customer-sited DERs so that their collective capability can be presented to a utility or system operator as one or more coordinated resources.

The aggregator generally serves as the interface between participating customers and the utility and may be responsible for customer recruitment and enrolment, device-level communications and controls, obtaining and maintaining customer consent and participation terms, verifying availability, executing dispatch instructions across the enrolled portfolio, and performance reporting. This allows the utility to interact with an aggregated portfolio rather than individual customer devices.

EfficiencyOne's demand response programming provides an example of the aggregator model in Nova Scotia.

- (e) Please refer to the table below.

Asset	Description	Power / Energy	Location / Substation	Related Project
Residential battery storage	134 batteries, 133 in customer homes and one for signal and integration testing. This integration will be accomplished via vendor aggregator mechanism.	Per Unit: 5 kW AC power, 13.5-18 kWh energy capacity	N/A Assets are distributed throughout the province at customer premises.	Smart Grid Nova Scotia (M09519)
		Fleet: 630 kW AC fleet power; 1,823 kWh fleet storage capacity		

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Asset	Description	Power / Energy	Location / Substation	Related Project
Commercial & Industrial BESS	Three sites (two industrial, one commercial)	Per Unit: 150-200 kW AC power, 300-400 kWh energy capacity	Site 1: Dartmouth / 99H, Site 2: Amherst / 22N, Site 3: Upper Nappan / 75N	Smart Grid Nova Scotia (M09519)
		Fleet: 550 kW AC power, 1,100 kWh fleet energy capacity		
Commercial & Industrial solar photovoltaic with smart inverters	Three sites, co-located at the facilities with the battery systems above	Per Unit: 200-300kW AC power		Smart Grid Nova Scotia (M09519)
		Fleet: 550 kW aggregated AC power		
Grid-Connected BESS	Feeder-interconnected	1.225 kW power 2.375 kWh energy	Elmsdale / 82V	Intelligent Feeder Project (M07981)
Aggregator*	Aggregator Integration	N/A	N/A	N/A

*This DERMS solution is able to integrate with aggregator platforms. The solution can also be scaled in future to support use cases including where additional programs and services are developed and coordinated through an aggregation platform. NS Power has not yet confirmed specifically which aggregator platforms, if any, will form part of this project but as mentioned in part (d), EfficiencyOne's demand response programming provides an example of the aggregator model in Nova Scotia.

(f) The DERMS platform will be deployed within NS Power's enterprise and operational technology environment and operated from the DCC. There is no distributed field deployment of DERMS hardware associated with this project. The project scope does not include installation of new DER field devices, however, some utility-owned DER sites noted above in part (e) require integration hardware and asset integration field work to connect these existing assets to the DERMS platform. Accordingly, there is no list of

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1 installation locations in the sense of field asset deployment. The DER assets contemplated
2 for integration are already installed.

- 3
4 (g) A passive connection operates independently of DCC operations and cannot be actively
5 coordinated with system needs.

6
7 For example, a distribution feeder serving a mix of residential customers with a rooftop
8 solar, program-enrolled customer-sited batteries, and residential smart thermostats
9 participating in demand response.

10
11 Today the aggregate behaviour of these resources is observable only as net effect at
12 monitored points. On a mild, sunny, low-load day, solar output masks underlying load and
13 can contribute to reverse power flow and voltage rise, without operators being able to
14 attribute the cause to DER behaviour. Program-enrolled batteries and thermostats operate
15 according to schedules established outside the DCC.

16
17 With the DERMS platform and integrations in place, NS Power will have improved
18 visibility of participating DERs, including their location, characteristics, status and
19 availability, in a consolidated operational view, allowing operators to associate observed
20 feeder conditions with known DER presence. The platform will also give NS Power the
21 ability to issue and track coordination requests through integrations with utility-owned
22 DER assets and aggregator platforms within the terms of applicable programs.

23
24 DER activity will become part of normal DCC operating practice, supported by
25 documented operational procedures established through this project with ability to scale as
26 DER penetration increases.

27
28 The degree of resource control available will depend on ownership, program terms,
29 customer consent, and the technical capability of the resource. For utility-owned assets,
30 coordination is direct. For program-enrolled customer resources, coordination can occur

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1 through an aggregator. DERs that are neither utility-owned nor enrolled in a program
2 would not become controllable through DERMs, although DERMS may improve visibility
3 of their potential impact on the distribution system.
4

5 This project will establish the platform, initial integrations, and operational procedures
6 required to support the coordinated use of DERs as active distribution system resources.
7

8 (h) At current DER penetration levels, the impacts of individual DERs are generally managed
9 through existing distribution planning and operating processes, and NS Power does not
10 separately track costs attributable to the lack of active DER coordination. Accordingly, NS
11 Power cannot quantify costs specifically attributable to DERs operating as passive
12 connections.
13

14 The project is intended to address an emerging operational capability gap as the number,
15 diversity, and penetration of DERs increase. Without centralized DER visibility and
16 coordination capabilities, NS Power has limited ability to identify where DER behaviour
17 affects distribution system conditions, understand available DER capabilities in real time,
18 and incorporate DER information into distribution system operations. The integration of
19 existing and future DER information through a DERMS platform embedded within DCC
20 operations will enable the visibility needed to better forecast, understand, and manage
21 potential DER impacts as penetration increases.
22

23 The DERMS platform will provide a scalable foundation for future coordination of DERs
24 as active grid resources rather than unmanaged influences on the distribution system, as
25 appropriate. The corresponding ratepayer benefits cannot be quantified at this stage
26 because they will depend on the future use cases, the type, quantity and location of
27 participating DERs, distribution system needs and constraints, and the extent to which
28 coordinated DERs can avoid or defer otherwise required costs.
29

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1 This phased approach is consistent with the DER Integration Roadmap, which identifies
2 DERMS as a foundational capability for advancing DER integration in Nova Scotia. As
3 specific future DER use cases are developed, their associated costs and benefits can be
4 evaluated, as appropriate, based on system needs, available DER capabilities, program
5 design, and the applicable regulatory framework.

- 6
- 7 (i) Constraint-related coordination is a capability the DERMS platform will enable, and may
8 support future use cases. As stated in the Application, the DERIR DER orchestration
9 strategy is intended to **allow** for coordination of DER behaviour to help avoid grid
10 constraints [**emphasis added**]. While this project will allow function in future, it is not part
11 of the current project.

12

13 Currently, when a feeder approaches a thermal or voltage limit, NS Power can respond by
14 reconfiguring where feasible, or through a capital investment to build additional capacity.
15 The DERMS platform could enable NS Power to identify available controllable DER
16 capability in that location and coordinate those resources to reduce the constraint. The
17 DERMS also provides the visibility and coordination capabilities needed to coordinate
18 existing DERs, or support the targeted deployment of non-wires alternatives where they
19 could defer, reduce or complement traditional infrastructure investments. By providing
20 visibility into the location, availability and status of DERs and the ability to coordinate
21 those resources where the necessary operational capability and participation arrangements
22 exist.

23

24 As a hypothetical example, consider a distribution feeder that is forecast to exceed its
25 capacity during a limited number of peak hours. If controllable DERs are available in the
26 affected area, the DERMS platform could identify the available capability and coordinate
27 discharge during those hours to reduce feeder loading. If sufficient capability is available,
28 this could defer or potentially avoid the need for reconfiguration or for a conventional
29 distribution capital investment as described above.

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1 NS Power has not quantified a ratepayer benefit associated with this example. The current
2 project is not being proposed to address a specific feeder constraint or avoid a planned
3 capital investment. Costs and benefits for a hypothetical scenario cannot be quantified at
4 this stage. They will depend on the future use cases, the type, quantity and location of
5 participating DERs, distribution system needs and constraints, and the extent to which
6 coordinated DERs can avoid or defer otherwise required costs.

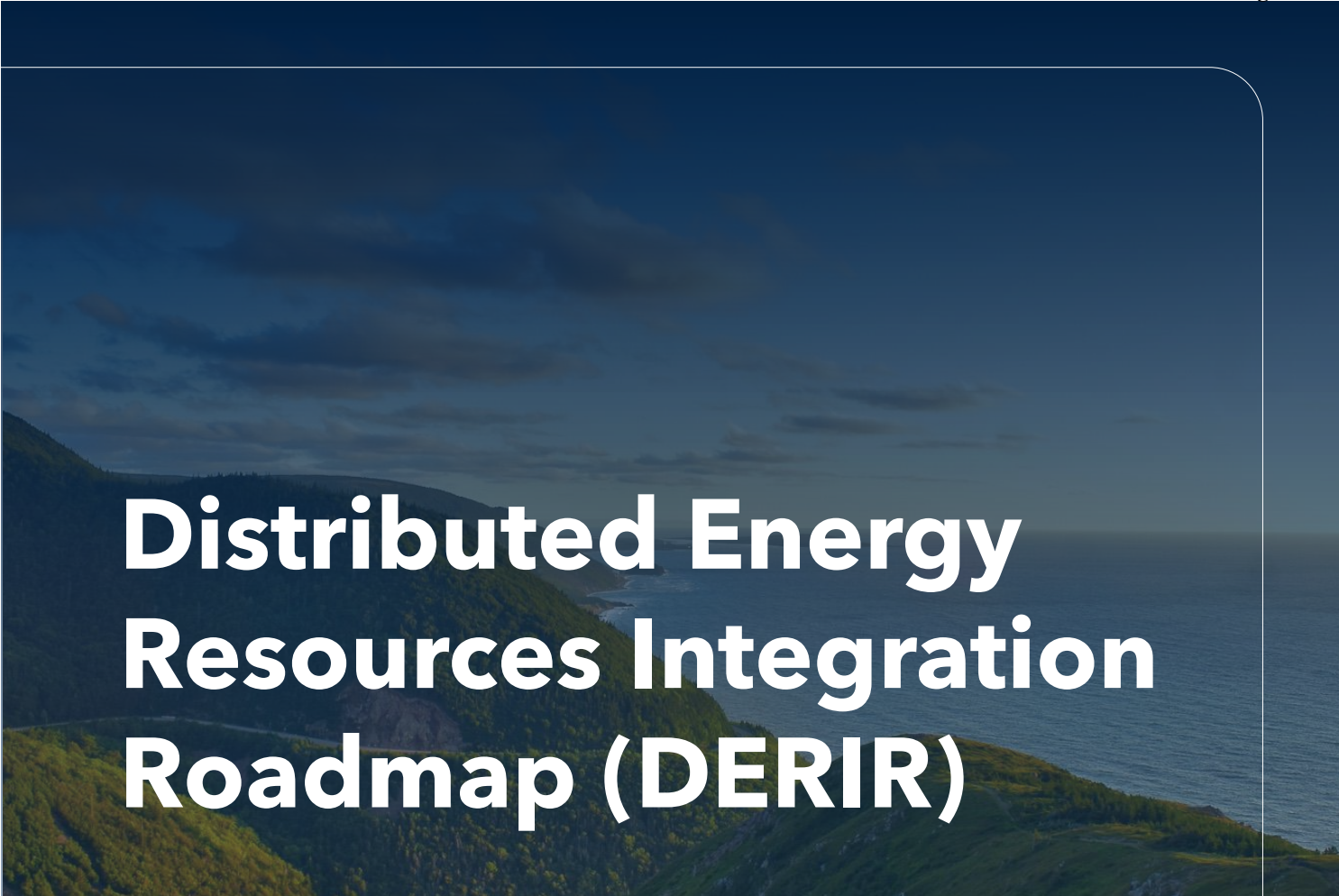
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1 **Request IR-2:**

2
3 **Please provide the Dunskey Distributed Energy Resource Integration Roadmap report noted**
4 **in the application.**

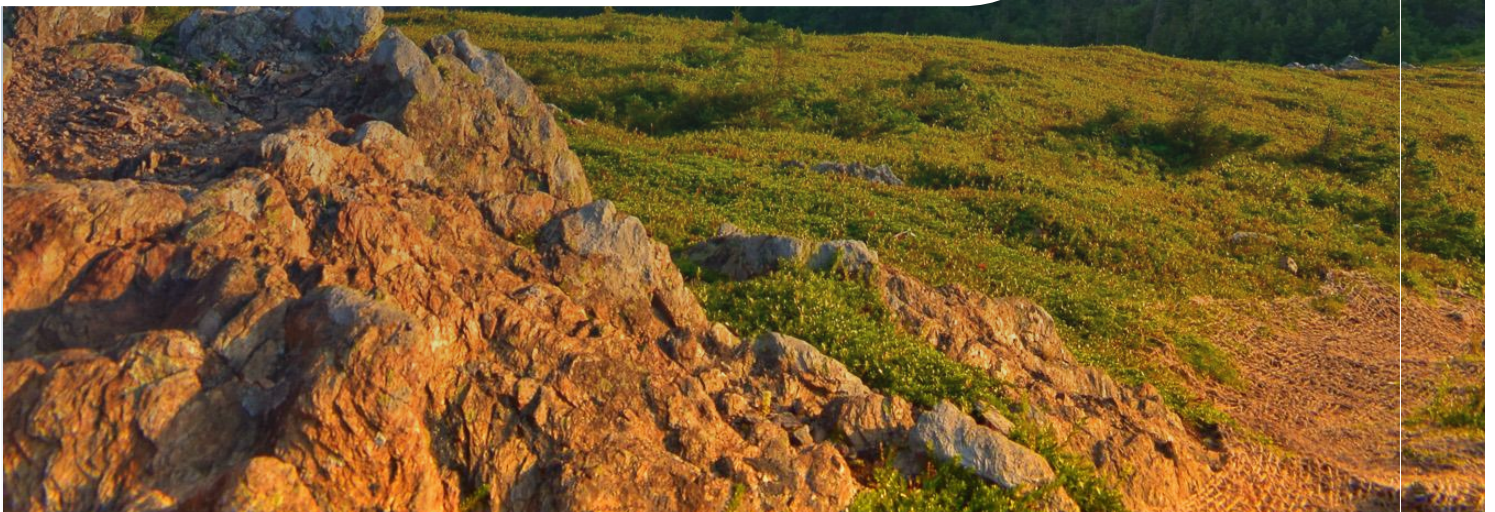
5
6 Response IR-2:

7
8 The Distributed Energy Resource Integration Roadmap (DERIR) was filed with the NSEB under
9 M12177. As noted in the Application, this Project advances the DER orchestration strategy set out
10 in the DERIR, which is intended to allow for coordination of DER behaviour to help avoid grid
11 constraints. Specifically, this project supports the DERMS Requirement and Evaluation
12 Framework and DERMS Procurement and Progression initiatives. Please refer to Attachment 1.



Distributed Energy Resources Integration Roadmap (DERIR)

A Roadmap for Successful
DER Integration in Nova Scotia



JUNE 2026

Submitted to:



Nova Scotia Power

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About Dunsky



Dunsky supports leading governments, utilities, corporations and others across North America in their efforts to accelerate **the clean energy transition**, effectively and responsibly.

With deep expertise across the Buildings, Mobility, Industry and Energy sectors, we support our clients in two ways: through rigorous **Analysis** (of technical, economic and market opportunities) and by designing or assessing **Strategies** (plans, programs and policies) to achieve success.



Dunsky is proudly Canadian, with offices and staff in Montreal, Toronto, Vancouver, Ottawa and Halifax. Visit dunsky.com for more information.

Foreword

In 2024, Nova Scotia Power (NS Power) was directed by the Nova Scotia Energy Board (NSEB) to lead the development of a Distributed Energy Resource Integration Roadmap (DERIR) in consultation with stakeholders. While NS Power has been tasked with shepherding this effort forward, the DERIR is intended to be a holistic, province-wide roadmap that supports a coordinated, system-wide approach to planning, enabling, and integrating distributed energy resources across Nova Scotia.

To support this work, NS Power commissioned Dunskey Energy + Climate Advisors to provide research, stakeholder engagement support, and strategic advice to inform the DERIR development by drawing on jurisdictional research, stakeholder perspectives, and professional judgment regarding DER integration practices and priorities relevant to Nova Scotia.

WHAT THE DERIR IS AND ISN'T

The objectives of the DERIR are to:

- **Articulate a holistic, coordinated, and common vision** for planning, enabling, and integrating DERs in Nova Scotia;
- **Identify and prioritize key strategies and initiatives** needed to advance DER integration; and
- **Support broad alignment among stakeholders** on the roadmap's goals, strategies, initiatives, and sequencing.

The DERIR should be understood as an initial strategic planning tool. It identifies high-level actions and sequences them over time to help stakeholders move toward a shared DER vision. By design, it focuses on "what needs to happen" and "in what sequence."

It is the bridge between vision and implementation: it is strategic and directional, not prescriptive. It does not define, in detail, how each initiative will be implemented, who will ultimately be accountable for each action, how initiatives will be funded, or what approvals may be required. Too much detail too early can make the roadmap rigid and reduce its usefulness as a coordination tool. It should be viewed as a proposed strategic direction for Nova Scotia's DER integration efforts, not as a detailed implementation plan or binding commitment by any party. Those details will need to be developed through subsequent steps.

ROLES AND RESPONSIBILITIES

Although NS Power has led the development of the DERIR in response to NSEB direction, successful delivery of the roadmap will require action and coordination across a broader set of parties. These include Nova Scotia Power, EfficiencyOne, the Independent Energy System Operator of Nova Scotia, the Government of Nova Scotia, NSEB, market participants, customers, and other stakeholders. The roadmap is therefore not intended to represent a plan owned or implemented by any single entity. Rather, it provides a shared strategic framework to guide coordinated action across the province.

A robust governance model will therefore be critical to translating the roadmap into coordinated progress. Establishing this governance model (Roadmap Initiative 1.1.1) will be an important next step in confirming priorities, assigning accountabilities, and determining how specific initiatives should advance.

UPDATE AND NEXT STEPS

The roadmap reflects Dunsky's professional judgment, jurisdictional experience, stakeholder input, and the information available through the roadmap development process. The inclusion of an initiative in the DERIR should not be interpreted as approval, funding, authorization, or a firm commitment to implementation by NS Power or any other party.

Initiatives will need to be refined, added, removed, reprioritized, or sequenced as technologies, customer adoption, market conditions, system needs, policy priorities, and regulatory requirements evolve. Ultimately, the DERIR should enable and kick-start a common vision and coordinated progress on DER integration for Nova Scotia while remaining adaptable to changing circumstances.

Acknowledgements

This roadmap report was prepared by Dunsky Energy + Climate Advisors (Dunsky) for Nova Scotia Power (NS Power) in response to a directive from the Nova Scotia Energy Board (NSEB).

The roadmap was informed by input from stakeholders representing a broad range of interests and perspectives across Nova Scotia, helping ensure it reflects diverse views on successful DER integration in the province. We are grateful for their time, insights, and contributions.

We engaged more than 30 stakeholders from 14 organizations through three workshops and six group interviews. A special thank you to representatives from the following organizations that contributed their time and expertise to the roadmap development:

- Canadian Renewable Energy Association (CanREA)
- Consumer Advocate (Pink Larkin Lawyers | Advocates)
- Dalhousie University
- Efficiency One
- Energy Storage Canada
- Government of Canada (Natural Resources Canada)
- Government of Nova Scotia (Nova Scotia Department of Energy)
- IESO-Nova Scotia
- Industrial Group (Stewart McKelvey)
- Nova Scotia Community College
- Nova Scotia Energy Board (NSEB) and its consultant (Synapse)
- Nova Scotia Power
- Small Business Advocate (Blackburn Law)
- Solar Nova Scotia

While this report benefited from significant stakeholder engagement and support, the recommended strategies, initiatives, prioritization, and sequencing presented reflect the author's independent analysis, expertise and judgement.

Executive Summary

Nova Scotia's electricity system is entering a period of significant transformation. Growing electricity demand, increasing adoption of distributed energy resources (DERs), and progressively ambitious decarbonization objectives are reshaping how the electricity system must be planned and operated. DERs, including distributed generation, energy storage, electric vehicles, and flexible loads, offer promising opportunities to support affordability, reliability, and emissions reductions. However, as DER adoption grows, it also introduces new operational, planning, and regulatory challenges that require a coordinated and strategic approach.

At the same time, Nova Scotia's electricity sector is evolving. Recent reforms under the Energy Reform Act have introduced a more distributed governance model which establishes the NS Energy Board, regulating energy-related matters and IESO Nova Scotia, NS Power and Efficiency One. The IESO Nova Scotia is the independent energy system operator responsible for planning and management of the bulk electricity system, while NS Power is responsible for asset planning, grid maintenance, and distribution planning. E1 continues to lead demand-side programs. This requires greater coordination among organizations responsible for planning, operating, regulating, and enabling the electricity system. As DER adoption and electrification grow, deliberate action is needed to ensure the province can capture the benefits of DERs while maintaining system affordability, reliability, and efficiency.

Nova Scotia Power commissioned the development of a Distributed Energy Resources Integration Roadmap (DERIR). Developed by Dunskey Energy + Climate Advisors and informed by stakeholder engagement, the DERIR identifies a strategic path to unlock the value of DERs for customers and the electricity system while supporting Nova Scotia's clean energy objectives.

DER INTEGRATION ROADMAP

Six core principles guided the DERIR development: DER integration should be beneficial, affordable, reliable, equitable, adaptable, and collaborative. Together, these principles support a vision in which DERs contribute to a more affordable, reliable, and cleaner electricity system for all Nova Scotians.

The DERIR is intended to serve as a strategic planning framework rather than a detailed implementation plan. It organizes work across three interconnected pillars:

Pillar 1: Planning for DERs



This pillar focuses on establishing the foundations required for effective DER integration. Key priorities include strengthening governance and stakeholder coordination, building institutional capacity, developing DER valuation frameworks, improving forecasting and hosting capacity assessments, and identifying future regulatory needs.

Pillar 2: Enabling DER Participation



This pillar focuses on creating the conditions that allow customers and third parties to adopt and participate in DER programs. Priorities include customer engagement, equity considerations, enabling technologies, demand response, time-varying rates, and future DER compensation and procurement frameworks.



Pillar 3: Integrating DERs

This pillar focuses on the systems, processes, and grid investments required to manage increasing DER penetration. Priorities include DER management systems (DERMS), improved DER visibility and data management, modernization of interconnection processes, and targeted grid modernization investments.

Across these pillars, the roadmap identifies 12 strategies and 28 initiatives. Several initiatives are already underway, while others require future planning, regulatory direction, and investment. Collectively, they provide a coordinated path for integrating DERs into Nova Scotia's electricity system while maintaining affordability and reliability.

LOOKING AHEAD

The DERIR represents an important first step. Implementation will require sustained commitment, collaboration, and clear accountability. Regulatory clarity and direction regarding leadership roles, responsibilities, and decision-making authority are critical to advance roadmap initiatives. Ongoing stakeholder engagement will also remain essential to ensure the DERIR reflects evolving technologies, market conditions, and customer needs.

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List of Acronyms

Advanced Distribution Management Systems (ADMS)

Advanced Metering infrastructure (AMI)

Behind the Meter (BTM)

Benefit Cost Analysis (BCA)

Critical Peak Pricing (CPP)

Distributed Energy Resources (DERs)

Distributed Energy Resources Integration Roadmap (DERIR)

Distributed Energy Resources Management System (DERMS)

DR Working Group (DRWG)

Demand Side Management (DSM)

Demand Side Management Advisory Group (DSMAG)

EfficiencyOne (E1)

Electric Vehicles (EVs)

Front-of-the-Meter (FTM)

Geographic Information Systems (GIS)

Innovation Justification Criteria (IJC)

Independent Energy System Operator Nova Scotia (IESO-NS)

Integrated Resource Plan (IRP)

Jurisdiction-Specific Test (JST)

Key Performance Indicators (KPIs)

Multi-Unit Residential Buildings (MURBs)

North American Electric Reliability Corporation (NERC)

Non-Energy Benefits (NEB)

Non-Wire Alternatives (NWAs)

Non-Wires Solutions (NWS)

Nova Scotia Energy Board (NSEB)

Nova Scotia Power (NS Power)

National Standard Practice Manual (NSPM)

On-Bill Financing (OBF)

On-Bill Repayment (OBR)

Operation and Maintenance (O&M)

Outage Management Systems (OMS)

Property Assessed Clean Energy (PACE)

Program Administrator Cost Test (PAC)

Photovoltaic (PV)

Smart Grid Nova Scotia (SGNS)

Societal Cost Test (SCT)

Supervisory Control and Data Acquisition (SCADA)

Tariff On Bill (TOB)

Time of Use (TOU)

Time Varying Rates (TVR)

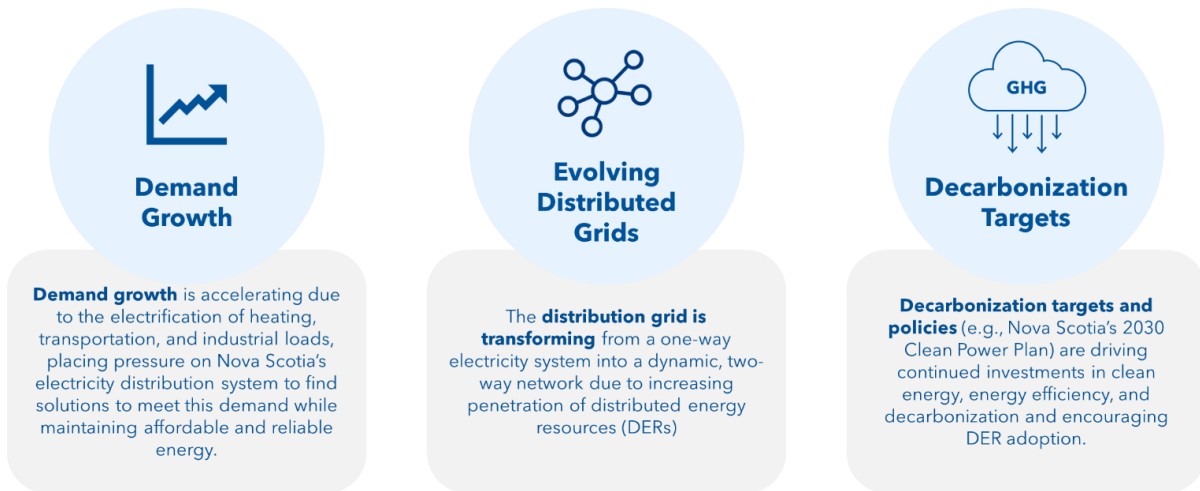
Value of DER (VDER)

Virtual Power Plant (VPP)

Introduction

Why DERs?

Nova Scotia's electricity system is facing an evolving energy landscape shaped by three key trends:



Distributed Energy Resources (DERs) are recognized as key enablers of decarbonization goals, system flexibility, and load management, among other system benefits. However, as DER adoption scales, new operational challenges are introduced. Properly coordinated DER deployment increases grid operators' visibility and control, improving grid security, affordability and reliability. Interoperability gaps and fragmented regulations can complicate DER integration, underscoring the need for a coordinated, strategic approach to support a reliable, affordable, and clean electricity grid.

What are DERs?

DERs are flexible loads or generators enabled by smart technologies that interact with the electricity system at the distribution level. They may be directly connected to the distribution grid (front of the meter) or located on a customer's property (behind the meter). Examples include battery storage, electric vehicles (EVs), solar generation, and demand response technologies such as smart thermostats and water heaters. Together, DERs enable greater customer and third-party participation in the electricity system and support a more flexible, bidirectional grid.

As DER adoption and electricity sector evolution accelerate, deliberate action is essential to support an affordable, reliable, and clean electricity system.

State of Play in Nova Scotia

In Nova Scotia, DER adoption and electrification has increased. From 2019 to 2024, EV vehicle registrations have increased significantly from 160 annual registrations in 2019 to over 2,800 in 2024¹, and net-metering interconnections tripled (from 764 in 2019 to over 2,000 in 2025, hitting a high of over 2,800 in 2024²). Most are solar installations driven largely by incentive programs. Heating electrification has also expanded significantly in the province. Heat pump installations are also growing in the province, with an estimated 21,300 installations in 2025. The 2026 Load Forecast Report projects that about 50% of homes use heat pumps for heating (63% for cooling) in 2026, increasing to 73% for heating (89% for cooling) by 2036.³

This increase in adoption is driven by a combination of supportive policies and programs (see text box above), declining technology costs, and increasing consumer interest in sustainability and energy cost savings. Electrification has resulted in **Nova Scotia's system peak demand forecast to increase approximately 28% between 2024 and 2035.**⁴ These trends highlight the need for proactive planning and management to manage electrification-driven demand growth.

¹ Statistics Canada. [New motor vehicle registrations, quarterly, by geographic level, annual sum.](#)

² Nova Scotia Power 2025 Net Metering Report (M12165) and 2025 Commercial Net Metering Report (M12164)

³ Nova Scotia Power. 2026. 2026 Load Forecast Report.

⁴ Nova Scotia Power. 2025. [2025 10-Year System Outlook.](#)

In Nova Scotia, DER adoption and electrification is **increasing**

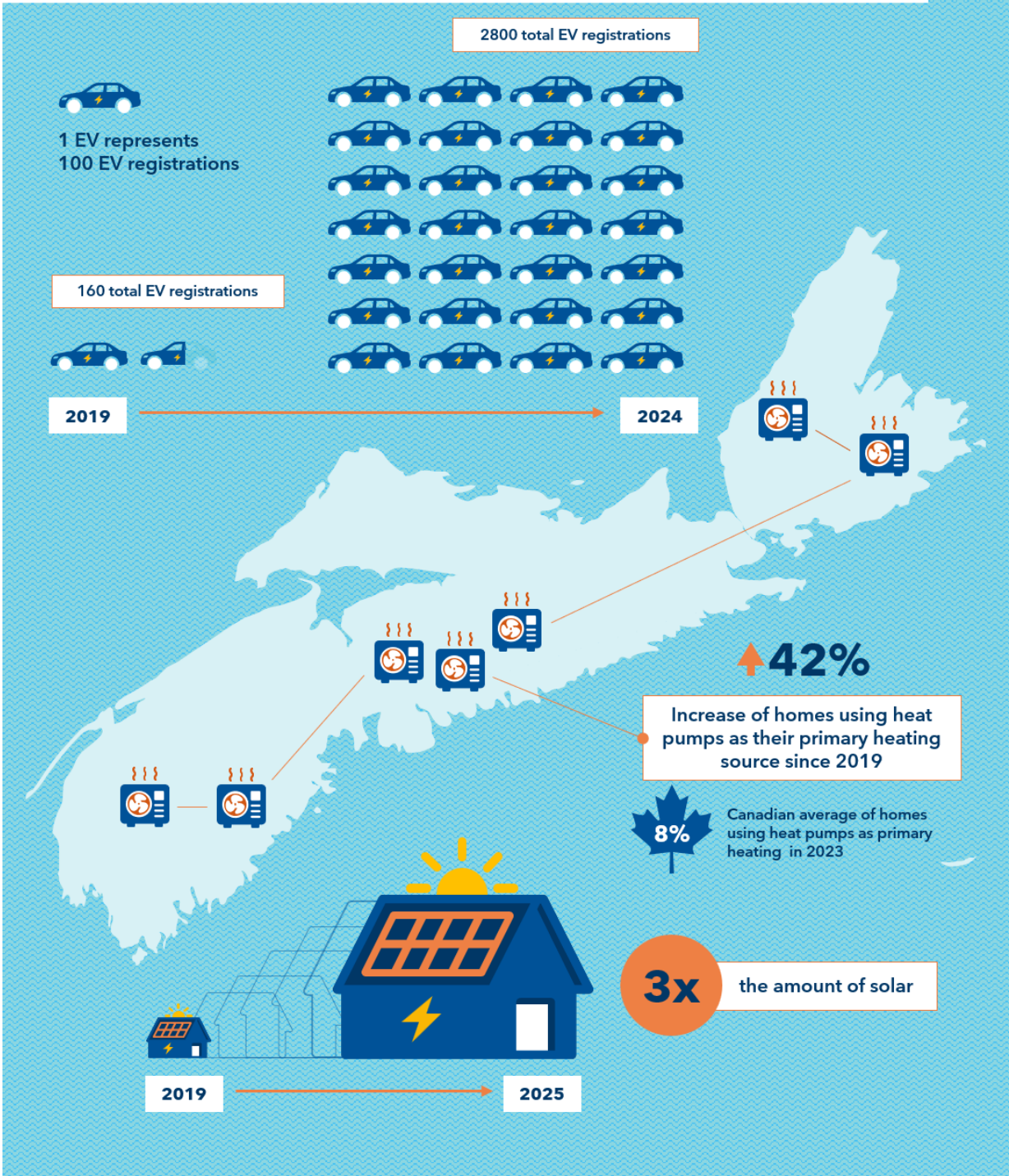
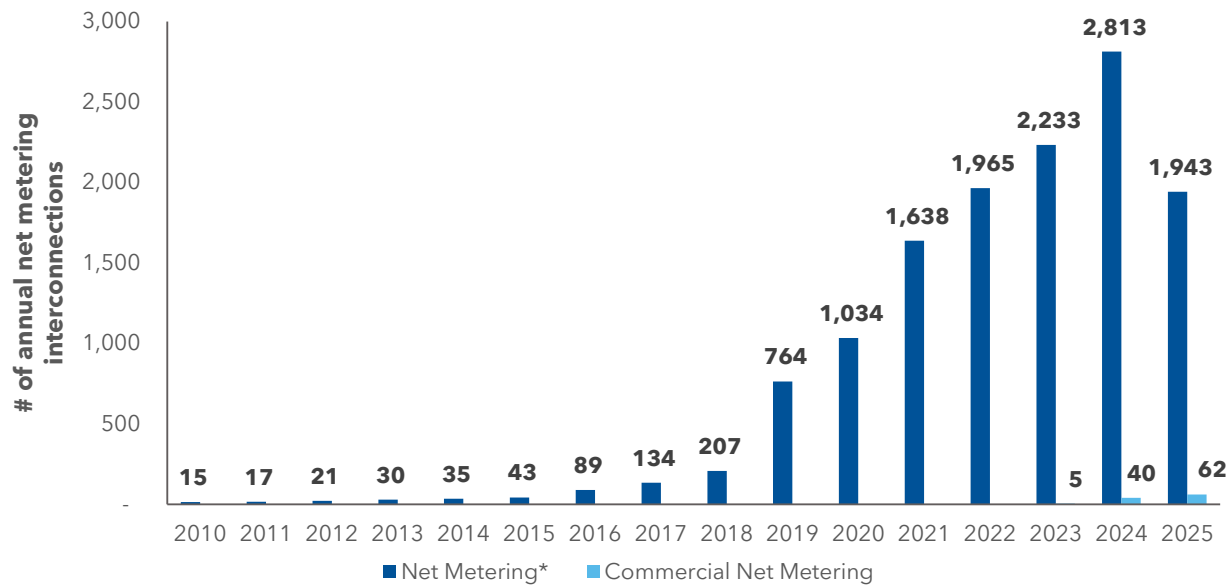


FIGURE 1: NET METERING INTERCONNECTIONS ACROSS NOVA SCOTIA 2010-2025²

NS Power and EfficiencyOne (E1) have deployed several initiatives to support DER integration.

NS Power has deployed advanced metering infrastructure (AMI) and implemented several time-varying rates to encourage load shifting. E1 delivers demand response programs and offers incentives to support DER adoption. Additionally, the multi-partner Smart Grid Nova Scotia (SGNS) project tested a distributed energy resource management system (DERMS) to coordinate and control a portfolio of DERs, including EV chargers, energy storage, and building management systems. The project demonstrated that actively managed DERs can provide benefits which support affordability, reliability, and environmental compliance and highlighted the importance of collaboration between E1 and NS Power.⁵

In tandem with increased DER adoption, Nova Scotia is simultaneously structurally changing the electricity sector. **Recent governance reforms under the Energy Reform Act have reshaped the institutional landscape of Nova Scotia's electricity sector.** The Act establishes the NS Energy Board (NSEB), focused on energy-related matters and IESO Nova Scotia, NS Power and E1 oversight. The IESO Nova Scotia is the independent energy system operator responsible for planning and management of the bulk electricity system⁶, while NS Power is responsible for asset planning, grid maintenance, and distribution planning.⁷ E1 continues to lead demand-side programs, which are regulated and approved by the NSEB. These changes reflect a more distributed governance structure in which multiple organizations must work together to plan, operate, and manage the electricity system effectively.

⁵ Nova Scotia Power. 2024. Smart Grid Nova Scotia Project Final Report.

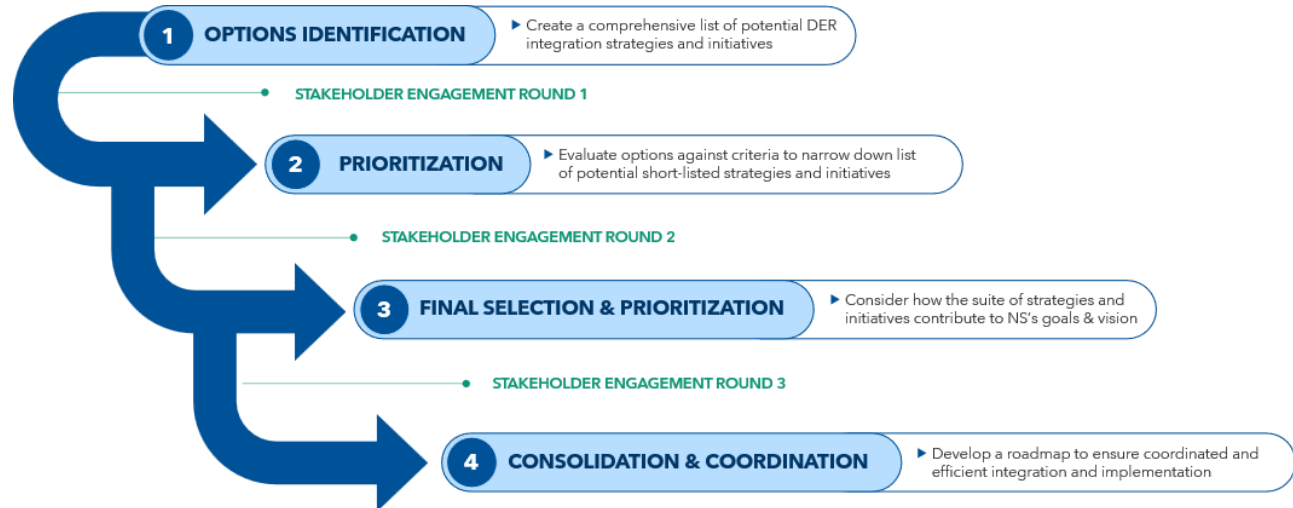
⁶ The bulk electricity system means a transmission system and all generating facilities that must be registered with the IESO under market rules, including all related communications, protection and control systems.

⁷ Nova Scotia Legislature. 2024. [An Act to Reform the Law Respecting Energy and Electricity](#).

Approach

DERIR development involved four stages (Figure 2), with three rounds of stakeholder engagement woven throughout the process.

FIGURE 2: DERIR DEVELOPMENT APPROACH



- **STEP 1: OPTIONS IDENTIFICATION**

A jurisdictional scan of North American utilities' DER integration efforts was conducted. The scan compared Nova Scotia's efforts with other utilities, identified best practices, and mapped the range of options available to Nova Scotia. Findings are woven throughout this report to support decisions, and additional details are in a supplementary document (see Appendix A: Jurisdictional Scan).

- **STEP 2: PRIORITIZATION**

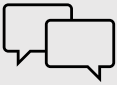
To prioritize the strategies and initiatives in Step 1, each was qualitatively assessed across four dimensions: Strategic Fit, Benefits, Costs and Risks. Assessment results are in the Roadmap Initiatives section, and the assessment criteria details are in Appendix B: Qualitative Assessment.

- **STEP 3: FINAL SELECTION & PRIORITIZATION**

Initiatives were selected and prioritized as: Foundational, Evolving, or Emerging (see Roadmap Overview section). Prioritization was based on the qualitative assessment, stakeholder feedback, and Nova Scotia's goals and vision.

- **STEP 4: CONSOLIDATION & COORDINATION**

The roadmap outlines the selected Strategies and Initiatives and illustrates how they are sequenced and coordinated over time (see Roadmap Initiatives section).

**STAKEHOLDER ENGAGEMENT: KEY DERIR INPUT**

Stakeholder engagement was a core component of the DERIR development process and directly informed the final roadmap. More than 30 stakeholders from 14 organizations were engaged through three workshops and six group interviews to identify gaps, refine strategy and initiative prioritization, and incorporate diverse perspectives and system realities. Stakeholder insights are embedded throughout the report in grey text boxes.

These are summaries of **“WHAT WE HEARD”** through engagements and should not be interpreted as Dunsky’s recommendations.

Stakeholder insights informed the final prioritization, sequencing, and coordination of strategies and initiatives. Stakeholder input is one of several sources considered. Dunsky has drawn on a review of the NS context, a jurisdictional scan and professional expertise to assess DERIR strategies and initiatives. As such, not all stakeholder suggestions may be reflected in the final recommendations. Additionally, the resulting strategies and initiatives do not necessarily reflect the views of individual stakeholders and should not be interpreted as endorsement or approval.

Roadmap Overview

Guiding Principles

The goal of the DERIR is to provide a path that unlocks both grid and customer benefits from DERs, to support a more affordable, reliable, and clean electricity system for Nova Scotia. The following principles will guide decisions and actions in the development and implementation of a Nova Scotia DERIR:

- **Beneficial.** DERs are effectively integrated to deliver broad, system-wide benefits to utilities, customers, and the environment.
- **Affordable.** DER integration supports affordability and limits upward pressure on rates by considering DER costs and benefits relative to alternatives and broader system outcomes.
- **Reliable.** DERs contribute to maintaining and improving system reliability and stability.
- **Equitable.** DER integration efforts strive for all customer groups to realize benefits, consider impacts to vulnerable customer groups and distribute benefits and costs equitably.
- **Adaptable.** DER integration efforts can respond to evolving customer needs, policy, technology and market dynamics.
- **Collaborative.** DER integration efforts are planned and implemented through effective partnerships with E1, IESO-NS, government, industry and other stakeholders.

Role of the DERIR

The objectives of the DERIR are to:

- Articulate a **holistic, coordinated and common vision to plan for, enable, and integrate DERs** in Nova Scotia
- **Identify and prioritize key strategies and initiatives**
- **Find broad alignment among stakeholders** on the DERIR goals, strategies, initiatives and sequencing.

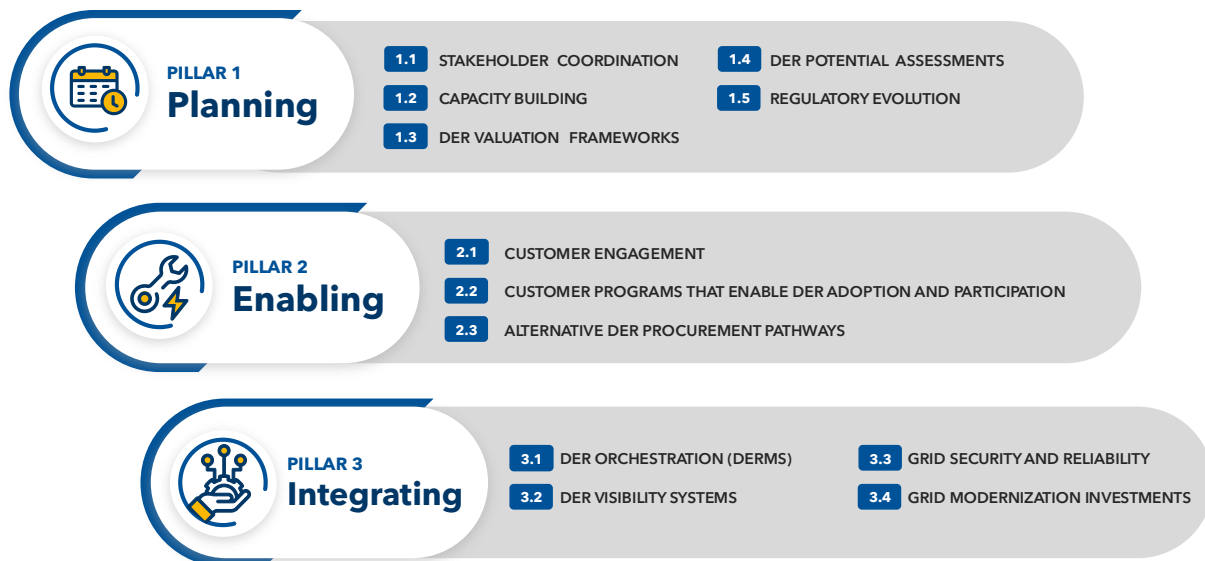
The roadmap builds on past efforts, considers current policy and regulatory direction, recognizes ongoing efforts and elevates new initiatives that can support successful integration of DERs.

Summary of Roadmap

The DERIR is built around three core pillars

- 1. Planning for DERs** proactively to leverage DERs as a resource for meeting emerging system needs. Planning supports coordinated governance, analytical foundations, and regulatory alignment, which can help facilitate proactive and cost-effective DER integration. It focuses on fostering stakeholder alignment around shared planning assumptions, building institutional and workforce capacity, as appropriate, strengthening system intelligence, and applying consistent frameworks, when possible, to assess DERs. Together, these elements help enable transparent, forward-looking planning, program design and delivery decisions and support regulatory structures that can evolve to support emerging DER opportunities while maintaining oversight and accountability.
- 2. Enabling DER Participation** translates planning into action by envisioning clear, accessible pathways for customers and third parties to acquire, deploy and operate DERs. It focuses on coordinated customer engagement and delivery of programs, rates, and incentives that help align customer choices with potential system value. It seeks the right balance of solutions rather than simply many programs or DER deployments. It also assesses alternative procurement and utility ownership models which can help to accelerate DER uptake. Together, these strategies can lower participation barriers, improve program effectiveness, and enable efficient, equitable DER integration using an approach that is aligned with grid needs.
- 3. Integrating DERs** focuses on operationalizing DERs through real-time visibility, control, and coordination, which can help unlock grid and customer value. It centers on deploying DER orchestration capabilities through DERMS, strengthening system-wide DER and feeder visibility, and modernizing core grid operations and control platforms. These strategies can enable reliable and secure DER dispatch, support grid resilience and flexibility, and can help ensure DERs are integrated as active, controllable resources rather than passive connections.

Under the three pillars, **12 Strategies** and **28 Initiatives** were prioritized based on the jurisdictional scan, stakeholder input, and internal knowledge and experience.



Each DERIR initiative is prioritized as **FOUNDATIONAL**, **EVOLVING**, or **EMERGING**:

FOUNDATIONAL	EVOLVING	EMERGING
Foundational initiatives, aligned to current priorities that can advance DER Integration efforts, with sufficient understanding to enable progression when appropriate. Many of these are already implemented and/or ready to proceed. Initiatives include frameworks, foundational analysis, capacity building, pilots, scaling/enhancing programs, and priority investments.	Initiatives that are important but have dependencies with foundational initiatives and/or require further refinement, analysis, or alignment to define the appropriate approach (e.g., need more time, due diligence, direction or level of effort; ambitious/higher risk). Initiatives include analysis, clearer rules, new/enhanced programs, processes, and infrastructure.	Promising initiatives that need to be cultivated to better understand their potential, relevance, or feasibility. They may require time, information, space, or evolving conditions to mature, and/or will be revisited when the time is right. Initiatives include reviews, enhancements to existing/new programs, processes, or technology.

The DERIR pillars, strategies, and prioritized initiatives are listed in the table below. Initiatives that are already in progress are identified by an asterisk (*).

TABLE 1: DERIR PILLAR, STRATEGY, AND INITIATIVE PRIORITIZATION

PILLAR 1: PLANNING FOR DERS		
STRATEGY	INITIATIVE	PRIORITY
1.1 Stakeholder Coordination	1.1.1 Governance Model	FOUNDATIONAL
	1.1.2 Stakeholder Coordination Framework	FOUNDATIONAL
1.2 Capacity Building	1.2.1 Institutional Capacity and Capability Assessment and Plan	FOUNDATIONAL
	1.2.2 Workforce Development	EVOLVING
1.3 DER Valuation Frameworks	1.3.1 Benefit-Cost Analysis Framework	FOUNDATIONAL
	1.3.2 NWA Framework	EVOLVING
1.4 DER Potential Assessments	1.4.1 Hosting Capacity Assessments	FOUNDATIONAL*
	1.4.2 DER Potential Studies	FOUNDATIONAL
	1.4.3 Locational/Seasonal DER Forecasts and Analysis	EVOLVING
1.5 Regulatory Evolution	1.5.1 Regulatory Gap Assessment	EMERGING
PILLAR 2: ENABLING DERS		
2.1 Customer Engagement	2.1.1 Customer Engagement and Outreach Strategy	FOUNDATIONAL
	2.1.2 Equity Framework	FOUNDATIONAL
2.2 Customer Programs that Enable DER Adoption and Participation	2.2.1 DER Enabling Equipment Incentive Programs	FOUNDATIONAL*
	2.2.2 Demand Response Programs	FOUNDATIONAL*
	2.2.3 Time Varying Rate Programs	FOUNDATIONAL*
	2.2.4 Targeted Equity Programs	EVOLVING
	2.2.5 DER Compensation Framework Modernization	EVOLVING
	2.2.6 DER Financing Programs	EMERGING
2.3 DER Procurement Pathways	2.3.1 DER Procurement Framework	EMERGING
	2.3.2 Utility-Owned DER Participation Framework	EMERGING
PILLAR 3: INTEGRATING DERS		
3.1 DER Orchestration (DERMS)	3.1.1 DERMS Evaluation Framework	FOUNDATIONAL*
	3.1.2 DERMS Procurement & Progression	FOUNDATIONAL
3.2 DER Visibility Systems	3.2.1 DER Data Standards and Registry	EVOLVING
	3.2.2 Enhanced DER Detection and Visibility	EVOLVING
3.3 Grid Security and Reliability	3.3.1 Interconnection Process Review & Enhancements	EVOLVING
	3.3.2 Inverter & Protections Standards Modernization	EMERGING
3.4 Grid Modernization Investments	3.4.1 Identify Grid Modernization Strategies	FOUNDATIONAL*
	3.4.2 Implement & Evolve Grid Capabilities	EVOLVING

The table below describes how the roadmap aims to align with each guiding principle.

TABLE 2: DERIR GUIDING PRINCIPLES AND HOW THE ROADMAP ALIGNS WITH THEM

DERIR Guiding Principles	How The Roadmap Aims to Align with the Guiding Principles
Beneficial	The DERIR identifies actions with potential to unlock system, customer, and environmental value from DERs while mitigating the growing risks of unmanaged DER adoption within a rapidly evolving electricity ecosystem. Proactive, coordinated DER integration can support system reliability and security, strengthen distribution system planning and operations, help manage costs, promote equitable outcomes, and enable efficient, well-timed investments.
Affordable	The DERIR emphasizes DER valuation tools, potential assessments, customer programs, and procurement pathways to help identify where DERs could deliver net system value, and/or reduce customer costs, and/or help manage rate impacts.
Reliable	The DERIR proposes integrated DER planning, operational strategies and grid security and reliability initiatives to help anticipate where DERs will grow, deliver the greatest system value and support system reliability, stability, and grid performance as DER penetration increases.
Equitable	The DERIR incorporates an equity framework and targeted customer programs intended to help ensure that DER benefits and costs are distributed fairly, with consideration of vulnerable and underserved customers.
Adaptable	Where initiatives involve new or materially different approaches, the roadmap positions them as lower priority and highlights the need for clear frameworks, guardrails, and upfront assessments before proceeding. As conditions evolve (e.g., policies, technology, customer needs, stakeholder roles), there may be reason to adjust the planned initiatives and/or sequencing. .
Collaborative	The DERIR is informed by NS Power, E1, IESO-NS, NSEB, government, communities and the broader market through stakeholder and customer engagement, coordinated planning, institutional and workforce capacity building, and collaborative program design and delivery.

Roadmap Initiatives

This section presents the proposed roadmap strategies and initiatives to support DER integration, organized under each strategic pillar. The roadmap aims to clarify what is required, why it matters, and how strategies and initiatives should be sequenced over time.

Each pillar is structured by defining the underlying strategies, what each strategy involves, the key initiatives it comprises, and how it can help facilitate achieving effective DER integration. For each strategy, a qualitative assessment is provided to support its inclusion in the roadmap. This assessment reflects strategic fit, costs, and risks scored as high/medium/low. A high score indicates strong strategic alignment, potential benefits, lower resource requirements (funding, staff, technology, effort) and lower risk (high feasibility, less uncertainty and vulnerabilities that may impact success based on experience in other jurisdictions). A low score indicates lower strategic fit, fewer or unclear benefits, higher cost and risk. Detailed descriptions of the assessment criteria are provided in Appendix D.

Under each strategy, the individual initiatives are defined. An initiative is a distinct project, action or activity that contributes to DER integration and may help deliver specific benefits. In some cases, initiatives may require multiple actions to implement. Each initiative description explains its purpose, relevance to DER integration, and the benefits it may help deliver.

For each initiative, we identify the following:

- **Priority.** Foundational, Evolving, or Emerging.
- **Key pre-requisites.** Triggers, tipping points, and/or conditions that influence go/no-go decisions and the pace of implementation.
- **Critical dependencies.** Clarify sequencing requirements to implement initiatives.
- **Nova Scotia context.** Examples from Nova Scotia and other jurisdictions to illustrate what is already occurring in NS to support the initiative, build on and/or learn from.
- **Jurisdiction examples.** Examples from jurisdictions where similar approaches have been implemented to highlight successful practices and/or lessons learned. These examples are intended for reference only and should not be interpreted as prescriptive models or as recommendations that Nova Scotia adopt them directly. Additional details from the jurisdictional scan are included in Appendix A.

A visual illustration of prioritized actions across the 3 pillars, 12 strategies, and 28 initiatives is shown in Section 4: Implementation and Governance Implementation and Governance Considerations.

PILLAR 1

Planning for DERs



STRATEGY 1.1: STAKEHOLDER COORDINATION

Overview

Stakeholder coordination for DER integration planning is a structured process of working collaboratively across NS Power, IESO-NS, E1, NS Energy Board, DER providers, technical experts, communities, and other interested parties. Clear governance structures, defined approaches and regular coordination and communication help facilitate a collaborative response to DER planning, customer engagement, program design and delivery and DER integration.

This effort can inform decisions about how DERs are valued, forecasted, enabled and integrated into the distribution system. It enables planning processes that reflect diverse perspectives and needs, supports consistent technical analyses, promotes the use of enabling strategies that are relevant, accessible and impactful, informs regulatory processes, and helps increase overall transparency, trust and effective DER deployment.



“WHAT WE HEARD”. Stakeholders broadly agreed that stronger, more structured coordination is essential to successful DER integration.

There was strong support for “enhanced” coordination and regular, ongoing communication among E1, NS Power, and IESO-NS, supported by clear governance, shared mandates, structured information sharing and consistent messaging. Stakeholders emphasized the importance of integrated planning, coordination and customer engagement, with one stakeholder recommending building on models such as the DR working group (DRWG).

Early and active involvement between NS Power, E1 and IESO-NS was seen as critical to aligning assumptions, improving planning quality, and accelerating decisions, especially given upcoming planning milestones (e.g., IRP, DSM Plan, DSM Potential and ELCC Studies, capacity procurements) and regulatory matters, decisions and changes.

Qualitative Assessment / Rationale for Inclusion

Criteria	Assessment	Rationale
Strategic Fit	 HIGH	Strong coordination between stakeholders will help enable DERIR roadmap implementation. Alignment on strategies, initiatives, roles, expectations and processes can support collaborative DER planning, program design and delivery.
Benefits	 HIGH	While direct system and customer benefits may not be visible, stakeholder engagement and coordination play an important role in successful DER integration. Coordinated governance contributes to proactive and cost-effective planning, enabling, and integrating DERs informed by diverse perspectives and needs, as appropriate.
Cost Favourability	 HIGH	Likely requires dedicated resources for engagement and coordination, but overall cost impact is expected to be relatively low. It is anticipated that it can be scaled to pace DERIR implementation. Leveraging existing relationships and lessons learned can support effective execution while potentially minimizing costs.
Risk Management	 HIGH	Low overall risk: effective communication and alignment may reduce procedural delays, help secure stakeholder support, enhance market and public trust and lower overall implementation risk.

Roadmap Initiatives

1.1.1 Governance Model		FOUNDATIONAL
Description	A governance model will align NS Power, E1, and IESO-NS on DERIR priorities by clarifying roles and responsibilities, coordination mechanisms, and critical areas of collaboration. As part of the governance model, Nova Scotia should consider establishing advisory groups with sub-working groups, including, but not limited to: • System planning (e.g., alignment on DER assumptions, etc.) • Customer programs (e.g., coordinated customer engagement, program delivery) • Operations (e.g., coordinated transmission and distribution dispatch, data sharing protocols, etc.). The roadmap can serve as a communication and coordination tool, helping stakeholders track progress and align efforts over time. Effective governance models in other jurisdictions define how progress is measured, the process and schedule to monitor, report and update.	
Prerequisites / Triggers	None (foundational initiative)	
Dependencies	All Planning, Enabling and Integrating Strategies and Initiatives	
Nova Scotia Context	Existing groups like the Demand Side Management Advisory Group (DSMAG) and DRWG may serve as models, offering insights into effective (or ineffective) practices and lessons learned from past challenges. While the existing groups have specific mandates and may not be the appropriate venue for DER integration work, these efforts can serve as useful reference points and lessons learned.	

1.1.1 Governance Model		FOUNDATIONAL
Jurisdictional Example	Based on requirements outlined in House Bill 3141 (2021), Portland General Electric and Energy Trust of Oregon jointly developed a Utility-Specific Action Plan to coordinate DSM and DER activities. The partnership focuses on aligning planning horizons, sharing program pipelines, and co-deploying DSM/DER offerings.⁸ The Ontario IESO launched the Transmission-Distribution Coordination Working Group (TDWG) to work closely with Local Distribution Companies (LDCs) to inform the DER market vision and engage in discussions on coordination protocol among the IESO, LDCs, and DER participants.	

1.1.2 Stakeholder Coordination Framework		FOUNDATIONAL
Description	The coordination framework is designed to align planning, enabling, and integrating initiatives, supported by coordinated customer engagement, education, and outreach. These frameworks typically define the objectives of stakeholder coordination and engagement, who should be involved, when and how to support DERIR strategies and initiatives. Engagement may include technical working groups, advisory committees, consultations, public workshops, and collaborative data or knowledge sharing processes. These can help to ensure that DER planning initiatives are informed by diverse perspectives, grounded in practical realities, and aligned with regulatory frameworks and community needs. The purpose is to help build a shared understanding of needs and constraints; promote use of consistent technical analysis, where appropriate; enhance transparency; reveal community priorities and equity considerations; and potentially reduce conflict and streamline regulatory processes.	
Prerequisites / Triggers	Initiative 1.1.1 (Governance Model)	
Dependencies	All Planning, Enabling and Integrating Strategies and Initiatives	

STRATEGY 1.2: CAPACITY BUILDING

Overview

Capacity building refers to developing the skills, tools, processes, and institutional readiness for Nova Scotia to plan for and integrate DERs. It includes assessing current capabilities across a variety of functions, upskilling staff in distribution planning and DER program delivery as required, and cultivating a broader workforce with technical and analytical expertise which supports DER growth and operation of DER assets. Strong capacity building helps enable informed planning, reliable operations, effective program implementation, and coordinated action across the electricity sector.

⁸ 81st Oregon Legislative Assembly 2021 Regular Session. [House Bill 3141](#)



“WHAT WE HEARD”. Stakeholders broadly supported the need for institutional capacity building, but several raised concerns about resource requirements, costs, and funding sources.

Stakeholders emphasized the need to clarify evolving roles to ensure DERIR-related capabilities are complementary and not duplicative. Stakeholders also suggested that capacity and capability assessment and planning should happen early to ensure roadmap progress.

Qualitative Assessment / Rationale for Inclusion

Criteria	Assessment	Rationale
Strategic Fit	●●● HIGH	Building capacity helps ensure people have the skills, tools, and knowledge to support DERIR implementation; Improved tools, processes, and upskilling, as needed supports coordinated, timely DER integration and may create cost efficiencies.
Benefits	●● MED	While capacity building does not directly deliver direct system benefits or customer bill impacts, it can enable cost-effective DER integration over time. Improved staff capabilities, tools, and processes support planning and program implementation and smoother coordination across functions. These improvements can help reduce the need for rework and potentially expedite DER implementation.
Cost Favourability	●● MED	Determining and achieving the appropriate level of capabilities will likely require additional staff, resources and tools across multiple functions. However, there may be an opportunity to stage costs over time as DERIR implementation evolves and potential funding from federal and/or provincial programs may offset some costs.
Risk Management	●●● HIGH	Low risk because capacity building can be staged, as appropriate, and activities such as training, process development, and tool enhancements can be adapted as needs evolve. Implementing the initiative may also reduce DER planning or program delivery risks over time.

Roadmap Initiatives

1.2.1 Institutional Capacity and Capability Assessment and Plan		FOUNDATIONAL
Description	This initiative involves assessing Nova Scotia’s current capacities and capabilities to deliver on relevant DERIR strategies and initiatives; developing a plan that outlines required skills, expertise, resources, and training requirements to build DER capacity and capability; and implementing targeted capacity building, as appropriate, to provide staff with knowledge and tools that can help launch DERIR strategies and initiatives effectively.	
Prerequisites / Triggers	Initiative 1.1.1 (Governance Model)	
Dependencies	All planning, enabling and integrating strategies and initiatives	

1.2.2 Workforce Development		EVOLVING
Description	Workforce development starts with assessing market capacity and capabilities needed to support delivery of relevant DERIR strategies and initiatives, developing new enabling strategies and/or enhancing existing initiatives, as appropriate, and training and/or certifications to strengthen DER integration technical and analytical skills, if required. It is important to help the market launch and manage DER initiatives efficiently and confidently; ensure the sector is prepared to support both near-term deployment and long-term transformation; and coordinate roles, responsibilities, and expectations, where possible.	
Prerequisites/ Triggers	Initiative 1.1.2 (Stakeholder Coordination Framework)	
Dependencies	Enabling strategies and initiatives; DER Orchestration, DER Visibility Systems, Grid Security and Reliability	
Nova Scotia Context	NS Power and E1 have Preferred Contractor Networks with established relationships. One of E1's current strategic priorities is to increase partner capacity and build and maintain a high-performance workforce to accelerate the transition. ⁹	

STRATEGY 1.3: DER VALUATION FRAMEWORKS

Overview

This strategy involves the examination of potential benefit-cost, optimization, and valuation frameworks, which can support DER investment and planning processes. These frameworks often define rules, methods, and inputs used by different system actors to evaluate DERs. By creating a common language and shared expectations, these frameworks help enable consistent evaluation of DER opportunities. These frameworks promote transparency and consistency across various system actors in planning, program design, and operational decisions, as appropriate.



"WHAT WE HEARD". Stakeholders emphasized the need for clear, consistent definitions of costs and benefits to ensure alignment between NS Power, E1, and IESO-NS in DER valuation.

Questions were raised about how a BCA framework would be applied to determine which DERs are included in the roadmap, and how costs would be allocated and recovered to support affordability objectives. One stakeholder suggested that the Program Administrator Cost (PAC) test may not fully capture the value of DERs and called for further exploration of more comprehensive Benefit Cost Analysis (BCA) approaches. Another suggested that costs and benefit definitions be established to ensure consistent DER program valuation.

⁹ E1 has a strategic priority to build for the long-term by working with partners to increase capacity to accelerate the energy transition, building and maintaining a talented, high-performing workforce to lead the industry transformation and investing in and testing new technologies and approaches to advance industry and market readiness. EfficiencyOne Five-Year Strategic Plan.

Qualitative Assessment

Criteria	Assessment	Rationale
Strategic Fit	 HIGH	DER valuation framework directly advances the delivery of least-cost, reliable, and clean electricity and aligns with provincial climate and affordability goals. It can support coordination across the electricity sector and allow for transparent and consistent evaluation of DERs.
Benefits	 HIGH	Valuation frameworks can support consistent and transparent, assessment of DER options. By improving how DERs are quantified and compared across different use cases, these frameworks can help support cost-effective DER planning and program design, help identify opportunities to defer or avoid infrastructure upgrades, and provide transparent decision-making. This could lead to system cost savings and improved customer outcomes through more targeted DER deployment and investment prioritization.
Cost Favourability	 MED	These frameworks often require internal analytical/modelling capacity, external expertise and tool development. Though it is unlikely that major infrastructure changes would be required, the process to develop valuation frameworks is time intensive and will likely require committed resources.
Risk Management	 HIGH	DER valuations frameworks should be regularly updated as the energy landscape evolves in Nova Scotia, including to maintain alignment with legislative changes and/or regulatory changes and/or approvals.

Roadmap Initiatives

1.3.1 Benefit Cost Analysis Framework		FOUNDATIONAL
Description	A benefit-cost analysis framework sets out the overarching approach for assessing the cost effectiveness of investments by comparing the benefits and costs of alternative options. DER BCA frameworks set out a methodology and approach which enables different potential DER market actors to compare DERs with each other and with alternatives in a consistent, transparent way. Ideally, a DER BCA framework should align with benefits and costs principles, methodologies and approaches consistent with established practice, like the National Standard Practice Manual¹⁰ Benefit-cost analysis frameworks that have been directed in other comparable jurisdictions should be considered and assessed for their suitability in the Nova Scotia context as it relates to evaluating DERs.	
Prerequisites / Triggers	None; foundational initiative	

¹⁰ The National Standards Practice Manual is developed by the [National Energy Screening Project](#) - a stakeholder organization working collaboratively to provide a comprehensive framework to improve cost-effectiveness screening practices for energy efficiency and other distributed energy resources (DERs). The manual is published by the National Association of State Energy Officials (NASEO).

1.3.1 Benefit Cost Analysis Framework		FOUNDATIONAL
Dependencies	Initiative 1.4.2 (DER Potential Studies) and 1.3.2 (NWA Framework) Strategy 2.2 (Customer Programs That Enable DER Adoption and Participation)	
Nova Scotia Context	DSM investments in Nova Scotia are screened based on a Board-mandated BCA (PAC test), as per the Public Utilities Act, while other utility investments follow the NSEB-approved Capital Expenditure Justification Criteria (CEJC). In a recent BCA matter, stakeholders were divided on how cost-effectiveness, as dictated in the Public Utilities Act, should be balanced with sustainable development and sustainable prosperity goals outlined in the Energy and Regulatory Boards Act. The NSEB found that the purpose of the demand-side management provisions in the Public Utilities Act is to reduce electricity costs for customers and that the Board's obligation to give appropriate consideration to certain factors in s. 6(2) of the Energy and Regulatory Boards Act, including sustainable development and sustainable prosperity cannot override specific statutory requirements elsewhere.¹¹	
Jurisdiction Examples	The State of New York Public Service Commission (NYPSC) established a Benefit-Cost Analysis Framework (BCA Order), which requires New York Joint Utilities to use the Societal Cost Test (SCT) as the primary test to measure cost-effectiveness. The NYPSC also directed New York's Joint Utilities¹² to develop and file BCA Handbooks, which provide a consistent and transparent methodology for calculating the benefits and costs of potential projects and investments. The Michigan Public Services Commission directed that utilities develop a Michigan specific benefit-cost test for pilot DER programs, guided by the NSPM. This BCA test was approved in October 2023. The MPSC subsequently directed the development of a flexible and transparent tool to measure the cost-effectiveness of DER programs, through a collaborative process including commission staff, utilities, and stakeholders. The Benefit-Cost Analysis Tool Collaborative is in the process of developing the BCA tool, to model Michigan's Jurisdiction Specific Test (JST) for DERs.	

¹¹ NSEB, Decision, 2025 NSEB M12282 (Application by EfficiencyOne for Approval of a New BCA Test for Evaluating DSM Plans).

¹² Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation

1.3.2 NWA Framework		EVOLVING
Description	A Non-Wire Alternatives (NWA) framework sets out a standardized approach for identifying and evaluating potential NWA solutions. An NWA framework enables consistent and transparent, evaluation of Non-Wires Alternatives in utility planning. These frameworks typically outline the requirements, guardrails, and standards which are used in NWA assessments by different system actors. Non-Wires Alternative frameworks that have been implemented in other comparable jurisdictions should be considered and assessed for their suitability in the Nova Scotia context as it relates to evaluating NWAs.	
Prerequisites / Triggers	None; foundational initiative	
Dependencies	1.4.3 (Locational/Seasonal DER Forecasts and Analysis)	
Jurisdiction Example	The Ontario Energy Board's Non-Wires Solutions Guidelines guide the role of non-wires solutions for rate-regulated electricity distributors, including the treatment of non-wires solutions in distribution rates. The guidelines direct that "distributors are required to document their consideration of non-wire solutions when making investment decisions on electricity system needs with an expected capital cost of \$2 million or more as part of distribution system planning". The guidelines set out how electricity distributors should address non-wire solutions.	

STRATEGY 1.4: DER POTENTIAL ASSESSMENTS

Overview

This strategy examines the planning and analytical capabilities needed to support efficient, equitable, and cost-effective DERs. It leverages existing electricity system intelligence tools, such as hosting capacity maps, to actively identify where DERs can be connected without significant network upgrades. The strategy includes consideration of DER potential assessments and NWA assessments, which can help anticipate how and where DER adoption will grow, how it might affect system performance and how DERs can be evaluated against alternatives. It can involve deployment of economic valuation tools, including marginal avoided cost studies and locational net benefit analyses, to quantify system value and inform planning decisions, operational priorities and incentive design, as appropriate. Together, these capabilities can provide a forward-looking, location-specific view of system needs, enable proactive decision-making and support timely, reliable, and cost-effective DER integration.



“WHAT WE HEARD”. Stakeholders encouraged stronger coordination between NS Power, E1 and IESO-NS to reduce duplicative costs and align DER potential assessments with DSM planning, including enabling locational DSM pilots.

Stakeholders emphasized that DER potential assessments were a crucial component to scale programs effectively. They suggested refreshing hosting capacity data annually to reduce interconnection delays, guide near-term DER siting and program design, and quantify DER potential to inform IRPs and avoid suboptimal procurement decisions. One stakeholder group suggested targeted locational analyses should follow shortly after DER potential assessments to identify constrained, high-value areas and inform DER compensation programs.

Qualitative Assessment

Criteria	Assessment	Rationale
Strategic Fit	●●● HIGH	Enhanced DER forecasting and analysis supports planning for capacity, reliability, and DER integration. It aligns with current provincial climate goals and grid modernization efforts, and requires coordination between NS Power, E1 and IESO-NS to support consistent system-level insights.
Benefits	●●● HIGH	DER forecasting enables cost-effective distribution planning, can strengthen reliability by anticipating feeder impacts and supporting resilience investment planning, and can support operational efficiencies. It can also deliver high system and customer value by identifying where DERs can defer or replace traditional infrastructure. Improved hosting tools can reduce interconnection delays and costs and enable efficient siting of local DERs. Improved forecasting helps support higher DER penetration and could help advance Nova Scotia's decarbonization and economic objectives.
Cost Favourability	●● MED	DER forecasting and analytical tools may require upfront investment in platforms, and data integration, as well as ongoing model maintenance, potentially with recurring software and data management costs. Costs may be partially offset through federal programs or research partnerships, and precedents in other jurisdictions can provide models to adapt.
Risk Management	●●● HIGH	Risk is low; DER forecasting approaches in other jurisdictions have helped to reduce uncertainty. Key risks relate to data integration, the accuracy of hosting or forecasting tools, security considerations, and stakeholder alignment.

Roadmap Initiatives

1.4.1 Hosting Capacity Assessment		FOUNDATIONAL
Description	Hosting capacity maps are screening-level visual tools that provide a preliminary assessment of where and how much new electricity generation from rooftop solar or other DERs the power grid can handle without needing major upgrades. They offer transparency and can help users quickly see where it may be easy to connect new DERs to the grid, where the grid is at its current hosting capacity limit and/or where flexibility may help manage the grid. They complement comprehensive system impact studies required in Distribution Generator Interconnection Procedures.	

1.4.1 Hosting Capacity Assessment		FOUNDATIONAL
	Regular review of hosting capacity map data can help to identify DER growth areas and system constraints. Baseline system visibility provides a clear picture of how the electricity grid is performing today and can help avoid guesswork, potentially saving time, reducing interconnection delays, supporting better planning and helping target investments. Over the long term, consideration should be given to modernizing hosting capacity maps, as appropriate. Potential modernization options could include developing maps for additional DER types, moving from static, annual maps to automated, dynamic, real-time or near-real-time assessments to reflect changing grid conditions.	
Prerequisites / Triggers	None	
Dependencies	1.4.2 (DER Potential Studies) and 1.4.3 (Locational / Seasonal DER Forecasts and Analysis)	
Jurisdiction Example	As an example, Hydro One's Flexibility Initiative publishes congested areas on the NODES Platform , incentivizing registered flexibility service providers (commercial & industrial customers, aggregators, and energy management providers) to offer flexibility in affected regions. Long-term flexibility requests are published on the platform, and registered flexibility service providers can reply to requests to offer flexibility in exchange for compensation.	

1.4.2 DER Potential Studies		FOUNDATIONAL
Description	DER potential studies estimate the likely and achievable adoption of DERs across locations, based on policy, economics, customer interest, and technical constraints. Typically, jurisdictions maintain a regular cadence of studies and data updates to ensure DER forecasting inputs remain current and relevant. DER potential studies can play an important “bridge” role when they sit upstream of both planning and procurement, as they can shape how DERs are valued before they are evaluated in IRPs, distribution planning, BCAs, or programs. They can help DERs be expressed in the same terms as supply-side resources (capacity, energy, ramping, flexibility), prevent DERs from being undervalued as only “energy reducers,” and allow for comparison with supply-side options, when appropriate. These forecasts typically support long-term planning, including capacity needs and investment decisions. A comprehensive forecasting approach which incorporates hourly and feeder-level granularity might be considered to help enable future evolution, capability and opportunity as DER adoption continues to grow. Over time, planning practices typically evolve to better integrate locational value and system flexibility.	
Prerequisites / Triggers	Strategy 1.3 (DER Valuation Frameworks)	
Dependencies	Strategy 2.2 (Customer Programs the Enable DER Adoption and Participation); Strategy 2.3 (DER Procurement Pathways)	

1.4.2 DER Potential Studies		FOUNDATIONAL
Jurisdiction Example	IESO-Ontario commissioned Ontario's first DER potential study in 2022.¹³ The potential study determined the types and volumes of DERs that could emerge in Ontario over a 10-year timeframe (2023-2032) and their ability to contribute to the province's emerging system needs. Portland General Electric has created a DER forecasting model, "AdopDER," for a hybrid top-down and bottom-up modelling approach to estimate load impacts. It assesses the adoption of 50+ DER and electrification measures and can assess feeder level impacts. Increasing forecast granularity from the system level to specific geographies (e.g., substations or feeders) has provided distribution planners with greater visibility into DER adoption, load impacts, and local asset capacity. However, this increased locational detail comes with reduced forecast accuracy at individual sites.	
1.4.3 Locational /Seasonal DER Forecasts and Analysis		EVOLVING
Description	Building on DER potential assessments, there may be opportunity to apply a more granular analytical lens so that DER potential studies become progressively more sophisticated over time. Examples of more granular analyses that have been carried out in other jurisdictions that could be considered for Nova Scotia include: • NWA assessments to evaluate whether DERs can defer or replace traditional grid investments. • Locational/Seasonal DER forecasts and saturation analyses • Avoided cost studies, which quantify location- or seasonal-specific avoided costs from DER deployment, • Locational and seasonal net benefits analysis which assess DER costs and benefits at the feeder level These activities can help enable smarter and more cost-effective grid upgrades, potentially expedite interconnection processes, improve reliability and support decarbonization goals.	
Prerequisites / Triggers	Strategy 1.3 (DER Valuation Frameworks), 1.4.1 (Hosting Capacity Assessment)	
Dependencies	Strategy 3.2 (DER Visibility Systems), Strategy 3.4 (Grid Modernization Investments)	

¹³ IESO, Dunskey Energy + Climate Advisors. 2022. Ontario's Distributed Energy Resources (DER) Potential Study. Volume 1: Results and Recommendations.

STRATEGY 1.5: REGULATORY EVOLUTION

Overview

This strategy does not propose bypassing established legislative and regulatory processes. Instead, it recognizes that as the electricity system and DER landscape evolve, policy and regulatory frameworks in Nova Scotia may also need to adapt to support emerging technologies, new roles, and system needs that are not yet fully clear.

Accordingly, this strategy focuses on identifying where regulatory structures may need to evolve to facilitate longer-term DER innovation, flexible utility planning, and an adaptive, future-ready electricity system.



“WHAT WE HEARD”. Stakeholders stressed that regulatory oversight and approval will be required at all stages of the roadmap; endorsement of the roadmap should not be interpreted as approval to proceed without regulatory review.

Some expressed concern that slow regulatory processes could delay initiatives, particularly if timely approval of related spending is needed.

There were also questions about how the DERIR will align with ongoing NSEB proceedings (e.g., Interconnection, DSM, TVP, etc.), the transition of transmission and system planning responsibilities from NS Power to IESO-NS, and affordability considerations. Stakeholders highlighted the need to account for existing regulatory matters already before the NSEB, and to clarify whether new legislation or regulations will be required and the associated timelines and risks.

Qualitative Assessment

Criteria	Assessment	Rationale
Strategic Fit	●● MED	Regulatory evolution can support DER integration efforts as needed. Potential regulatory changes are expected to become clearer as DER adoption grows and/or policies, technologies, systems, and conditions evolve.
Benefits	●● MED	New regulatory models could incentivize and encourage DERs/NWAs. Innovation Sandboxes are one example of a regulatory model that can enable new innovative pilots, which can benefit customers and the system, provide flexibility and improve utility responsiveness. An innovation sandbox is a controlled environment that allows regulated entities and their partners to test new technologies, business models, programs, or regulatory approaches on a limited scale and with appropriate regulatory flexibility before broader deployment.
Cost Favourability	●● MED	Moderate incremental investment required in regulatory filings and planning, and ongoing efforts required to participate in stakeholder processes.
Risk Management	●● MED	Precedent exists in other jurisdictions, but implementation can be complex and lengthy (e.g. insufficient stakeholder consensus could also delay implementation). DER integration activities must consider recent and potential regulatory reforms to ensure consistent and predictable signals.

Roadmap Initiatives

1.5.1 Regulatory Gap Assessment		EMERGING
Description	This initiative involves reviewing the existing regulatory structure and identifying gaps or where clarity is needed to support or allow for the deployment of DER strategies and initiatives. Some elements in the DERIR, particularly those related to future DER capabilities, evolving market functions, adaptive planning practices and/or new pilots/programs, may require regulatory or legislative change/clarity. For example, some jurisdictions have implemented a common regulatory sandbox that allows for testing of innovative technologies, services, and models which may provide greater flexibility and responsiveness. As roles and responsibilities evolve in the energy sector in Nova Scotia and the energy landscape becomes increasingly dynamic, regulatory tools may need to expand or evolve to enable longer-term, system-wide DER strategies that extend beyond today's established categories.	
Prerequisites / Triggers	Unclear. As the electricity system and DER landscape evolve, regulatory frameworks will need to adapt, as appropriate.	
Dependencies	Unclear	
Nova Scotia Context	Consideration should be given where different regulatory models exist for different entities in Nova Scotia. For example, customer equipment incentives and demand response programs are included in E1's multi-year DSM Plans, subject to NSEB approval with established decision-making processes around expenditures, savings, and customer impacts. Similarly, time-varying rate pilots have been approved through formal regulatory proceedings. NS Power and E1 follow different Board-approved models for innovation investments.	
Jurisdiction Example	The OEB Innovation Sandbox in Ontario allows proponents to have informal conversations with regulators about innovative project ideas and test their innovations under a limited regulatory waiver.	

PILLAR 2

Enabling DER Participation



STRATEGY 2.1: CUSTOMER ENGAGEMENT

Overview

Customer engagement is key to building awareness and trust, developing DER programs which reflect Nova Scotians' needs and enabling broad participation. Simplicity and accessibility are also critical. If customers struggle to understand which programs apply to them, which can be stacked, or how to participate, unintended barriers to adoption can arise.

Engaging customers early and throughout program design and implementation helps align program design with real-world motivations and barriers, improving accessibility, understanding, and adoption. While strong customer education and support already exist through various initiatives delivered by E1 and NS Power, further coordination among key system actors and more targeted approaches can help to build on these successes. Strengthened customer engagement can support better program outcomes, higher participation, and can help mitigate system and equity impacts.



WHAT WE HEARD. Stakeholders prioritized equity and encouraged embedding clear equity parameters and measurable targets directly into program design and incentive structures.

There were calls to recognize and consider diverse customer interests, needs and perspectives; equity considerations are not limited to income. For example, one stakeholder group suggested that previous program

incentives were insufficient to attract small business participation.

They also emphasized the importance of coordinated messaging to avoid duplication and market confusion and provide consistent customer signals.

Qualitative Assessment

Criteria	Assessment	Rationale
Strategic Fit	 HIGH	Customer engagement is key to empowering customers to participate. Targeted engagement can help reduce barriers, ensure programs and services meet customer needs, and increase access to and uptake of DERs and broader system benefits for all customers.
Benefits	 MED	Effective engagement helps increase DER program awareness and participation, which can improve customer experience, support targeted and effective programming, build public trust and potentially reduce system costs over time.
Cost Favourability	 MED	Costs are expected to be primarily related to outreach campaigns and customer engagement channels, approaches and/or platforms, though some support may be offset through federal or provincial funding. Customer education can also help households identify bill-saving opportunities.
Risk Management	 HIGH	Expected to be relatively low risk. However, coordination, which ensures roles/responsibilities and objectives of engagement are clear, can help to enhance customer experience and avoid market confusion.

Roadmap Initiatives

2.1.1 Customer Engagement and Outreach Strategy		FOUNDATIONAL
Description	A DER engagement and outreach strategy generally sets out a structured, ongoing approach to involving customers in the design and delivery of DER programs. Its purpose is to ensure programs reflect customer needs, motivations, and barriers, enabling higher participation, sustained adoption, and equitable outcomes. A DER engagement and outreach strategy can help facilitate accessible, understandable, DER programs that are attractive to diverse customer groups and aligned with real-world customer decision-making. Customer engagement and outreach activities build understanding and trust, and can reduce participation barriers, drive program uptake, improve program performance, support equity goals, and enhance grid outcomes. Coordination among key actors through a collaborative customer engagement and outreach strategy can help enable DER awareness, adoption, and participation at scale. Coordination can help ensure system needs are considered, avoid market confusion and duplication, enhance customer experience and maximize participation.	
Prerequisites / Triggers	Initiative 1.1.1 (Governance Model); Initiative 1.2.1 (Institutional Capacity and Capability Assessment and Plan)	
Dependencies	All Customer Programs that Enable DER Adoption and Participation	
Nova Scotia Context	NS Power, E1 and other stakeholders currently provide province-wide and program-specific education, advisory services, and customer support.	

2.1.2 Equity Framework		FOUNDATIONAL
Description	An equity framework promotes a shared understanding of equity and can help guide future DER programs, so they address customer needs. These frameworks typically set out the definition of equity in the context of DER Integration. The word equity is both widely used and widely misunderstood, and its meaning changes depending on the application, audience, and purpose. Without a clear, context-specific definition, people can interpret equity in ways that may be inconsistent with intent. Clarity about what equity is in the context of DER Integration promotes common understanding, enables stakeholders to work toward common goals, and helps focus DER integration efforts. These frameworks often define equity-deserving groups, beyond income only, as equity and accessibility can be much broader. Equity-deserving groups identified in other jurisdictions include, but are not limited to, renters, rural communities, First Nations, and small businesses. Additionally, these frameworks frequently establish equity goals and objectives, with clear equity parameters to support equitable program designs and outreach strategies outline indicators which can be used to monitor and track equitable outcomes. Best practice is to embed the principles set out in the equity framework across all DER programs (not just targeted equity programs), if possible.	
Prerequisites / Triggers	Initiative 1.1.2 (Stakeholder Coordination Framework); Initiative 1.2.1 (Institutional Capacity and Capability Assessment and Plan)	
Dependencies	All Customer Programs that Enable DER Adoption and Participation	
Jurisdiction Example	Examples of indicators that are tracked in other jurisdictions include: • Participation and access: dedicated investment in equity-deserving groups, participation representative of community demographics, interconnection or program enrollment wait times or approval rates, solutions meet community needs. • Affordability and energy burden: average bill reductions for participants and net bill impacts of DER programs on non-participants • Geographic: DER capacity installed, hosting capacity and interconnection access in different neighbourhoods, resilience (e.g., backup power in vulnerable communities). • Workforce and economic development: DER deployment jobs, training, or contractor participation from local or equity-deserving communities. • Procedural: Stakeholder representation in DER planning and program design, the number of community organizations engaged, and community partnerships developed, to support program implementation.	

STRATEGY 2.2: CUSTOMER PROGRAMS THAT ENABLE DER ADOPTION AND PARTICIPATION

Overview

There are multiple ways to enable customer DER adoption and participation. Some are better suited to specific DER technologies or customer use cases, and in many cases the most effective approach is a combination of mechanisms. Jurisdictions with successful DER integration typically intentionally weave together a coordinated portfolio of customer programs and market mechanisms that align customer motivations with system benefits and are practical to implement together in the real world.

Planning and assessing these initiatives holistically, allows them to harmonize and helps ensure they can achieve their intended outcomes. For example, a customer's decision to purchase and install a DER may be influenced by upfront incentives, the availability of financing and ongoing compensation. At the same time, DER programs often have distinct characteristics and design considerations and are typically administered as separate initiatives. Accordingly, they are grouped under a single strategy in this roadmap, while qualitative assessments are addressed individually for each initiative. This differs slightly from how the qualitative assessment is applied for the other Pillars and Strategies but is necessary to capture and understand program differences.



"WHAT WE HEARD". Stakeholders underscored affordability, funding sources, and cost allocation as central considerations. Several called for clarity on who benefits from programs and how they will be assessed, as well as alignment between short-term program plans and longer-term technology partnerships.

There was strong emphasis on delivering a seamless, coordinated customer experience, avoiding parallel or conflicting programs through aligned branding, messaging, rate design, incentive structures, and backend coordination between NS Power and E1. Stakeholders recommended applying lessons from early pilots/programs, using small-scale pilots to test complex coordination and customer response, adopting a common evaluator model for joint initiatives, and embedding equity parameters and measurable targets across all programs.

Additional feedback suggested ensuring incentive design aligns with grid needs, locational priorities, and future DER orchestration requirements, reviewing tariff design and battery participation rules under ongoing NSEB matters (including time varying pricing (TVP) and net metering), clarifying current and future net-metering, and assessing behind-the-meter storage and load-shifting technologies system and capacity value.

Roadmap Initiatives

2.2.1 Equipment Incentive Programs		FOUNDATIONAL
Description	Targeted incentives encourage and enable DER technology adoption and transform consumer equipment purchases into grid assets. Many DER technologies cost more upfront than conventional alternatives. Incentives like customer rebates, point-of-sale discounts, tax credits, and/or upstream incentives to manufacturers/contractors help to reduce the upfront and operating costs of DERs, so that customers choose equipment capable of participating in a flexible, modernized grid. The governance model, customer engagement strategy, and lessons learned from prior program experience, may result in reevaluating incentives and/or program design and expanding to new customer segments to support greater and targeted DER participation. Most jurisdictions periodically review programs to assess their effectiveness and appropriateness in supporting DER deployment while balancing overall system costs and benefits.	
Prerequisites / Triggers	Initiative 1.1.1 (Governance Model); Initiative 1.2.1 (Institutional Capacity and Capability Assessment and Plan), Initiative 1.3.1 (BCA Framework), Strategy 2.1 (Customer Engagement)	
Dependencies	Incentives are often coupled with DR programs (Initiative 2.2.2)	
Nova Scotia Context	E1 currently offers incentives for smart thermostats, heat pump water heaters, heat pumps, and EV chargers for MURBs. Residential customers with eligible models can also receive an incentive to enroll and participate in the Eco Shift DR program. E1 also offers free smart thermostats and a hot water heater controller installed at no cost through the Efficient Product Installation program. Customers are automatically enrolled in the Eco Shift DR program and paid to participate.	
Jurisdiction Example	Other jurisdictions have tied incentives to participation in time-varying rate and demand response programs. For example, Green Mountain Power in Vermont provides a free Level 2 EV charger when enrolling in EV rates, and provides a battery rebate of up to \$10,500 to incentivize participation within their virtual power plant (VPP) program.	

Qualitative Assessment of Incentive Programs

Criteria	Assessment	Rationale
Strategic Fit	 MED	Incentives support and encourage electrification and decarbonization objectives and reduce upfront cost barriers of DERs, in particular, those DERs where natural uptake is slow to meet policy timelines. Targeted programs can help to influence when and where DERs are installed which can support system benefits.
Benefits	 HIGH	Targeted incentives can support peak reduction and defer grid upgrades, though benefits depend on program design. Capacity, demand, or coincident-peak gains are limited unless considered holistically (e.g., paired with controls or DR/TOU integration). For customers, incentives can meaningfully reduce upfront costs and can help with long-term bill savings.
Cost Favourability	 MED	Expected to require upfront funding and ongoing administrative and program delivery costs. Federal and provincial funding can potentially offset some expenses, but not all DERs may qualify for external support. A strategic approach to gradually phase out incentives may help enable early adoption of DERs and prevent market disruption while potentially minimizing long-term costs as technologies move from niche to mainstream and adoption grows
Risk Management	 MED	Most technologies carry low reputational risk. Risks of secondary peaks, misaligned system benefits and/or antagonistic interactive effects can be minimized if incentives are coordinated with rate design or a DERMS.

2.2.2 Demand Response Programs		FOUNDATIONAL
Description	Demand response (DR) programs enable electricity demand to act as a flexible resource. DR pilots and programs can be broken down into two categories: - Voluntary DR programs encourage customers to shift or reduce load during peak periods in response to incentives or signals. - Direct load control programs allow aggregated remotely managed customer devices such as thermostats, water heaters, EV chargers, and batteries to shift or shed load in exchange for incentives Highly effective and inclusive DR programs are typically designed and delivered based on customer experience and insights from program experience, best practices from other jurisdictions, and the customer engagement strategy. Like incentive programs, DR programs typically undergo periodic reviews to assess their effectiveness and appropriateness in supporting DER deployment while balancing overall system costs and benefits.	
Prerequisites / Triggers	Initiative 1.1.1 (Governance Model); Initiative 1.2.1 (Institutional Capacity and Capability Assessment and Plan), Initiative 1.3.1 (BCA Framework), Strategy 2.1 (Customer Engagement), Strategy 3.1 (DER Orchestration (DERMS))	
Dependencies	None	
Nova Scotia Context	There are several existing DR programs in Nova Scotia, including voluntary programs (EcoShift , Smart Synergy) and direct load control initiatives (Generation Replacement and Load Following (GRLF) tariff, Interruptible Rider to Large Industrial (IRLI) and Extra Large Industrial Active Demand Control tariffs). Lessons learned from these programs could be	

2.2.2 Demand Response Programs**FOUNDATIONAL**

used to enhance future programming, including expanding DR programs to other sectors/customers and/or advancing DR integration.

Qualitative Assessment of Demand Response Programs

Criteria	Assessment	Rationale
Strategic Fit	 HIGH	DR programs are aligned with broader grid modernization and electrification objectives and allow Nova Scotia to build on existing knowledge and programs to allow for further demand flexibility.
Benefits	 HIGH	DR provides peak shaving, capacity from existing assets and can provide emission reduction benefits (avoiding peak fossil-based generation), though the degree of system value potentially achieved depends on customer participation and DERMS integration. In some jurisdictions, customer bills are offset by DR participation payments.
Cost Favourability	 MED	DR is expected to require limited infrastructure investment, and costs are anticipated to be primarily driven by program design, customer recruitment, engagement and any potential evaluation activities, as required.
Risk Management	 MED	Programs can typically be launched relatively quickly, but if they underdeliver on peak reductions, customer buy-in could be lost and stakeholder confidence could erode. Strong coordination will help support successful program design, customer engagement and experience and outcomes.

2.2.3 Time Varying Rate Programs**FOUNDATIONAL**

Description	Time-of-use (TOU) rates, critical peak pricing (CPP), and equipment-specific time varying rates (TVRs) (e.g., for EV chargers, smart thermostats, or batteries) are pricing structures in which the cost of electricity changes based on when it is used. These electricity pricing structures encourage customers to shift when they use power, typically through rates which are higher during periods when the grid is most stressed (e.g., peak hours or critical events) and lower when demand is low or renewable generation is abundant. Assessing pilot outcomes can help to determine scalability and the need for formalized, permanent rate structures. This type of assessment may help identify opportunities to expand subsequent pilot phases.
Prerequisites / Triggers	Initiative 1.1.1 (Governance Model); Initiative 1.2.1 (Institutional Capacity and Capability Assessment and Plan), Initiative 1.3.1 (BCA Framework), Strategy 2.1 (Customer Engagement)
Dependencies	None
Nova Scotia Context	Several time varying rate pilots and programs are currently offered in Nova Scotia, including Time of Use Pilot , Critical Peak Pricing Pilot , Time of Day Rate .

Qualitative Assessment of Time-Varying Rates

Criteria	Assessment	Rationale
Strategic Fit	 HIGH	TVRs are aligned with broader grid modernization and electrification objectives and can help Nova Scotia to build on existing DER integration knowledge and programs to allow for further demand flexibility.
Benefits	 MED	TVRs can reduce system peaks, lower operating reserves, and potentially help defer grid upgrades, though actual impacts heavily depend on customer behaviour and participation. Customers that participate can see bill savings.
Cost Favourability	 MED	While several TVRs have been implemented, future programs or existing program expansion may come with additional complexity which may result in additional costs and IT systems updates. The scale and pace required for future programs or existing program expansion may also impact costs. Once IT upgrades are made, costs are expected to be incremental.
Risk Management	 MED	Some expected risks relate to customer uptake and experience, equity impacts, and execution when scaling pilots to programs or expanding existing programs. If programs underdeliver on peak reductions or customers experience pain points, stakeholder and stakeholder confidence could erode.

2.2.4 Targeted Equity Programs		EVOLVING
Description	This initiative involves assessing the potential for designing and delivering targeted programs for equity-deserving groups as defined in the equity framework (Initiative 2.1.2). Not everyone can access or benefit from DERs in the same way. Equity-deserving groups can face higher upfront costs, limited access to financing, rental or land-use restrictions, and fewer service options, among others. Targeted programs can help remove these barriers, so participation isn't limited to those with the means. Examples from other jurisdictions show that support can be financial (e.g. low-interest financing or higher incentives) or non-financial (e.g., different education and outreach channels, leveraging community-based governance models, equitable procurement practices, etc.).	
Prerequisites / Triggers	Initiative 1.1.1 (Governance Model); Initiative 1.2.1 (Institutional Capacity and Capability Assessment and Plan), Initiative 1.3.1 (BCA Framework), Strategy 2.1 (Customer Engagement)	
Dependencies	None	
Nova Scotia Context	E1 has established equity-focused programs. These include energy efficiency and electrification programs for low- and moderate-income households, First Nations, and African Nova Scotian communities. The Energy Poverty Task Force, a coalition of representatives from Nova Scotia's public, private and not-for-profit sectors, which was created with a vision for reduction in energy poverty, recommended continued expansion of targeted efficiency programs in Nova Scotia. ¹⁴	

¹⁴ Colton, Roger D., Energy Poverty Task Force. 2024. A Way Forward: A Made-In-Nova Scotia Home Energy Affordability Program. Accessed on January 16, 2026

Qualitative Assessment of Equity Programs

Criteria	Assessment	Rationale
Strategic Fit	 HIGH	Equity programs align with Nova Scotia stakeholder priorities. Public and stakeholder support for expanded energy-affordability measures is high, reflecting the fact that roughly 43% of Nova Scotians face energy poverty. ¹⁵
Benefits	 MED	Equity programs can deliver value to equity-deserving groups such as bill relief, improved reliability and resilience, and access to clean energy technologies. Overall system value benefit is limited, though there can potentially be indirect reliability and overall system cost benefits through reduced loads.
Cost Favourability	 MED	Costs are expected to be driven by financial and non-financial support. Costs are assumed to be incremental/complementary to funding which may be available through existing programs for equity-deserving groups.
Risk Management	 MED	Equity programs require careful design and delivery to ensure programs meet customers' unique needs and that benefits reach targeted participants. Successful implementation relies on strong coordination across multiple stakeholders.

2.2.5 DER Compensation Framework Modernization		EVOLVING
Description	DER compensation frameworks describe mechanisms to determine how DER owners and operators are paid, or credited for the electricity they produce, store and share with the grid through DERs like solar, storage and EVs. The current framework includes net metering, and modernization could involve exploring mechanisms implemented in other jurisdictions, such as value-based DER compensation.	
Prerequisites / Triggers	Strategy 1.1 (Stakeholder Coordination), Strategy 1.2 (Capacity Building), Initiative 1.3.1 (BCA Framework), Strategy 2.1 (Customer Engagement)	
Dependencies	None	
Nova Scotia Context	In 2022, the Government of Nova Scotia introduced legislation to update the existing net-metering program. ¹⁶	
Jurisdiction Example	Several jurisdictions are implementing VDER programs that can serve as reference. For example, New York Value of Distributed Energy Resources (VDER) - Value Stack Tariff for Solar PV (including community solar), storage, and other eligible DERs and Hawaii Smart Renewable Energy Programs for rooftop solar with/without batteries. BC Hydro has proposed a change from net metering to net billing , where customers are credited based on the value to the BC Hydro system rather than the customer's retail rate. The BC Utilities Commission held a hearing on the proposed application in November 2025, with final arguments submitted in December 2025. The British Columbia Utilities Commission approved changes to net metering service rates in March 2026. ¹⁷	

¹⁵ Ibid.

¹⁶ Government of Nova Scotia. April 2022. News Release. [Amendments to Electricity Act, Public Utilities Act](#)

¹⁷ British Columbia Utilities Commission. [Order Number G-64-26](#). March 24, 2026

Qualitative Assessment of Compensation Frameworks

Criteria	Assessment	Rationale
Strategic Fit	 LOW	DER compensation frameworks involve a high degree of coordination. Adjustments to the existing compensation framework will require careful collaboration with stakeholders.
Benefits	 HIGH	Modernized DER compensation frameworks can provide clear and transparent price signals that appropriately align customer compensation with the value DERs provide to the grid.
Cost Favourability	 MED	Program administration and analytical costs may be required to develop and maintain compensation methodologies. Billing and IT upgrades may also be required to facilitate compensation mechanisms.
Risk Management	 MED	Stakeholder consultation and clear communication of material changes to existing compensation mechanisms can lower the risk of market confusion and stakeholder frustration. Compensation frameworks must operate within legislative parameters.

2.2.6 Financing Programs		EMERGING
Description	Innovative financing for DERs is an option that can help address upfront cost barriers, manage risk, and spread costs over time, making DER adoption more accessible and attractive for customers. Examples of financing used in other jurisdictions, which could be explored in Nova Scotia, include: • On-bill Financing (OBF) or On-bill Repayment (OBR): Financing of DERs is repaid through the utility bill. OBF uses ratepayer funding while OBR is funded from private third-party sources. • Tariff On Bill (TOB): A utility tariff is used to recover the costs of DER upgrades. Funding is not considered a loan as it is tied to the utility meter of a home, not the property owner. This can reduce split incentive barriers and expand access to renters. • Property Assessed Clean Energy (PACE): Repayment occurs through municipal property taxes. Existing programs could expand to include DER measures. • Energy-As-A-Service Financing: A service provider offers a single-source solution to design, finance, install, manage and monitor building retrofits. • Personal Loan Supported by Credit Enhancement: Lenders offer loans backed by public or utility-supported risk mitigation in exchange for lower interest rates, longer terms, expanded access for higher-risk customers, and flexible repayment options. While financing mechanisms can improve DER technology access and support participation, clarity regarding which financing approaches are appropriate and which entities are responsible for delivery is needed.	
Prerequisites / Triggers	Initiative 1.1.1 (Governance Model); Initiative 1.2.1 (Institutional Capacity and Capability Assessment and Plan), Initiative 1.3.1 (BCA Framework), Strategy 2.1 (Customer Engagement), Strategy 1.5 (Regulatory Evolution).	
Dependencies	Coordination and partnerships with other entities (e.g., E1, municipalities)	

2.2.6 Financing Programs		EMERGING
Nova Scotia Context	NS Power is not currently authorized to offer financing. In October 2022, the province amended the Public Utilities Act, removing NS Power's ability to offer financing to customers for heating equipment.¹⁸ Several municipalities across Nova Scotia offer PACE and include DERs. For example, HRM Solar City currently supports solar PV and battery storage.	

Qualitative Assessment of Financing Programs

Criteria	Assessment	Rationale
Strategic Fit	 MED	Financing can support affordability and equity objectives by addressing the upfront cost barrier and access to capital to support DER adoption. Financing can be delivered in many ways.
Benefits	 MED	Financing reduces upfront costs and access to capital barriers to enable more customers to access and benefit from DERs. In some jurisdictions, programs such as DR allow for electricity bill savings to help offset financing repayment.
Cost Favourability	 MED	Financing program costs recovery would need to be determined. Program administration and IT system requirements may increase costs, particularly for on-bill financing. Existing financing programs with established infrastructure and systems can potentially be leveraged to minimize costs.
Risk Management	 MED	Clear program design and decisions on risk allocation could be lengthy to develop and launch. Customer defaults or concerns about repayment terms could create reputational risk, underscoring the need for strong program design and consumer protections. Although experience in other jurisdictions demonstrates extremely low default rates for these types of programs.

STRATEGY 2.3: DER PROCUREMENT PATHWAYS

Overview

This strategy aims to assess how alternative procurement pathways may complement customer programs to accelerate DER uptake in Nova Scotia, help reduce the cost of resource acquisition, promote operational efficiency, and foster competition.

Under a **centralized procurement model**, DERs or services are procured from third-party owners and operators. This approach can foster competition, cost efficiency, and flexibility, as well as shift some technology and performance risks from utilities to third-party aggregators.

Utility DER ownership can enable greater control and predictability of DERs and increased alignment with grid reliability and planning needs, particularly where services must be delivered at

¹⁸ Bill No. 228, Public Utilities Act (amended) Chapter 53 of the Acts of 2022

specific locations or are difficult to contract for through performance-based procurement. Across North America, there are several examples of utility ownership models for BTM assets as well as front-of-the-meter (FTM) assets that are located on the distribution system.

These models offer distinct benefits and trade-offs but are not mutually exclusive. In practice, many jurisdictions adopt a hybrid approach that combines customer programs with one or more of these options. While both approaches can be implemented together, stakeholders emphasized that additional assessment of the relative benefits of each model is needed, and if deemed appropriate for Nova Scotia, then clear rules and guardrails are required before adopting either model.



“WHAT WE HEARD”. Stakeholder feedback on DER procurement pathways reflected significant sensitivity and uncertainty, particularly regarding utility ownership models. Several requested greater transparency around ownership structure trade-offs. While some acknowledged potential advantages of shared cost-and-risk models and centralized approaches to build early momentum, others questioned whether centralized or utility-owned models are necessary at all.

One stakeholder emphasized the need to explain how utility ownership aligns with provincial goals to enhance competition and innovation, and to substantiate claims that it offers greater control, predictability, or reliability benefits. Stakeholders also asked what specific problem centralized procurement is intended to solve beyond existing program and market-based frameworks, underscoring the need for clearer articulation of purpose, safeguards, and market impacts.

Qualitative Assessment

Criteria	Assessment	Rationale
Strategic Fit	 HIGH	Both centralized procurement and utility-owned assets align with reliability, decarbonization, and DER integration objectives. Centralized procurement supports market development and aggregation, while utility ownership provides direct control and can accelerate deployment in high-value locations.
Benefits	 HIGH	Both models can deliver capacity, grid services, and non-wires alternatives. Centralized procurement enables competition and innovation, while utility-owned assets can accelerate the uptake of DERs in NS, enabling electrification and orchestration of DER benefits to be realized sooner, offer control over operations and maintenance, optimization, and more predictable and dispatchable system benefits. Realized benefits will depend on participation and execution.
Cost Favourability	 MED	Regardless of the model, upfront costs for planning, procurement, and contract management as well as ongoing costs will likely be needed. Centralized procurement can help spread costs across utilities and third parties, and competitive processes can help control prices, whereas utility-owned assets increase overall cost exposure to one entity.
Risk Management	 LOW	Centralized procurement requires strong coordination and market design to ensure aggregator participation and customer enrollment. Utility-owned assets may face stakeholder concerns about crowding out private investment, and utilities take on technology and performance risks.

Roadmap Initiatives

2.3.1 DER Centralized Procurement Framework		EMERGING
Description	At this stage, greater clarity and direction are required before proceeding with centralized DER procurement. A DER Procurement Framework can establish clear, transparent rules and processes related to DER aggregation, procurement structures, evaluation and selection criteria, and performance monitoring. Engaging stakeholders as part of the framework development process can help shape effective and practical procurement approaches, support market readiness, and enhance transparency for DER developers, aggregators, and customers.	
Prerequisites / Triggers	Initiative 1.1.1 (Governance Model); Initiative 1.2.1 (Institutional Capacity and Capability Assessment and Plan), Initiative 1.3.1 (BCA Framework), Strategy 2.1 (Customer Engagement)	
Dependencies	None	

2.3.2 Utility-Owned DER Participation Framework		EMERGING
Description	At this stage, greater clarity and direction are required before proceeding with utility-owned DERs. A Utility-Owned DER Framework can establish clear, transparent rules and decision-making processes for utility ownership of DERs. These frameworks typically define eligibility criteria and use cases for utility-owned DERs (e.g., reliability, NWA, equity, or system optimization, etc.), outline how utility-owned options are evaluated alongside alternatives, and specify planning, approval, and oversight requirements. These frameworks also typically address cost recovery, risk allocation, operational responsibilities, and performance measurement. Clear policy and regulatory direction are required to define the utility's role and scope. Framework development should involve NSEB, the government and market participants and an independent evaluation to ensure alignment with public interests.	
Prerequisites / Triggers	Initiative 1.1.1 (Governance Model); Initiative 1.2.1 (Institutional Capacity and Capability Assessment and Plan), Initiative 1.3.1 (BCA Framework), (1.3.2 NWA Framework), Strategy 2.1 (Customer Engagement)	
Dependencies	None	
Nova Scotia Context	NS Power has piloted utility-owned DERs, including a 1.25MW Battery Energy Storage System through the Intelligent Feeder Project and over 1MW distributed residential, commercial and industrial batteries through SGNS.	

PILLAR 3

Integrating DERs



STRATEGY 3.1: DER ORCHESTRATION (DERMS)

Overview

Distributed Energy Resource Management Systems (DERMS) enhance visibility and allow utilities to directly orchestrate and coordinate DER behaviour (e.g., curtailment, dispatch for local flexibility) to help avoid grid constraints. DERMS are integral to DER integration because they provide real-time DER visibility, coordination, and control. It connects to individual DERs, aggregates their capabilities, and supports real-time monitoring, forecasting, and dispatch based on grid needs, market signals, and operating constraints. In effect, DERMS turn orchestration from a concept into an operational capability.



“WHAT WE HEARD”. Stakeholders expressed no opposition to advancing DERMS and generally understood a DERMS role in enabling future DER orchestration. Some emphasized the importance of adapting DER program design over time to align with evolving orchestration capabilities, creating opportunities for flexible load and DER dispatch in response to grid needs. Key considerations included joint vendor evaluation and procurement coordination between NS Power and E1, incorporating lessons learned from prior DERMS pilots, and ensuring transparency around dispatch models, data-sharing protocols, and operational integration of resources. Stakeholders also highlighted the need for alignment on DERMS technical requirements, telemetry standards, and participation models for customer-sited DERs.

Qualitative Assessment

Criteria	Assessment	Rationale
Strategic Fit	●●● HIGH	A capable DERMS enables objectives such as real-time visibility, control, and optimization of DERs. It is also foundational for several initiatives included in the DERIR, such as direct-control DR programs and DER procurements - centralized or utility-owned, where applicable.
Benefits	●●● HIGH	DERMS in other jurisdictions have shown to deliver foundational system value by improving visibility, coordination, and operational efficiency as DER adoption grows. It supports reliability and enables DERs to function as operational grid resources. Customer bill impacts depend on program design, while emissions reductions and clean-energy benefits increase as DER penetration scales.
Cost Favourability	●● MED	DERMS implementation can be time-intensive and costly, given the complexity of integrating DER data and other system information, as well as the need for specialized expertise to support ongoing operations. However, prior experience (e.g., SGNS and the Intelligent Feeder project) can help reduce implementation complexity, and some costs could potentially be offset through external funding programs.

Criteria	Assessment	Rationale
Risk Management	 MED	Risks are dependent on the underlying network and DER data. DERs must be able to send data promptly, have adequate communications bandwidth to store and process data, and incorporate system constraints into the DER decision framework. Practical experience from NS and other jurisdictions will reduce uncertainty and may help offset some risks. Implementation will require close coordination between relevant stakeholders.

Roadmap Initiatives

3.1.1 DERMS Requirement and Evaluation Framework		FOUNDATIONAL
Description	This initiative involves assessing and defining DERMS requirements for Nova Scotia. This initiative focuses on identifying the functional, technical, and integration capabilities a future DERMS must have to meet system needs. Key considerations in this framework could include priority use cases, security and data governance requirements, integration with existing and planned systems, performance and scalability requirements, and alignment with regulatory and market frameworks and integration with DR aggregators. Generally, DERMS strategies should be adaptable and involve industry engagement to understand current DERMS capabilities and focus on immediate needs. Typically, jurisdictions take an incremental approach that begins with clearly defined problems that can be addressed in phases, rather than building a comprehensive solution immediately.	
Prerequisites / Triggers	None; foundational initiative	
Dependencies	Initiative 3.1.2 (DERMS Procurement, Deployment and Enhancements)	
Nova Scotia Context	NS Power piloted a DERMS platform through Smart Grid Nova Scotia (SGNS) and the Intelligent Feeder Project to register and centrally manage a portfolio of DERs, including residential batteries, C&I solar-plus-storage sites, commercial HVAC systems, and smart EV chargers. The pilot demonstrated DERMS capabilities for several use cases, including peak demand reduction, renewable integration (curtailment reduction and reverse power flow reduction), and grid reliability and resilience. NS Power aims to initiate a DERMS in 2026 (subject to approval). NS Power is currently undertaking an alternatives analysis to evaluate DERMS requirements and implementation approaches. As part of the undertaking, architecture considerations will be included to enable integration between E1's demand response management system (DRMS) and a future NS Power DERMS. The future DERMS is also expected to integrate with the ADMS and be grid-aware and support feeder-level DER dispatch as needed.	

3.1.2 DERMS Procurement & Progression		FOUNDATIONAL
Description	Once DERMS requirements for Nova Scotia are established, a formal competitive procurement process should be completed to procure a DERMS platform. The procurement process should clearly articulate system needs, platform requirements and	

3.1.2 DERMS Procurement & Progression		FOUNDATIONAL
	evaluation criteria to ensure the selected vendor meets the defined requirements and is suitable for full-scale deployment. Following the procurement process, selected DERMS platform could be deployed to support electricity system operational use cases. Examples from other jurisdictions highlight the importance of integrating with existing systems, establishing clear roles and operating procedures, and validating performance, before transitioning the solution into full operational use. This is not intended to represent a one-time activity. Over time, advanced capabilities and use cases may evolve as DER integration evolves in Nova Scotia, as appropriate.	
Prerequisites / Triggers	Initiative 3.1.1 (DERMS Requirement and Evaluation Framework)	
Dependencies	Strategy 3.2 (DER Visibility Systems)	

STRATEGY 3.2: DER VISIBILITY SYSTEMS

Overview

This strategy aims to strengthen visibility across DERs, feeders, and assets, considering a unified data architecture and synchronized systems and platforms. Through a future DERMS platform, and integration and exploration of distributed intelligence applications on smart meters, greater visibility of emerging behind-the-meter loads such as EVs, solar generation, batteries and heat pumps may be leveraged for operational and forecasting tools.



“WHAT WE HEARD”. Stakeholders emphasized the importance of transparent information-sharing on locational needs and evolving grid constraints to support effective DER visibility and control. They highlighted the need for ongoing data and information feedback loops to ensure emerging distribution-level constraints and opportunities inform customer program adaptations. Stakeholders also reiterated that interoperability is essential.

Qualitative Assessment

Criteria	Assessment	Rationale
Strategic Fit	●●● HIGH	DER visibility systems strongly align with grid modernization efforts. As DER adoption grows, better data and visibility can help maintain reliability, expedite interconnection processes, and support broader participation.
Benefits	●● MED	Improved grid data and visibility enable more targeted planning and may indirectly support deferral of system upgrades. Enhanced system insight can improve outage response and create operational efficiency. Customers may benefit indirectly through better service quality and improved access to flexible rates.
Cost Favourability	●●● HIGH	Will likely require investment in IT systems, along with ongoing costs for data management, software licensing, cybersecurity, and resources. While these investments are material, after initial investment, costs are expected to be incremental.
Risk Management	●● MED	Implementation across several systems can be complex, though existing systems and experience can mitigate this risk. Cybersecurity is an important consideration.

Roadmap Initiatives

3.2.1 DER Registry and Standard		EVOLVING
Description	A standard DER registry and data platform can serve as a centralized source of DER information across the electricity system. These platforms can capture consistent data on DER assets. For example, in some jurisdictions, data can include technology type, capacity, operational characteristics, locational attributes, interconnection status, ownership, and real-time or historical performance metrics where appropriate. A data standard and governance model can integrate DER information from NS Power, E1, aggregators, customers, market operators, and other stakeholders into a unified system. Typically, central DER registries align with core utility systems, such as GIS, ADMS/OMS, and AMI. This alignment helps enable secure data sharing and interoperability across planning, operational, and market functions, which may help to reduce data silos, minimize inconsistencies, and limit use of manual processes While a registry can increase visibility and benefit the system, collaboration with appropriate stakeholders is needed to strike the right balance of visibility, accessibility, privacy, security, and right-sized effort.	
Prerequisites / Triggers	Strategy 1.1 (Stakeholder Coordination); Strategy 3.1 (DER Orchestration)	
Dependencies	Strategy 3.2.2 (Enhanced DER Detection and Visibility), Strategy 3.4 (Grid Modernization Investments)	
Jurisdiction Example	Con Edison's Distributed System Implementation Plan calls for an enterprise GIS (eGIS) to serve as the network model backbone and a DER "System of Record" to integrate key DER attributes with GIS, ADMS and DERMS. Portland General Electric is similarly developing a DER System of Record to capture attributes, performance and cost-effectiveness data.	

3.2.2 Enhanced DER Detection and Visibility		EVOLVING
Description	As grid modernization initiatives are implemented and DER data systems evolve, additional opportunities to use advanced analytics for DER detection should be explored. For example, AMI, along with ADMS and GIS, provide a real-time network model and granular usage data. As investment in distribution system telemetry continues, more devices will likely be available for distribution system operator visibility and control. Through AMI analytics platforms, these types of behind-the-meter systems can run analytics on meter data for rate design and customer segmentation. Emerging use cases in other jurisdictions show that enhanced AMI can support distribution planning, day-to-day grid monitoring and outage management. The number and location of DERs and flexible end-use devices are key drivers of achievable DER potential and distribution infrastructure requirements and can provide valuable data about customer adoption and program participation, which may help improve the accuracy of planning, forecasting and program design. However, this data is currently hard to come by without direct visibility to end-use devices connected on the customer's side of the meter. For certain technologies, locational visibility is highly valuable. For example, EV charging load growth tends to be highly localized with neighbourhood clustering effects, meaning that the associated infrastructure needs and DER opportunities become material at the individual feeder level at relatively low province-wide adoption levels. Analytics tools leveraging data science techniques can recognize patterns in aggregated customer load data to help identify DERs located behind-the-meter, such as EV chargers, air conditioners or solar panels.	
Prerequisites / Triggers	Strategy 3.4 (Grid Modernization Investments)	
Dependencies	Strategy 3.3 (DER Visibility Systems)	
Jurisdiction Example	The California Public Utilities Commission commissioned an Electrification Impacts Study, using data disaggregation techniques to identify EV charging demand and forecast infrastructure upgrade needs at the feeder level. In Ontario, Oshawa Power conducted a project funded by the Ontario IESO's Grid Innovation Fund to similarly identify and forecast EV charging loads at the feeder level.	

STRATEGY 3.3: GRID SECURITY AND RELIABILITY

Overview

This strategy helps ensure DERs can be interconnected and operated in a way that preserves system security, protection, and reliability as DER penetration increases. It focuses on interconnection processes and modern technical standards which can help ensure DERs behave predictably during normal and abnormal grid conditions. Initiatives include periodic review of interconnection procedures and identification of modernization and automation opportunities. The strategy also examines inverter and protection standards modernization.

Qualitative Assessment for Grid Interconnection

Criteria	Assessment	Rationale
Strategic Fit	 MED	Grid security and reliability initiatives can directly support the operation of a safe, secure, reliable system. Clear interconnection, protection, and inverter standards for DERs will support DER integration as penetration increases.
Benefits	 MED	Interconnection standards and updated inverter and protection standards do not necessarily directly defer investments, but they can enable higher hosting capacity, non-wires solutions, and stable DER integration. While customers may not see direct bill savings, there can be reliability benefits from protection upgrades, as well as potentially faster interconnections and fewer outages.
Cost Favourability	 MED	Costs are expected to be generally moderate and consist primarily of standards development, engineering analysis, stakeholder engagement, and compliance oversight. Compared to other initiatives, these initiatives are expected to require relatively low upfront investment, with most costs anticipated to be related to administration and enforcement rather than physical infrastructure.
Risk Management	 MED	Risks relate to implementation and coordination rather than technology. Strong collaboration and alignment between interconnection, planning, and operations is required.

Roadmap Initiatives

3.3.1 Interconnection Process Review & Integration		EVOLVING
Description	Interconnection procedures should be reviewed regularly. During these reviews, opportunities to modernize should be examined. Examples of modernization opportunities could include automation potential, data requirements and development and implementation of flexible hosting capacity agreements.	
Prerequisites / Triggers	None; expands on existing initiatives	
Dependencies	None	
Nova Scotia Context	A series of regulatory proceedings about transmission/distribution interconnection processes was recently completed, and NS Power has initiated several improvements through the interconnection process review. In addition, the province recently updated the net-metering framework that supports ongoing customer DER interconnections. ¹⁹	
Jurisdiction Example	Interconnection delays and interconnection process pain points are commonly cited barriers to DER adoption across North America and have been a focus. For example, Con Edison improved its interconnection process by expanding fast-track eligibility for small solar projects, automating screening and case management to reduce manual reviews and improve process efficiency.	

¹⁹ [Bill No. 145 to amend the Electricity Act](#) accessed on January 16, 2026

3.3.2 Inverter & Protection Standards Modernization		EMERGING
Description	Inverter & Protection Standards Modernization involves defining how DERs behave when connected to the grid. It can help enable and operate safe, predictable, and coordinated DER integration. For example, requiring voltage and frequency ride-through²⁰, standardized anti-islanding behaviour²¹, and a consistent response to abnormal grid conditions. This initiative could involve considering industry standards like IEEE 1547-2018, which defines how DERs must connect to and operate on the electric grid. It may also include reviewing interconnection technical requirements, certification and testing processes, and utility operating procedures and updating, as appropriate. Nova Scotia standards should be harmonized with Canadian, North American and international standards wherever possible, to minimize market-entry barriers and maximize the availability of suitable technologies to Nova Scotians.	
Prerequisites / Triggers	1.4.1 (DER Potential Assessment)	
Dependencies	None	
Nova Scotia Context	Interconnection procedures and technical requirements for inverter-based resources (both ≤ 100 kW and larger units) that specify protection and performance expectations for DERs and storage are formally published.	

STRATEGY 3.4: GRID MODERNIZATION INVESTMENTS

Overview

Grid modernization focuses on evaluating potential upgrades to the foundational operational, control, and data systems used to plan, operate, manage and monitor the distribution grid safely and efficiently. This includes core operational platforms like Advanced Distribution Management Systems (ADMS) (including OMS, D-SCADA, FLISR), Geographic Information Systems (GIS), Supervisory Control and Data Acquisition (SCADA), and systems like Advanced Metering infrastructure (AMI), and Distribution Automation. These efforts are technology- and capability-driven and apply broadly across the system regardless of whether DERs are present.

Grid modernization is a DER integration enabler. Modern operational control systems, data, processes and integrations, provide the visibility, situational awareness, and control to help accommodate growing DER penetration.

²⁰ Ensuring DERs stay connected and keep operating during short, minor grid disturbances instead of immediately shutting off.

²¹ All DERs reliably and consistently shut off when the grid goes down, so they don't accidentally keep energizing power lines.

Qualitative Assessment

Criteria	Assessment	Rationale
Strategic Fit	●●● HIGH	Grid modernization helps ensure safe and reliable distribution operations and compliance with government reliability performance standards. As DER penetration increases, these systems will provide the operational backbone needed to manage system complexity.
Benefits	●●● HIGH	Grid modernization can deliver system-wide benefits by helping to improve reliability, outage response, and operational efficiency. Investments can help provide the enabling infrastructure for future DER integration.
Cost Favourability	●● MED	Grid modernization is expected to require significant upfront investment in platforms, devices, and system integration. These investments are typically recovered over long time horizons; however, many of these core systems have already been implemented in Nova Scotia, and implementation of additional functionalities can be staged as DER integration evolves.
Risk Management	●● MED	Implementing grid modernization systems can be complex and requires vendor coordination, data migration, advanced grid analytics, cybersecurity, and ongoing licensing and maintenance. Conversely, there may be risks to affordability, reliability, public trust and decarbonization efforts without grid modernization.

Roadmap Initiatives

3.4.1 Identify Grid Modernization Strategies		FOUNDATIONAL
Description	Grid modernization efforts are focused on defining and prioritizing requirements across core planning and operational systems (such as GIS, ADMS, SCADA, OMS, and distribution automation) to better support DER integration and enable phased deployment of advanced control capabilities, as appropriate. Examples of grid modernization efforts could include, but are not limited to, the following: - Enhanced GIS functionality, which provides operators with accurate visibility into DER locations and their impacts on the distribution system. This supports improved hosting capacity analysis, interconnection decisions, and upgrade planning. Without robust GIS capabilities, DER impacts may be mischaracterized, increasing reliability risks or unnecessary investment. - Automated ADMS and DER-aware system to enhance real-time visibility, automation and analytics. Advanced DER operational functions can be enabled through deeper AMI integration, distribution state estimation, and tighter DERMS integration. - Enhancements to AMI such as distributed intelligence apps. For example, applications that sit on the meter and can identify what is behind it (e.g., EVs, solar).	
Prerequisites / Triggers	None; expands on existing initiatives	
Dependencies	Strategy 1.4 (DER Potential Assessments), Strategy 3.3 (Grid Security and Reliability), Initiative 3.4.2 (Implement & Evolve Grid Capabilities)	

3.4.1 Identify Grid Modernization Strategies**FOUNDATIONAL****Nova Scotia
Context**

Grid modernization elements are reflected in NS Power's Five-Year Reliability Plan and in system upgrade projects like GIS, ADMS and SCADA.

3.4.2 Implement and Evolve Grid Capabilities**EVOLVING****Description**

Over time, modernized digital tools, data and integrated models can help improve how accurately and dynamically the electric distribution system is modelled and monitored. This could involve developing more detailed and up-to-date grid models, creating an integrated digital model linking GIS, SCADA, AMI, DERMS, etc., integrating real-time data from meters and sensors, implementing faster, more automated analysis and connecting planning and operational systems so utilities have a clear, shared view of grid conditions. Strong digital representation can enable faster and more transparent DER interconnection, support higher levels of DER penetration and allow utilities to operate the grid more efficiently and proactively as DER adoption grows. Typically, enhanced operational control capabilities are phased to ensure systems are interoperable, data is accurate and timely, and operational processes, as well as privacy, equity and cybersecurity safeguards, evolve alongside technology to safely and efficiently integrate DERs.

**Prerequisites /
Triggers**

None; expands on existing initiatives

Dependencies

Strategy 1.4 (DER Potential Assessments)

Implementation and Governance Considerations



“WHAT WE HEARD”. Stakeholders stressed that the roadmap timelines reflect the urgency of 2030 targets and the impending coal phase-out. It was suggested that assessment phases may need to be shortened and implementation accelerated to achieve meaningful progress. Several emphasized that real-world implementation takes significant time and that existing regulatory proceedings and decisions already underway should be accounted for in the sequencing and pacing of initiatives.

While all stakeholders supported the roadmap concept and were broadly supportive of the roadmap direction, there was some discomfort with fully endorsing the roadmap without greater clarity on governance, accountability, and funding. Stakeholders highlighted ongoing uncertainty around roles and responsibilities among NS Power, E1, IESO-NS, and NSEB, and stressed that clear leadership, defined ownership, and transparent cost allocation, particularly for ratepayer-funded programs, are essential to ensure effective and coordinated implementation.

Stakeholders consistently noted that Nova Scotia’s electricity system has been evolving at an unprecedented pace since 2020, a trend expected to continue. The roadmap must be flexible and adaptable.

Implementation Planning

This roadmap is a strategic and directional planning tool, not a detailed implementation plan. Clarity is needed regarding future DERIR leadership, implementation and accountability in Nova Scotia, including governance and defining specific actions, resourcing, and sequencing for respective DERIR strategies and initiatives. That said, effective roadmap execution will require attention to several key implementation considerations, which are outlined below to clarify expectations and inform next steps.

INDICATIVE TIMELINES AND INITIATIVE STAGING

The three pillars, 12 strategies and 28 initiatives provide a strategic foundation for coordinated action prioritized within an indicative timeline: Foundational (in less than 5 years), Evolving (within the next 5-10 years), & Emerging (over the next 10+ years).

For each initiative, the roadmap identifies indicative sequencing, relative priority and duration (short-, medium-, and long-term) rather than fixed start or end dates. The proposed roadmap considers jurisdictional review findings, stakeholder input, and consideration of the current sector transition and evolving roles and responsibilities. It should be noted that the proposed roadmap is directional and subject to change.

Where relevant, initiatives are described as multi-stage, reflecting that delivery requires progression through phases such as

- **Assessment/planning:** initial efforts including foundational research, studies, stakeholder engagement, business case development, relevant approval processes, detailed program design and planning.
- **Implementation:** the execution of initiatives, including developing defined plans or frameworks, launching and delivering programs and enabling strategies, procuring and implementing technologies and systems to support DER integration.
- **Enhancement or expansion:** periodic reviews/evaluations to assess initiative effectiveness and appropriateness in supporting DER deployment, applying lessons learned to enhance, expand to other sectors/customers and/or advance DER integration.

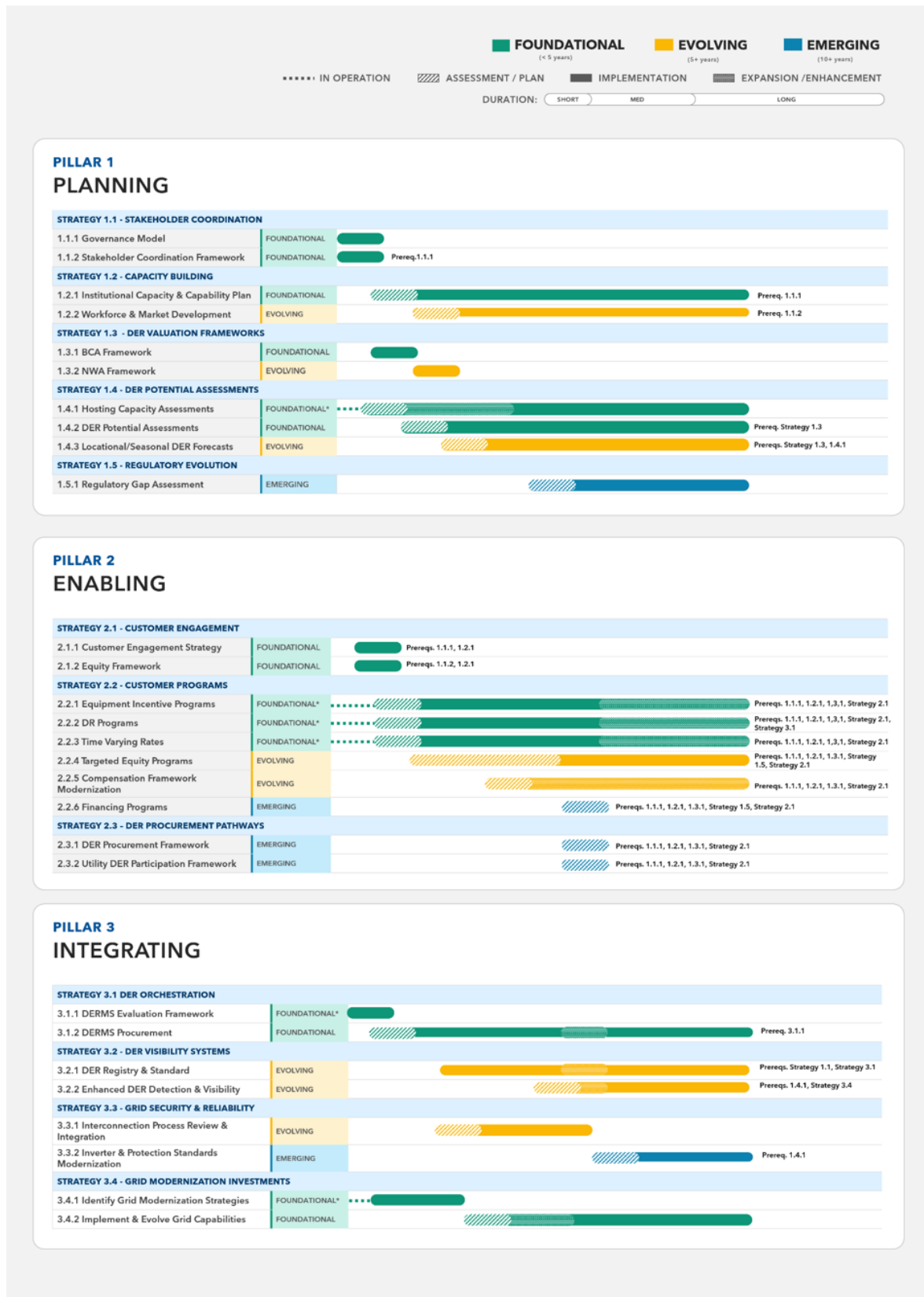
In some cases, initiatives are intentionally limited to early stages (e.g., assess or plan). This reflects the need for greater clarity before proceeding.

The roadmap should not be interpreted as an automatic “all systems go.” Implementation may be affected by budgetary, resource, capacity, or other constraints, as well as evolving system conditions. Specifically:

- **Initiatives identified as “evolving” or “emerging”** are sequenced later and therefore subject to greater uncertainty. These initiatives should be interpreted as signals to continue exploring, monitoring, and preparing rather than committing to immediate action.

External factors may necessitate changes to priorities, timing, or scope. Stakeholders have consistently noted that Nova Scotia’s electricity system has been evolving at an unprecedented pace. Current and anticipated policy developments and existing regulatory matters may materially influence distribution system needs and roadmap timeline.

The figure on the following page illustrates the proposed sequencing of the roadmap strategies and initiatives.



Roadmap Governance



“WHAT WE HEARD”. Stakeholders emphasized that strong governance and coordination will be critical to successfully implement the roadmap. They called for clear assignment of responsibility and accountability, particularly among NSP, IESO-NS, E1, noting significant uncertainty about IESO-NS’s role in DERIR.

Many stressed the importance of identifying who will “hold the pen” and drive the process forward, warning that unclear roles could lead to duplication, inefficiency, and ineffective execution if responsible bodies are not clearly empowered and actively involved.

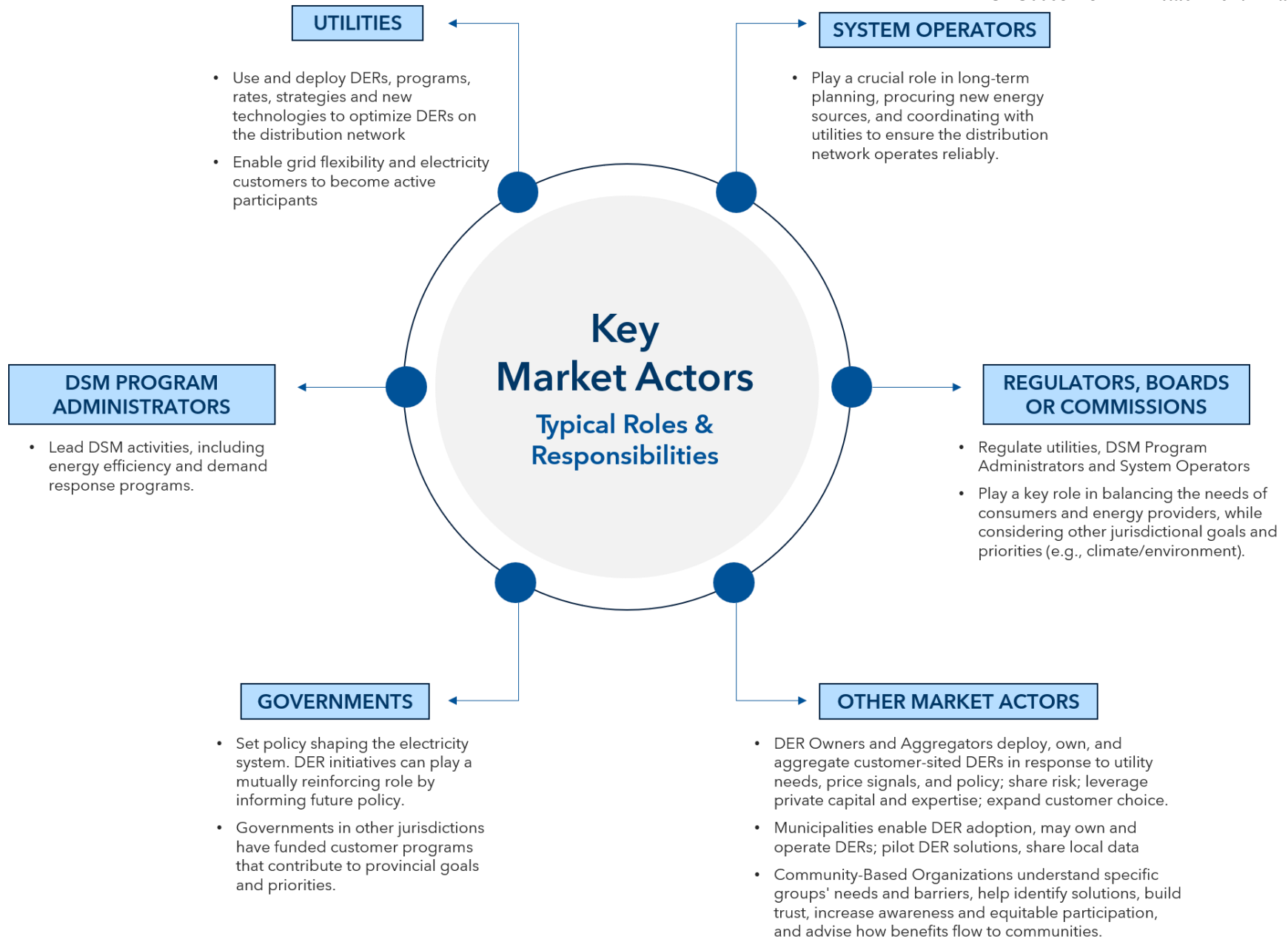
REGULATORY AND DECISION-MAKING PATHWAYS

The roadmap assumes that most initiatives will proceed through established regulatory, legislative, and governance processes. At the same time, several initiatives represent new approaches or material changes that may require additional regulatory or legislative direction or clarification before they can proceed.

ROLES AND RESPONSIBILITIES

Recent governance reforms have reshaped the institutional landscape of Nova Scotia’s electricity sector. IESO Nova Scotia is responsible for bulk electricity system planning and management, NS Power is responsible for asset and distribution planning and maintenance, and E1 continues to lead DSM programs. These changes reflect a more distributed governance structure in which multiple organizations must work together to plan, operate, and manage the electricity system. Key market actors and their typical roles to support DER integration in other jurisdictions are described at a high level in the figure below.

As a next step, roles and responsibilities in Nova Scotia must be determined. Clarity is needed regarding DERIR leadership and accountability among relevant institutions (e.g., NS Power, EfficiencyOne, and IESO-NS) to advance strategies and initiatives.



STAKEHOLDER ENGAGEMENT

Ongoing and regular stakeholder engagement will be key to successfully implementing the DERIR. Stakeholder involvement will help maintain roadmap accountability and ensure that implementation reflects diverse perspectives, builds transparency and trust, and benefits from stakeholder expertise and experience as planning, enabling and integrating approaches evolve.

A LIVING AND ADAPTIVE ROADMAP

Roadmaps are prepared at a specific point in time. To remain relevant and effective, roadmaps should be treated as a living document. Typically, strategies, initiatives, and priorities are periodically reviewed and updated as system conditions change, new information becomes available, or significant policy, regulatory, or market developments occur. Roadmap implementation, reviews and updates typically consider and align with the timing and scope of other relevant actions (e.g., potential studies, DSM planning and IRP processes).

Appendix A: Jurisdictional Scan

Jurisdictional scan findings are detailed in a supplementary document.

Appendix B: Qualitative Assessment

Qualitative Assessment Criteria

To prioritize the strategies and initiatives, each was qualitatively assessed across four dimensions:

- **Strategic Fit:** Alignment with stakeholder mandates, directives, goals and objectives, and there is clear market demand/need for the initiative.
- **Benefits:** Demonstrated or potential electricity system, customer and societal benefits. Expected costs (e.g., system capital, operations and resources) are reasonable, feasible and comparable or lower than alternatives to achieve the same benefits.
- **Cost Favourability:** Existence of available funding from other sources (government/private sector) to support the initiative; additional capital and operating costs are required.
- **Risk Management:** Where there are proven models or lessons from other utilities/jurisdictions that reduce risk and improve confidence; implementation risk associated with complexity, time and execution; technology/solution maturity and implications to public and stakeholder trust; and consideration of potential consequences of inaction or delayed action.

We summarize the qualitative assessment criteria below.

STRATEGIC FIT

Strategic fit was scored based on alignment across five perspectives.

Criteria	Description
Alignment (NS Power and Regulatory Direction)	Degree initiative supports NS Power's efforts to provide reliable, affordable, and clean electricity, and aligns with regulatory expectations and directives.
Alignment (E1)	Extent to which the initiative supports E1's DSM efforts, programs, and role (e.g., avoids duplication and enables coordination).
Alignment (Gov Policy)	Fit with federal and provincial government priorities, policies, and legislation (e.g., climate, electrification and affordability goals).
Alignment (Stakeholders, Industry)	Extent to which initiative aligns with customer, community, and industry expectations (e.g., developers, municipalities). Support, or acceptance from customers, community groups, industry partners, and external stakeholders. Reflects political/social license to operate.
Market Need	Urgency and scale of the need addressed and whether there is a clear and timely use case (e.g., grid constraints, customer demand, reliability need). Potential to scale or replicate across the province once proven

ELECTRICITY SYSTEM AND CUSTOMER BENEFITS

We assessed value qualitatively from three perspectives: electricity system, customer and society.

Criteria	Description
System Capital Deferral	Potential to defer or avoid distribution/transmission capital investments.
System Reliability & Resilience	Impact grid resilience, and stability. For example, reduced outage duration/frequency (SAIDI, SAIFI) through automation, flexibility, or DER dispatch.
System Operational Benefits	Initiative offers efficiency gains, O&M savings, improved asset utilization, reduced ancillary service costs and/or enables more DERs to connect cost-effectively; benefits outlast incentives.
Customer Monetary Value	Direct financial savings to participating (e.g., lower bills, cost avoidance, protection against future electricity price increases, revenue from selling excess energy or grid services) and all customers—including non-participants—benefit from system-wide cost savings, reduced rate pressures, and improved grid efficiency.
Customer Non-Energy Benefits (NEB)	Other DER program benefits accruing to participants (e.g., improves access to participate; better engagement and control; convenience, health and safety and productivity).
Societal Value	Broader public benefits – job creation, local economic development, emissions reduction, environmental performance.

COST FAVOURABILITY

Cost was assessed qualitatively based on three indicators regardless of who delivers the strategy or initiative (NS Power, E1, others).

Criteria	Description
Access to Gov/Private Sector Funding	Availability of federal/provincial grants, clean energy funds, or partner contributions to offset capital and operational costs (see below).
Total Implementation Capital Costs	Upfront capital required (infrastructure, IT, hardware). Additional costs required, including feasibility studies, engineering assessments, and technical requirements development (individual project studies as well as general requirements development) if tied to a specific asset. Training/workforce specific to asset commissioning (where capitalizable through projects)
Total Integration and Operational Costs	Ongoing operational, integration, and maintenance costs over the initiative lifecycle. For example, building frameworks, agreements, collaboration models, general strategy, capability building, software licenses, insurance.

RISK MANAGEMENT

We considered five indicators to assess potential risk.

Criteria	Description
Precedent	Existence of proven models or lessons from other utilities/jurisdictions that reduce risk and improve confidence.

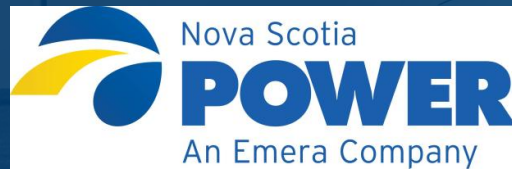
Criteria	Description
Complexity and Time	Difficulty and duration of implementation, including dependencies and delivery risks
Operational Risk	Risks to day-to-day reliability, safety, or performance once deployed. Requires new systems, processes, resources to deliver; potential for cybersecurity risk; regulatory risk (delayed or uncertain permitting; unclear regulatory frameworks; dependency on future regulation)
Social Acceptance Risk	Technology/initiative is not mature (e.g., Technology Readiness Level is low). Lack of understanding could impact community and stakeholder acceptance and participation. Potential consequences if a solution fails (e.g., stakeholder and public trust erode, and accountability becomes an issue)
Engagement/ Partnership Potential	Extent to which success depends on effective coordination and collaboration across stakeholders and customers.



"NO DISCLAIMERS" POLICY

This report was prepared by Dunsky Energy + Climate Advisors, an independent firm focused on the clean energy transition and committed to quality, integrity and unbiased analysis and counsel. Our findings and recommendations are based on the best information available at the time the work was conducted as well as our experts' professional judgment.

Dunsky is proud to stand by our work.



Distributed Energy Resources Integration Roadmap (DERIR)

Jurisdictional Scan

July 11th, 2025



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 6. Key Findings
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Current Situation and Gap Analysis

Jurisdictional Scan Overview – Utilities Reviewed



Dunsky combined their experience and knowledge with a scan of peer and leading utilities' DER integration efforts to:

- Compare NSPI's efforts to date to industry peers across North America and beyond
- Map the breadth of options that NSPI can employ in developing its roadmap
- Identify best practices based on learnings from other utilities' explorations
- Capture case studies of DER integration journeys and innovative efforts by leading utilities

Utility	Jurisdiction	Status*	Overview of DER integration efforts
 Nova Scotia Power An Emera Company	Nova Scotia	Emerging	Have made progress integrating DERs with several rates and pilot DR programs in place. Have also tested DERMS ability to monitor and control DER technologies through the SGNS pilot.
 GREEN MOUNTAIN POWER	Vermont	Developing	GMP's IRP considers DER impacts on load forecast/demand and role as a grid resource. Several programs and rates in place to enable DERs, and AMI/DERMs implemented to support integration.
 Portland General Electric	Oregon	Leader	Comprehensive planning strategy (distribution system plan, IRP, transportation electrification plan), several programs and rates to enable DERs, and AMI/DERMs/other grid mod software used.
 Manitoba Hydro	Manitoba	Emerging	In the early stages of DER deployment. A DR strategy was recently completed by Dunsky (not yet published) which outlines a roadmap to deploy programs and a governance structure.
 CMP An Avangrid company	Maine	Developing	Actively working to integrate DERs through an upcoming Integrated Grid Plan and NWA screening, in which CMP hopes to build a portfolio of NWA DER projects
 alectra Discover the possibilities	Ontario	Developing	Alectra is actively involved in grid innovation projects, including demonstrating residential and workplace managed EV charging, NWA demonstration project, integrated solar-plus-storage units and an energy management system (EMS) and pricing. Several projects were supported by the IESO Grid Innovation Fund and OEB innovation sandbox.
 newfoundland labrador hydro	Newfoundland	Emerging	In the early stages of DER deployment with an EV smart charging pilot recently conducted. Resource planning is still focused on traditional poles and wires.
 Hydro Québec	Quebec	Developing	Electricity Supply Plan considers DR, and HQ is planning to assess DER potential (per their Strategic Plan). Large focus on DR with several programs/rates and DERMS/AMI implemented.
 conEdison	New York	Leader	Comprehensive planning strategies (e.g., published its 4 th Distributed System Plan), utility-owned DERs and DER procurements implemented, and provides compensation for DERs through VDER.
 PG&E Pacific Gas and Electric Company	California	Leader	Comprehensive planning strategies and rates/programs to enable DERs. Plans in place to release Enterprise DERMS, ADMS, and AMI 2.0 to further support DER integration
 Hawaiian Electric	Hawaii	Leader	DERs integrated within load forecasting and system planning. Several rates/programs to enable DERs, including procurement of NWAs. Also prioritizing grid modernization investments such as DERMS, AMI, and ADMS.

*Utility DER integration status: Emerging – Early-stage integration; Developing – Some DER initiatives underway; Leader – Advanced, coordinated DER integration

Current Situation and Gap Analysis

Jurisdictional Scan



We conducted deep dive into three jurisdictions and targeted research into seven to tackle specific questions.

Why are utilities engaging in DER integration efforts:

1. What **key industry trends** are shaping utilities' DER integration strategies?
2. What **key barriers or enablers** are influencing DER implementation? (e.g., interdepartmental coordination, coordination across multiple stakeholders, customer engagement, pilot-to-scale pathways, etc.)
3. What are the **internal and external drivers** for actions? (e.g. policy, regulations)

How are utilities responding:

4. What **initiatives** are being employed to support DERs? (e.g., technologies, use cases, strategies that support the planning, enablement and integration of DERs)
5. What **enabling infrastructure** are utilities deploying to support DER integration?
6. How are utilities managing **uncertainty and innovation** in DER integration? (e.g., sandbox environments, iterative planning, phased implementation)
7. What insights can be drawn from **regulatory proceedings** related to DERs? (e.g., regulatory treatment and decisions, opinions) **To be included in roadmap, not in the framework*

Jurisdictions and/or Utilities Selected and Rationale

Jurisdictions	Rationale for Selection			
	Market Context	Geographic/ Climate Context	Strong Infrastructure / Programs	Recognized Leader
Vermont	Qs 1-7			
Oregon	Qs 1-7			
Manitoba	Qs 1-7			
Maine	Qs 5, 6			
Ontario	Qs 5, 6			
Newfoundland Hydro		Qs 2, 4		
Hydro-Québec		Qs 2, 4		
New York (Con Edison)				Qs 1, 2, 7
California (PG&E)				Qs 1, 2, 7
Hawaii (HECO)				Qs 1, 2, 7

Note: numbers indicate the research questions we prioritized for the jurisdictional scan

Current Situation and Gap Analysis



Key Trends and Drivers for Action



Demand Growth

Increased heating, transport, and industry electrification is driving significant demand growth requiring **innovative solutions to maintain grid affordability and reliability**



Evolving Distributed Grids

Increased DER penetration is creating a more **distributed and dynamic grid with two-way energy flows**, but many DERs remain unoptimized



Decarbonization Targets

Emission reduction targets, policies and programs are driving **investments in clean energy, efficiency, and decarbonization, including DERs**

Nova Scotia Power, like their peers, is experiencing these trends, highlighting the need for a strategic approach to DER integration to enable the reduction of peak demand, defer costly T&D upgrades, and support clean energy adoption

Current Situation and Gap Analysis

Key Barriers Commonly Driving Utilities' DER Integration Efforts



Planning



- Inconsistent **treatment and consideration of DERs** in system planning at the generation, transmission and distribution levels
- **DERs viewed as a “load modifier”** and not a resource class that can be scaled
- **Limited data and visibility on** current DER deployments and their operations
- **Uncertainty around the pace and magnitude of DER market** adoption and participation
- **Stakeholder buy-in** into DER's contributions (internal and external)

Enabling



- Limited **customer awareness or understanding** of DERs and programs
- Existing compensation mechanisms may not align with the **full value that DERs** provide across generation and T&D systems
- Limited **coordination between stakeholders** on policy, market, program and regulatory efforts to enable DERs
- **Lack of clarity on roles and misalignment of incentives** between actors (e.g. utilities, efficiency program administrators)
- Lengthy or complex **interconnection processes**
- Regulatory **uncertainty** regarding utility ownership of BTM assets
- Lack of clarity regarding pathways to **pilot and scale new innovations**

Integration



- **Uncoordinated siting, deployment and use** of distributed assets
- Lack of **centralized control or coordinating infrastructure** to coordinate and optimize DER dispatch
- Limited **G, T&D system interoperability** impacts ability to integrate and capture the full value of DERs across system levels
- **Limited efforts to mitigate unintended system impacts** (e.g. power quality, voltage regulation, harmonics, etc.)
- **Lack of standardized data-sharing protocols, technology interoperability, cybersecurity concerns,**

Spotlight: Ontario



Ontario has made progress in enabling and integrating DERs, including **successful procurements** for distribution-connected battery storage. However, the province continues to experience **fragmented planning and operational protocols** between local distribution companies (LDCs) and the IESO, and **misaligned incentives** between distribution rates and wholesale market participation.

Ongoing efforts led by the IESO and the Ontario Energy Board (OEB) aim to address these barriers, including exploring a distribution system operator (DSO) model, identifying and clarifying roles and responsibilities between the IESO, LDCs and DER providers, and developing wholesale market participation models that better enable DERs.

Current Situation and Gap Analysis

Initiatives Employed to Support DERs



NSPI's Progress

Planning Strategies



- **Integrated Resource Plans (IRPs):** Evaluation of both supply and demand side resources, grid requirements and long-term requirements/action plans to meet grid needs
- **Distribution System Plans (DSPs):** Utility DSPs typically consist of plans to modernize the distribution grid, including DER integration, non-wire alternatives (NWA), and other investments (AMI, DERMs, etc.)
- **Multi-stakeholder Coordination:** Utilities are engaging industry stakeholders, customers and communities to educate them about DERs and capture and incorporate their feedback in plans,

- 2020 IRP completed with annual action plan updates.
- IRP set a target of 75 MW of DR capacity by 2035 and modelled DERs

Enabling Strategies



- **Rates:** Time-varying rates such as time of use and critical peak pricing (sometimes specific to equipment like EV specific TOU rate), and net-metering for distributed solar
- **Programs:** Demand response programs such as direct load control of smart thermostats, EV smart charging, and energy storage
- **Procurement:** Competitive processes such as RFPs to acquire DERs to meet grid needs
- **Utility-owned assets:** DERs that are owned and operated by utilities to enhance grid flexibility and reliability
- **Value of DER tariffs:** Compensation mechanism for DERs based on value they provide to the grid

- DR programs including smart thermostats, EV chargers, BESS
- TVR programs (TOU, CPP, TOD rate)
- Utility-owned community solar garden in Amherst

Integration Strategies



- **AMI:** Nearly all utilities reviewed have implemented AMI, with some advancing to next generation AMI
- **DERMs:** Most utilities have deployed DERMs to monitor, control, and optimize DER integration
- **Other grid modernization software:** Can include minimum network performance requirements (MNPRs), fault location isolation and service restoration (FLISR), and volt/var optimization (VVO) which help enhance the utility's ability to monitor, control, and optimize the distribution grid
- **Hosting capacity maps:** Indicates amount of DG hosting capacity within a utility's distribution network
- **Interconnection process improvements:** Streamlining processes, including fast-track approvals and clearer technical requirements

- AMI implemented
- DERMs piloted through SGNS

Current Situation and Gap Analysis



Portland General Electric – DER integration initiatives



Spotlight: Portland General Electric (PGE)

Planning Strategies



- **Integrated Resource Plan:** PGE submits a Clean Energy/Integrated Resource Plan, which anticipates and plans for growing electricity demand and a pathway to achieving state GHG reduction targets. It emphasizes the importance of DERs and DR in meeting its capacity needs, while acknowledging the importance of existing generation resources.
- **Distribution System Plan:** PGE's 2024 DSP is a comprehensive strategy for a modern clean energy grid. It includes a detailed action plan that prioritizes investments in DER integration, grid modernization, VPP platform development, and traditional infrastructure
- **Transportation Electrification Plan:** Details plans for PGE to plan for (expanding forecasting abilities), serve (portfolio of rates and programs), and manage (DR, telematics) EV loads

Enabling Strategies



- **Rates:** Time of day rate with an off-peak, mid-peak, and on-peak rate; net-metering for solar
- **Programs:** Peak time rebate program is a behavioural DR program with an award of \$1/kWh reduced; direct load control (DLC) DR programs with smart thermostats, multi-family water heaters, EV smart chargers, and batteries
- **Procurement:** In Nov 2024, PGE issued an RFP to acquire at least 65 MW of distributed solar paired with storage. This will be followed by an RFP to procure an additional 90 MW in 2030
- **Co-deployment with DSM administrator:** PGE and Energy Trust Oregon (ETO) are evolving their co-deployment processes to include a multi-year plan development process. Co-deployment between the two entities is currently focused on programs serving high energy burdened customers, and will encompass common marketing, outreach, and messaging to efficiently deliver complementary energy services to customers.

Integration Strategies



- **AMI:** PGE currently has AMI 1.0 meters installed. In its latest DSP, PGE plans to transition to AMI Next Gen, with plans for 20% of the system to be updated by 2028, and a full system update following that.
- **DERMs:** While PGE currently uses DERM to manage several programs, it is planning to release an Enterprise DERM in three phases. The Enterprise DERM is a centralized platform that will oversee PGE's complete DER portfolio integrated with its other operational systems
- **Other grid mod software:** PGE has implemented basic ADMS and is focusing on adding advanced functions such as FLISR, Distribution State Estimation, and Fault Protection Analysis
- **Hosting capacity maps:** Hosts a Distributed Generation Evaluation Map to display additional distributed generation capacity

Current Situation and Gap Analysis

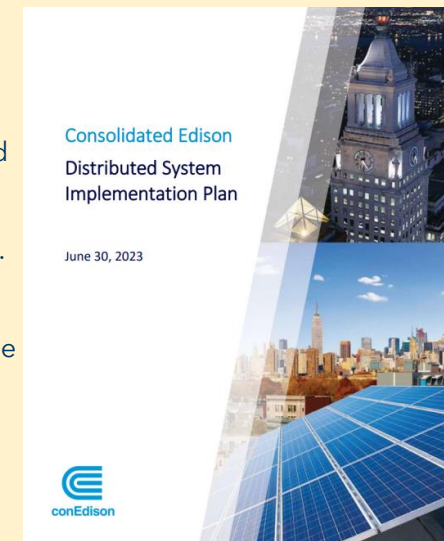
Con Edison - Distributed System Implementation Plan



Spotlight: Highlights from Con Edison's Distributed System Implementation Plan

Con Edison's Distributed System Implementation Plan is a comprehensive plan to achieve its future vision for its Distributed System Platform (that will forecast, plan, interconnect, monitor, and manage DERs). **It includes the following key DER integration related components:**

- **DER Growth and Market and Enablement:**
 - **NWA programs:** Deferring utility infrastructure using EE, DG, and energy storage technologies within specific substation areas (e.g. Brooklyn-Queens Demand Management Program).
 - **Utility-owned DERs:** Building experience installing and operating utility-owned BESS projects to provide local grid benefits and participate in markets to offset costs to customers.
 - **Market integration:** Worked with several stakeholders to implement NYISO's DER Aggregator market. Con Edison will play a key role in registering and validating DER participants and developing monitor and control technologies.
- **Expanded Data Sharing:** Hosting capacity maps updated to include features such as sub-feeder level data, DG connected, and nodal constraints for solar PV and storage maps. Their Share My Data initiative allows customers to provide registered DER providers access to their energy usage and account data, supporting customer choice and market participation.
- **Grid Modernization:** Planning to implement an Enterprise GIS (eGIS) which will consolidate mapping and visualize the physical location and characteristics of DERs. Con Edison is also in the process of implementing an Enterprise DERMs in phases over the next few years, starting with DER data and management, then progressing to planning, forecasting, monitoring and control functions.
- **Ongoing Stakeholder and Customer Outreach:** Con Edison recognizes that collaboration with key stakeholders and state entities, as well as customer engagement is crucial to delivering on its goals. Communication with stakeholders takes place through various channels, such as technical conferences, newsletters, and webinars. Con Edison also participates in developing a quarterly DSP Enablement Newsletter with the Joint Utilities to update key stakeholders.



Current Situation and Gap Analysis

Hawaiian Electric- Customer Energy Resource Strategy

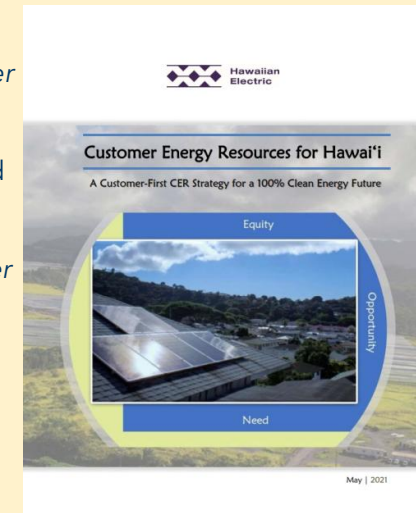


Spotlight: Highlights from Hawaiian Electric Company's (HECO) Customer Energy Resource Strategy

HECO's Customer Energy Resource (CER) strategy centers around three "Cs" that are enabled through three "Ps":

- **Choice:** Customers chose which rate (**pricing**) works best for them based on their energy use.
HECO currently offers tariffs for distributed generation (primarily rooftop solar PV and storage) and is exploring other opportunities for advanced rate design and modernization, including time-of-use rates and critical peak pricing.
- **Coordination:** Customers can enroll in a HECO administered CER **program**, enabling direct utility management and coordination among CERs, grid-scale resources and grid-protective devices
HECO currently offers a C&I direct load control (DLC) program (targeting CERs such as behind-the-meter generators, pumps, HVAC, non-emergency lighting), a Small Business and Residential DLC program (targeting water heaters and HVAC systems), and a fast demand response program, offering increased incentives for commercial customers that respond within 10 minutes of an event activation, targeting behind-the-meter generation, storage, and HVAC systems. They are exploring future program opportunities, such as bundled grid services.
- **Collaboration:** HECO contracted an independent aggregator through a competitive **procurement** process to provide additional customer offerings.
Current procurement efforts are targeting bulk system grid services, transmission and distribution grid services/NWAs, and shared solar. They are exploring future opportunities for all-resource procurement with their integrated grid planning framework.

HECO's strategy also recognizes that success hinges on close coordination with **grid modernization** efforts and their **integrated grid planning framework**. They are investing in **DERMS, AMI, ADMS**, and have played a leading role in defining **interconnection standards for advanced inverters** with overvoltage capabilities, frequency responsive functions, and more, to help facilitate unprecedented levels of rooftop solar interconnection.



Current Context and Gap Analysis

DER Integration Governance with DSM Administrators



In jurisdictions studied with independent DSM administrators, utilities typically lead DER planning, integration, rates and programs, while DSM administrators support by providing incentives, recruiting customers, and conducting EM&V.

Jurisdiction	Utility	DSM Administrator	Roles and Responsibilities
Nova Scotia			The DERIR will clarify NSPI and E1's roles. Preliminary roles/responsibilities from SGNS: • NSPI: Procure DERMs, define program parameters, and call DR events • E1: EM&V, coordinate and deliver EE/DR programs, and procure a DRMS
Vermont			• GMP: Plans for DER growth, oversees DER connections (e.g. interconnection guidelines), manages DER specific rates and programs • EVT: Conducts high level studies to assess DER potential (e.g. Role of Energy Storage in Meeting Vermont's Energy Goals report), provides DER equipment incentives • Co-deployment: GMP and EVT co-deliver pilots, such as the Flexible Load Management pilot. GMP administers the pilot, calls events, and analyzes peak probabilities, while EVT leads customer recruitment and EM&V
Oregon			• PGE: Plans for DER growth, oversees DER connections (e.g. interconnection guidelines), manages DER specific rates and programs • ETO: Provides DER equipment incentives • Co-deployment: PGE and ETO are starting a multi-year plan development process and plan to co-deploy DER programs, starting with programs targeting high energy-burdened customers.
Manitoba			• Manitoba is in the early stages of DER integration. Dunsky recently completed a DR Strategy for both MH and EM, which included a governance structure recommendation with roles/responsibilities aligned with other utilities with a separate DSM administrator.

Note: This is based on publicly available information identified through desktop research. It may contain gaps, as companies do not always disclose all relevant details

Current Context and Gap Analysis

Risk, Uncertainty and Innovation



Risk and Uncertainty



- **Planning Risks:** Planning processes are adapting to account for risk and uncertainty associated with when, where, and how many DERs will show up on a utility system. This includes scenario analysis, flexible signpost-based strategies, and increasingly localized distribution system planning.
- **Technology risks:** Pilots are leveraged to test and de-risk emerging technologies and strategies (e.g., DER functionality, roles, market design, coordination models)
- **Regulatory risk:** Regulatory processes and frameworks are evolving to allow more agile responses to uncertainty

NSPI's Progress

From the SGNS experience, NSPI **recognizes the need** to address risk and uncertainty in the evolving DER landscape through continued exploration, iterative refinement and **DERIR development**.

Innovation



- **Innovation funds** provide dedicated funds to finance DER pilots and innovation projects
- **Regulatory sandboxes** provide customized regulatory guidance and temporary relief from regulatory requirements, enabling utilities to test innovations
- **Innovation pilot frameworks** enable expedited implementation of pilot projects, and provide clear pathways for scaling successful pilots

The Nova Scotia Energy Board (NSEB) developed a **definition of innovation within their Capital Expenditure Justification Criteria** (CEJC). SGNS was the first project under the CEJC.

Spotlight: HECO



HECO has adopted an **Integrated Grid Planning (IGP) framework** that holistically considers generation, transmission, distribution, and customer resources. A core component of this framework is a detailed **distribution system planning process** with analysis of DER hosting capacity and grid needs, analysis of wires and non-wires solutions, and a Transmission and Distribution Action Plan.

HECO works closely with a **Technical Advisory Panel (TAP)**, which plays a key role in proactively identifying emerging risks – such as system stability under high DER penetration, voltage control challenges, and fault protection. This **collaboration has informed mitigation actions**, including DER interconnection improvements, and testing of smart inverter functions and grid-forming technologies.

They have also implemented an **innovation pilot framework**, which **expedites pilot projects** and includes provisions to **scale successful pilots**.

Current Context and Gap Analysis



Key Findings and Next Steps

The findings of the current situation and gap analysis will be used to **inform priority areas for further investigation** through **additional research** and **stakeholder engagement**, to produce a long list of roadmap initiatives that will be prioritized based on the criteria in the next section.

Key findings from *preliminary* research includes:



Planning: Leading utilities are systematically integrating DERs as a resource in IRPs and in distribution planning. While NSPI has an IRP process that considers DER, the jurisdictional scan highlights opportunity to enhance DER considerations in planning and consider more granular distribution system planning. There is also opportunity to strategically integrate analysis of risks and uncertainty associated with DERs, to reduce uncertainty for system operators, inform action plans and support DER integration.



Enabling: Competitive procurement strategies, utility-owned assets, innovative rates and programs, streamlined interconnection processes and strategic partnerships are crucial to successfully enable DER integration. Building on this review, we will dive deeper into strategies and approaches and explore opportunities for utility procurement, VDER frameworks, programs and partnerships.



Integrating: Most jurisdictions are using DERMs to maximize DER potential. The SGNS pilot demonstrated cost savings, reliability benefits, and emissions reductions potential. We will also explore DERMs, other infrastructure and strategies to mitigate key barriers and risk to DER integration observed across jurisdictions.

Next steps: Dunsky will concentrate on jurisdictions of interest to create a long list of potential options and investments, identify innovative initiatives relevant to NSP, and highlight key learnings to consider for the DERIR.



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1 **Request IR-3:**

2
3 **What will be the yearly operating cost for this technology over the next five years?**

4
5 Response IR-3:

6
7 As set out in the Total Cost of Ownership (TCO) provided on page 8 of the Application, there are
8 no operating costs forecast for 2026-2027 and the operating costs for 2028, 2029 and 2030 are
9 forecast to be \$879,553, \$1,047,465, \$1,047,465, respectively. For 2031 and 2032, they are
10 forecast to be \$1,078,889, and \$1,111,256, respectively.

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1 **Request IR-4:**

2
3 **The application notes the following:**

4
5 **...The DERMS will be capable of monitoring and coordinating DER**
6 **aggregations, communicating with DER aggregators, and will be able to**
7 **integrate DERs into NS Power's OT ecosystem through interfaces with other**
8 **NS Power enterprise systems such as ADMS.**
9

10 **Please explain whether any cybersecurity requirements apply to this integration and**
11 **describe how those requirements will be evaluated.**
12

13 Response IR-4:

14
15 Yes. NS Power's Cyber Security Team has supported vendor evaluation and will ensure the
16 DERMS platform aligns with NS Power's Cyber Security policies and standards. The team will
17 evaluate cyber security through a risk assessment to be completed prior to implementation of the
18 DERMS platform and integration with existing systems.
19

20 Key items that will be evaluated through the cybersecurity risk assessment include:

- 21
22 • Authentication and Access Control
23 • Data Security
24 • Application Security
25 • Infrastructure Security
26 • Monitoring and Incident Response
27 • Compliance and Governance

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Request IR-5:

The application notes the following:

Increased customer adoption of DERs, increasing severity and frequency of weather events, and environmental policy mandates (e.g. 80 percent renewable energy) are all key considerations within Nova Scotia's current energy landscape. NS Power needs to establish operational management capabilities and processes which provide DER visibility and enable coordination, where appropriate.

Board staff understand that operational control centre functions will ultimately be transferred to the newly formed Nova Scotia Independent Energy System Operator.

(a) Did the utility consult the Nova Scotia Independent Energy System Operator before submitting this project?

(i) If yes, please provide a copy of the correspondence.

(ii) If not, please explain why such consultation was not required.

Response IR-5:

(a) No, NS Power did not formally consult with the IESO-NS prior to submitting this project as Phase II of the transition of functions from NS Power to IESO Nova Scotia is still in the early stages of development. However, the Company notes that this project advances the DERMS Requirement and Evaluation Framework and DERMS Procurement and Progression initiatives identified in the Distributed Energy Resources Integration Roadmap (DERIR), which was developed in consultation with key stakeholders, including the IESO-NS. The DERIR is provided in IR-2 Attachment 1.

(i) N/A.

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1 (ii) While certain system operator functions currently performed by NS Power will
2 transition to IESO Nova Scotia as part of the ongoing transition of responsibilities,
3 NS Power will continue to have responsibility for the operation of its distribution
4 system. NS Power is currently the only user of the proposed DERMS technology,
5 as it is only applicable to internal NS Power functions at this time.