# Integrated Resource Plan Action Plan Update

2025

Nova Scotia POWER
An Emera Company

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# Introduction

**Nova Scotia Power is pleased to provide this update to its IRP Action Plan**

On November 30, 2020, Nova Scotia Power submitted **Powering A Green Nova Scotia, Together: 2020 Integrated Resource Plan (IRP)** to the Nova Scotia Utility and Review Board.

The IRP Final Report provided the findings and recommendations in the form of an Action Plan and a Roadmap to support the long-term strategy:

- A commitment to an Evergreen IRP process was included in the Roadmap; if significant changes to the planning environment are observed, the Evergreen IRP process enables further assessment and an update to the Action Plan and Roadmap, if required
- Since the 2020 IRP, changes in environmental policy, load growth and emerging resources triggered further study
- As a result, an Evergreen IRP process was undertaken; the 2022/2023 Evergreen IRP and the resulting update to the Action Plan and Roadmap was completed in August of 2023

This is the fourth annual Action Plan Update, which provides the following:

- An update on electricity planning environment changes
- An update on the Action Plan and Roadmap items for 2024/2025 to date
- For ongoing items, a description of planned work for the remainder of 2025

# IRP Action Plan Overview

## *Action Plan Items*

Nova Scotia Power's IRP Action Plan consists of 5 Action Plan Items, some of which include multiple elements:

1. REGIONAL INTEGRATION STRATEGY
2. ELECTRIFICATION
3. THERMAL PLANT PLANS
4. DEMAND RESPONSE STRATEGY
5. AVOIDED COSTS OF DSM

This Annual Report provides an update on each of these Action Plan Items

Descriptions of the Action Plan Items can be found in the updated 2023 Evergreen IRP Action Plan and Roadmap

# IRP Action Plan Overview

## *Roadmap Items*

NS Power also monitors the following 11 Roadmap Items for potential impact on Action Plan execution:

1. Wind Integration Studies
2. Sustaining Capital
3. Monitor Alternative Fuel Sources
4. Track Installed Costs of Wind, Solar and Energy Storage
5. Track Federal Clean Electricity Regulations (CER)
6. Monitor Electrification & Load Growth
7. Evergreen IRP Process
8. Monitor Emerging Technologies
9. Offshore Wind Support
10. Monitor Hydrogen Tariff Impacts
11. Monitor Firm Imports

In this report, updates on relevant Roadmap item updates have been provided throughout the document.

# The Path to 2030 – References

For Action Plan/Roadmap Items with the most recent updates included in the Path to 2030 document filed with the 2025 ACE Plan in December of 2024, please see the references below (UARB Matter M12012):

| Action Plan/Roadmap Item | Topic | Path to 2030 Reference |
|---|---|---|
| Planning Environment Updates | NSIESO | Section 5.0, page 15 |
| Action Plan 1: Regional Integration | Reliability Tie | Section 6.3, page 32 |
| Action Plan 2: Electrification | Electrification Strategy | Sections 7.1 and 7.2, pages 39 - 42 |
| Action Plan 3: Thermal Retirement Plan | Fast Acting Generation Capacity | Section 6.4, page 35 |
| | Wind Procurement Strategy (RBP) | Section 6.1.1, pages 17 - 19 |
| | Wind Integration Studies | Section 6.2.3, pages 30 – 32 |
| | Offshore Wind | Section 7.4, pages 44 – 45 |
| | Thermal Plant Conversions | Section 6.5, pages 35 – 37 |
| | BESS | Section 6.2, pages 28 – 32 |
| Action Plan 4: DR | DR Programming | Section 7.2, pages 40 – 42 |

# Planning Environment Updates

# Planning Environment Updates

## Clean Electricity Regulations – Intent, Timing and Development

### *Roadmap Item 5*

- The Clean Electricity Regulations (CER) is a Federal Government regulation developed by Environment and Climate Change Canada (ECCC) to achieve a net zero electricity system in Canada by 2050
- The intent of the regulation is to limit electricity generation from emitting resources starting in 2035 with the intent to achieve a net zero electricity system by 2050
    - The regulations will come into effect starting in 2035 and will apply to all NSP emitting generation that is considered “existing” or “new” under the CER
- The development of the CER was supported by ECCC modeling using their NextGrid model, the results of which feed into ECCC’s Energy, Emissions and Economy Model (E3MC) economy wide model for Canada that forms the basis of the Regulatory Impact Analysis Statement (RIAS)
- Development of the CER involved a series of ECCC milestones with significant stakeholder engagement

March 2022: Discussion Paper → July 2022: Proposed Regulatory Framework → August 2023: Draft Regulations in Canada Gazette, Part 1 → February 2024: Public Update → December 18 2024: Regulations Published in Canada Gazette, Part 2

# Planning Environment Updates

## Clean Electricity Regulations – NSP Engagement and Process

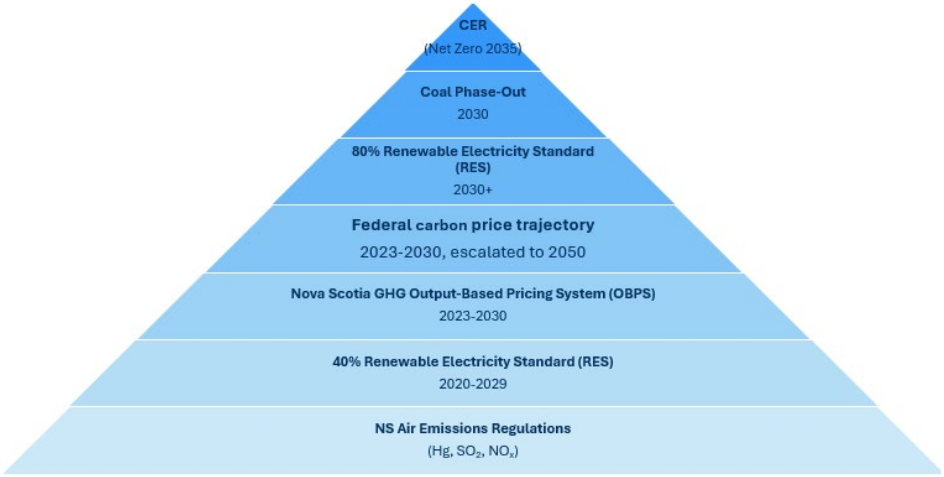
## *Roadmap Item 5*

- Since the development of the CER was brought forward by ECCC in the fall of 2022, Nova Scotia Power (NSP) has been engaged with ECCC as part of the stakeholder engagement process and through Electricity Canada (modeling and policy teams)
- Throughout this process, NSP has worked to assess the proposed CER regulatory framework at various stages of the process and shared our findings with ECCC

# Planning Environment Updates

## Clean Electricity Regulations – Alignment to Provincial Policy

*Roadmap Item 5*




- Emitting generation is required to balance wind and ensure grid reliability and to meet customer demand
  - Level of use of emitting generation in NS beyond 2030 is limited due to the legislated requirement for 80% of sales to be supplied by renewable resources
  - Our evergreen IRP work indicated the need for additional fast acting generation in the form of combustion turbines to balance intermittent renewables and provide required firm capacity to maintain reliable system operation.
- A proxy for an allowable emissions limit was included in the Evergreen IRP work – aligned with the requirement for emitting generation in a peaking capacity
- The operational flexibility required to operate the thermal fleet is supported in the final version of the CER

# Planning Environment Updates

## Components of the CER – Annual Emissions Limit (AEL) and Offsets

## *Roadmap Item 5*

- The Annual Emissions Limit (AEL) is calculated for each generator based on an allowable intensity of 65 tonnes/GWh until the end of 2049; then it is reduced to zero in 2050
- The operator will have the ability to purchase offsets, above the 65 tonnes/GWh emissions limit, if needed
  - 2035 – 2049 (inclusive): up to 35 tonnes/GWh annually; 2050+: 45 tonnes/GWh annually
- Definition of net zero – no emissions intensity but offset purchases are allowed up to 45 tonnes/GWh

| Capacity of unit: | 100 MW | 200 MW | 300 MW | 400 MW |
|---|---|---|---|---|
| AEL (using 65 t/GWh): | 57 kt/yr | 114 kt/yr | 171 kt/yr | 228 kt/yr |
| AEL with max offsets (using 100 t/GWh): | 88 kt/yr | 175 kt/yr | 263 kt/yr | 350 kt/yr |

# Planning Environment Updates

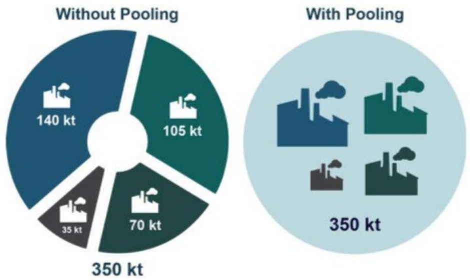
## Components of the CER – AEL and Units Subject to the CER

## *Roadmap Item 5*

The following table defines the application of the AEL based on the definition of various units on the system:

| Type of Unit | Description | Date AEL starts to apply |
|---|---|---|
| **New Units** | A unit commissioned on or after January 1, 2025, and that is not a planned unit | January 1, 2035, or date they are commissioned, if commissioned after 2035 |
| **Planned Units** | A unit that meets specific criteria by December 31, 2025, and is under construction by December 31, 2027, and is commissioned by December 31, 2034 | January 1, 2050 |
| **Existing Units** | A unit commissioned on or before December 31, 2024 | On the latter of January 1, 2035, or January 1 of the calendar year following the calendar year that is 25 years after the commissioning date |
| **Other Units** | A unit that combusts coal | January 1, 2035 |
| | Converted coal-to-gas boiler units | On the latter of January 1, 2035, or January 1 of the calendar year in which the prohibition set out in the Natural Gas Electricity Regulations would have begun to apply |
| | A unit that has increased its generation capacity by 15% or more since registration | January 1, 2035, or January 1 of the year following the capacity increase |

# Planning Environment Updates
## Components of the CER – Pooling and Banking
## *Roadmap Item 5*




- Pooling is the provision within the CER that allows for units designated in the pool to combine their allowable emissions
  - The pool size is established based on all thermal capacity built by 2030 and "the transfer of compliance credits" between units in the pool is allowed until 2050
  - Units of equal or lesser capacity (installed MW) can be swapped into the pool for an existing unit in the pool
  - Unused compliance credits can be carried forward to future years (5 years); entities can also bank non-transferrable compliance credits (units outside of the pool)
  - The pool includes converted and fuel switching units in the pool (coal to gas, coal to heavy fuel oil, etc.)

- The ability to share emissions "room" amongst units allows for:
  - The shift of dispatch to our lower cost and lower emitting units (e.g. Tufts Cove) by transferring emissions "room" from our higher cost and higher emitting units (e.g. diesel CTs)
  - Reduction in capital expenditures for new CTs to meet needs during peak periods by more efficiently using the existing fleet

# Planning Environment Updates
## Components of the CER – Planned Units
## *Roadmap Item 5*

- Planned Units
  - Planned thermal units (examples: fast acting combustion turbines) are new thermal units in which investments have been made and planning has been advanced in good faith prior to the development of the CER and are critical to enabling the integration of variable renewable generation (wind/solar).
  - These units are not subject to the AEL if they meet the following criteria:
    - Meet certain progression milestones by the end of 2025
    - Have started construction by the end of 2027
    - Are commissioned by 2035

# Planning Environment Updates

## Components of the CER – Emergency Provisions

### *Roadmap Item 5*

- In section 25 of the regulation, the emitting fleet is exempt from the CER if an "irresistible emergency event" is experienced by the system operator, which can be determined by the system operator, and those units are needed to assist with the identified electricity supply interruption (notification is required to the Minister 7 days following the use of the generation to support the emergency event).

- This is a significant benefit allowing utilities to react to emergency circumstances in real time to ensure the reliability of the grid and the safety of customers.

# Planning Environment Updates

## Clean Electricity Regulations – Impacts on NSP Long Term Strategy

## *Roadmap Item 5*

What does this mean for NSP and the Province?

- The CER supports and is in alignment with Path to 2030 and the Integrated Resource Plan (IRP)
    - The proxy used in the Evergreen IRP led to resource plans that can be compliant with the CER
    - The terms of the final CER do not require any changes to the Path to 2030 resource plan
    - The use of emitting generation beyond 2035, which was demonstrated to be part of the low-cost resource plans in the Evergreen IRP, continues to be permitted under the CG2 CER
    - NS Power's engagement with ECCC led to the inclusion of important flexibilities that are aligned to Evergreen IRP resource plans
- NSP anticipates incremental system costs associated with meeting the CER's targets compared to current policy.

# Action Plan Item 1: Regional Integration Strategy

# Regional Integration Strategy
## *Action Plan Item 1*

This strategy will identify methods of gaining access to firm capacity and low-carbon energy while increasing the reliability of Nova Scotia’s interconnection with North America.

The key components of this strategy include monitoring the potential for firm capacity imports and the progression of the reliability tie project.

# Regional Integration Strategy
## *Action Plan Item 1a: Reliability Tie*

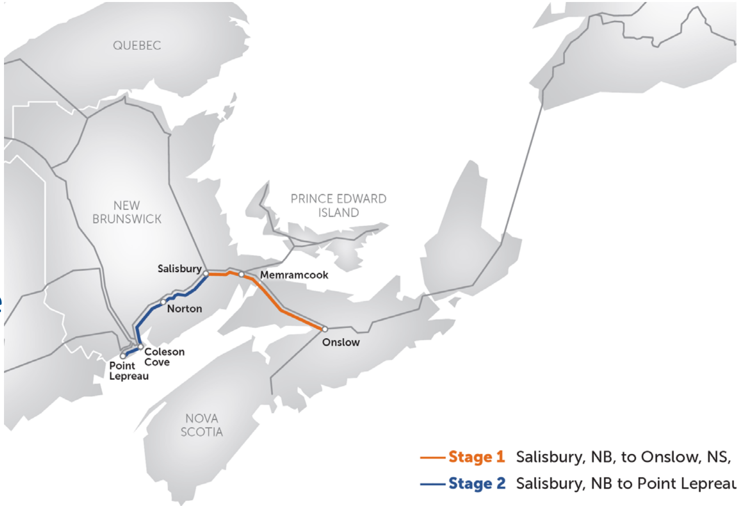
- On April 9th, NS Power filed the Reliability Tie application with the Nova Scotia Energy Board (NSEB)
- The scope of the application is to seek approval for the capital spend to build the 345kV line and related facilities from Onslow, NS to Salisbury, NB

# Regional Integration Strategy
## *Action Plan Item 1b: Regional Integration*

The 2030 Provincial Clean Power Plan notes the potential for the Reliability Tie to incorporate an extension from Salisbury, NB to Point Lepreau, NB:

- This would enable greater access to New Brunswick, New England and Quebec energy exports and imports
- The Reliability Tie (phase 1, application recently filed with the NSEB) identifies future potential import value of stage 1 and 2 if the project is approved
    - Stage 1: potential for 100MW firm capacity
    - Stage 2: potential for additional energy and firm capacity
- This approach was also identified in the Province of New Brunswick's recently released report, *Powering our Economy and the world with Clean Energy – Our Path Forward to 2035*

NS Power will continue to monitor opportunities for near-term firm imports over existing and planned transmission infrastructure




**Stage 1** Salisbury, NB, to Onslow, NS, 2027/28 in service

**Stage 2** Salisbury, NB to Point Lepreau, NB, 2028/29 in service

# Action Plan Item 2: Electrification Strategy

# Electrification Impacts – T&D System
## *Action Plan Item 2c & Roadmap Item 6*

As outlined in **Roadmap Item 6**, NS Power continues to monitor electrification and load growth, to reflect these impacts in developed load forecasts for Nova Scotia.

Electrification Impacts to the NS Power Transmission & Distribution system continue to be studied, with more accurate information becoming available due to system modelling improvements.

- SCADA data continues to be utilized to monitor the annual transmission system peak load and to set up transmission system generation dispatch in system models.
- Further integration of AMI data into distribution modelling software has been accomplished to understand individual feeder peaks at multiple timeframes to capture any feeders that are morning, afternoon, and summer peaking (versus a typical evening winter system peak). It is also being used to identify overloaded downline equipment by feeder, including reclosers, voltage regulators, and stepdown transformers.
- Finally, the annual load forecast has also been used to better understand system peak on a more granular level by reallocating the load at the feeder level.

# Electrification Impacts – T&D System

## *Action Plan Item 2b & Roadmap Item 6*

The 2024 load forecast, the Province's Clean Power Plan and the 2024 10 Year System Outlook provide a clear picture of the generation resources required to serve load over the next five to ten years.

NERC Transmission System Planning Performance Requirements (TPL) assessment of the Long-Term (10 year) Planning Horizon was completed in 2024, revealing the need for three corrective action plans:

- Add a third 392 MVA, 230kV - 138kV transformer at 120H-Brushy Hill
- Adjust corridor flow limits related to contingency loss of L-6503 with L-8003 out of service.
- Modify / reconfigure / upgrade existing Remedial Action Schemes to accommodate "Path to 2030" generation additions

The 2024 Feeder Assessment and 2024 System Load Snapshot reports have identified feeders and substation transformers that are overloaded or expected to become overloaded within the next 5-10 years. No issues have been identified so far that would not be able to be mitigated within that time.

More detailed studies to support the NERC TPL and NPCC Area Transmission Review requirements were completed in 2024.

Planning studies for the areas identified in the 2024 annual reports are being prioritized for completion in 2025 by the Distribution Planning team.

# Action Plan Item 3: Thermal Retirement Plan

# Thermal Plant Depreciation Study

## *Action Plan Item 3b*

- The GRA Settlement Agreement submitted to the UARB in 2023 recommended a Decarbonization Deferral Account (DDA) to recover undepreciated thermal asset net book values (NBV) and unrecovered decommissioning costs.
- NS Power will complete a depreciation study and file it along with or in advance of the next GRA.
- The study determines the depreciation rates and recovery strategies to better align depreciation with updated lifetimes of generation assets.

# Procurement Strategy for Variable Renewable Resources
## *Provincial Green Choice Program*
## *Action Plan Item 3d*

The provincial Green Choice Program (GCP) focuses on acquiring renewable generation to serve participating NS Power customers with 100% renewable energy to meet their load requirements.

The goal of this program is to build low-impact renewable generation capacity, which large scale energy customers (with >10,000 MWh of annual load) can contract to achieve greenhouse gas emissions reduction targets, while supporting NS Power's 2030 decarbonization goals.

The program is managed by independent Procurement Administrator (PA) Coho, and on January 27, 2025, it was announced that the following IPPs were selected to provide total of 625MW of wind capacity in the Province:

- Yellow Birch, Pictou County; developed by SWEB in partnership with Glooscap First Nation
- Melvin Lake, Hants & Halifax counties; developed by ABO Energy Canada in partnership with Eskasoni, Potlotek, We'koqma'q L'nue'kati and Wagmatook First Nations
- Rhodena, Inverness County; developed by ABO Energy Canada in partnership with Eskasoni, Potlotek, We'koqma'q L'nue'kati and Wagmatook First Nations
- Blueberry Acres, Cumberland County; developed by SWEB in partnership with Glooscap First Nation
- Sugar Maple, Pictou County; developed by SWEB in partnership with Glooscap First Nation
- Eigg Mountain, Antigonish County; developed by Renewable Energy Systems Canada in partnership with Paq'tnkek and Pictou Landing First Nations

# Thermal and CT Investment

## *Roadmap Item 2*

Updated sustaining capital profiles are included as an assumption in the ongoing Evergreen IRP update and corresponding modeling work (please refer to the Evergreen IRP assumptions material).

<u>Thermal investment:</u>

The sustaining capital profiles for the thermal units have been updated based on the Evergreen IRP utilization factor approach and the 2030 coal phase out requirements.

To maintain resource adequacy while minimizing capital investment into thermal units, operating restrictions were put in place at Trenton 5 that limit the number of operating hours, while still meeting system firm capacity requirements.

<u>CT investment:</u>

The sustaining capital values for the diesel CTs has decreased as compared to the 2020 IRP assumptions for 2023, with 2023 values being lower than 2022 sustaining capital. This confirms the Evergreen modeling approach to assume ongoing operation of the diesel CT fleet.

# CT Financial Reporting – 2021/2022/2023/2024

## *Roadmap Item 2*

| Description | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|
| OM&G fixed - CT (diesel units) | $689,996 | $693,186 | $923,945 | $966,057 |

| Sustaining Capital | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|
| Burnside-1 | $2,165,499 | $565,241 | $207,790 | $1,045,824 |
| Burnside-2 | $248,105 | $182,846 | $133,310 | $171,581 |
| Burnside-3 | $248,011 | $146,739 | $205,940 | $97,466 |
| Burnside-4 | $248,731 | $407,266 | $1,595,224 | $144,369 |
| Victoria Junction-1 | $2,209,427 | $7,263,449 | $0 | $202,834 |
| Victoria Junction-2 | $155,639 | $32,295 | $438,243 | $1,594,102 |
| Tusket-1 | $1,724,185 | $1,552,561 | $541,178 | $1,899,950 |
| **Total** | **$6,999,597** | **$10,150,397** | **$2,746,101** | **$5,156,128** |

# CT Financial Reporting – 2021

## *Roadmap Item 2*

| Unit | Net Generation (MWh) | Net Capacity Factor (%) | DAFOR (%) | Availability Factor (%) | Failed Starts | Maintenance Outage Hours | Operating Hours |
|---|---|---|---|---|---|---|---|
| Burnside-1 | 505 | 0.2% | 98.2% | 65.8% | 2 | 2 | 46 |
| Burnside-2 | 1,691 | 0.6% | 15.9% | 96.0% | 2 | 40 | 111 |
| Burnside-3 | 1,768 | 0.7% | 95.0% | 73.9% | 11 | 5 | 105 |
| Burnside-4 | 1,990 | 0.8% | 15.7% | 92.3% | 0 | 386 | 123 |
| Victoria Junction-1 | 510 | 0.2% | 75.6% | 93.7% | 2 | 35 | 32 |
| Victoria Junction-2 | 383 | 0.1% | 74.7% | 95.0% | 1 | 6 | 26 |
| Tusket-1 | 65 | 0.0% | 6.1% | 84.8% | 2 | 1015 | 31 |
| **Total (avg for %)** | **6,913** | **0.38%** | **54%** | **86%** | **20** | **1,489** | **474** |

# CT Financial Reporting – 2022

*Roadmap Item 2*

| Unit | Net Generation (MWh) | Net Capacity Factor (%) | DAFOR (%) | Availability Factor (%) | Failed Starts | Maintenance Outage Hours | Operating Hours |
|---|---|---|---|---|---|---|---|
| Burnside-1 | 3,792 | 1.4% | 96.2% | 41.3% | 6 | 21 | 202 |
| Burnside-2 | 6,698 | 2.5% | 74.4% | 84.9% | 1 | 15 | 317 |
| Burnside-3 | 6,303 | 2.4% | 9.2% | 94.7% | 8 | 2 | 316 |
| Burnside-4 | 1,924 | 0.7% | 46.7% | 59.1% | 2 | 7 | 119 |
| Victoria Junction-1 | 1,400 | 0.5% | 60.1% | 72.8% | 4 | 10 | 68 |
| Victoria Junction-2 | 984 | 0.4% | 37.4% | 97.0% | 2 | 2 | 68 |
| Tusket-1 | 831 | 0.3% | 71.6% | 93.5% | 6 | 18 | 73 |
| **Total (avg for %)** | **21,931** | **1.19%** | **57%** | **78%** | **29** | **75** | **1,163** |

# CT Financial Reporting – 2023

## *Roadmap Item 2*

| Unit | Net Generation (MWh) | Net Capacity Factor (%) | DAFOR (%) | Availability Factor (%) | Failed Starts | Maintenance Outage Hours | Operating Hours |
|---|---|---|---|---|---|---|---|
| Burnside-1 | 3,182 | 1.2% | 19.6% | 94.2% | 5 | 31 | 177 |
| Burnside-2 | 2,900 | 1.1% | 12.1% | 94.2% | 3 | 42 | 157 |
| Burnside-3 | 2,295 | 0.9% | 21.5% | 91.6% | 7 | 311 | 128 |
| Burnside-4 | 1,006 | 0.4% | 34.4% | 85.8% | 2 | 309 | 64 |
| Victoria Junction-1 | 922 | 0.4% | 17.7% | 93.1% | 2 | 2 | 331 |
| Victoria Junction-2 | 961 | 0.4% | 41.8% | 87.6% | 2 | 9 | 68 |
| Tusket-1 | 657 | 0.3% | 42.9% | 93.6% | 2 | 17 | 178 |
| **Total (avg for %)** | **11,923** | **0.65%** | **27%** | **91%** | **23** | **720** | **1,102** |

# CT Financial Reporting – 2024

*Roadmap Item 2*

| Unit | Net Generation (MWh) | Net Capacity Factor (%) | DAFOR (%) | Availability Factor (%) | Failed Starts | Maintenance Outage Hours | Operating Hours |
|---|---|---|---|---|---|---|---|
| Burnside-1 | 4,058 | 1.5% | 93.9% | 60.3% | 7 | 3 | 217 |
| Burnside-2 | 3,834 | 1.5% | 23.5% | 93.4% | 5 | 38 | 194 |
| Burnside-3 | 3,211 | 1.2% | 39.8% | 91.7% | 4 | 96 | 152 |
| Burnside-4 | 2,065 | 0.8% | 19% | 95.1% | 1 | 13 | 112 |
| Victoria Junction-1 | 754 | 0.3% | 0.7% | 98.3% | 3 | 5 | 19 |
| Victoria Junction-2 | 1,142 | 0.4% | 40.2% | 96.6% | 1 | 46 | 46 |
| Tusket-1 | 46 | 0% | 93.8% | 73.4% | 7 | 11 | 58 |
| **Total (avg for %)** | **15,110** | **0.8%** | **44.4%** | **87%** | **28** | **212** | **798** |

# Hydrogen
## *Roadmap Items 3 & 11*

NS Power is engaged with the prospective H2 developers is to assess both the impacts of future development on the power system and assess future opportunities for the use of H2 as a green fuel source.

- Hydrogen Tariff:
  - Hydrogen tariff development continues to progress as the hydrogen industry develops in Nova Scotia, as per **Roadmap Item 11**.
  - As a product of this engagement, the development of a hydrogen tariff to identify H2 developer specific utility services and the corresponding cost structure is currently under development.
  - The tariff will be subject to NSEB approval
- Domestic Hydrogen Fuel Source:
  - The value of a future domestic source of hydrogen from these developers was studied in the Evergreen IRP, based on Evergreen IRP modelling results, hydrogen enabled fast acting generation was not selected as a resource
  - Updated information on hydrogen fuel pricing and availability can be assessed in the future through the Evergreen IRP process as a part of **Roadmap Item 3**.

# Geothermal in NS – Overview
## *Roadmap Item 8*

- As part of the Evergreen Integrated Resource Planning (IRP) process, NSP considers both existing/commercially available sources of generation as well as emerging resources when evaluating our long-term electricity strategy
- In the most recent IRP, geothermal was included among the emerging resources studied within the planning horizon (to 2050)
- Inclusion of this resource in the IRP is supported by research conducted in Nova Scotia that evaluates the potential for geothermal within the Province (Phase I: Assessment of Geothermal Resources in Onshore Nova Scotia | Net Zero Atlantic)
    - At the time of the publication of the Evergreen IRP, research on geothermal potential in NS pointed to the value associated with direct heat use
    - However, the potential for geothermal as a grid scale electricity generation resource through the use of enhanced geothermal systems was noted as a potential emerging resource, albeit one that is currently in the pilot phase globally

# Geothermal in NS

## *Roadmap Item 8*

- The map shows areas where geothermal to support electricity generation in the Province may be possible; all, except for a small region, point to the need for enhanced geothermal systems (EGS)
- Geothermal potential identified at depths beyond the temperature data point, correlations were used to estimate the reservoir temperatures for the purpose of this analysis
- A portion of the province is lacking in temperature and seismic data to evaluate geothermal potential beyond the areas indicated.
- Given this, there may be other areas of geothermal potential within the region to support electricity generation

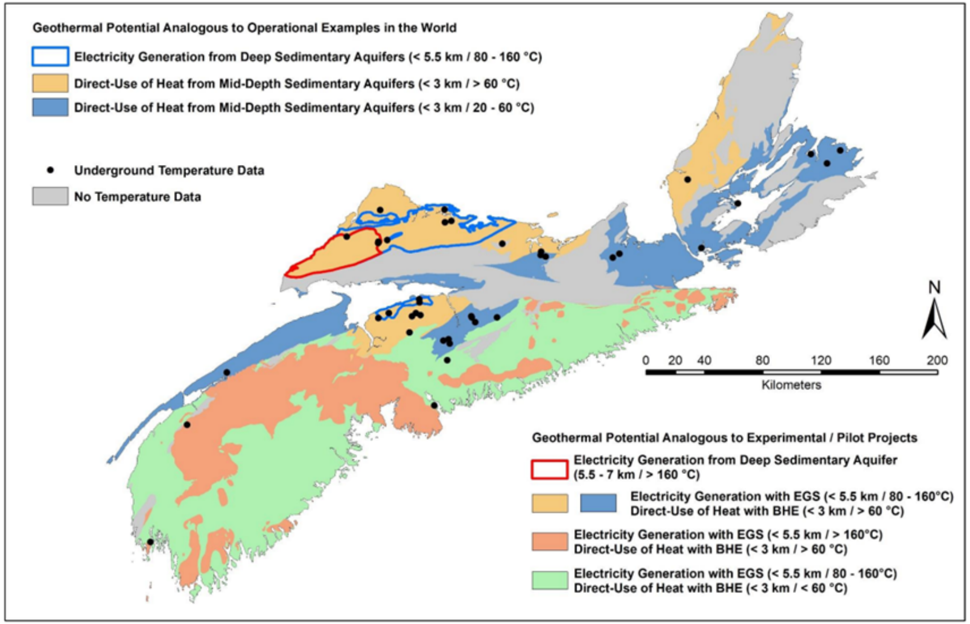



**Figure A.** Geothermal potential in Nova Scotia for electricity generation and direct-use of heat, based on similar operational examples around the World. Geothermal potential in Nova Scotia for electricity generation, with or without stimulation (enhanced geothermal systems: EGS), and direct-use of heat with or without borehole heat exchanger technology (BHE), based on similar operational examples around the World.

# Advancements in Geothermal

## *Roadmap Item 8*

- NSPI spoke with companies operating in the emerging geothermal operations (focused on EGS) to better understand development in the EGS space
- Discovered two interesting approaches:
    - Use of a wellbore system for heat exchange instead of having separate injection and production wells, with fluids interacting below the surface
        - Fluid is pumped into the reservoir and pumped to the surface once it achieves necessary temperatures for geothermal operations
        - Requires multiple wells to ensure a dispatchable project and hydraulic fracking for geothermal purposes
    - Closed loop geothermal systems – heat exchange happens within the wellbore (closed systems for reservoir and working fluids (requires 180 degrees to 300 degrees C operating temperatures)
- For both approaches, the working fluid enters a binary cycle plant at surface, which is powered by the steam created from the working fluid to support electricity generation. The movement of the working fluid is managed by ground source heat pumps.

# Geothermal – Conclusion
## *Roadmap Item 8*

Based on these observations and discussions with geothermal developers, the following is noted for reflecting and evaluating geothermal in NS Power's long-term planning work:

- More temperature and seismic data would be needed in Nova Scotia if further assessment of the potential for geothermal (including EGS) for electricity generation is to be completed.
- The costs for geothermal development as an assumption in future IRP work will need to reflect the developing technology and the project scope needed to support dispatchable generation and the significant depth required to access the potential.
- Commercialization of EGS has not yet been realized and will most likely be beyond 2030. This timing should be reflected when establishing when various resources will be available for selection in future modeling.

# Small Modular Reactors (SMRs)

## *Roadmap Item 8*

- As part of the emerging resources modeled in the Evergreen IRP, Small Modular Reactors (SMRs) were included as potential resources for consideration in the future.
- There have also been two major developments in the policy space related to SMRs:
  - In 2024, the Province of Nova Scotia updated legislation to allow for the build of SMRs in the Province (Nova Scotia Legislature - Bill 404 - Energy Reform (2024) Act - RA)
  - The Federal Government has released an SMR Action Plan (Canada's Small Modular Reactor (SMR) Action Plan) which looks to enable SMRs in Canada as a viable resource to support a low carbon and resilient future
- There were no major changes to trigger a need for an IRP update however, NS Power will continue to monitor commercial development for SMRs and the associated costs

# Hydrogen Enabled Combustion Turbines (CTs)
## *Roadmap Item 8*

- In addition to modeling a generic domestic hydrogen production plant load, the availability of a domestic source of hydrogen fuel for the CTs was also enabled in the Evergreen IRP
- Recently, the Resource Planning team has gathered updated information related to the cost and timing of these resources
  - Today manufactures can support between 5% and 35% hydrogen blending.
  - Most manufactures are working towards having their units capable of operating on 100% hydrogen fuel between 2030 and 2035.
  - Current models would need to be retrofitted to operate using 100% hydrogen as a fuel source.
- For the Reliability Tie analysis the cost for Aeroderivative CTs was updated to match internal estimates developed in 2024 during capital project development.
- The capital cost adder for Aeroderivative CT's capable of operating with 100% hydrogen fuel was reviewed and the Evergreen IRP assumption of 10% was confirmed to still reflect market conditions.
- E3 reviewed the domestic and imported pricing assumptions for hydrogen fuel used in the 2023 Evergreen IRP and concluded they still reflect market expectations.

- The updated information does not trigger an IRP update, however, NS Power will continue to monitor this emerging resource as part of Roadmap Item 8

# Action Plan Item 4: Demand Response

# Hybrid Peak Electrification Scenario

## *Action Item 4b*

- As part of the electrification study, a hybrid heating electrification profile was assessed:
    - Represents the peak load reduction associated with retaining back up heating sources (natural gas, oil, wood, etc.) to be utilized during the coldest hours of the year when the peak load is the highest and when heat pumps are less efficient (below -15 degrees Celsius)
- This hybrid peak electrification approach was assessed as part of the Evergreen IRP and demonstrated value to the system by reducing resource capacity requirements and system costs.
- As there would be costs associated with the hybrid peak mitigation approach,  further assessment is required to determine program cost estimates and validation of savings potential.
- Net Zero Atlantic, with support from the Province of Nova Scotia, is progressing study work to further assess the cost and benefits of the hybrid peak approach
    - NS Power is committed to participate in this work to provide a balanced assessment of the cost impacts and provide necessary information to conduct a more refined assessment of the program from an electricity system cost perspective
    - To date, NS Power has participated in meetings with the Net Zero Atlantic and provincial staff in a working group setting, with Net Zero Atlantic as the lead party completing the study. This work will continue into 2025.

# Evergreen IRP
## *Roadmap Item 7*

- The most recent Evergreen IRP Action Plan and Roadmap was released on August 8th, 2023.
- In preparation for future Evergreen IRP updates, NS Power is progressing items to support the next IRP including:
  - An updated Effective Load Carrying Capability Study (ELCC)
  - Advancement of the assumptions for integration of renewables based on outcomes of the IBR report released in 2024
  - Continuing to monitor and assess policy changes affecting the electricity planning environment (e.g. CER)
  - Include any known regulatory changes (CER) and monitor developing work that could influence future IRP assumptions (Hybrid Peak)
- As required in Bill 404, the NSIESO is required to initiate an IRP within one year of that section of the Bill coming into force. Until that time, the most recent NS Power Evergreen IRP update will inform electricity planning activities.