NOVA SCOTIA IRP TRANSMISSION INDEPENDENT COLD EYES PLANNING PEER REVIEW REPORT

October 10, 2023

Prepared for:
Government of Nova Scotia
Department of Natural Resources
Clean Electricity Solutions Task Force

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Project Number:
126500373

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Executive Summary

Stantec conducted a peer review of a wide range of documents and analysis models as outlined in this report with a focus on determining if the present and future electric grid capacities in Nova Scotia are sufficient to achieve Nova Scotia's renewable energy goals. In particular, whether the transmission system would be capable of supporting the planned integration of renewable energy and provide the necessary capacity, reliability and voltage stability.

Many of the documents reviewed are associated with the Integrated Resource Plan (IRP) developed by Nova Scotia Power, which forms the cornerstone of a plan to support provincial decarbonization and provide a clean, reliable energy system while focusing on customer affordability in both the near and long term. The development of the IRP is a dynamic process which acts to define and further refine action plans and roadmaps continuously as the planning environment changes and technology or market options evolve.

Overall, Stantec observed that the methodology, analysis, and recommendations established in the 2020 IRP and the 2023 Evergreen IRP to be consistent with processes found in other jurisdictions throughout North America. The 2023 Evergreen IRP is the reflection of the action plan identified in 2020 IRP and proves the effectiveness of the original objectives that started with 2020 IRP.

The 2023 Evergreen IRP is more aligned with the federal and provincial Net Zero objectives. It considered two Net Zero scenarios, years 2035 and 2050 as opposed to years 2045 and 2050 considered in the 2020 IRP. Also, the coal retirements are completed by 2030 in 2023 Evergreen IRP as opposed to years 2035 and 2040 considered in the initial 2020 IRP. The 2023 Evergreen IRP also considered new resources in the generation mix, such as, hydrogen, SMR, etc.

However, while the 2020 IRP and 2023 Evergreen IRP outlined development scenarios which included the retirement of coal fired generation, addition of new renewable generation and interregional transmission, as of the time of review, there was no associated transmission plan prepared outlining required transmission developments within the province that may be needed to support the implementation of the IRP. It was initially expected that a specific transmission plan was developed based upon the IRP findings and recommendations, and a corresponding PSS®E system model developed to reflect that transmission plan. The studies required to meet these objectives, however, have not yet been performed.

The 2023 10-Year System Outlook provides load forecast until year 2033. Typically load forecast and transmission plan provided by utilities covers 10-year planning horizon. The 2023 Evergreen IRP scenarios provide long term outlook up to 2050. The next cycle of NSPI transmission plan should consider the time horizon aligned with IRP process.

The 2021 Transmission Plan indicated it did not include the 2020 IRP components as relevant studies are ongoing at the time of the Transmission Plan posting. It is noted that timeframe considered in the Transmission Plan is up from 2022 to 2031. There are no elements in the Transmission Plan to be compared with the directions provided in the IRP. The PSS®E case associated with the Transmission Plan represents year 2024—2025 which also could not be used for comparison as it does not include any IRP directions through the Transmission Plan.

The Manitoba Hydro International Study Report on the Large-Scale Integration of Inverter Based Resources (IBRs) in Nova Scotia as well as the Power Advisory document regarding Nova Scotia Ancillary Service Provision by Variable Output Renewable Energy Resources, both touched on transmission system challenges that would be faced by Nova Scotia under large scale penetration of renewable generation as contemplated in the IRP associated with frequency and voltage regulation. While the MHI report discusses the benefits of interconnections such as the Regional Interconnection and Reliability Tie identified in the IBR, the report does not identify specific changes required within the provincial transmission system necessary to support the IBR.

While several documents included in the scope of review referenced various transmission developments that may come about or be required as a result of implementing the IRP, as noted previously, no full transmission planning study or assessment of the existing system was conducted that could be used to determine if the existing or planned transmission system would be capable of supporting the planned integration of renewable energy and provide the necessary capacity, reliability and voltage stability.

Acronyms / Abbreviations

CATR	Comprehensive Area Transmission Review
CER	Clean Electricity Regulations
DER	Distributed Energy Resources
DSM	Demand Side Management
ELCC	Effective Load Carrying Capability
ELIADC	Extra-Large Industrial Active Demand Control
FFR	Fast Frequency Response
HFO	Heavy Fuel Oil
IBR	Inverter Based Resource
IRP	Integrated Resource Plan
MHI	Manitoba Hydro International
MMWG	Multiregional Modeling Working Group
NPVRR	Net Present Value of Revenue Requirement
NSPI	Nova Scotia Power Inc.
NSPSO	Nova Scotia Power System Operator
NSUARB	Nova Scotia Utility and Review Board
OERA	Offshore Energy Research Association
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
RoCoF	Rate of Change of Frequency
SDGA	Sustainable Development Goals Act
SIS	System Impact Study
SMR	Small Modular Reactor
T&D	Transmission and Distribution
TPL	Transmission Planning
TSR	Transmission System Request

1 Introduction

The Clean Electricity Solutions Task Force has been established to explore ways to modernize Nova Scotia's electricity infrastructure and regulatory environment. Stantec understands that the mandate of the Task Force is to:

1. Examine electricity infrastructure needs for reliability, capacity, and storage to meet climate change goals.
2. Examine connections to other essential services such as telecommunications.
3. Review the Nova Scotia Utility and Review Board Act in terms of electricity generation, transmission and rates. and,
4. Engage subject matter experts, the Mi'kmaq and other interested Nova Scotians.

The Clean Electricity Solutions Task Force requested Stantec to perform a peer review and validation of key present and future electrical grid transmission capacity findings, by reviewing reports and studies with a view to achieving Nova Scotia's 2030 Action Plan for Energy Security and Energy Independence.

2 Scope of Work

The scope of work for this project is as follows:

1. Reviewing the Integrated Resource Plans (starting with 2020 IRP to 2023 Evergreen IRP) to understand the province's objectives regarding energy transition and renewables development that will drive the need for future transmission developments in the province.
2. Performing a review of the long-term load forecast and the generation resource adequacy to assess the sufficiency of the IRP to meet the needs of the province.
3. Reviewing the summary incremental capacity assumptions.
4. Reviewing the E3 RESOLVE and PSS®E models, input to the models, sensitivity runs and a comparison of both models in terms of modelling alignment and robustness. The E3 RESOLVE model was used as a preliminary screening tool which reduced the amount of candidate resources within PLEXOS. As such, the E3 RESOLVE model was not reviewed in detail.
5. Reviewing the models developed and reports previously prepared by Synapse for NS Power and the Department of Clean Electricity for the Province of Nova Scotia.
6. Considering Nova Scotia Power's long term load forecast and IRP in identifying whether the E3 models and assumptions reflect and follow the incremental load growth and resource adequacy as mentioned in the long-term load forecast and the IRP.

7. Reviewing and validating the E3 study report that was prepared in 2021 and updated in 2022. The report focuses on transmission requirements needed to support the objectives of Nova Scotia Power Inc. (NSPI)'s Integrated Resource Plan, including modelling, underlying assumptions, and sensitivity runs. The review is to focus on the technical findings and recommendations made to ensure that the transmission system is capable of supporting the planned integration of renewable energy outlined in the IRP while providing the necessary capacity, reliability, and voltage stability.
8. Reviewing a high-level assessment of interregional interfaces and interdependencies; and,
9. Preparing a report outlining the review and findings (draft and final).

3 Documents Reviewed

The following documents were reviewed in this project:

1. NS Power 2020 IRP Report – November 27, 2020
2. IRP Action Plan Update – April 2022
3. IRP Action Plan Update – February 2023
4. 2023 Evergreen IRP
5. 2023 10-Year System Outlook
6. MHI Report
7. The PLEXOS input/output spreadsheet, modeling results
8. Final portfolio study – PLEXOS
9. Nova Scotia Power's latest long term transmission plan
10. Generation Adequacy Report
11. RESOLVE results and PSS®E models/results
12. E3 Supply Option study
13. Synapse Energy Economics Inc. – Generation utilization and optimization report
14. E3 Planning Reserve Margin and Capacity Value Study
15. 2021 Comprehensive Area Transmission Review for the NSPI portion of the Maritime Area
16. 2021 TPL-001-4 Assessment for the NSPI portion of the Maritime Area
17. TSR411 Atlantic Loop transmission study
18. Final Pre-IRP Report – updated November 01, 2019

19. Power Advisory Ancillary Service Report, Nova Scotia Ancillary Service Provision by Variable Output Renewable Energy Resources – August 20, 2020
20. Power Advisory Grid Code Review Report, Review of NSPI Transmission System Interconnection Requirements, April 30, 2021
21. Nova Scotia System 2024/2025 Winter Peak PSS®E Case

4 Documents Summary

4.1 2020 Integrated Resource Plan (IRP)

Nova Scotia Power is committed to support provincial decarbonization and providing a clean, reliable energy system while focusing on customer affordability – for both the near and long term. 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 following an intensive, collaborative project. It set out both an Action Plan and a Roadmap to advance the findings of the IRP.

4.1.1 IRP OBJECTIVES

The objective of the Nova Scotia Power IRP process is to undertake long-term system planning to understand how the electricity system will continue to meet the needs of customers and respond to changes in the electricity planning landscape. The IRP is based on three primary objectives:

1. To develop a robust, risk-weighted, lowest-cost long-term electricity strategy to deliver energy in a safe and reliable manner. The strategy would continue provincial decarbonization using non-emitting resources and keeping affordability for the customers.
2. To develop an Action Plan and Roadmap outlining the key tasks to be undertaken to implement the strategy in the next five years. The Action Plan and Roadmap would be dynamic to be aligned with future changes. They would include signposts to monitor and decision gates to be addressed to enable changes in the strategy as the external policy, technology, and market landscape changes.
3. To develop a collaborative, transparent, and evergreen electric utility resource planning process reflecting industry best practices and promoting understanding and consensus among all stakeholders.

4.1.2 IRP SCENARIOS

The IRP considered number of factors in its process and initial and final scenarios were prepared from the combination of these factors. The factors considered in the IRP process were:

1. Decarbonization: GHG emissions and coal retirements

2. Load Forecast: The load forecast included Base Load Forecast, Electrification, Demand Side Management (DSM), and Distributed Energy Resources (DER).

3. Resource Strategy: The IRP considered three resource strategies including current landscape, distributed resources, as well as regional integration.

Table 1 shows the key modeling scenarios considered in the IRP.

Table 1: Key Modeling Scenarios

Scenario	Decarbonization Driver	Load Driver	Resource Strategy
1.0 Comparator	• Comparator GHG Trajectory • Coal retires by 2040	• Low Electrification • Base DSM	A. Current Landscape C. Regional Integration
• 2.0 Net-Zero 2050 • Low Electrification	• Net-Zero 2050 Trajectory • Coal retires by 2040	• Low Electrification • Base DSM	A. Current Landscape C. Regional Integration
• 2.1 Net-Zero 2050 • Mid Electrification	• Net-Zero 2050 Trajectory • Coal retires by 2040	• Mid Electrification • Base DSM	A. Current Landscape B. Distributed Resources C. Regional Integration
• 2.2 Net-Zero 2050 • High Electrification	• Net-Zero 2050 Trajectory • Coal retires by 2040	• High Electrification • Max DSM	A. Current Landscape C. Regional Integration
• 3.1 Accel. Net-Zero 2045 • Mid Electrification	• Accelerated Net-Zero 2045 Trajectory • Coal retires by 2030	• Mid Electrification • Base DSM	B. Distributed Resources C. Regional Integration
• 3.2 Accel. Net-Zero 2045 • High Electrification	• Accelerated Net-Zero 2045 Trajectory • Coal retires by 2030	• High Electrification • Max DSM	B. Distributed Resources C. Regional Integration

Nova Scotia Power considered and performed a number of sensitivity scenarios in addition to the key scenarios to find the impact of specific inputs to an optimal portfolio developed during the PLEXOS simulation process.

Nova Scotia Power used the PLEXOS capacity expansion simulation software for developing the optimal resource portfolio based on the scenarios considered. It also used RESOLVE software as the screening tool prior to running the complex PELXOS model.

4.1.3 IRP PREFERRED SCENARIO

The PLEXOS output was used in selecting the optimal scenario suitable for Nova Scotia. The following factors were considered in the selection process:

- Resource Additions and Retirements
- Energy Mix
- Greenhouse Gas Emissions
- Resource Plan Cost
- Relative Rate Impacts
- Reliability
- Operability
- Sensitivity Analysis

The IRP Final Portfolio Study found the scenario 2.0C which represents Low Electrification, Base DSM, Net Zero by 2050 and Regional Integration to be the least cost solution. The scenario is Nova Scotia Sustainable Development Goals Act (SDGA) compliant and has the lowest 25-year Net Present Value of Revenue Requirement (NPVRR).

4.1.4 IRP KEY FINDINGS

The IRP summarizes its findings based on common themes and insights from the modeling results and observations obtained from the scenarios studied. The 2020 IRP key findings are as follows:

1. Steeply reducing carbon emissions in line with Nova Scotia's Sustainable Development Goals Act will require significant efforts from each sector of the economy, with the electricity sector playing a major role.

    a. Key pillars of economy-wide decarbonization include greater reliance on non-emitting electricity supplies, focused demand side management, and electrification of end uses currently reliant on fossil fuels.

    b. Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors. The IRP rate analysis demonstrates the importance of managing the relative growth of peak and energy requirements, highlighting the need to pursue beneficial electrification.

    c. Nova Scotia Power's direct carbon emissions are reduced to between 0.5 MT and 1.4 MT per year by 2045 in all resource plans, representing an 87-95% reduction from 2005 levels. Earlier emissions reductions are possible at incremental cost relative to the lowest cost plans.

2. Decarbonizing Nova Scotia Power's electricity supply will require investment in a diverse portfolio of non- and low-emitting resources.

    a. Regional Integration (i.e., investment in stronger interconnections to other jurisdictions) is an economic component of the lowest-cost plans under each load scenario. Both the Reliability Tie, which strengthens the connection to the North American electrical grid, and a Regional Interconnection, which enables access to firm capacity and energy imports, are shown to have value.

    b. Wind is the lowest cost domestic source of renewable energy and is selected preferentially over solar in all resource plans. Incremental wind capacity in the range of 500 - 800 MW is selected by the model by 2045, with major installations paired with coal retirement dates to provide replacement emissions-free energy. The availability of lower priced wind is shown to accelerate the wind buildout in the mid-2020s, with up to 600 MW selected under the modeled low wind price, mid-electrification sensitivity.

        To enable wind additions beyond what was studied in the pre-IRP analysis (more than 100 MW incremental with the current system, or more than 400 MW incremental with identified wind integration investments), additional system stability studies are required.

    c. Coal units are generally sustained economically until their model-imposed retirement date, with capacity factors falling in line with declining emissions caps. Many resource plans incorporate economic retirement of one coal unit in the near term, as early as 2023, and some plans see economic retirement of a second coal-fired unit in 2030. New firm capacity is required to offset retiring coal units, to lower carbon emission intensity, and to meet growing electricity demand in all scenarios.

    d. Nova Scotia Power's existing domestic Hydro resources provide economic benefit to customers and are economically sustained through the planning horizon with the modeled level of sustaining capital investment. Economic justification as part of a capital application will be required to confirm decision to pursue Mersey Hydro redevelopment, following the completion of the IRP.

    e. DSM energy efficiency programs and costs in the range of the "Base" profile, per the EfficiencyOne 2019 Potential Study, are shown to be most economic relative to other options evaluated under the primary IRP metric of 25-year NPV of Revenue Requirement (with end effects). A focus on peak demand mitigation is indicated and could be optimized into future DSM planning. Other levels of DSM in resource plan sensitivities show higher NPVRR with end effects, as well as mixed effects on other metrics, when compared to Base DSM; Low DSM levels are shown to reduce relative rate impact, while Mid DSM levels are shown to reduce new capacity requirements and GHG emissions, both at a higher NPVRR. Due to the discrete nature of the DSM profiles modeled in the IRP future DSM program development should incorporate the learnings obtained from the full range of sensitivities and metrics considered in the IRP.

3. Firm capacity resources will be a key requirement of the developing Nova Scotia Power system in both the near and long term.

    a. New combustion turbines, operating at low capacity factors, are currently the lowest-cost domestic source of firm capacity and replace retiring thermal capacity in all resource plans. These units are also fast-acting, meaning they can quickly respond to changes in wind and non-firm imported energy. 50-150 MW is required by 2025, while 600-1000 MW of new capacity is required by 2045 to support retirement of steam units.

    b. Nova Scotia Power's existing combustion turbine resources provide economic benefit to customers and are economically sustained through the planning horizon with the modeled levels of sustaining capital investment.

    c. Low-cost, low emitting generating capacity may be provided economically from coal-to-gas unit conversions, which are selected economically in many resource plans.

    d. Battery storage can enable wind integration while providing firm capacity and energy storage; however, its ability to substitute for firm capacity resources is limited by its relatively short duration. Up to 120 MW of storage by 2045 is selected in the portfolios with deployments of 30-60 MW by 2025 in many plans.

    e. The aggregated Demand Response programs modeled in the IRP have economic value to the Nova Scotia system, offsetting firm generation capacity requirements. A DR program with a target final nameplate capacity of approximately 75 MW is shown to have value across all resource plans under IRP cost assumptions, while higher DR capacity is shown to be economic under high electrification scenarios.

    f. A Planning Reserve Margin of 9% (on a UCAP basis, consistent with 20% on an ICAP basis for the current resource mix) is found to maintain supply reliability across the studied range of resource plans and electrification scenarios.

4. The SDGA-compliant key scenario which minimizes the cumulative present value of the annual revenue requirement of the 25-year planning horizon (adjusted for end effects) is 2.0C (Low Electrification / Base DSM / Net-Zero 2050 / Regional Integration).

    a. During the Action Plan 5-year horizon, resource plans 2.0C and 2.1C (among others) include many common resource investments and retirement trajectories. This commonality informs Nova Scotia Power's IRP Action Plan and ensures the resulting long-term electricity strategy is robust to a broad range of potential futures.

    b. Similar resource plans are selected when considering both 2030 and 2040 coal unit retirement dates. The earlier retirement scenarios are less economic on an NPV basis but have similar cumulative rate implications by 2045.

4.1.5 IRP ACTION PLAN

The IRP Action Plan is prepared based on common themes and findings from the scenarios studied. The "no-regrets" approach was taken in preparing the action plan. As such, it contains the observations and insights obtained across the scenarios considered in the 2020 IRP. The IRP action plans are outlined in Table 2.

Table 2: IRP Action Items

Area	Action Items
Regional Integration Strategy	A. Identifying opportunities for near-term firm imports over existing transmission infrastructure B. Immediately commencing the development of a Reliability Tie and Regional Interconnection[1] via an appropriate regulatory process with target in-service dates as follows: • Reliability Tie: 2025-2029 (or earlier if practical and feasible) • Regional Interconnection: 2027-2035 C. Conducting detailed engineering and economic studies for firm import options requiring new transmission investment and strengthened regional interconnections, including evaluations of availability and security of supply, emissions intensity, and dispatch flexibility.
Electrification	A. Initiate an Electrification Strategy to develop options for encouraging beneficial electrification with the goals of maintaining rate stability, the strategy would include: • Incorporate industry best practices such as those identified by the Regulatory Assistance Project as well as other relevant work, for example, electrification programs in other jurisdictions and the details already contained in the Deep Decarbonization Pathways report. • Develop and propose pilots and/or programs that focus initially on transportation and building electrification as identified in the Deep Decarbonization Pathways report as key sectors for early electrification adoption.

[1] The Reliability Tie comprises of a new 345 kV AC line between Onslow, Nova Scotia and Salisbury, New Brunswick.
In addition to the available Reliability Tie, the Regional Interconnection scenarios add two additional candidate transmission expansion options: 1) an HVDC line connecting Salisbury, New Brunswick to Quebec, and 2) a 345 kV AC line from Salisbury, New Brunswick to Coleson Cove, New Brunswick, which would provide access to the ISO New England power markets.

	B. Initiate a program to collect detailed data, including data on the quantity, flexibility and hourly load shape of incremental electrification demand, to assist with further system planning work. C. Address electrification impacts on the Transmission & Distribution system as additional experience and data become available. This will include an analysis of available and projected T&D capacity at varying levels of electrification as well as identification of potential mitigation options and cost estimates.
Thermal Plant Retirement, Redevelopment, and Replacement	A. Develop a plan for the retirement and replacement of Trenton 5, targeting 2023, while identifying required replacement capacity and energy in parallel. Begin decommissioning studies for NS Power's other coal assets and develop and execute a coal retirement plan including associated regulatory approval process. B. Complete a thermal plant Depreciation Study to update depreciation rates and a recovery strategy to better align depreciation with updated useful lives for generation assets. Invest sustaining capital into individual thermal units appropriate to their retirement categorization. C. Develop a plan for the redevelopment or replacement of existing natural gas-powered steam turbines to provide low-cost, fast-acting generating capacity to the Nova Scotia system. Fuel flexibility is a component of this work, including consideration for low/zero carbon alternative fuels. D. Initiate a wind procurement strategy, targeting 50-100 MW new installed capacity by 2025 and up to 350 MW by 2030. This strategy will solicit Nova Scotia-based market pricing information which will inform the selected wind capacity profile and timing, informed by the IRP wind sensitivities. E. Complete system stability studies to determine whether additional dynamic system inertia constraints, operating limits, and/or provision of alternate services like Fast Frequency Response (FFR), are required to enable higher levels of wind integration on the Nova Scotia system, particularly in advance of the commissioning of integration measures such as the Reliability Tie.
Demand Response	A. Create a Demand Response Strategy targeting 75 MW of capacity, for deployment by 2025. • The strategy will be closely linked to the Electrification Strategy being developed in parallel. The strategy will build on learnings from NS Power's Smart Grid Project, NS Power's Time Varying Pricing application, the DR Joint Working Group between NS Power and EfficiencyOne, the ELIADC tariff, and the Large Industrial Interruptible Rider.

Demand Side Management	A. NS Power will calculate Avoided Costs of DSM (capacity and energy) for scenarios 2.0C and 2.1C. 2.0C will be used as the Reference Plan and 2.1C will be available for additional reference.

4.1.6 IRP ROADMAP

The future changes in the planning environment may require changes in the IRP strategy. The IRP Roadmap would identify signposts to monitor and decision gates to be addressed for enabling the appropriate triggering of changes to the Strategy. The roadmap items would help identifying what and when the portions of the Strategy require refinement or revaluation. Nova Scotia Power developed the following Roadmap to:

1. Advance engineering study work on coal to gas conversions at Trenton and Point Tupper Generating Stations.

   Monitor cost outputs of this work relative to IRP assumptions and update the balance of new and converted capacity resources accordingly.

2. Complete detailed system stability studies under various current and future system conditions, reflective of both stressed system states and normal operating conditions, while considering higher quantities of installed wind capacity as seen in the IRP modeling results.

   Monitor results for significant divergence from wind integration assumptions modeled in the IRP and trigger an update as needed.

3. Pursue economic reinvestment in existing hydro and combustion turbines with individual capital applications as applicable; economic justification as part of a capital application will be required to confirm decision to pursue Mersey Hydro redevelopment. Continue sustaining capital investment in thermal units, aligned with their projected retirement classification.

   Monitor required levels of sustaining capital investment for significant changes from IRP assumptions and, if observed, trigger a unit-specific analysis of alternatives. Monitor unit reliability for significant changes from IRP assumptions.

4. Monitor the development of low/zero carbon fuels that could replace natural gas in powering generating units to provide firm, in-province capacity.

5. Continue to track the installed costs of wind, solar, and energy storage to look for variations from the trajectories established in the IRP (in particular, monitoring for divergence from the “Base” to the “Low” pricing scenarios as defined in the IRP Assumptions).

6. Track the ongoing development of the Nova Scotia Cap-and-Trade Program, including auction results and developing regulations. In particular, monitor GHG market size for indications that value from incremental allowance sales (beyond the projected economic emissions reductions shown in the IRP results) can be incorporated into long-term resource planning decisions with greater certainty. Significant changes in the value of incremental GHG reductions could influence

resource plan components including non-emitting generation procurement, DSM levels, and coal retirement trajectories.

7. Monitor electrification growth in Nova Scotia to understand at what point the provincial load profile starts to move from Low, to Mid, to High levels of electrification as defined in the IRP Assumptions for firm peak and/or annual energy requirements.
8. Continuously refine the Action Plan and Roadmap items via an evergreen IRP process. This process should facilitate annual updates as conditions change and technology or market options develop, and as Action Plan items are completed or significantly advanced. NS Power will include a summary of updates as part of IRP Action Plan reporting and will incorporate the opportunity for stakeholder comment and feedback as part of the update process.

4.2 2023 Evergreen IRP

The 2020 IRP identified action plan and roadmap items that are intended to advance NS Power's long-term electricity strategy. As a part of the roadmap, NS Power proposed an evergreen IRP process incorporating an update on the IRP Action Plan items. The evergreen IRP analysis focused on areas of significant change in the planning environment to understand the outcome of these impacts on the electricity strategy. The assumptions which are not materially changed since 2020 IRP, or which are not anticipated to significantly impact the modeling outcomes, were not updated to ensure an efficient evergreen process.

The evergreen IRP process included updates to the assumptions and new modeling scenarios to reflect significant changes since the 2020 IRP and corresponding modeling work to support the assessment of these changes. The 24 scenarios assessed as part of the evergreen IRP capture a broad range of potential planning environment outcomes and are outlined in Table 3.

Table 3: Evergreen IRP Modeling Scenarios

Scenario	Clean Energy Policy	Electrification	Resource Strategy	Sensitivities
CE1-E1-R1	NZ2035	Current Policy and Trends	Atlantic Loop	
CE1-E1-R1-DH				Domestic Hydrogen
CE1-E1-R1-LFPP				Fuel and PP - Low
CE1-E1-R1-HFPP				Fuel and PP - High
CE1-E1-R1-MMDSM				Modified Mid DSM
CE1-E1-R1-BPDSM				Base+ DSM
CE1-E1-R1-HDER				High Distributed Energy Resources
CE1-E1-R1-AAT				Adjusted Atlantic Loop Timing

Scenario	Clean Energy Policy	Electrification	Resource Strategy	Sensitivities
CE1-E1-R1-WI				Wind Integration Constraints Removed
CE1-E1-R1-DACC				Direct Air Carbon Capture – 2035+
CE1-E1-R1-BD				Bidirectional Transaction – Atlantic Loop
CE1-E1-R2	NZ2035	Current Policy and Trends	No Atlantic Loop	
CE1-E1-R2-DACC				Direct Air Carbon Capture – 2035+
CE1-E1-R2-DH				Domestic Hydrogen
CE1-E1-R2-MMDSM				Modified Mid DSM
CE1-E1-R2-HDER				High Distributed Energy Resources
CE1-E2-R2	NZ2035	Hybrid Peak Mitigation	No Atlantic Loop	
CE1-E2-R2-HB/HR				
CE1-E2-R2-MMDSM				
CE1-E3-R1	NZ2035	Accelerated Electrification	Atlantic Loop	
CE1-E3-R2			No Atlantic Loop	
CE2-E1-R1	NZ2050	Current Policy and Trends	Atlantic Loop	
CE2-E1-R2	NZ2050	Current Policy and Trends	No Atlantic Loop	
CE2-E1-R2-DH				Domestic Hydrogen

**The scenarios in red reflect additional scenarios included in the final modeling results.*

The scenarios are defined by the range of net zero targets (2035, 2050), electrification pace and trajectory, the resource strategy (with the Atlantic Loop, without the Atlantic Loop) and additional sensitivities to assess future unknowns.

The key drivers for 2023 Evergreen IRP Modeling scenarios are follows:

1. Carbon policy
    a. Net Zero 2035
    b. Net Zero 2050
2. Electrification
    a. Current Policy and Trends E1
    b. Hybrid Peak Mitigation
    c. Accelerated Electrification
3. Resource Strategy
    a. Atlantic Loop
    b. No Atlantic Loop

4. Sensitivities
    a. Domestic Hydrogen Production
    b. High Distributed Energy Resources
    c. Direct Air Carbon Capture
    d. Modified Mid DSM
    e. Base+ DSM
    f. Low Fuel and Power Prices
    g. High Fuel and Power Prices
    h. High-Cost Battery Storage/Renewables
    i. Bi-Directional Transaction – Atlantic Loop
    j. Adjusted Available Timing – Atlantic Loop
    k. Wind Integration Constraint Relaxation

Table 4 shows the key scenario differences between 2020 IRP and 2023 Evergreen IRP. Sensitivity scenarios are not mentioned in this table.

Table 4: Key Scenario Differences Between 2020 IRP and 2023 Evergreen IRP

Scenario	2020 IRP	2023 Evergreen IRP
Planning Horizon	2021 – 2045	2025 – 2050
Decarbonization Driver/Carbon Policy	• Net Zero – Years 2045 and 2050 • Coal retirements by 2030 and 2040	• Net Zero – Years 2035 and 2050 • Coal retirements by 2030
Electrification	• Net Zero 2050 Low, Mid, High Electrification • Net Zero 2045 Mid, High Electrification	• Current Policy and Trends • Hybrid Peak Mitigation • Accelerated Electrification
Resource Strategy	• Current Landscape • Distributed Resources • Regional Integration	• Atlantic Loop (with and without) • Regional Integration

4.2.1 2023 EVERGREEN IRP KEY FINDINGS

The 2023 IRP reported the following key findings based on the study outcomes:

1. Variable renewable capacity additions are required to meet the 2030 target. Up to 1500 MW of additional wind capacity is required on the system in addition to the current 600 MW.
2. The addition of 200 MW of solar capacity is consistent among all scenarios by 2030 and requires further assessment as a near term renewable resource option.
3. The Reliability Tie was added in all scenarios including the No Atlantic Loop scenarios, indicating this resource demonstrates value to the system with or without the Atlantic Loop.
4. The addition of firm capacity in the form of new fast acting generation is observed in all scenarios; most scenarios add at least 150 MW and up to 900 MW by 2030. This resource is critical to meet the peak capacity and dispatch around renewable generation availability. New fast acting capacity is required in all scenarios. The ultimate capacity requirement depends on firm peak growth rate, presence of the Atlantic Loop, and availability of Demand Response programs such as those evaluated in the hybrid peak scenario.
5. Battery storage is added in all scenarios; at least 100 MW is added by 2030 in all of the No Atlantic Loop scenarios. Battery storage addition begins as soon as 2025 in many scenarios.
6. The Atlantic Loop shows lower system costs and overall emissions than without Atlantic Loop scenario. This is considering a bi-directional flow, the development of local wind capacity in Nova Scotia, and enabling import and export transactions.
7. Synchronous condensers will be an important aspect of the system in the future to enable inverter-based resource integration.
8. The hybrid peak scenario demonstrates overall system value through the reduction in system peak requirements. This points to an area of focus as part of the electrification strategy.
9. SMRs are added at the later planning stage for all No Atlantic Loop scenarios. This demonstrates the value of emerging technologies capable of providing firm, dispatchable, and non-emitting generation. It could play as the system requirements, the environmental policies, and the commercial availability of developing technologies beyond 2030.

4.2.2 2023 EVERGREEN IRP ACTION PLAN

The Action Plans updated from 2020 IRP mentioned in 2023 Evergreen IRP are outlined in Table 5.

Table 5: 2023 Evergreen IRP Action Items

Area	Action Items
Regional Integration Strategy	A. Reliability Tie: Continue to develop the Reliability Tie via an appropriate regulatory process with target in-service date of 2028. B. Regional Interconnection: Continue working with neighboring jurisdictions in support of the Atlantic Loop and other opportunities for regional integration, conducting detailed engineering and economic studies for firm import options requiring new transmission investment and strengthened regional interconnections.
Electrification	A. Electrification Strategy: Publish Electrification Strategy report, developed as part of the IRP Action Plan, in 2023 with opportunity for stakeholder review and comment. B. Data Collection: Continue to collect detailed data, including data on the quantity, flexibility and hourly load shape of incremental electrification demand, to assist with further system planning work. C. Electrification Impacts – Transmission and Distribution (T&D) System: Address electrification impacts on the T&D system as additional experience and data become available. This will include an analysis of available and projected T&D capacity at varying levels of electrification as well as identification of potential mitigation options and cost estimates.
Thermal Plant Retirement, Redevelopment, and Replacement	A. Thermal Plant Retirement: Proceed with Trenton 5 retirement plan based on the updated evergreen IRP projections (2027/2028). NS Power will manage operating restrictions of the thermal fleet to meet firm capacity requirements are met but minimize utilization to reduce sustaining capital investment. Continue to develop coal retirement plan for remaining units including consideration of cold reserve operating modes to enable the integration of new resources and reduced utilization over time. B. Thermal Plant Depreciation Study: As per the General Rate Application Settlement Plan Nova Scotia Utility and Review Board (NSUARB) decision, NS Power will conduct a depreciation study and file prior to the next General Rate Application. C. Fast Acting Generating Capacity: Initiate development of new fast-acting generating capacity resources to address growing demand, balance variable renewable generation, and maintain the reliability of the Nova Scotia system. Scope will include the addition of fast acting generation of approximately 300 MW by 2027 and an additional 300 – 600 MW by 2030. Fuel flexibility is a component of this work, including consideration for low/zero carbon alternative fuels such as

Area	Action Items
	hydrogen. Existing combustion turbines will continue to be sustained through the planning horizon. D. Procurement Strategy for Variable Renewable Resources: Develop a procurement plan for incremental variable renewable resources, targeting approximately 1000 MW by 2030. Anticipated renewable procurements and programs, such as the Green Choice Program, Community Solar Program, and Renewable to Retail, will contribute to meeting the total system requirement for variable renewable resources. A series of regular procurements, balancing resource additions and the associated requirements for engineering, construction, and commissioning resources to 2030, is preferred. Complete additional study work to identify opportunities to reduce curtailment of variable renewable generation on the system. E. Thermal Plant Conversions and Fuel Transitions: Progress plans for the following thermal plant conversion and fuel transition projects; these projects will support system capacity requirements with limited energy output. • Complete coal to gas conversion on 1 thermal unit by 2028. • Progress coal to heavy fuel oil (HFO) transition for 3 thermal units, targeting 2029. F. Battery Storage Capacity: Develop 4-hour battery storage additions to the system targeting at least 100 MW in-service by 2030, with battery storage additions beginning by 2025. Continue to explore the potential benefits of additional energy storage quantities beyond this target as part of the transition to 2030. G. Synchronous Condensers: Complete generator site-specific system impact studies for new variable renewable generation to assess the need for synchronous condenser support. Progress the development of 100 – 200 MVA of synchronous condensers by 2030 to support system reliability and strength with the increase in variable renewable generation on the system.
Demand Response	A. Pilot Programming Continue to progress the Demand Response Strategy via the existing pilot programming, targeting the expansion of the programming to 75 MW of nameplate capacity, for deployment by 2025. B. Hybrid Peak Electrification Scenario: Further assess the value of the hybrid peak building electrification scenario based on the outcomes of the evergreen IRP. This will include development of program cost estimates and validation of savings potential. Where possible, NS Power will incorporate learnings from other North American utilities that have implemented similar programs.

Area	Action Items
Avoided Costs of DSM	A. NS Power will update avoided costs of DSM based on the evergreen IRP in collaboration with the DSMAG, targeting completion before the end of 2023.

4.2.3 2023 EVERGREEN IRP ROADMAP

The roadmap of the Evergreen IRP is provided below. NS Power will monitor the roadmap items in parallel with execution of the Action Plan:

1. Publish the results of the ongoing wind integration studies in 2023. Provide guidance on integration asset requirements in alignment with the planned addition of renewables. Continue to monitor results for significant divergence from wind integration assumptions modeled in the evergreen IRP and trigger an update as needed.
2. Pursue economic reinvestment in existing hydro and combustion turbines with individual capital applications as required; An economic justification will be required to confirm a decision to pursue Mersey hydro redevelopment as part of a capital application. Continue sustaining capital investment in thermal units, aligned with their projected utilization and retirement date.

   Monitor required levels of sustaining capital investment for significant changes from IRP assumptions and, if observed, trigger a unit-specific analysis of alternatives. Monitor unit reliability for significant changes from IRP assumptions and, if observed, trigger an Effective Load Carrying Capability (ELCC) calculation and/or Planning Reserve Margin (PRM) study.
3. Continue to monitor the development of low/zero carbon fuels which could replace the natural gas in powering generation units to provide firm, in-province capacity. Specifically, NS Power will monitor the price and availability of domestic hydrogen fuel as the hydrogen production industry develops in Nova Scotia.
4. Continue to track the installed costs of wind, solar, and energy storage to look for significant variations from the trajectories analyzed in the evergreen IRP. If observed, update capacity mix as required.
5. Track the ongoing development of the Federal Clean Electricity Regulations (CER). Monitor the changes to carbon pricing policy or limitations on the use of gas and oil-fired generating facilities beyond those already considered in the evergreen IRP.
6. Continue to monitor electrification and load growth in Nova Scotia relative to the 2022 and 2023 Load Forecast reports which incorporate electrification impacts. Also, monitor for the addition of large industrial customers which may impact the identified resource requirements.
7. Refine the Action Plan and Roadmap items via an evergreen IRP process. This process should facilitate annual updates as conditions and technology change or the market options develop, and as Action Plan items are completed or significantly advanced. NS Power will include a summary

of updates as part of IRP Action Plan reporting and will incorporate the opportunity for stakeholder comment and feedback as part of the update process.

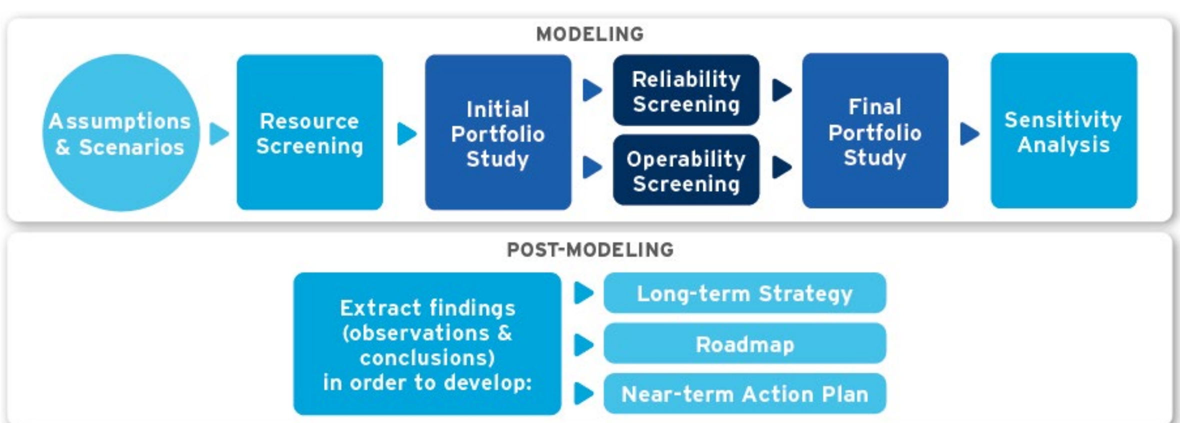
8. Monitor developments in technology/enabling policy for emerging resources, including but not limited to, SMRs, geothermal, hydrogen combustion turbines, and long duration storage. Significant changes in cost or availability from IRP assumptions may trigger a specific analysis as needed.
9. Support the provincial plan for Offshore Wind as appropriate, monitor technology, cost, and policy development.
10. Continue to monitor opportunities for near-term firm imports over the existing transmission infrastructure.
11. Monitor the development of the hydrogen industry in Nova Scotia, including tariff structures specific to hydrogen development. Assess the impacts as they relate to the future modeling assumptions.

4.3 PLEXOS

Nova Scotia Power utilized the PLEXOS capacity expansion and production simulation modeling software in developing the optimal resource portfolios during the Portfolio Study phases of the IRP. PLEXOS is a leading capacity expansion and production cost modeling software package that uses mathematical optimization to provide simulation capabilities for the electric power system.

In the initial portfolio study phase, Nova Scotia Power conducted capacity expansion optimization modeling with PLEXOS LT (supplemented with E3's RESOLVE model where required), which resulted in an economically optimized resource portfolio for each scenario (i.e., the resource plan with the lowest 25-year NPV revenue requirement for that scenario's set of assumptions). Figure 1 shows the flowchart of the 2020 IRP modeling in which PLEXOS was used for the Initial Portfolio Study and Final Portfolio study.

Figure 1 2020 IRP Modeling Process[2]



[2] Figure 14 of 2020 IRP

The modelling phase was started with Assumptions & Scenarios. The Assumptions & Scenarios were created with establishing a comprehensive set of analysis assumptions, reflecting publicly available, documented and/or independent vetted source where possible.

The Resource Screening phase refines candidate resources to be available to model in each scenario. It is a combination of qualitative evaluation with PLEXOS and/or quantitative modeling using E3's RESOLVE model. This phase ensures reasonable model execution time and focuses computational resources on more critical decisions.

Initial Portfolio study was performed using PLEXOS. This portfolio study relied predominantly on capacity expansion optimization modeling using PLEXOS LT, with supporting analysis utilizing PLEXOS MT/ST and E3's RESOLVE model.

After the Initial Portfolio Study, two additional modelling phases, namely, Reliability Screening and Operability Screening were performed. Reliability Screening involved a robust assessment of the reliability of key scenarios in 2045, including estimating the achieved loss-of-load over thousands of simulated years of weather and resource output using E3's loss of load probability model, RECAP. For Operability Screening, Nova Scotia Power ran key scenarios through PLEXOS MT/ST to evaluate the production costs (e.g., fuel and purchased power) and dispatch at a more granular level.

With the revised capacity expansion optimization modeling with PLEXOS LT from the Reliability Screening and Operability Screening, a Final Portfolio study was conducted using PLEXOS MT/ST. The resulting generation and production cost outputs were incorporated into the IRP analysis to increase the granularity of the final runs.

The PLEXOS LT Model was used for capacity expansion optimization while the PLEXOS MT/ST module was used for production cost modeling (as a component of NPV) and energy balance reporting for each PLEXOS LT produced scenario.

After completion of the portfolio studies and operability and reliability screening phases, NS Power worked with stakeholders to prioritize the sensitivities and identified applicable portfolios. The following are the potential sensitivities evaluated:

1. Increase in Renewable Energy Standard policy
2. Low capital cost of wind
3. Low capital cost of storage
4. Low/High pricing of import energy
5. Low/High pricing of natural gas
6. High Pricing of Biomass
7. High Sustaining Capital Costs
8. Loss of Large Industrial Load
9. Mersey Hydro System retired

10. No New Emitting Resources
11. Fuel security sensitivities
12. Resiliency testing

Some of these sensitivities required the capacity expansion optimization to be rerun (e.g., DSM, Sustaining Capital), while others are run on the resource plan without reoptimizing (e.g., Fuel Prices).

4.4 2021 Transmission Planning (TPL)

The 2021 TPL-001-4 Planning Assessment for 2022 – 2031 was performed in conjunction with the 2021 Comprehensive Area Transmission Review for the Maritimes Area, with this report fulfilling the requirements of TPL-001-4. The analysis and results documented in the 077-2021-TPL R1 report demonstrate that NSPI is in compliance with TPL-001-4: Transmission System Planning Performance Requirements for the years 2022 – 2031.

However, the 2021 TPL-001-4 does not contain the required transmission upgrades and generation additions and retirements to meet the new NS Renewable Electricity Standard of 80% by 2030 and Federal requirements to phase out coal generation by 2030. The studies required to meet these objectives are not yet complete. As such, these requirements are not included in this TPL. The network upgrades and facilities associated with these studies will be included in subsequent TPL assessments as projects receive regulatory approval or move to the Combined T&D Advanced Stage Interconnection Request Queue.

4.5 TSR411 System Impact Study Report

Stantec also reviewed the TSR411 System Impact Study (SIS) report for the 550 MW Long-Term Firm Point-to-Point Transmission Service from NB to NS, commencing on January 1, 2025.

The TSR 411 was originally applied for 800 MW firm from NB to NS. However, the Transmission Customer modified the request for 550 MW firm from NB to NS. As such, this SIS report is for NS with 1,150 MW flow from QC to NB via the new HVDC transmission line and 550 MW flow from NB to NS via existing and new AC lines. The TSR is expected to be in service in 2025 and a system study is currently underway to determine the associated upgrades to the Nova Scotia transmission system. These upgrades are expected to materially alter the configuration of the transmission system in Nova Scotia.

4.6 2021 Comprehensive Area Transmission Review (CATR)

The CATR is performed based on IRP and Transmission Plan directives. The 2021 Comprehensive Area Transmission Review report was created for the NSPI portion of the Maritime Area for the study year of 2026.

Since the 2016 CATR, NSPI has added 16 MW (net) of generation to its transmission and distribution system. Transmission projects from 2022 to 2026 include an additional 95 MW of transmission connected generation. The 500 MW DC Maritime Link (ML) between Nova Scotia and Newfoundland was placed in service on January 15, 2018, and delivery of the NS Block of capacity and energy began on August 15, 2021. Full utilization of ML is in-service with a capacity of 475 MW import to Nova Scotia.

Only those transmission projects in the advanced stages of the interconnection queue and expected to proceed are included in the review. Based on this interconnection queue, there are no significant changes to the BPS transmission facilities planned for 2022 to 2026.

The analysis, results and planned projects documented in this report demonstrate that, for the 2021 study year, NSPI is in compliance with applicable criteria as described in NPCC Regional Reliability Reference Directory # 1, Design and Operation of the Bulk Power System, September 30, 2015 (Version 4) for an Area Transmission Review.

4.7 2023 10-Year System Outlook

The 2023 10-Year System Outlook is Nova Scotia Power System Operator (NSPSO)'s annual assessment of NSPI's system capacity and adequacy. Table 6 shows the historical and forecasted coincident peak demand.

Table 6: Coincident Peak Demand with Future DSM Program Effects

Year	Interruptible Contribution to Peak (MW)	Demand Response (reduction in Firm Peak only) MW	Firm Contribution to Peak (MW)	Net System Peak (MW)	Growth (%)
2013	136	-	1,897	2,033	8
2014	83	-	2,036	2,118	4.2
2015	141	-	1,874	2,015	-4.9
2016	98	-	2,013	2,111	4.8
2017	67	-	1,951	2,018	-4.4
2018	80	-	1,993	2,073	2.7
2019	111	-	1,949	2,060	-0.6
2020	96	-	1,954	2,050	-0.5
2021	94	-	1,875	1,968	-4
2022	155	4	2,061	2,216	12.6
2023*	146	12	2,105	2,256	1.8
2024*	147	24	2,111	2,271	0.7
2025*	148	36	2,119	2,291	0.9
2026*	156	39	2,148	2,340	2.1
2027*	157	39	2,198	2,395	2.3

Year	Interruptible Contribution to Peak (MW)	Demand Response (reduction in Firm Peak only) MW	Firm Contribution to Peak (MW)	Net System Peak (MW)	Growth (%)
2028*	157	39	2,259	2,454	2.5
2029*	157	38	2,325	2,520	2.7
2030*	156	38	2,395	2,589	2.8
2031*	156	38	2,468	2,662	2.8
2032*	156	38	2,545	2,738	2.9
2033*	156	37	2,627	2,819	3

**Forecast value*

4.8 Nova Scotia System PSS®E Case

The 2024/2025 Winter Peak PSS®E case which was developed from 2018 Series Multiregional Modeling Working Group (MMWG) base case library was reviewed. This PSS®E case was utilized to perform TSR411 System Impact Study. The total demand of the NS PSS®E case was 2,172 MW. Based on the Nova Scotia Utility and Review Board 2023 10-Year System Outlook, the forecasted system peak of Year 2024 is 2,271 MW. The Transmission Plan indicated that it did not include the IRP components as relevant studies are ongoing at the time of the Transmission Plan posting. The provided PSS®E case represents year 2024—2025 which also could not be used for comparison to IRP as it does not include any IRP directions via the Transmission Plan.

4.9 Manitoba Hydro International (MHI) Report

Manitoba Hydro International Ltd. provided initial findings and recommendations to NS Power in the Large-Scale Integration of Inverter Based Resources (IBRs) in Nova Scotia Frequency Control and System Strength Assessment, June 30, 2023 report.

The recommendations MHI provided regarding frequency control and system strength excerpted from the MHI report are presented below:

1. Stable and Reliable Integration
    a. Based on study to date, there are significant concerns for the ability of the existing and future generation fleet to ride through high RoCoF events. It is recommended that network response under high RoCoF contingencies be verified through EMT simulations.
    b. Survey NSPI existing legacy generation plants and DER to have sight of the RoCoF ride through capabilities. If the survey identifies potential for widespread cascade tripping, the existing RoCoF limit of 2.5 Hz/s on a 500ms sample time as a system design metric will require further study to determine the system support needed to reduce the RoCoF to that acceptable to NSPI.

   c. Regularly review and recommend updates to the Transmission System Interconnection Requirements to address concerns identified during system study (RoCoF, models, harmonics, voltage, BESS, Solar, grid forming requirement for IBR). MHI has provided recommendations for additions and revisions to the existing requirements for the next TSIR revision.
   d. Update Distribution System Interconnection Requirements to align with IEEE 1547-2018 Category 3 for RoCoF.
   e. As existing wind PPAs terminate, where feasible, require additional inertia support and other upgrades to meet the current grid code to avoid unnecessary curtailment and to support the addition of IBR facilities.
   f. Perform incremental studies for each wave of load and generation additions, and generation retirements to the NSPI grid.
   g. As synchronous plants are retired, additional grid support for inertia and System Strength is expected to be required. It is recommended that studies be undertaken to determine the optimal locations for the grid support.
2. Resource Planning for High IBR Penetration
   a. Update IBR and inertia constraints for PLEXOS modelling.
   b. FFR is also demonstrated in simulation as a good replacement for at least some traditional inertia to support both RoCoF and frequency damping. Develop a sliding scale for Inertia/FFR and system load as an input to future dispatch scenarios.
   c. Until technology evolves such that all online generation resources provide SCMVA as with a traditional grid, online SCMVA to maintain System Strength at critical buses will be a new metric to input into resource planning.
3. Good Planning Practice
   a. MHI recommends performing an annual assessment of NSPI System Inertia and Strength requirements in the 10-year horizon to identify potential issues.
   b. Document and publish updated model requirements for Load and Generation customers.

      It is recommended that NSPI publish specific model requirements for all load and generation connecting to the NSPI system that will require detailed PSS®E and PSCAD modelling.
      It is recommended that NSPI publish a document outlining the model quality and dynamic response tests performance required as validation for the submitted models.
   c. Perform a system study of the expected load growth and hydro generation availability for western Nova Scotia. For the planned 2030 grid, small hydro plants in the western area of the province must run or some portions of the grid will disconnect and go offline due to low System Strength during some simulated system disturbances. NSPI System Planning should assess whether additional resources are required to address this concern.

4. System Operator Transition to High IBR Grid
    a. Develop a methodology to estimate the minimum SCMVA and SCR online prior to the addition of IBR (WEC, BESS, HVDC etc.) to the NSPI grid for operating guidelines and Outage Coordination.
    b. Develop a methodology to estimate the inertia online to maintain the minimum SCMVA required for a stable grid prior to the addition of additional IBR (WEC, BESS, HVDC etc.) to the NSPI grid.
    c. Review and update all operating guidelines, as required, for the NSPSO in advance of next round of Transmission connected IBR (WEC, BESS, HDVC etc.) wind integration. EMT study will be required.
5. Black Start Restoration Planning
    1. Review and assess potential Blackstart options for the planned 2030 grid, considering the generation mix available at that time.

4.10 Power Advisory Nova Scotia Ancillary Service Provision by Renewable Energy Resources

Power Advisory prepared a document regarding Nova Scotia Ancillary Service Provision by Variable Output Renewable Energy Resources on August 20, 2020, for Offshore Energy Research Association (OERA). Power Advisory performed a study recommending changes to the standard form Power Purchase Agreement (PPA) and procurement process to support the provision of ancillary services by variable output renewable energy resources. This intent of the study intent was to identify the types of ancillary services that could be procured as part of a renewable energy project and determine how providers may differentiate their bids by offering these services.

This report provides the recommendations regarding ancillary services, existing wind generation requirements, obligation to provide ancillary services, compensation for relevant ancillary services. Power advisory also recommends Fast Frequency Response (FFR) capability would be available on all new transmission-connected wind generation projects, primary frequency response, secondary frequency response, reactive support and voltage control, visibility and controllability of inverter-based generation, renewable energy forecasting, visibility of distribution connected assets, high speed cutout, cold weather capability, de-icing packages, cumulative wind ramp rate.

5 Findings and Recommended Next Steps

The IRP establishes a preferred resource development scenario for the province to meet decarbonization targets and provide a clean, reliable energy system while focusing on customer affordability in both the near and long term. However, while the IRP includes scenarios which consider inter-regional transmission, the IRP itself does not address the needs of the Nova Scotia transmission system to ensure that the transmission system is capable of supporting the planned integration of renewable energy outlined in the IRP while providing the necessary capacity, reliability, and voltage stability. While elements of future transmission development in the province have been studied, no focused examination of the transmission system development needed to support the IRP has been conducted.

As a result, Stantec recommends that power system studies be performed based on selected scenarios presented in 2023 Evergreen IRP as an essential next stage to ensure that Nova Scotia is equipped for success in the transition to a greener grid.

These studies should consider:

- An assessment of the bulk transmission system identifying existing limitations and the ability of the system as it currently exists to support the effective integration of additional renewable generation as outlined in the IRP.
- Identification of changes/upgrades required to the existing transmission system to overcome the limitations identified to allow the transmission system to securely, reliably, and cost effectively deliver the renewable energy developed as planned in the IRP.
- Estimate the level of investment required to implement these changes and upgrades.
- Examine limitations on interprovincial transmission and their possible impact on system reliability.
- Consider how non-wire alternatives, that could defer or eliminate the need for some transmission system enhancements, should be assessed.

Appendix A

Documents Reviewed (contained in a separate document)