Large Scale Integration of

Inverter Based Resources in Nova Scotia

Frequency Control and System Strength Assessment

Initial Findings and Recommendations

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Executive Summary

Nova Scotia is on a path to build a cleaner, greener future for the province, phasing out coal and working towards 80% renewable energy by 2030. Inverter-based generation will displace conventional synchronous machine-based power generation. This will introduce significant technical challenges that can be identified through careful planning and detailed studies, and mitigation measures implemented to ensure safe and reliable operation of the electric system.

The system studies scope to understand the system requirements to meet an 80% renewables target for Nova Scotia includes full EMT study results. However, due to delay in getting adequate plant models, it was determined that the initial findings and recommendations should be published immediately. An updated report will be published when the EMT studies are complete.

First stage studies and consultation with industry experts provided the following findings and recommendations:

Primary Finding

NSPI can incorporate renewables, in particular inverter-based resources (IBRs) such as wind, limited only by the load to be served and the best economic dispatch to meet environmental requirements. There will be technical challenges and the grid will need significant support as many legacy thermal plants are phased out or converted to alternate fuels. That said, it is achievable with the existing and evolving technologies.

A complete list of Findings can be found in Section 7.1.

Recommendations

Stable and Reliable Integration of Renewables

- Verify network response for high Rate of Frequency (RoCoF) system disturbances through EMT simulations. 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. The existing allowable RoCoF for NSPI may be too high, which could lead to cascade tripping for loss of the NS/NB tieline under high import conditions. It should be noted that when NSPI stays connected to the Eastern interconnection the RoCoF will be low.

- Survey NSPI existing legacy generation plants and Distributed Energy Resources to confirm 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 a limit that is acceptable.

- Regularly review and recommend updates to the Transmission System Interconnection Requirements to address concerns identified during ongoing studies. MHI has provided recommendations for additions and revisions to the existing requirements.

- Update Distribution System Interconnection Requirements to align with IEEE 1547-2018 Category 3 for RoCoF. It may be necessary to specify type and RoCoF requirements for future DER as there is the possibility of a cascading tripping event under maximum RoCoF conditions.

- As existing wind contracts expire, where feasible, require additional inertia support and other upgrades to meet the current grid code to avoid unnecessary operating restrictions. The performance of many of these facilities in a high IBR grid is well below that expected of newly connected facilities.

- Perform incremental studies for each wave of load and generation additions, and generation retirements to the NSPI grid. The cases for the analysis for this report studied the 2030 grid with the load as forecast in 2020. Due to the limitations of SCR as a planning metric, MHI recommends NSPI conduct a full grid study in PSS®E and PSCAD™ for each wave of new IBR to be added to the NSPI grid to identify transitory conditions or operational challenges. For the next wave of wind integration, well before 2030, the studies would look at confirmed in service changes to the system and updated load forecast. All system operating guidelines will need review, and many will need to be updated, taking 1 to 2 years to complete for each review.

Resource Planning for High IBR Penetration

Update IBR and inertia constraints for resource planning based on the findings herein. At the present time, studies indicate that there is no hard limit on IBR penetration and dispatch if there is adequate frequency and system strength support online.

- Develop a sliding scale for Inertia/FFR and system load as an input to dispatch scenarios.

- The requirement for inertia to support the Nova Scotia grid is not completely removed with the addition of a second tie. Specifically, inertia or its equivalent, will be required in the long term and day ahead planning to maintain the SCMVA required for stable operation. The metric for the bullet above should capture the requirement for inertia with two 345kV tielines in service.

- Until technology evolves such that all online generation resources provide SCMVA as with a traditional grid, SCMVA to maintain System Strength at critical buses will be a new metric to input into resource planning. It will need to be dynamically planned and dispatched in the future grid as it will be highly dependent on the generation mix online.

Good Planning Practices to Integrate Renewables in Nova Scotia

- Perform an annual assessment of NSPI System Inertia and Strength in the 10-year horizon to identify potential issues. See Section 2.2. Include FOR and planned maintenance outages in the assessment. Confirm a unit outage can be managed with operating guidelines and/or out of merit dispatch.

- 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.
- 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.

- Maintain existing SCMVA at benchmarked buses unless studies determine that lower levels do not adversely impact NSPI customers.

System Operator Support to Transition to High IBR Grid

- Develop a methodology to estimate the minimum SCMVA and SCR online prior to the addition of additional IBR (WEC, BESS, HVDC etc.) to the NSPI grid.

- Develop a methodology to estimate the inertia online to maintain the minimum required for a stable grid prior to the addition of additional IBR (WEC, BESS, HVDC etc.) to the NSPI grid.

- 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.

As noted in the introduction, the study scope includes full EMT study results. As generation and load facility EMT models become available and studies are completed, an update with additional findings on mitigations specific to Nova Scotia may be required to address fault ride-through, control interactions, sub synchronous interactions, system oscillations, and other issues associated with expanded IBR interconnections.

Black Start Restoration Planning

- Review and assess potential Blackstart options for the planned 2030 grid, considering the generation mix available a that time.

Acronyms

Acronym	Term
BES	Bulk Electric System
BESS	Battery Energy Storage System
CI	Control Interaction
EMT	Electromagnetic Transient
FACTS	Flexible AC Transmission System
FFR	Fast Frequency Response
IBR	Inverter Based Resource
LVRT	Low Voltage Ride Through
ML	Maritime Link
MHI	Manitoba Hydro International
MW	Unit of Active Power, MegaWatt
MVar	Unit of Reactive Power, MegaVolt Amperes Reactive
NSPSO	Nova Scotia Power System Operator
PLL	Phase Locked Loop
PE	Power Electronic
POI	Point of Interconnection
RoCoF	Rate of Change of Frequency
SCL	Short Circuit Level
SCR	Short Circuit Ratio
SCMVA	Short Circuit MVA
SIR	Synchronous Inertial Response
SIS	System Impact Study
SSCI	Sub-synchronous Control Interaction
SSTI	Sub-synchronous Torsional Interaction
SVC	Static Var Compensator
WEC	Wind Energy Converter

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1 Introduction

This document outlines the general planning criteria and recommendations to specifically address large scale integration of Inverter Based Resources (IBRs) such as wind generation and grid scale battery projects.

Results and observations from the 'first stage' assessments and studies are also included in this report.

1.1 Background

Most power systems in North America, Europe, Australia, and the Middle East have seen increased penetration of renewable energy-based generation of from 10% to 30% over the past decade. In 2021, close to 30% of NSPI electricity came from renewable resources and NSPI is working towards 80% by 2030. This will introduce significant technical challenges that can be identified through careful planning and detailed studies, and mitigation measures implemented to ensure safe and secure operation of the overall system.

Large-scale penetration of renewable inverter-based generation will displace conventional synchronous machine-based power generation. This has the potential to lower the overall system inertia and will result in lower short circuit levels at the Point of Interconnection (POI) of renewable resources. Renewable resources, such as wind, are interfaced to the power system via power electronic (PE) inverters. Operation of inverter-based equipment under low inertia and low short circuit conditions is challenging. Specific challenges include fault recovery response, unstable oscillatory interactions, and potential impact on torsional oscillations of thermal generating units. Most of the technical challenges associated with PE inverter-based generation connections can be related to the conditions of the network in a local area. However, as overall IBR generation penetration levels reach significant levels (say over 50%), the technical issues can impact the stability and the security of the power system.

1.1.1 Frequency Control

In an electrical system, generation and load must be balanced at all times to maintain system stability. Load is the demand for electricity at any instance in time. Generation is the electrical energy to supply the load at that instance in time. The generation can be within Nova Scotia or imported from a neighbouring utility.

If the load (MW) and generation balance is not maintained the system frequency, 60Hz in North America, will fluctuate and equipment may trip, or electrical power swings may occur. The Rate of Change of Frequency (RoCoF) can also impact system performance. A high RoCoF can make it difficult for equipment in the network to stay connected or operate stably.

For a system disturbance, such as following a lightning strike resulting in a generator or line trip, the challenge is to ensure that the remaining equipment operates stably, without tripping, and helps the system reach a stable state within timeframes specified in grid codes or accepted as general industry standard.

Traditional synchronized generators resist a change in frequency as they are large machines with a very heavy rotating mass inherent to their design. The heavy mass continues to rotate at close to 60Hz for up to a few seconds after a system interruption and acts to resist the frequency change in the grid due to the changing conditions. This is known as Synchronous Inertial Response (SIR) and measured in units of MW*s. These generators “drag” the grid along at around 60Hz, helping system stability from a frequency perspective over the short duration. This short duration support allows online generation to adjust their MW output to balance the load and further stabilise the system.

Newer renewable resources such as wind, solar and batteries generate DC current which is inverted to a 60Hz AC supply in Nova Scotia. Such a plant will often be referred to as an Inverter Based Resource (IBR). Typically, they do not have a heavy rotating mass directly connected to the AC grid and do not inherently support system frequency swings (the inverter acts to decouple inertia of the generator, even in the case of wind energy). Thus, IBR based plants do not provide the natural SIR that the traditional synchronous machines provide.

However, there are IBR facilities that can be designed and programmed to produce active power very fast to arrest a change in frequency, (on time frames close to SIR support and synchronous unit response times) following a disturbance. Different IBR technologies and control methodologies can provide this type of fast power injection within the relevant time frames to avoid activation of load tripping and to recover system frequency to nominal values in a reasonable amount of time [1]. It should be noted that such response is not inherent to IBR connections in the way it is inherent to synchronous machines. Such responses can be considered “simulated” or “virtual” responses through appropriate control system extensions.

If the frequency deviations can be well damped and RoCoF managed to allow the system load and generation to remain online, system stability will be maintained.

1.1.2 System Strength

In an electric system, to be able to transmit power to the customer load, the voltage level on the transmission grid must be maintained within a specific range. When there is a system disturbance, such as lightning striking electrical equipment, a short circuit can result and current will flow into the faulted path. The amount of current that flows into the faulted path is known as short circuit current and referred to as Short Circuit Level (SCL) at a particular point on the grid. While SCL is a measure of current, it can also be calculated as Short Circuit MVA (SCMVA).

The general term used for the ability of the system to withstand voltage events is System Strength, measured as SCMVA. Historically, the large synchronous machines supplied reactive power (MVars) in additional to active power (MWs), resulting in a high SCMVA levels in most areas, and the system was considered “strong”. With the phasing out of synchronous generating units, there will be a need to replace the support provided by the MVars from synchronous units that kept the system strong. Traditional synchronous units could typically supply over 500 MVA SCMVA per 100 MW of generation. Without additional plant support, IBR resources can typically supply 10 to 20% compared to a similar sized synchronous unit. As IBRs make up a greater percentage of the generation mix, the system will become “weaker” unless resources are added to support the required SCMVA and system stabilizing characteristics provided by synchronous machines. The weaker the system, the greater the change in voltage following a disturbance.

Low System Strength generally leads to increased network voltage volatility under normal and disturbed operating conditions. Potential concerns under low System Strength of a power system are summarized below [2,3]:

- A weak system may take longer to stabilize or may become unstable after a system disturbance causing collapse of parts of the electrical interconnection.
- Degraded ride-through response of inverter-based resources (wind, BESS, HVDC and FACTS devices) following faults and other system disturbances due to increased voltage volatility (both phase and magnitude changes).
- Undesirable CI between two or more dynamic devices in close proximity, leading to unstable or poorly damped oscillations.
- Torsional interactions (SSTI) with potential adverse impact on thermal generator shafts.
- Wider area undamped voltage and power oscillations.
- Mal-operation or failure of protection equipment to operate.
- Prolonged voltage recovery after a disturbance.
- Larger voltage step changes after switching capacitor or reactor banks.
- Instability of generator / dynamic plant voltage control systems.
- Increased harmonic distortion (a by-product of low System Strength and higher system impedances).
- Deeper voltage dips and higher over-voltages (e.g., transients).

The current IBR technology is based on “grid following” technology. The IBR is expected to “follow” the grid frequency, voltage magnitude and phase. In order for grid following IBR to operate stably, a specific requirement is a strong grid as viewed from the point of the IBR POI. At a strong POI, the changes to voltage magnitude and phase following disturbances are relatively small compared to what may take place in a weaker location. In a weak grid, the large changes in voltage conditions at the POI are harder to follow and that could lead to unacceptable dynamic response of IBR.

For IBR interconnection, the Short Circuit Ratio (SCR), the ratio of the three phase SCMVA divided by the facility MVA rating (or MW depending on methodology used) at the POI is frequently used as a measure of the facility's ability to reliably operate at that location. Past industry experience indicates that when the SCR at the POI drops to around or below 2, there is potential for overall system dynamic response concerns. This represents an overall system stability risk when a large number of PE interfaced generation, energy storage, HVDC links and Flexible AC Transmission System (FACTS) devices are expected to be connected in near future. When multiple inverter-interfaced devices are in close proximity to each other in a weak area (low SCR), undesirable Control Interaction (CI) between two or more dynamic devices may lead to unstable or poorly damped oscillations.

IBR can be used to support a grid SCL but additional equipment (synchronous condensers, Static Var Compensator (SVC)s or other fast acting reactive power sources) may have to be installed to support the voltage in local regions as there are some challenges with using numerous IBR units to mange System Strength. In addition to IBR support,

- IBRs are designed to operate to at minimum SCR. If the SCR is below the IBR design level, it may trip of during a system disturbance or lead to undesirable oscillatory modes.
- To clear a system fault, protections relays operate to disconnect the damaged area from the grid. These protection relays detect the higher-than-normal current flowing towards the faulted area. If traditional units have been retired and little or no fault current injecting sources have been added, the current available to flow into a fault may be lowered and protection devices may not operate as designed.
- During an event, MVar production is usually triggered when measured voltage at a target location deviates outside a set range. As MVars need to be delivered close to the event location, there can be many sources of MVars located in or near the area. There is potential for multiple IBR units in a local area to interact with each other, producing oscillations and instability in the grid.
- The NSPI grid has large switchable capacitive and reactor banks for MVars. With a weak grid, switching these devices will result in a larger voltage step change. NSPI is required to maintain voltage within a bandwidth to meet grid criteria. If the step change is large, it will be difficult for the System Operator to maintain adequate voltage levels on the transmission system.
- The above bulleted occurrences can also result in slow recovery of the system normal voltage levels. There is an increased potential for harmonics, transients, and sub-synchronous interactions with online synchronous units.

The design of PE interfaced devices under low inertia and low SCR is technically challenging. To overcome these technical challenges, the specific control strategies and settings must be carefully selected considering the system characteristics at the POI, expected credible N-1 and other contingencies, and interaction with other dynamic devices in the vicinity [2,4,5]. It is also prudent to verify that the influx of PE based devices does not adversely affect the torsional oscillations of thermal generator shafts. Based on a literature review as well as NSPI's subject matter expert Manitoba Hydro International (MHI)'s experience on similar system expansions, the main concerns from stability and dynamic response point of view are as listed below.

- Impact on overall system stability due to reduced inertia, reduced System Strength and RoCoF.
- Voltage control.
- Fault ride-through capabilities: Ride-through response of inverter-based resources such as wind, Battery Energy Storage System (BESS), HVDC and FACTS devices following faults and other system disturbances.
- Fault current contributions.
- Harmonics and power quality.
- Control interaction (CI): Undesirable interaction between two or more dynamic devices in close proximity, leading to unstable or poorly damped oscillations.
- Impact from torsional oscillations, sub synchronous Interactions (SSTI), on thermal generator shafts.

There has been much study and industry discussion on how to manage frequency control due to phasing out of thermal plants. Synchronous condensers, Fast Frequency Response (FFR) from IBR, etc. can be designed to meet the grid needs. Frequency control is well understood and MWs will travel within an electrical interconnection to balance frequency. The only determination is how many MWs are needed to balance the load and the speed of response required to prevent additional generation or loads from tripping. Required levels of inertia or FFR and response times for an area can be determined for various operating scenarios with existing methodologies and system study.

However, high penetration of power electronics resulting in lowered SCRs has given rise to a need for specific investigation into System Strength, which was not as critical when the generation was predominantly based on synchronous machines [6]. Careful planning and due diligence can prepare for power systems with high penetration of renewables under low SCR. Standard planning practices that have been followed over the years [7] including screening level studies, as well as specialized electromagnetic transient (EMT) simulation based studies are appropriate for System Strength study.

This is specifically the case for:

- Weak in-feed (interconnection) points resulting in low SCR. NSPI has weak AC connections to the Eastern Interconnection.

- Multiple dynamic devices in the local area: NS is planning for large scale wind, BESS and increasing solar in addition to existing HVDC and SVC facilities.

- N-1 contingencies that are likely to further reduce the SCR. In particular, the loss of the tie with NB under high import is a significant contingency.

- N-1 contingencies are likely to result in significant changes to the bus voltages near PE interfaced devices [8].
    - Tripping of heavily loaded lines results in larger changes to bus voltage magnitude, and phase angle.
    - When conventional generation (synchronous machines) are relatively far from the PE interfaced devices (wind, solar), larger changes to voltage angle (both magnitude as well as rate of change of the voltage angle) occur during a system disturbance.

1.2 Scope

The following scope will be investigated to ensure a stable NSPI system as it transitions to large scale integration of renewables:

1.2.1 Frequency Control

- Perform an assessment to determine minimum inertia required to maintain frequency stability for the Nova Scotia system under existing and 2030 load and generation dispatch scenarios.

- Perform detailed system simulations to identify stability and fault ride though concerns and identify potential RoCoF concerns.

- Recommend mitigation options to identified issues, including recommendations for system design and plant ride-through RoCoF.

1.2.2 System Strength

- Perform a screening level assessment to benchmark 2023 SCMVA levels at 69, 138 and 230 KV buses.

- Document minimum SCMVA at load sensitive locations.

- Document minimum SCR at all Wind Plants, SVC and HVDC locations.

- Identify Potential IBR Connection Issues.
- Provide recommendations for resolving issues associated with low fault levels, including SCMVA, SCR for increased IBR, post contingency voltage, fault ride-through, control interactions and sub synchronous oscillations.
- Determine minimum support requirements (synchronous condensers, BESS, grid-forming technology, etc.) to maintain acceptable levels of System Strength for the expected 2030 grid.

This report was to include full EMT study results. However, due to delay in getting adequate EMT plant models, it was determined that the initial findings and recommendations should be published immediately. This includes results from the first stage of system studies and analyses, and provides recommendations based on the findings to date. An updated report will be published when the EMT studies are complete.

2 Assessment Metrics and Methodologies

The metrics and methodologies described below are utilized for this study. The assessment is looking at 2030 and aims to identify any deficiencies in frequency and voltage control due to the changing nature of the generation fleet. All applicable criteria and standards approved by the Nova Scotia UARB are applied in system study.

It should be noted that the traditional system planning exercises including load flow and voltage stability analysis, short circuit calculations, dynamic stability analysis and harmonic analysis are still an integral part of the overall process. This document focuses on specific analysis that are required in addition to those traditional methods to facilitate large scale integration of IBR.

2.1 Frequency Control

As noted in Section 1.1.1, SIR is an immediate response provided by conventional synchronous machines. It is not a synthesized response through control actions but rather the natural response of a synchronous machine. It is the deployment of energy from the kinetic energy stored in the generator rotor. This response is vital to maintaining system stability following disturbances. The converter-based IBR generators do not contribute to SIR and can potentially make the power system vulnerable following system disturbances such as transmission system faults.

For NSPI, system inertia and FFR from IBR is important from the point of view of two technical requirements:

1. System frequency response determines the system RoCoF. This is not currently a concern for NSPI due to high inertia from the existing generation mix. In the future planned grid, with maximum renewable generation online, RoCoF would be expected to increase if there is no replacement for the reduction in SIR when the existing synchronous units are offline. Understanding the inertia and other frequency response requirements to dampen frequency excursions and to understand RoCoF for the future grid are necessary for a number of reasons:

    - Inertia and other frequency response mechanisms such as IBR FFR supports overall system stability and security.

    - Frequency excursions must be managed to allow measures such as load shedding to be effective.

    - The Nova Scotia grid is designed and operated to maintain RoCoF within a range that will allow for customer reliability and increased penetration of renewables.

    - IBR and generation facilities are designed to stay online and ride through grid events up to a specified RoCoF.

For NSPI system design RoCoF, multiple scenarios for today's system dispatch and configuration are assessed to determine the maximum RoCoF for various system conditions. The highest RoCoF documented is used as the maximum allowable for the 2030 study scenarios for first stage studies. It was noted that this RoCoF, which could be experienced under today's operating guidelines with high imports and maximum renewable generation, was not specifically assessed in the past as it was not a concern due to high SIR plants online keeping RoCoF low. A recommendation of this report will be for a specific study on RoCoF to determine the maximum value for which plants will ride through frequency excursions. It may also require a more aggressive RoCoF ride-through requirement for DER.

2. System inertia impacts the rate of change of voltage phase angle at POIs of IBR plants. IBR plants perform poorly during Low Voltage Ride Through (LVRT), or other disturbances, when subjected to large and rapid voltage phase shifts. Until IBR technology is further advanced, some SIR will be required to maintain acceptable performance for an NSPI generation mix that includes large scale IBR.

As mentioned previously, converter-based IBR generators do not provide SIR comparable to traditional synchronous units. Mechanical inertia from WECs can provide limited SIR through control actions as well as FFR. Thus, the response will depend on the specific plant design and could vary from site to site. The use of IBR plants to provide frequency response to replace SIR, is carefully evaluated through both PSS®E and PSCAD™ based studies. The specific response requirements from each new IBR plant will be specified based on existing grid codes, interconnection requirement specifications and system impact study (SIS). NSPI Transmission Interconnection Requirements specify a ride through RoCoF of 4 Hz/s for all new generation facilities. This will be an important specification for plants to operate the system under very high IBR penetration conditions in future.

For NSPI system study, inertial support or its equivalent may be achieved through several options.

- Online synchronous generation
- AC tie-lines to neighbouring systems
- HVDC interconnector
- Synchronous condensers
- Fast frequency support from IBR plants, BESS or supercapacitors

Various scenarios for dispatch and generation types are studied to determine inertia requirements for NSPI. Once a solution (or potential options) for the minimum inertia requirement is found in PSS®E, those scenarios are then studied for System Strength criteria in PSS®E .

2.2 System Strength

As noted in Section 1.1.2, for the connection of additional IBR generation, the SCMVA is predominantly known to as System Strength in industry. Typically, the SCMVA is estimated by calculating the fault current at a specific point of interconnection. Higher fault current levels will result in higher SCRs while lower fault current levels result in low SCRs, indicating a weaker system[9]. A weak grid implies a higher system impedance as seen from the POI (looking towards the AC network). In general, it is an indication of:

- Low system inertia (relatively low presence of synchronous machines in the local area).
- Lack of parallel Transmission paths (e.g. radial connections to IBR plants through long AC lines).

While there's no industry accepted standard, the following classifications listed in [10] are generally a reasonable indication of the System Strength.

- A high SCR - SCR greater than 3.
- A low SCR - SCR between 2 and 3.
- A very low SCR - SCR lower than 2.

A low SCR is an indication of potential dynamic response issues with PE interfaced devices.

A weak connection point, with an SCR of less than 3, generally indicates that there could be potential issues such as:

- Fault recovery issues.
- Unstable or poorly damped oscillations due to interaction with other plants near by.
- Inability to operate to Grid Code requirements (fast power recovery following faults).
- Difficult to control bus voltage.

Accordingly, points of interconnection with an SCR less than 3 are typically categorized as weak connection locations. In such situations, detailed assessments are typically required to confirm acceptable performance of the plant and the system with respect to fault recovery, voltage stability, control interactions issues with other nearby devices, and protective relay operation issues [11]. Detailed EMT studies are generally required to verify the acceptable performance of the plant and the system under weak grid connection conditions.

Although SCR is a high-level screening measure to identify potential dynamic response and stability issues (IBR response as well as overall system), it is only one indicative index. Other system measures such as the overall inertia and the location of machines providing inertia (proximity to inverter-fed devices) will also have a significant impact on the stability of inverters and hence the power system. The available inertia, including the location in the network where the machines are connected, determines the rate of change of voltage at the POI (specifically the voltage angle) and has a significant impact on the fault ride-through response of PE based devices [8].

From an overall system planning perspective with large scale penetration of IBR based generation, two technical items are to be considered.

1. Lower fault current levels impact on existing protection system performance:

   To address this concern, modern grid codes may require that the IBR plants contribute a reactive current injection during low voltage conditions at its connection location. This is not specified in the existing NSPI grid code. However, while this specification will support protection system operation, the fault current contribution from IBR should not be considered in the SCR calculations for specific IBR plants. This is because the IBR plant does not necessarily support the dynamic response of an IBR plant by limiting the rate of change of bus voltage conditions (as would a synchronous machine through its natural inertial actions).

2. Maintain sufficient SCR levels at known IBR connection locations or potential renewable energy hub areas:

   Present day IBR plants are designed based on grid following technology. For grid following inverters to operate stably under transient conditions, it is essential that the voltage conditions at the POI do not go through rapid changes during the recovery period. SIR in the vicinity of the POI as well as a strong network that would limit the overall voltage change (between the pre fault and post fault steady states) is essential to ensure the stability of the IBR plants and ultimately, the stability of the overall system. High SCR is an indication of the presence of synchronous machines in the local area and/or a strong, meshed transmission system.

SCR, including Effective SCR and Weighted SCR, has been a widely used screening level metric to identify potential concerns (dynamic response) when connecting PE based generation, HVDC or BESS at a specific point on a grid. However, the NSPI approach is to look at the future grid with as high penetration of renewables as is possible with existing technology and develop a planning and study process to achieve the best mix of renewables and grid support mechanisms to meet decarbonization targets.

MHI recommends NSPI conduct a full grid study in PSS®E and PSCAD™ for each round of new IBR to be added to the NSPI grid to determine if additional system support is needed to accommodate the new IBRs. MHI recommends performing an annual assessment of NSPI Frequency Control and System Strength requirements in the 10-year horizon to identify potential issues.

It is essential that the planning engineers exercise sound engineering judgement when assessing SCR values. The specific nature of potential issues would depend on several other factors that are not fully illustrative though SCR values:

- Harmonic impedance (resonance characteristics) of the AC system as seen at the POI.
- Series compensated transmission lines in the local area.
- Specific technology (vendor specific) and specific protection and control settings of the PE inverters and other plant equipment.
- The MW rating or the MW output of the PE based plant is used to calculate the SCR (as described in previous sections). However, the inverter-based plants may have a much higher MVA rating considering their reactive power capacity. This can influence the plant response under weak grid conditions.
- If the MW rating is used to estimate the SCR, the impact of nearby STATCOMs, HVDC, BESS may not be captured. These PE based plants will also contribute to potential dynamic response issues. The planner may consider using the MVAR rating instead of the MW rating in such cases.
- Under operating conditions, when calculating Operating SCR (OSCR), the MW output depends on the power reference set point and/or the number of inverter units in service inside the plant. The OSCR does not capture this difference. However, the number of inverters in operation (in service) as well as the operational MW set point can both influence the dynamic response of the plant and the system, following disturbances.

Detailed studies are carried out to verify the acceptable operation of the plant under foreseeable operating conditions.

As noted in the section above, Frequency Control and System Strength are closely related to each other as the online status of synchronous machines have a significant contribution to both. Thus, it is prudent to set the inertia constraints prior to performing any SCR calculations. It should be noted that the SCR calculations are performed considering specific IBR connection location while the inertia requirements are estimated more at a system level.

For System Strength Analysis, the following criteria is used:

- Maintain SCR of at least 3 at existing IBR locations unless lower acceptable values are documented.
- All new IBR connections should operate stably and meet NSPI TSIR requirements at SCR of 3, or lower, as dictated by the SIS for the Interconnection request.
- Maintain SCMVA close to existing levels unless it can be shown by studies that it will not adversely impact power quality in the local area.
- Increase SCMVA as needed to allow for increased renewables interconnection.

To assess the criteria, PSS®E cases are dispatched to weakest system expected for the current and future grid. Three phase faults are applied and current levels compared to future levels to identify any areas seeing a reduction in SCL.

For retiring units, an assessment of remaining generation units and motor loads is performed to determine if any change in the SCR is acceptable or if additional system support is needed to replace that lost with the unit retirement.

For new transmission load and generation connections, full study in PSS®E and PSCAD™ is undertaken to identify any SCL conditions that may cause tripping or control interactions.

2.3 Iterative Assessment

The initial assessment and metrics used for these studies follow the traditional load flow and dynamics methodologies with the intent to then take critical cases into PSCAD™ for EMT analysis. Upon examination of the PSS®E first stage studies results, it quickly became evident that there were many unknowns. To get stable and well damped results in PSS®E simulation required a particular number of thermal units online. However, when the SCMVA was reviewed for some dispatches that produced good frequency damping results in PSS®E, it was noted that SCMVA was very low in some areas of the province. It was particularly low in the western region of the province when the small hydro units were offline.

With a low SCMVA, nearby connected IBR would be unlikely be able to ride-through due to SCR dropping below 3. Most Wind Energy Converters (WECs) are expected to stay online at an SCR of 3.

A very low SCMVA can increase the tripping of local manufacturing plants for low voltage events such as lightning strikes. To decrease SCMVA levels below existing levels would cause a drop in reliability for customers. MHI recommends maintaining, and where possible improving the grid conditions to enable generation and customer load to ride-through system disturbances.

As an example, with results of the first grid simulation iterations complete, high inertia units were required online to maintain frequency and voltage at levels that would potentially be viable for system stability (to be verified in PSCAD™ simulation). For thorough analysis, traditional units supplying inertia were then taken offline and replaced with IBR frequency response enabled generation (Maritime Link HVDC link with frequency support from NL). The cases solved and had good settling out of frequency within NERC criteria. However, this further reduced the SCMVA and many voltage violations were observed.

While technological advances now provide for both frequency and voltage support from IBR, the ability to support frequency is further advanced than for System Strength support. Section 6.1 has an overview of the potential IBR mechanisms for both Frequency Control and System Strength support. Frequency support from IBR facilities such as extracting mechanical inertia from WECs and Fast Frequency Response can be specified for new facilities. IBR support for System Strength is still in the developing stages and not commercially viable in many instances.

With this in mind, it was decided to decouple system requirements for frequency control (inertia and FFR) from the system requirements to support voltage events (System Strength) and the following iterative approach was implemented to complete the study:

- Determine the minimum inertia and FFR required for the scenarios under study to maintain a good frequency response without consideration for any voltage outside criteria limits and the SCMVA.

- Take the resulting scenarios with adequate frequency support for study to determine minimum requirements to achieve a SCMVA adequate for system protection and SCR sufficient for IBRs to stay online during system disturbances.

- With the minimum requirements for both Frequency Control and System Strength identified, run all scenarios in traditional PSS®E simulation to identify any unexpected issues. For any issues, identify grid support needed to achieve adequate results to meet NSPI design criteria.

- Run critical scenarios from the PSS®E in PSCAD™ to further assess as per the mythology described in Section 2.1

- Iterate through the above steps as needed to achieve an acceptable performance as described in Sections 2.1 and 2.2 above.

3 Frequency Control Assessment in PSS®E

For frequency control assessment, the Nova Scotia grid will experience the greatest frequency deviation and potential high RoCoF when it separates from the North American grid.

- The critical dynamics contingency for inertia assessment and RoCoF is the loss of the tie between NS and NB. This involves the loss of transmission line L-8001 which then cross trips transmission line L-6613. The import on the line was set to the maximum allowed based on tie line restrictions and the need to limit UFLS for loss of the line.
- UFLS is allowed and expected for this contingency.

3.1 Frequency Excursion Damping

Boundary cases for light load and peak load for the 2030 load conditions, with maximum renewables online, were run. Simulations were run iteratively to get the online synchronous generation dispatched to the minimum needed to maintain a stable and well damped frequency response for loss of the NB tie.

Simulation cases for the first stage studies focused on light load and peak winter load as most definitive in determining grid requirements for frequency control. Dozens of cases were run and those failing basic criteria in load flow were discarded. Ten cases were taken forward for further assessment. The six light load and four peak 2030 load cases meeting basic criteria over a range of conditions are listed in Table 1 below.

Table 1: Minimum Inertia for Frequency Control, First Iteration

Case	Dispatch	Thermal Units or Equivalent	Dispatch Notes
1	Light Load	4	TUP, TR6, TUC2 & ML, Biomass / existing wind
2	Light Load	3	TUP, TR6 & TUC2/ existing wind
3	Light Load	3	TUP, TUC2 & ML, Biomass/ existing wind
4	Light Load	2	TUP & TUC2/ existing wind
5	Light Load	2	TUC2 & ML, Biomass on / existing wind
6	Light Load	2	TUC2 & ML, / existing wind
7	Winter Peak	4	TUP, TR6, TUC2, TUC 4, & ML. Biomass and Hydro online / existing wind plus 500 new wind, 190 new BESS
8	Winter Peak	4	TUP, TR6, TUC2 & ML. Biomass and hydro online / existing wind plus 550 new wind, 190 BESS
9	Winter Peak	3	TUP, TR6 & TUC2. Biomass and hydro online / existing wind plus 701MW new wind, 192 BESS
10	Winter Peak	3	TUP, TR6 & ML, Biomass online / existing wind plus 621 new wind, 190 BESS

The dispatch for the case was load dependent:

- The light load cases were run with 6 variations. In light load, NSPI has sufficient wind and imports to serve load with 100% renewable energy. Hydro resources are offline. Variations of FFR and inertia were simulated with the goal of taking inertia as low as possible while providing for well damped and stable frequency response.

- The cases for winter peak are more complex. Small hydro is required to operate in the West under high load conditions for voltage and stability support. There are limited energy resources in the western part of the province and it is remote from the large synchronous plants. As the EMT studies progress, it is expected that evolving technology in IBR resources will be able to provide voltage support to the weaker parts of the grid. It may be possible to reduce hydro online when there is sufficient wind to meet the system load. However, at this time, for system stability, hydro and some additional thermal is required online, raising the inertia online in the cases. To meet the load, while reducing the thermal units, new wind and BESS was added to the simulation cases.

Load Flow and Dynamic assessment was performed for the loss of NB tieline with high NS imports.

Case 5, with a low amount of inertia online, did meet the criteria. Removing one more small unit to find the minimum threshold for adequate performance the case, Case 6, would not solve for dynamics and was discarded as a nonviable scenario. For the remaining cases, while system frequency was stable and settled out to meet grid criteria for frequency response, it was observed that winter peak load cases had post-contingency voltage issues. The voltage issues gradually increased as the number of thermal units online were decreased to the minimum for stable frequency response. Under winter peak load conditions, grid simulations determined that frequency damping control is not the limiting factor in determining the minimum number of thermal units or other synchronous support required online for system reliability. Voltage issues were noted and addressed in the System Strength portion of this study. See Section 4.

It was also noted that the system RoCoF was above 4 Hz/s for some cases. As some facilities may trip off at high RoCoF further simulations, focusing on RoCoF, were run. See Section 3.2.

It was found that the Maritime Link with FFR enabled was able to reduce the inertia required for frequency control. With this in mind, assessment for the 2030 grid includes a review of potential FFR from IBRs as a potential source to reduce synchronous resources required to be online. IBR technology is evolving rapidly and both WEC and BESS may be able to support frequency in the 2030 timeframe.

Notwithstanding the voltage issues and RoCoF, which are addressed in the following sections, iterative study identified variations of case 5 for light load and case 10 for winter peak load as defining the minimum inertia and FFR required online to provide for well damped frequency for loss of the tielines to New Brunswick. The minimum requirements, shown in Table 2, are required to maintain a stable and well damped frequency response with all load served by renewables and imports other than that supplied by the thermal units online to maintain stable frequency response.

Case	Dispatch	Total Inertia (MW*s)	Dispatch Notes
51	Light Load	1044	TUC5, TUC6 & ML 50 MW FFR, Biomass on / existing wind
52	Light Load	1102	TUC2, TUC6 & ML on no FFR, Biomass on / existing wind
53	Light Load	1603	TUP, TUC2 & ML offline, Biomass on / existing wind
101	Peak Load	2381	TRE6, TUC2 & ML 50 MW FFR, hydro online/ existing wind plus 899 MW new wind, 182 MW BESS
102	Peak Load	2381	TRE6, TUC2 & ML on no FFR, hydro online/ existing wind plus 899 MW new wind, 182 MW BESS
103	Peak Load	3158	TUP, TRE6, TUC2 & ML offline, hydro online/ existing wind plus 901 MW new wind, 182 MW BESS

Table 2: Minimum Inertia and FFR Required for Frequency Control

Winter peak load has the highest inertia requirement for stable frequency response. The case dispatches for the peak load, with maximum renewables:

- System load 2145 MW (2030 peak as forecast in 2020), including PHP at 152 MW
- ML at 152 MW with 50 MW FFR for case 101, ML at 150 MW without FFR for case 102, offline for case 103
- NB imports at 296 MW
- Wind: approximately 474 MW existing transmission-connected wind, 900 MW planned wind additions
- BESS: 182 MW, no FFR
- Thermal: TRE6 and TUC2 for case 101, Tupper, TRE6 and TUC2 for case 103

While the first iterations for inertia, focusing on a stable and well damped frequency response, identified a minimum inertia required online, it does not consider RoCoF. As the NSPI generation mix has a large synchronous component, RoCoF has not previously been an issue or routinely considered in system studies. With the expected reduction in online SIR, RoCoF was noted as a more determining factor in the requirement for online SIR and FFR. To evaluate the impact of changing RoCoF, additional assessment focused on RoCoF was undertaken.

3.2 RoCoF

Historically, there have been RoCoF requirements for generation facilities and some protection devices to ensure they function as expected during frequency swings. The requirements are as needed to stay online for a grid with good SIR response. As the grid SIR has potential to decline with the phasing out of some synchronous generation and increase of renewable generation, simulations were run to better understand the impact on RoCoF. The NERC whitepaper “Fast Frequency Response Concepts and Bulk Power System Reliability Needs” [1] provides a good overview of the fundamentals of frequency response and the FFR as a mechanism to replace a portion of the existing SIR required to maintain frequency and RoCoF.

To determine the inertia needed to maintain an adequate RoCoF, a performance metric was needed to benchmark the scenarios against. As a metric, a RoCoF for system design has no established industry best practice or recommendation for a RoCoF for grid design.

Earlier recommendations for grid RoCoF were very general and often did not include the sample time which is needed to apply a RoCoF requirement. More recently, in 2022, an international survey was conducted over several entities in the Americas, Europe and Australia on RoCoF experiences, ride-through and operational standards and control measures [12]. Findings indicate that there is no common measure for RoCoF and in some cases no RoCoF requirements for system design.

The time sample over which RoCoF is calculated varies from utility to utility. 500ms is the middle ground and was utilized for this study.

Simulations were run to determine the most severe RoCoF possible for the existing NSPI grid. At light load, case 2 in Table 3 below, with minimum required SIR online as per the existing operating guidelines, the RoCoF in simulation for the most severe contingency is 1.4 Hz/s calculated over a 500ms sample time. With all wind online, maximum imports and three thermal units on for inertia support the highest load that can be served is approximately 1437 MW. That case, #11 in Table 3 below has a RoCoF of 2.3 for the most severe contingency.

Table 3: Most Severe RoCoF, 2023 Grid

Case	Load	Total Inertia (MW*s)	ML FFR	RoCoF
2	Light Load	2224	Offline	1.4
11	Summer Peak Load	2487	Offline	2.3

Case 2 is a light load case with three large units on as per the existing operating guideline.

Case 11 dispatch is the worst case achievable under existing transmission system configuration and operating guideline for 3 thermal units and ML on for inertia:

- The maximum load that could be served with imports, wind and the minimum three thermals online for inertia: 1372 MW + 65 MW for PHP
- Imports from NB: 298 MW
- Imports from NL: 300MW (ML frequency control at 0MW)
- Hydro: 0 MW but 13V Gulch and 16V Weymouth online for System Strength support
- Thermal units: Tuft’s Cove 3, Trenton 6 and Tupper online
- Transmission Wind online: 431 MW

In the previous section, the minimum inertia required to maintain stable frequency response was determined as shown in Table 2. When RoCoF was measured in these cases it was much higher than for the existing grid and generation mix – in excess of 4Hz/s measured over 500ms. The GHD report [12] suggests “±2 Hz/s for a moving average of 500 ms window” as a minimum RoCoF for ride-through for generation facilities.

Until further research or study dictates otherwise, sufficient inertia and FFR to maintain a RoCoF of under 2.5 Hz/s on a 500ms sample time for the most severe contingency will be used in ongoing system studies. This value is aligned with what could be experienced with 2023 dispatch conditions and operating guidelines. That said, it is recommended that further study on an appropriate RoCoF metric for Nova Scotia be undertaken.

The GHD survey [12] found that of the entities surveyed, only EirGrid had direct experience in investigating generator ride-through for RoCoF. Eirgrid validated its legacy generation and had confidence it its ability to ride through 1 Hz/s on a 500ms sample time. MHI recommends NSPI survey existing legacy and Distributed Energy Resource (DER) generation sources to have sight of the RoCoF ride through capabilities. If 2.5 Hz/s on a 500ms sample time can be maintained, it allows more flexibility in the transmission system design. However, if there is potential for widespread cascading, the 2.5 Hz/s on a 500ms sample time may need to be reduced. Additional SIR or FFR grid support would be needed to reduce the RoCoF.

For new generation connections, the NSPI Transmission System Interconnection Requirements [13] require facilities to ride-though a RoCoF of 4 Hz/s.

With the study condition to maintain RoCoF under 2.5 Hz/s, as per existing guidelines, iterations of the Series 5 and 10 cases in Table 2 were run with variations of the ML online, with and without FFR enabled. For the first RoCoF simulations with the cases carried forward as having the minimum inertia/FFR online for frequency damping response during a grid event, it was found that the RoCoF was above the desired 2.5 Hz in most cases as shown in Table 4.

Table 4: First Iteration for 2030 RoCoF

Case	Load	Total Inertia (MW*s)	ML FFR	RoCoF
51	Light Load	1044	50MW	2.65
52	Light Load	1102	0MW	3.41
53	Light Load	1603	offline	2.32
101	Peak Load	2404	50MW	3.02
102	Peak Load	2404	0MW	3.27
103	Peak Load	3181	offline	2.48

The cases were re-dispatched, increasing inertia and FFR online to get RoCoF below 2.5 Hz/s as shown in Table 5. A significant increase in online inertia was required to meet the RoCoF target.

Table 5: Minimum Inertia for RoCoF below 2.5 Hz

Case	Load	Total Inertia (MW*s)	ML FFR	RoCoF
511	Light Load	1536	50MW	2.19
521	Light Load	1890	0MW	2.22
531	Light Load	2586	offline	2.15
1011	Peak Load	4219	50MW	2.17
1022	Peak Load	4355	0MW	2.19
1023	Peak Load	4233	offline	2.17

As BESS grid support capability is evolving rapidly, a test run was initiated on the 6 RoCoF cases with 200MW of BESS dispatched at 50% to allow for up to 100MW of FFR support.

Table 6: BESS FFR support for RoCoF

Case	Load	Total Inertia (MW*s)	ML / BESS FFR	RoCoF/delta
511	Light Load	1536	50MW / 100 MW	1.50/32%
521	Light Load	1890	0MW / 100 MW	1.66/25%
531	Light Load	2586	offline/ 100 MW	1.58/27%
1011	Peak Load	4219	50MW / 100 MW	1.87/14%
1022	Peak Load	4355	0MW / 100 MW	1.89/14%
1023	Peak Load	4233	offline/ 100 MW	1.90/12%

As can be seen in Table 6, RoCoF was reduced significantly. As BESS with FFR with the capability to respond in 100ms is integrated into the NSPI grid, the inertia required online for RoCoF can be reduced as indicated by system study.

4 System Strength Assessment in PSS®E

A minimum level of System Strength is required for the power system to remain stable during system disturbances. A minimum level is also required for inverter-based facilities to stay online during system disturbances and for switching events such as large motor starting.

Testing and analysis were conducted with a full contingency set based on the criteria applicable to the NSPI grid and recommendations from the 2020 IRP preliminary studies. The case dispatch started from the cases used for frequency control and RoCoF assessment as described in Table 5. The 6 cases, dispatched to the minimum inertia needed for peak and light load conditions, were carried forward for System Strength assessment. The full contingency set, 146 of the most critical contingencies, was run on the cases.

4.1 Existing Fault Level Assessment

To understand the System Strength of the 2023 Nova Scotia grid, an “average” day dispatch was taken as the benchmark for existing SCMVA.

Dispatch for benchmarking SCMVA has 3 thermal units, ML, all hydro, biomass and PHP motors online. Wind is off to avoid counting the contribution of fault current from legacy wind as it does not support the grid during a system disturbance.

Changing system load, different generation dispatch, or a transmission element out of service can greatly influence the values. This “average” day dispatch will be reviewed against future expected grid conditions on a similar average day to get a high-level indication of change as the grid evolves. This is meant to be a high-level screening metric as we move forward. System design studies, Interconnection studies, etc. will run a full system impact study and look at a multitude of values over time.

See high level benchmarking screening level SCMVA for 69, 138 and 230 kV buses in Appendix A: SCMVA Benchmark Values.

4.2 Minimum SCMVA for Sensitive Facilities

While the above metric will be a measure of overall SCMVA and a measure of change over time, it will be necessary to monitor the minimum SCMVA for sensitive facilities such as manufacturing plants and HVDC facilities where a minimum, or existing, design SCMVA must be met to ensure continued reliability for the customer. The existing minimum, with all elements in service, is documented in Table B - 2. If the future grid will see a reduction in the minimum SCMVA, study will be undertaken to ensure there is no reduction in reliability for the customer. If adverse impact is identified, mitigation will be taken to ensure grid reliability is maintained.

4.3 Minimum SCR for Existing Wind Plants

For existing facilities, the minimum SCR documented in the Interconnection Request will be maintained. If no minimum ride through value has been documented for an existing facility, NSPI will target to maintain an SCR of 3 at the low side customer bus, usually around 34kV. For the purposes of this study, the SCR values were benchmarked at the NSPI Transmission Level voltage for consistency and high-level analysis of the change for various future dispatch patterns, as shown in Table C - 2. The values cannot be used to determine the actual ride through SCR at the wind facility.

4.4 System Support Requirements

System Strength requirements will be driven by the need to support existing facilities as the grid transitions to high renewables as well as to strengthen the grid to support the addition of significant quantities of IBR to meet NSPI, provincial and federal targets.

4.4.1 Post Contingency Voltage Support

To maintain post contingency voltage within the range required by NSPI, NPCC and NERC criteria, reactor and capacitor banks were added at several locations in the province. For the winter peak cases, small capacitor banks (5 to 15 MVars) were added at several substations in the West and Sydney area to improve post-contingency voltage. For the light load cases, a small reactor was added in the Sydney area to bring post-contingency voltage to the range required. This proved adequate to maintain post contingency voltage for many scenarios.

Load growth will usually increase the need for static voltage support of this type. As NSPI load grows, the exact location and size of these banks will be determined by detailed System Planning studies. Future studies may indicate a need for dynamic reactive power support if load growth is at a faster rate than currently forecast.

4.4.2 SCMVA for Sensitive Buses

With all contingencies solving well for the 6 cases, a comparative look at the SCMVA for sensitive buses was run. See Appendix B: Sensitive SCMVA Buses for the tables of values. As can be seen in Table B - 1, Table B - 2, Table B - 3 and Table B - 4 there can be a wide range of SCMVA depending on the future generation dispatch. For example, the scenario which considers a second 345kV tieline to New Brunswick will need inertia to support sensitive buses. EMT studies are ongoing to determine if some of the support can come from IBR sources but, at this time, synchronous condensers are the preferred mechanism to provide this type of grid support. Without a second tieline, much higher inertia is required online to maintain a RoCoF of 2.5Hz/s or less. This higher inertia requirement, if dispersed around the province, will contribute to SCMVA support for sensitive buses.

4.4.3 SCR as a Screening Index

SCR can be considered as a screening level index for a potential POI for IBR. However, engineering judgement should be exercised when making screening level conclusions based on such indices. This can be illustrated with the following example:

- Consider a POI bus with a SCMVA of 1000 MVA, and connected to this bus there is a 500 MVA grid following IBR. The Short Circuit Ratio for this IBR is 2.0 (SCR IBR_1 = 1000/500 = 2.0).
- Assume that the lowest SCR this IBR technology can handle is 1.5 (min SCR=1.5).
- For a second IBR project of the same rating is to be connected at the same POI, consider two different scenarios:
    - **Case A:** If we consider the Short Circuit contribution of the first IBR as contributing to the System Strength, the SCR for the second IBR would be:
        - SCR IBR_02 = 1500/500 = 3.0 (> than min SCR of 1.5, therefore a strong POI)
        - Similarly, the contribution from IBR_02 would affect the SCR of the IBR_01 so that the SCR _IBR-01 is also 3.0
    - **Case B:** If we don't take into account the SC contribution of the first IBR as contributing to the System Strength, the SCR for the second IBR would be:
        - SCR IBR_2 = 1000/500 = 2.0 (> than SCR_minimum of 1.5; therefore project OK)

Both calculations are misleading. More so in case A, as according to the SCR calculations, the hosting capacity of the system for grid following IBRs would increase the more grid following IBRs are added to the system.

As for calculation B, although not as optimistic as calculation A, it still overestimates the hosting capacity of the system.

The hosting capacity of the system will be more closely dictated by the combined size of both IBR projects connected to the bus (or system). In this case, since both projects are connected to the same bus, the hosting capacity likely should be estimated as:

- Available SCMVA/SCR min = 1000 MVA/1.5 = 667 MVA
- The available capacity to connect would be combined plant total of 667 MVA

So far, industry wise, the SCR calculation has been used as a high level method to estimate whether a project can be connected to a system. This screening estimate holds as long as the overall penetration of grid following IBRs in the system remains low. However, calculation in Case B shows that this method of estimating whether a project can connect starts to provide misleading results once there is high penetration of grid following inverter-based resources in the system. Currently the method for assessing whether a new project can be connected to a system with high IBR penetration is to perform dedicated EMT studies designed to evaluate whether the IBR can ride-through events and does not negatively interact (CI, SSCI, SSTI etc.) with other devices in the system.

Most of the technical discussions on System Inertia and Strength assume that IBR plants are operating on grid following technology. The need to implement new concepts and technology such as grid-forming inverters, virtual synchronous machines, synthetic inertial response must be evaluated on a case-by-case basis as part of the EMT study work.

4.4.4 IBR SCR

As noted in Section 4.4.3, SCR has limitations in its usefulness as a screening metric for the connection of additional IBR. However, it is still a measure of a wind facility's ability to ride through system events and usually specified by the manufacturer. Additionally, as noted in Section 2.3, while there is currently no industry accepted standard, an SCR between 2 and 3 is considered low and below 2, very low. For legacy IBR plants, the intent will be to maintain SCR at the POI, for the summed total MW of IBR facilities at that POI, to at least SCR of 3 unless a lower value was identified in the facility SIS. New facilities, as per the NSPI Transmission System Interconnection Requirements [13], may provide to NSPI a minimum SCR for unrestricted operation at the time of interconnection. System short circuit level may decline over time and the generating facility shall be able to accommodate these changes.

A comparison between SCR for a typical dispatch for 2023 and 2030 was reviewed. See Appendix C: SCR Sensitive Facilities for the table of values. These values, benchmarked at the NSPI Transmission level, should not be used for any other purpose as they are specific to this study.

As can be seen in the tables, the SCR can vary considerably depending on the dispatch scenario. For each new interconnection to and retirement from the NSPI grid, system study will be required to determine when and where grid support is required. A large-scale maximum wind study, with and without a second 345kv tie to New Brunswick, is ongoing and will provide direction on the quantity and location of grid support mechanisms.

4.4.5 Stability Requirement

When sufficient inertia, FFR and reactive support was added to meet criteria (Frequency, Voltage, and RoCoF, SCMVA etc) as defined in this report there were no observed stability issues in PSS®E. Stability and Control interactions are best observed in EMT and will need further analysis in PSCAD™ as per Section 5.

5 Frequency Control and System Strength Assessment in PSCAD^{TM}

First Stage studies, RMS analysis in PSS®E, have been completed as detailed in the sections above. Stage Two focused on EMT analysis in PSCAD are ongoing. As there are significant findings in the First Stage studies, the results are to be released in this report and an updated report will be issued when Stage Two studies are complete.

5.1 EMT Analysis Methodology

NSPI, in collaboration with MHI, is in the process of developing the full NSPI network (including portions of neighbouring areas) in PSCAD^{TM}. The EMT model includes transmission details including 69 kV level and down to distribution voltages where necessary to best model generation and larger manufacturing facilities. All dynamic plants are represented by detailed models provided by the equipment supplier where available.

The PSCAD^{TM} model is tied to a corresponding PSS®E case. Different study scenarios (load dispatch conditions, generation online, etc.) are implemented in the PSS®E case and the corresponding network conditions transferred to the PSCAD^{TM} cases using python based scripts.

The general EMT study procedure is quite similar to the well established PSS®E based RMS dynamic simulation study approach. Due the higher computational time of EMT simulations, the critical contingencies under assessment in PSCAD^{TM} are determined based on screening studies (SCR levels, network resonance conditions at POI etc.) and RMS based study outcome.

Illustrative EMT results are shown in Figure 1, Figure 2, Figure 3 and Figure 4. These results are for illustrative purposes only and do not correspond to NSPI system response.

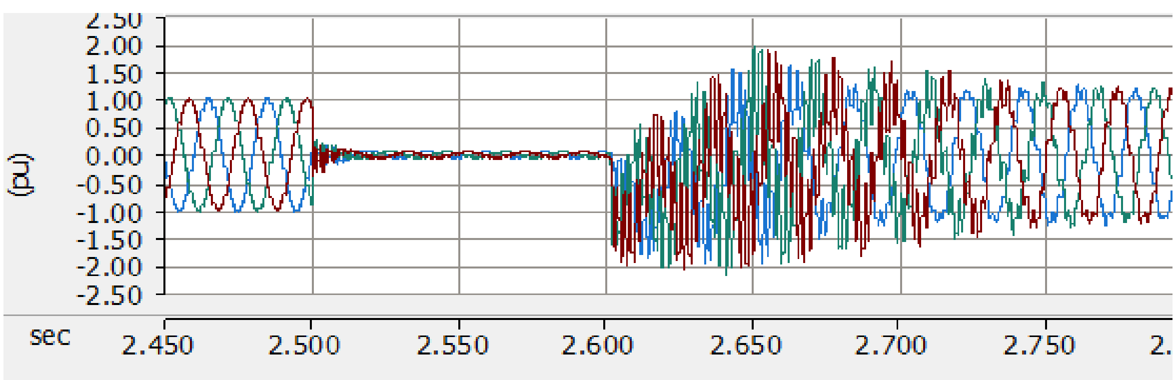

Figure 1: Illustrative POI Voltage Waveforms Following a Fault Clearance.

The transients post fault, fault recovery period, can impact the performance of the IBR.

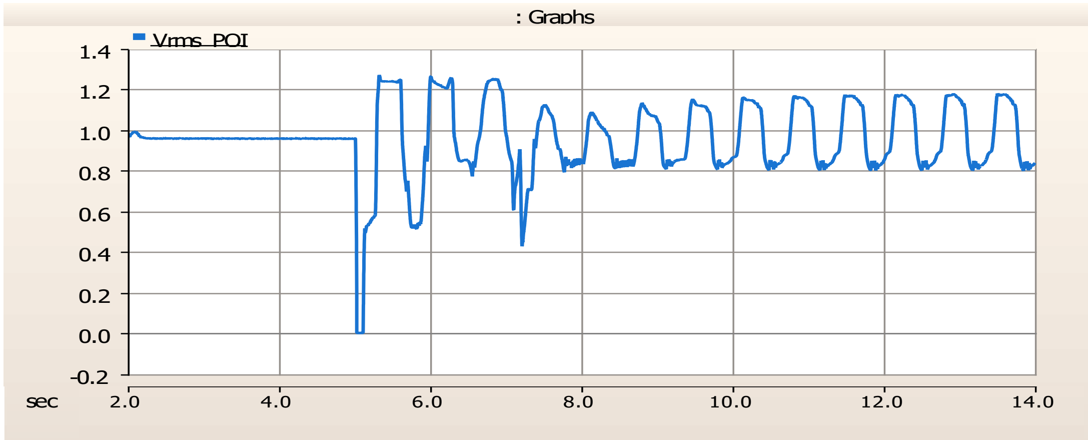

Figure 2: PSCAD™ Simulation Showing Unstable Oscillations

The PSCAD simulation, in Figure 2 showing unstable oscillations at a connection point of two IBR plants shown in Figure 3

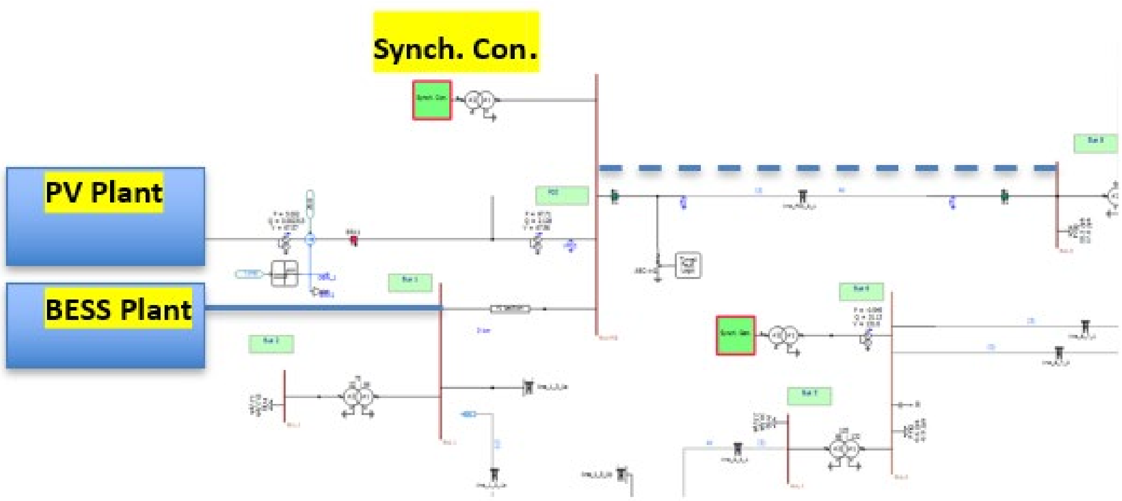

Figure 3: Example System to Illustrate Unstable Interactions

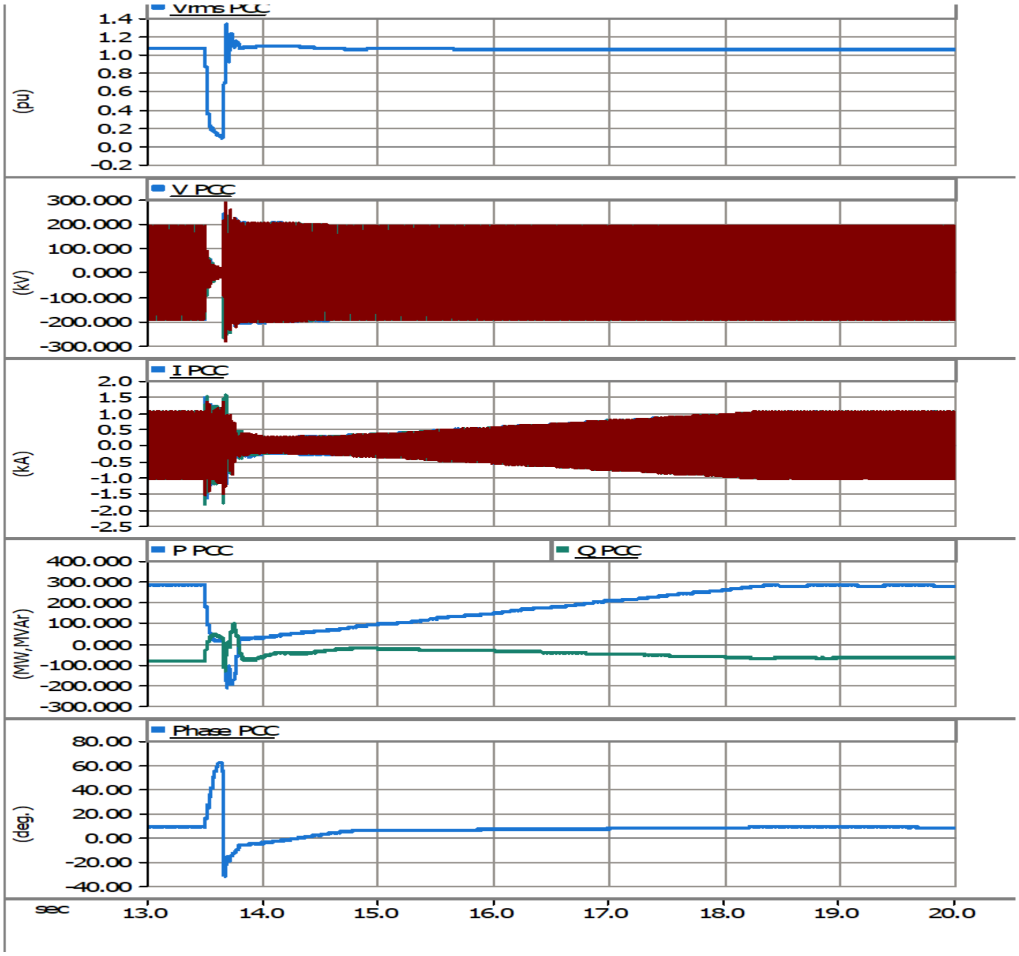

Figure 4: Illustrative PSCAD Results Showing Power Reversal

PSCAD™ results showing power reversal immediately following fault clearance - simulation of a wind farm fault ride through.

5.2 EMT Models

NSPI requires that all new interconnection customers provide accurate, site-specific models of their plant in PSCAD™ format. In addition to the PSCAD™ model, a corresponding PSS®E model that is benchmarked for performance should be provided to NSPI by all plant owners. Accurate models are essential to plan the NSPI future power system for stable and secure operation under a range of load, dispatch, and equipment outage conditions.

While the PSS®E models for legacy plants on the NS grid as well as new models received from interconnection customers are performing reasonably well, it has proven difficult to get working accurate models in PSCAD™. Getting the existing Nova Scotia PSCAD™ generation facility models working has also proved challenging. This is an industry wide problem. A NERC IBR Modelling Update, Review of Findings and Recommendations form NERC Disturbances Reports and Guidelines[14], identifies concerns with EMT models and recommends establishing EMT modelling requirements and model quality checks to ensure models not only perform well in simulation but are an accurate representation of the installed equipment.

- MHI recommends 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.

- MHI recommend that NSPI publish a document outlining the model quality and dynamic response tests performance required as validation for the submitted models.

5.3 Detailed PSCAD™ Simulation

Detailed PSCAD™ simulations are used to identify stability and fault ride though concerns and further assess potential RoCoF concerns.

EMT simulations have become critical when integrating PE inverter-based plant and other power electronic based equipment to AC networks. EMT simulations highlight technical challenges related to the connection to the power electronic based equipment. Performing dynamic simulations in RMS platforms may not uncover design considerations that may result in project delays and cost implications.

Grid following IBR plants may not operate as intended if SCR SCMVA too low. Traditional RMS simulation (PSS®E) will not pick up off-fundamental frequency oscillations. The Australian experience highlights the need to utilize wide area EMT models to replicate system observed issues that were not reproducible by any other means [15].

Increasing the short circuit level is an obvious approach to enable greater IBR penetration with synchronous support being the optimal solution. New transmission build is also an acceptable option for System Strength issues in many cases but is generally not economically viable when compared to the alternatives. EMT study results will provide more detailed recommendations for the support required and best locations for synchronous support. Further detailed analysis of the future NSPI grid will assess advances in technology[1] for IBR contribution to System Inertia and Strength as a potential replacement for synchronous support for System Strength.

[1] One avenue with demonstrated potential is the use of IBR controls at the inverter level rather than at the Farm Control Unit (also referred to as Power Park Control). A Cigre article [15] documents the Australian system as a network with a high number of IBR, SVC and STATCOMs as having the potential to show network oscillations due to controller interactions. The report references a sub-synchronous control Interaction (SSCI) event observed in the Queensland transmission network due to low System Strength. NSPI future grid will be very similar to the South Australia portion of the Australia in terms of system load, number and size HVDC and AC tieline and high penetration of IBRs.

5.4 Potential IBR Connection Issues

The EMT analysis will review technical interconnection issues associated with large scale connection of IBR.

5.4.1 Fault Ride-Through

NERC Reliability Standard PRC-024-2 describes how generator protective relays should be set such that generating units remain connected during frequency and voltage excursions (see Figure 5). The curves specify a “No Trip Zone” where the bulk electric system (BES) resources should not trip within the specified time durations. Outside this designated area, BES resources may remain online to support grid reliability to the greatest extent possible. There is no explicit requirement for BES resources to trip, driven by plant protection requirements or local grid reliability issues.

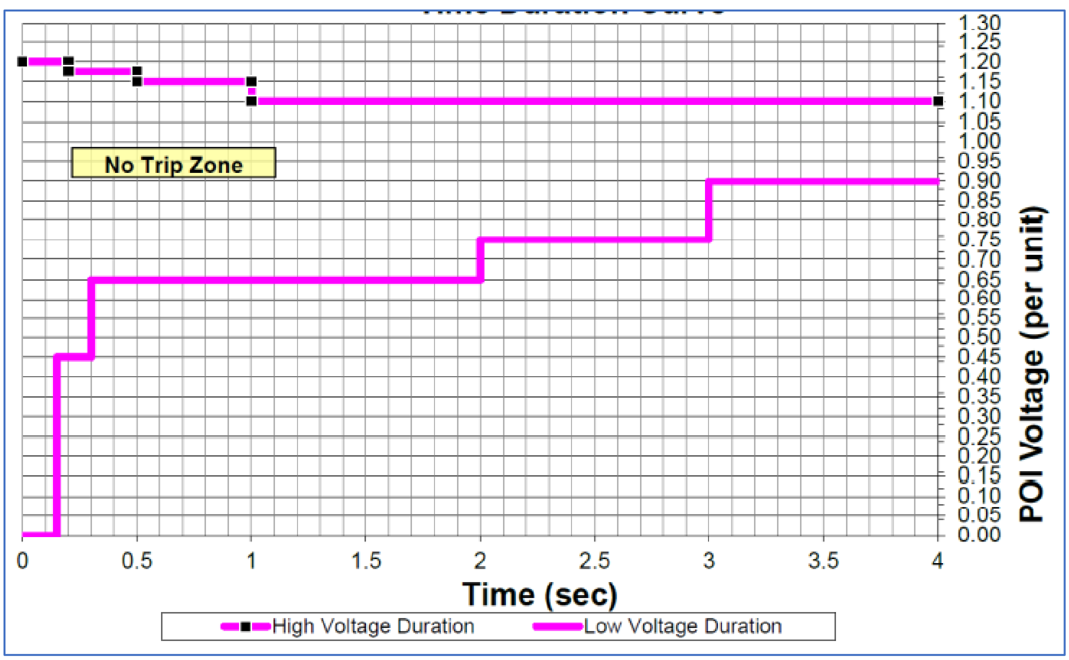

Figure 5: PRC-024 NERC Voltage Ride-Through Time Duration Curve

Meeting LVRT requirements under weak grid condition is challenging for PE inverter-based plants operating based on grid following technology due to the following reasons.

- High rate of change of bus voltage angle - (limitations in Phase Locked Loop response).
- Larger voltage phase angle change following a system disturbance - (limitations in Phase Locked loop response).
- dV/dQ sensitivity of the weak grid.

- Low voltage ride-through performance is critical under weak grid conditions.

- Tripping of the plant will reduce voltage control capacity in the weak local area (where synchronous machines that can provide support are already limited or nonexistent).

- Tripping of the plant will reduce power transfer in (potentially long) lines or cable, further complicating voltage control requirements.

- Tripping of multiple plants (or large plants) will impact system frequency and stability [16,17].

5.4.2 Control Interactions

Control Interactions (CI) is a specific issue that can impact the coordinated operation of Power Electronic devices in a local area. Control systems of dynamic devices can interact in an undesirable manner resulting in unstable or poorly damped oscillations following system disturbances such as fault recovery. Integration of large-scale power electronic based devices to the power systems has elevated the need to analyze the potential CI risks; especially when two or more dynamic devices are operating in parallel at relatively weak grid locations. The fast-acting reactive power controllers are identified as a primary contributor to CI issues. Generally, if CI issues are identified at design stages, these issues can be mitigated through careful tuning of control parameters [2,4].

Based on MHI experience, the following conditions are identified as situations for high potential for CI risks:

- The dynamic devices are connected to a weak grid location.

- The dynamic devices provide fast reactive power support.

- The reactive power controllers have comparable response times.

- Devices that can lead to control interactions are Wind, Solar PV, HVDC, STATCOMs and conventional power plants with fast acting exciters and PSS.

- Interactions between windfarms.

- Interactions between HVDC ties (Ex: Nemo & Nautilus in Europe) and windfarms.

- Interaction with the rest of the AC power system.

ERCOT has dealt with sub synchronous interaction issues for over 10 years and have provided several useful observations [18].

- SSR/SSCI events were not easily observable.

- In many ways, the disturbance appeared to be a simple relay trip.
- Detection of oscillations required high resolution measurements.
- PMUs are not suitable for detecting SSCI events.

- Reproducing the disturbance requires detailed analysis.
  - Model adequacy and assumptions are critical.
  - Need to represent other dynamic devices in the vicinity as well as a significant part of the ac system in an EMT type simulation setup.
  - IP issues when having to obtain vendor level models from different entities.

- Controller tuning is inherently difficult.
  - Tuning has to consider a variety of grid conditions and dispatch conditions – tuning to damp oscillation under a N-x condition may impact robustness of operation under normal grid conditions (example – Fault Ride Through under normal conditions).
  - May require controller re-design (not simply a parameter change) – Damping controllers for sub synchronous frequency ranges are harder to design, and if not done judiciously, may impact robustness under normal operation.

- Mitigation is vendor specific, and their participation is required in most situations.

The Maritime Link HVDC, with newer VSC technology, was designed to operate in a "weak grid" to support the integration of renewables. It was designed to avoid adverse sub synchronous torsional interactions with existing thermal plants. With the significant increase in IBR and PE, their control systems interaction with NSPI generation plants requires detailed study to ensure there is no adverse interactions not only between the PE controls but with the shafts on the remaining synchronous machines.

5.4.3 Sub Synchronous Control Interaction

When an IBR is connected to a network, the voltage and phase at the IBR terminals are each sensitive not only to the inverter output but also to the output from other nearby IBR projects or FACTS devices. This cross-coupling of control loops within as well as between projects provides many opportunities for resonances and Sub-Synchronous Control Interactions (SSCI) to manifest. [15]

Sub Synchronous Control Interaction and Instability is a specific concern when IBRs are connected close to series compensated lines. The IBRs (especially Type 3 wind units) may provide negative damping to sub synchronous frequency voltage and current transients that can result due to disturbances near series compensated lines. NSPI does not have series compensated lines at this time. However, they are under consideration for some studies and the potential for SSCI will need to be taken into consideration.

5.4.4 Sub Synchronous Torsional Interaction

Mechanical shafts of generators will undergo transient torque oscillations following disturbances in the electric network. Large and poorly damped transient torques can damage the generator shaft or impact the shaft life due to material fatigue. Each occurrence of such an event will reduce the shaft life. Network events that can lead to large amplitude transient torque oscillations are system faults, transmission line switching and insertion of series capacitors.

SSTI due to interaction with power electronic converters:

Power electronic converters and their controls can interact with the natural modes of generator shafts and give rise to poorly damped mechanical shaft oscillations. A main objective of EMT study is to investigate possible SSTI impacts due to interactions with power electronic based devices (STATCOM, HVDC, wind) in close vicinity of generating stations in transmission system.

Torsional interactions due to network resonance conditions:

In addition to SSTI due to interactions with power electronic converters, transient torque magnitude and damping can be negatively affected when series compensated transmission are located in the vicinity of the generator. The addition of series compensation will change the overall network electrical characteristics (network resonance points) of the system, when viewed from locations close to the series compensated line ends. Of specific interest from a sub-synchronous resonance and interaction point of view, is the network series resonance points at sub-synchronous (below 60Hz) frequencies. During disturbances (faults, switching, capacitor insertion, etc.), the transient voltage and current waveforms will contain dominant frequency components corresponding to such resonance frequencies (fe). The transient sub-synchronous currents entering the electrical machines will lead to torque oscillations at complementary frequencies (60-fe) and present potential risk to thermal generators and their mechanical shaft-mass systems.

If a natural frequency (fm) of the mechanical shaft mass system is close to the complement of the sub-synchronous network resonant frequency (60 – fe), the interaction between the electrical (generator/line series capacitor) and mechanical systems (long shafts and masses of thermal units) can result in a unstable resonant condition. This condition can be avoided through careful consideration at the system planning stage or by adopting necessary system operating practices.

5.4.5 IBR Low Frequency Oscillations

According to field results and detailed simulation-based studies, the operation of many inverter-based devices in a weak network area can result in sustained low-frequency oscillations. The oscillation frequencies are typically in the 8 Hz – 12 Hz range. Even though these oscillations are small in magnitude and stable, the frequency range is of concern from the standpoint of visible flicker. This is a relatively new finding, first observed in Australia around 2019. CIGRE paper[2] "Practical experience with mitigation of sub-synchronous control interaction in power systems with low system strength" [15] documents low frequency oscillation phenomena experienced in Australia. The network contains high numbers of IBRs, SVCs and STATCOMs and under specific conditions may show network oscillations due to controller interactions.

This is an important area for NSPI to explore and model thoroughly as they will have high IBR penetration and solutions for System Strength issues include SVC, STACOM and other dynamic equipment.

5.4.6 RoCoF

The addition of IBR and the subsequent phasing out of conventional generation in Nova Scotia has potential to adversely impact the system RoCoF. This in turn will have impacts on the stable operation of IBRs that are based on grid following technology (current technology) as well as the ability of legacy plants to stay online during frequency events.

"System Rate of Change of Frequency, A GHD survey of international views, identified RoCoF as a potential concern as IBR increases [12]:

- System operators are concerned that legacy generators may not be able to comply with the RoCoF ride-through requirements expressed in grid codes and that failure to ride-through could further exacerbate a RoCoF event.
- ENTSO-E review of global experience with high RoCoF events suggests that emergency controls like UFLS may not manage to prevent blackouts if RoCoF exceeds 1 Hz/s measured over 500 ms.
  - NSPI needs a better understanding of RoCoF ride through capability of the existing generation fleet and DER.
  - MHI recommends a survey of NSPI generation plants and DER to determine the RoCoF needed for NSPI to avoid a cascading event.
- For larger networks, like the European interconnected system, the highest RoCoF events are expected following events that lead to the formation of islands that are separated from the primary interconnected system
  - When NSPI says connected to the Eastern interconnection during a grid disturbance RoCoF will be low.
  - A second AC tie to a neighbouring area would reduce the inertia required to maintain a low RoCoF. With two 345kV tielines, it would take n-1-1 to island NS. Rather than

[2] This paper [15] examines a phenomenon regarding controller interaction that has been observed in transmission systems with a high penetration of IBR devices and can be reproduced in detailed wide-area models. The paper looks at the practical consequences of these interactions in a wide area simulation of the Queensland (Australia) transmission network.

maintaining a required RoCoF for system design, fast acting jets, FFR or inertia forming machines could be dispatched out of merit for that short duration when one of the 345kV lines was out of service for maintenance or trip event.

The existing operating guidelines for NSPI would allow for system conditions that could result in a RoCoF of up to 2.5 Hz/s over a 500ms sample time for loss of the NB tie. For First Stage studies, NSPI will strive to maintain the current allowable minimum RoCoF of 2.5 Hz/s.

MHI recommends that network response under high RoCoF contingencies be verified through EMT simulations for the existing RoCoF allowable for NSPI. 2.5 Hz/s on a 500ms sample time is higher than that usually seen in industry.

5.4.7 Motor Starting

Industrial motor starting has been a critical consideration of the NSPI power system planning process. With the expected penetration of IBR, EMT study-based verification may be required in specific situations. Data has been collected from the large manufacturing plants in Nova Scotia and plant models are under development to assess any adverse impact to the ability to start large motors via EMT study.

5.4.8 Transformer Inrush

NERC technical report: "Integrating Inverter Based Resources into Low Short Circuit Strength Systems" [9] raises concerns for the energization of transformers in a weak grid. Transformer inrush current initial peak magnitude can be significantly greater than the rated transformer current (3-8 times typically). The inrush currents decay relatively slowly, typically taking few hundreds of milliseconds to a few seconds to settle to lower (typically around 1% of the rated transformer current) steady state levels. The high inrush currents can cause voltage dips near the transformer location. This is specifically an issue when energizing transformers at weak grid locations. The voltage dip magnitude and the duration can impact the operation of other PE based plants in the local area. If the voltage dip magnitude and duration exceed the required low voltage withstand limits of the other plants, there is risk of plant tripping.

6 Potential Mitigation Options

Technology to support the integration of renewable energy sources is evolving quickly, in particular for IBR sites with PE controls. The following are mitigations under consideration to resolve issues identified as having the potential to have an adverse impact on the Nova Scotia grid. Some technologies are mainstream and well understood, some are emerging technologies and it remains to be seen how effective they will be.

6.1 IBR Control System Design

Fault ride-through, control interactions, RoCoF control, and low frequency oscillations are the primary concerns. The most cost-effective solution, where possible, may be the re-tuning of control settings or adoption of alternate control strategies (e.g. active or reactive power control, inverter level voltage control loops). A fast active and reactive power response from an IBR has the potential to effectively replace inertia from traditional plants.

6.1.1 Mechanical Inertia from WECs

Recent development in WEC turbines allow for the short-term extraction of mechanical inertia in wind turbine generators. IBR control design can support the fast delivery of this mechanical inertia to the grid. There are requirements on all new WECs to provide a frequency support contribution to the NSPI grid and that can include mechanical inertia from the turbine.

6.1.2 Grid Following and Grid Forming Inverters

Typically, IBRs have been grid following – taking a reference signal from the grid and matching output to synchronize with the grid angle and voltage. System voltage and frequency is maintained by SIR from synchronous generation sources. This works very well – until it doesn't. If there is a lack of additional grid strengthening measures to replace SIR as IBRs increase and synchronous generators are retired, there is potential for a reduction in System Strength. In a weak grid, the ability of the grid following inverters to follow and synchronize with the grid is reduced as voltage can change rapidly and the wave form becomes distorted. Once a grid following IBR loses synchronism, it may disconnect from the grid. In this scenario, with a large number of IBR online, a cascading event may occur resulting in significant adverse impact to the interconnected system. There is ongoing research and study into mechanisms to a keep grid following inverters online through a wider range of grid events.

Nova Scotia has 600MW grid following IBR at this time and anticipates a future grid with a much higher penetration IBR. In addition to having grid following IBR ride though on a weak system (as described above), there is also a focus on having IBRs strengthen the grid locally in addition to staying online. This approach would have an IBR to operate in "grid forming" mode or with novel control concepts such as "virtual synchronous machine emulation".

Grid forming inverters quickly change output to control voltage and frequency in a manner similar to a traditional synchronous machine. This energy source for grid forming IBRs can be batteries, wind, or other sources (PV, energy supplied across a HVDC link) [19, 20]. Grid-forming controllers have the potential to replace grid following controllers to augment the lower amount of available SIR in a high renewables grid.

There is significant research and in service projects supporting the advancement of IBR control systems:

- The NREL paper “Research Roadmap on Grid-Forming Inverters” provides a good overview of the challenges of increased inverter controls on the power system and the need for technical and system roadmaps to enable a 100% power electronics grid. Inverter-based, grid-forming resources will be necessary for the stable operation of the bulk power grid. [20]

- The Australian National Energy Market operates a high IBR grid in combination with synchronous generators online in all regions to ensure secure operation of the power system. As they move to periods of operation with fewer synchronous generators online, they have identified grid forming inverters as having the potential to support System Strength over and above what is needed to facilitate their own connection to the grid [19].

- The Dalrymple Battery Energy Storage System, a grid forming inverter BESS in South Australia, has demonstrated the ability of grid forming inverter control systems to strengthen the grid by replicating the behaviour and performance of a synchronous machine, providing reliability and flexibility services such as fast power injection, seamless islanding and black start of the local distribution network [21, 22]. The addition of frequency control, System Strength and high fault current from the grid forming BESS can allow higher levels of renewables to connect and operate.

- The Maritime Link (ML), a VSC HVDC link between Nova Scotia and Newfoundland is an application of an inverter-based PE control system strengthening the grid. It has demonstrated frequency support for Nova Scotia during contingency events when all or part of Nova Scotia disconnected from the North American grid. Fast response over the HVDC link helped arrest the frequency decline when power imports into the area were lost. The ML has also supported the island of Newfoundland when generation on the island tripped off or power imports suddenly dropped. The fast response of the controls provided a FFR that avoided or reduced the disconnection of customer load to stabilize the grid. The ML HVDC has also been designed with the capability to startup a blacked-out grid. While this has never occurred in Nova Scotia, there is always have a plan for “Black Start” This has traditionally focused on using smaller black start generators to get synchronous resources back up as fast as possible. As we move to renewables, we will need to redesign our “Black Start” plan and grid forming controls have the potential to be an important part of that plan.

6.1.3 Fast Frequency Response

Figure 6 in Section 7.1.2 demonstrates the ability of FFR from an IBR in damping a frequency deviation for a system disturbance. FFR from HVDC, BESS and other fast acting devices will be a valuable source of fast response to a drop of generation in NS. Storage device such as BESS that can provide a sustained response allowing the System Operator to ramp generation will be particularly valuable. These systems have the flexibility to rapidly change the injection or consumption of active power depending on state of charge at the time.

6.2 BESS

BESS can support the management of the energy supply in a renewable energy dominated NSPI system. Additionally, with appropriate specifications, the fast-acting nature of BESS inverters can also be used to mitigate stability related concerns. BESS systems are potentially the best candidate in the near term to provide grid-forming and virtual synchronous machine response.

6.3 Synchronous Condensers

The addition of synchronous condensers at selected locations in an electrical system is an effective technical solution to facilitate high IBR penetration. It is expected that additional synchronous support will be required for the NSPI grid to enable very high penetration of IBR. The study will also identify recommended locations and ratings as applicable.

Research and conversation with vendors is also ongoing to better understand the design and specification of synchronous condensers to support System Strength. For example, static excitation looks to provide better SCMVA support than brushless excitation. EMT models have been requested from vendors and assessment of the potential value to better support System Strength is underway.

In addition to System Strength support, synchronous condensers also provide RoCoF support and frequency oscillation damping during system disturbances.

6.4 FACTS, SVCs, STATCOM, Switched and Static Capacitor Banks

Both fixed shunt devices and dynamic voltage control devices can help mitigate local IBR connection challenges. The size and locations are identified during the interconnection study process.

6.5 Fast Acting Synchronous Generation

As the penetration of IBR increases, many of the larger synchronous thermal units will be phased out or operating infrequently. To plan for peak load periods when sufficient wind and imports are not available, there will be fast acting synchronous generators that can ramp up quickly to meet any energy shortfall. These sites can be specified to have synchronous condenser capability that can be dispatched as needed to support the local area when they are not operating as generators, enhancing the value provided by these new assets.

6.6 Transmission Connections

New transmission paths will generally strengthen a power system. The more the ties between areas of a power system the stronger the ability of the system to withstand grid events. For Nova Scotia, additional transmission connections with neighbouring area could mitigate high RoCoF concerns and raise SCMVA in the vicinity to the tie line terminus. Two area were noted with the potential to improve the ability of the greater area to increase IBR resources and operate over a wider range of system conditions.

6.6.1 Second Tie with NB

The addition of a second 345kV transmission line to New Brunswick would improve System Strength available from New Brunswick in the Onslow area and reduce the impact of the most critical contingency of the present system. In particular, the NSPI system can experience high RoCoF for the loss of the existing 345kV line under high imports. As IBR increases in Nova Scotia, keeping the RoCoF down may involve significant additional grid support and a second tie is a viable grid support option. The benefit of a second tie line to reduce RoCoF would be weighed against the reduction in System Strength if synchronous units are no longer online. In particular, the eastern and western areas of the province at 69 and 138kV may see SCMVA dip below that needed to keep WEC facilities online during a system disturbance.

6.6.2 Transmission Reinforcement in Western Nova Scotia

Traditionally a weak area of the NS grid, the western area of the province may need additional transmission build to support growing load. In the ongoing PSS®E studies, there are voltage and SCMVA violations for the 2030 load and generation dispatch. As new transmission lines help support the grid, additional transmission connections in this area may resolve many of these issues and allow for additional wind projects in this area.

6.7 Operating Guidelines

It is important to consider credible operating conditions when identifying potential issues and corresponding additional investments to strengthen the system. As an example, curtailing a portion of wind output during outlier conditions (e.g. high wind / low load, high wind / high AC imports) may be less expensive than building a system that would be stable under those conditions. Redispatch for rare combinations of system conditions that are causing an adverse impact may be more economic than designing the system to run without restrictions for all hours. Curtailed wind farms can be utilized for AGC control and the ability to ramp quickly providing FFR to the grid.

7 Findings and Recommendations

This study scope includes full EMT assessment. Due to delay in getting adequate EMT generation and load facility models, it was determined that the initial findings and recommendation should be published immediately. An updated report will be published when the EMT studies are complete.

Findings and recommendations provided in the following sections are based on the following:

- Technical literature reviews on industry experience and best practices.
- Technical workshops and discussions with industry experts including NSPI's consultant MHI.
- First Stage Studies assessment of inertia (including RoCoF) and SCMVA based on PSS®E studies, considering the present system and the 2030 projected system.

7.1 Findings

NSPI can incorporate renewables, in particular IBR resources, limited only by the load to be served and the best economic dispatch to meet target metrics for renewables. There will be technical challenges and the grid will need significant support as many legacy plants are phased out or converted to alternate fuels. That said, it is achievable with the existing and evolving technologies.

7.1.1 IBR for Frequency and System Strength Support

A decade ago, IBRs were not considered to provide good frequency and System Strength support. However, this is changing due to the introduction of new frequency and voltage control strategies.

In general, for IBRs to provide frequency support they must be operated below their maximum available power, such that it allows for the power output to increase or decrease as required. This is counter to typical IBR renewable energy generation dispatch, where they are set to generate the maximum available power. The NSPI strategy to maximize energy from renewable resources will allow for curtailment of wind as needed to provide frequency control or AGC headroom. BESS will also be used for the same support when available. Together these IBR will provide FFR and be able to change output quickly to meet the tie schedule during periods of high volatility of wind energy.

IBRs can also provide grid support during voltage excursions, both under voltages or over-voltages. IBR is generally required to inject or absorb current (1 pu or more of the plant rating) to maintain fault current levels so that existing system protection and relaying will have reliable levels of fault current to detect system faults. Most modern IBRs can provide up to 100% reactive current (Iq) during faults, thus contributing to the overall short-circuit MVA of the system. There is however a caveat to this last statement. Different definitions of short-circuit MVA should be adopted at this point:

- Short circuit MVA for fault detection and protection purposes.
    - This can include contribution of both synchronous machines and IBRs. This becomes crucial the weaker the system becomes.
- Short circuit MVA when using this quantity to assess System Strength (for IBR interconnection screening).
    - The prudent approach, due to potential interaction between IBR plants, is to not consider the contribution of IBRs in the overall calculation of the SCMVA.

7.1.2 Minimum System Inertia and FFR

The PSC study [23] performed for NSPI in 2019 documented the following:

- *A minimum of 3266 MW.sec of synchronous inertia will be required for steady state operation.*
    - *Synchronous condensers generally provide relatively low inertia, with inertia constants of less than 1.6 MW.sec/MVA.*
    - *High inertia SC designs fitted with flywheels can provide inertia constants of greater than 5 MW.sec/MVA.*
- *The kinetic inertia constraint was modeled at 3266 MW.sec minimum online requirement*
- *This is derived as allowing an approximate contingency of 500 MW.sec (~1 thermal generating unit) above the level of 2766 MW.sec that was found to be required for stability in the 2019 PSC Study*

The above was a recommendation based on study with four dispatch cases and did not consider RoCoF or System Strength. With a greater set of scenarios, studied in this assessment, it was found that the inertia requirement is not a static number but varies depending on system configuration and generation dispatch. Based on the First Iteration study results, as documented in this report, the methodology to maintain sufficient inertia for NSPI will be based on the RoCoF limit and criteria identified in the previous sections.

Until further research or study dictates otherwise, NSPI will study inertia and FFR based on current operating guidelines to achieve a RoCoF under 2.5 Hz/s on a 500ms sample time for its most severe contingency. That said, this metric should be reviewed to determine if it is suited for a grid with IBR as a high percentage of online generation.

There are many sources of inertia and FFR on the current Nova Scotia grid that contribute to arresting RoCoF. In addition to the large thermal units, the following also provided support to arrest frequency decline.

- Small and large hydro plants

- Biomass facility
- Customer facilities with large machine loads
- Maritime Link with FFR enabled.

In particular, the FFR provide by the Maritime Link provides very good RoCoF arresting capability. Simulation indicates that the ML with +/- 50 MW on frequency control can generally perform equivalent to a large synchronous machine with over 700 MW*s of inertia. This indicates that grid forming IBR with FFR will be a valuable source of frequency and RoCoF control. The addition of an additional Voltage Source Converter HVDC source into the Maritimes Area would also provide an opportunity for frequency support between utilities on either side of the link. Grid scale batteries can also provide this type of sustained FFR.

Figure 6 below demonstrates the response of the ML (ACTIVE_POWER [MW]), to a frequency drop in Nova Scotia during a system disturbance during which Nova Scotia separated from the North American grid and became an islanded system. The threshold for the ML FFR to activate is 59.85 HZ. As can seen in the plot, the ML ramped power very quickly to help frequency recovery in Nova Scotia as it passed the triggering threshold.

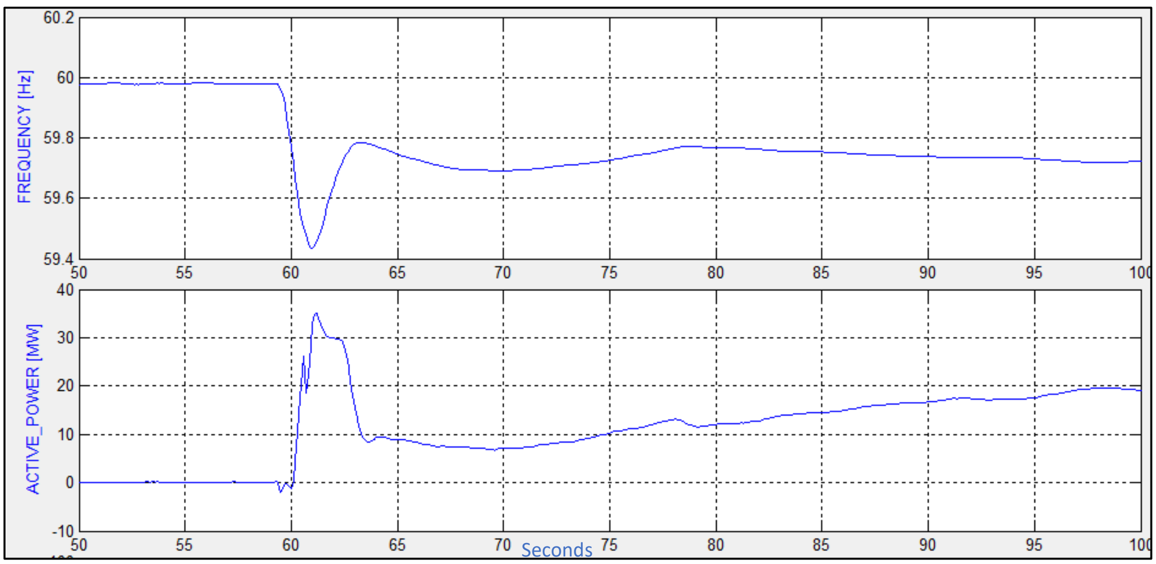

Figure 6: Maritime Link Frequency Response

Based on the above, with new technology and FFR capability, the inertia requirement for stable grid operation can be a dynamic value based on system load and generation mix. This dynamic requirement can be met via a combination of traditional SIR as well as FFR from IBR resources such as the HVDC link and BESS.

The minimum required online inertia requirement for frequency control, including RoCoF, has a range of 2224 MW*s under light load (Table 3) to 3181 MW*s (Table 2) during winter peak conditions. ML FFR can reduce this requirement to 1044 MW*s and 2404 MW*s respectively for the study scenarios.

As noted, the above assessment addressed only frequency control in line with the original PSC study. Depending on the location of the frequency support, additional SIR may be required online at specific locations to maintain SCMVA.

7.1.3 EMT Model Quality

IBR control systems and operating modes are evolving rapidly and have the potential to strengthen the grid and support a 100% renewable energy dispatch in Nova Scotia. Detailed analysis of options may provide more targeted and cost-effective solutions to directly address underlying issues without increasing the short circuit level. In this endeavor, high quality EMT models of the network and IBRs are essential for understanding the underlying phenomena and evaluating the possible solutions [15]. To study the effectiveness of these evolving technologies, vendor provided simulation models allow limited access to control parameters. While most vendors do provide access to specific inputs such as postfault power, reactive power ramp rates and plant level control gains, at present, models are frequently not performing well in large simulation cases and not always a good match for the planned or in service equipment.

The most critical element to developing project specifications and requirements is to have robust EMT models of the existing and proposed facilities as well as for new and evolving technology.

7.1.4 Operability

As the grid moves to higher penetration of IBR, reduced SCMVA that occurs due to forced outages and planned maintenance will need an assessment for SCMVA and IBR stability. This may be in the form of updated guidelines or real time studies. Real time data needs may increase substantially and real time calculations for inertia and SCMVA at critical buses may need to be visible to Transmission Operations staff.

- ***Distributed Energy Resources***

Increases in the total MW of DER and other behind the meter generation will pose a risk as it may not have the associated System Strength to remain stable during system disturbances. As IBR generation sources not controlled by the System Operator become a larger percentage of online generation, detailed study will be needed to understand the potential impact. At this time, it is not modelled or considered in the system studies as an IBR source due of lack of models.

- ***Protection and Control***

The expected short circuit levels, considering fault current contribution from IBR as well as without a contribution from IBR is noted in the above. This information and EMT study results should be reviewed by protection engineers to verify that the reduced fault current levels will not impact existing relay performance. The contribution of negative sequence current from generation sources for the new grid configurations should also be reviewed for Protection device impacts.

- ***Motor Load Customers***

Motor starts as noted in Section 5.4.7 and other reliability concerns for the industrial customer should be assessed for any significant change in point of interconnection conditions. As the transition to 2030 progresses, individual site specific studies will be needed to identify any issues that may require mitigation.

- ***Transformation***

Inrush issues may arise as noted in Section 5.4.8 and will be evaluated on a case-by-case basis as new plants and equipment are connected to the grid.

7.2 Recommendations

The following recommendations are advised to enable large scale integration of Inverter Based Resources in Nova Scotia.

7.2.1 Stable and Reliable Integration

Recommendations to facilitate the integration of renewables on the timelines in place for Nova Scotia:

- 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. The existing allowable RoCoF for NSPI may be too high, which could lead to cascaded tripping for loss of the NS/NB tieline under high import conditions. It should be noted that when NSPI stays connected to the Eastern interconnection, the RoCoF will be low. A second tieline in service would remove the RoCoF constraint. For the short timelines associated with a forced or maintenance outage for a NS/NB tieline, out of merit dispatch of hydro and fast acting generation in Nova Scotia would mitigate potential grid restrictions.

- 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.

- 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.

- Update Distribution System Interconnection Requirements to align with IEEE 1547-2018 Category 3 for RoCoF. It may be necessary to specify type and RoCoF class for future DER as there is the possibility of a cascading tripping event under maximum RoCoF conditions. See Section 3.2.

- 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 additional IBR facilities. The performance of many of these existing facilities in a high IBR grid is well below that expected of newly connected facilities.

- Perform incremental studies for each wave of load and generation additions, and generation retirements to the NSPI grid. The cases for this analysis studied the 2030 grid with the load as forecast in 2020. Due to the limitations of SCR as a planning metric, MHI recommends NSPI conduct a full grid study in PSS®E and PSCAD™ for each round of new IBR to be added to the NSPI grid to identify transitory conditions or operational challenges. For the next wave of wind integration, well before 2030, the studies should look at confirmed in service changes to the system and updated load forecast. All system operating guidelines will need review, and many will need to be updated; this is estimated to require 1 to 2 years to complete.

- 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. Rather than in the eastern area of the province, where the existing thermal fleet is concentrated, there may be benefit in spreading the grid support mechanisms around the province. For example, today the Valley and Western areas of the province are weaker areas of the grid.

7.2.2 Resource Planning for High IBR Penetration

Recommendations to facilitate current and future economic generation dispatch for increased renewables on the timelines in place for Nova Scotia:

- Update IBR and inertia constraints for Plexos modelling.

- Adequate frequency response is highly dependent on system load, particularly for RoCoF. Under certain conditions, higher inertia requirements than currently used in resource planning have been identified, see Section 3.2. 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.

- The requirement for inertia to support the Nova Scotia grid is not completely removed with the addition of a second NS/NB tie. It is reduced and should be captured in the metric identified in the bullet above. Specifically, inertia or its equivalent, will be required in the long term and day ahead planning to maintain the SCMVA required for stable operation.

- 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. It will need to be dynamically planned and dispatched in the future grid as it will be highly dependent on the generation mix online.

At the present time, studies indicate that there is no hard limit on IBR penetration and dispatch if there is adequate frequency and System Strength support online.

7.2.3 Good Planning Practice

Recommendations to implement good planning practices to the integration of renewables in Nova Scotia:

- MHI recommends performing an annual assessment of NSPI System Inertia and Strength requirements in the 10-year horizon to identify potential issues. See Section 2.2. Include FOR and planned maintenance outages in assessment. Confirm a generating unit outage can be managed with operating guidelines and/or out of merit dispatch.

- Document and publish updated model requirements for Load and Generation customers. See Section 5.2.
    - 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.
- 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.

- Maintain SCMVA as per Section 4.1 unless studies determine that lower levels do not adversely impact NSPI customers.

7.2.4 System Operator Transition to High IBR Grid

Recommendations to support the System Operator transition to a grid with high IBR online.

- Develop a methodology to estimate the minimum SCMVA and SCR online prior to the addition of additional IBR (WEC, BESS, HVDC etc.) to the NSPI grid for operating guidelines and Outage Coordination.

- 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.

- 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.

7.2.5 Black Start Restoration Planning

Recommendation to support restoring a blacked out grid:

- Review and assess potential Blackstart options for the planned 2030 grid, considering the generation mix available a that time.

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Appendix A: SCMVA Benchmark Values

Tables redacted in document to be released to the public due to sensitive customer information.

Appendix B: Sensitive SCMVA Buses

Tables redacted in document to be released to the public due to sensitive customer information.

Appendix C: SCR Sensitive Facilities

Tables redacted in document to be released to the public due to sensitive customer information.