

# Agenda

## Board of Trustees Meeting

April 16, 2026 | 12:00 -12:45 p.m. Eastern  
Virtual

### Attendees

Webinar Link: [Join Meeting](#)

Webinar Passcode: BoardApr26ATT

Audio Only:1-415-655-0002 US | 1-416-915-8942 Canada | Access Code:2317 204 7947

### Call to Order

[NERC Antitrust Compliance Guidelines](#)  
[NERC Participant Conduct Policy](#)

### Introduction and Chair's Remarks

### Agenda Items

1. **Level 3 Alert Essential Actions to Industry: Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control\* – Approve**
2. **Amendment to Nova Scotia Memorandum of Understanding\* – Approve**
3. **Other Matters and Adjournment**

\*Background materials included.

## **Level 3 Alert Essential Actions to Industry Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control**

### **Action**

Approve publication on May 4, 2026: the *Essential Action to Industry: Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control* in substantially the form presented (the Level 3 Alert).

Limited delegation of authority to the NERC Chief Executive Officer and President to approve updates to Level 3 Alert based on feedback from the Reliability and Security Technical Committee (RSTC), industry trade groups, forums, or the Federal Energy Regulatory Commission (FERC) in April 2026.

### **Background**

Since 2022, NERC has analyzed numerous load loss events across both the Eastern Interconnection and the Texas Interconnection resulting from unexpected disconnection of computational loads. These load losses were not predicted through the current planning studies. In response to these disturbances, NERC published an Alert titled *Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations*<sup>1</sup> (the Level 2 Alert) in September 2025. The analysis of the responses to the Level 2 Alert showed that computational loads, such as data centers, could increase exponentially in the next four years and that there are significant risks to the bulk power system (BPS) that need to be addressed through immediate industry action. These findings were underscored by discussion at NERC's February 2026 Large Load Technical Conference as well as work by the NERC Reliability and Security Technical Committee Large Load Working Group.

NERC has determined a set of immediate, Essential Actions that registered entities should take to reduce the risk to the BPS and warrant issuance via a Level 3 Alert. These actions relate to the modeling, studies, monitoring, commissioning, operation, protection, and control of computational load. The Level 3 Alert actions are also beneficial to computational load entities, currently not registered under NERC's existing registry criteria, seeking to interconnect to the BPS. The Level 3 Alert is intended to be published and implemented while NERC develops updates to its registry criteria and Reliability Standards to account for the needs associated with computational loads.

On April 7 through 14, 2026, NERC shared the draft Level 3 Alert with the RSTC, industry trade groups, forums, and FERC for socialization according to NERC's Level 3 Alert process. The Board of Trustees has received the Level 3 Alert for review and discussion at the April 16, 2026 meeting.

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<sup>1</sup> Available: <https://www.nerc.com/globalassets/programs/bpsa/alerts/2025/nerc-alert-level-2--large-loads.pdf>

## Summary

This Level 3 Alert is set to be issued to Transmission Owners (TO), Transmission Planners (TP), Planning Coordinators (PC), Transmission Operators (TOPs), Reliability Coordinators (RCs), and Balancing Authorities (BAs) to implement changes to the modeling, studies, monitoring, commissioning, operation, protection, and control of computational loads in order to mitigate specific risks to the BPS.<sup>2</sup> In developing the proposed Level 3 Alert, NERC provided Regional Entities, FERC, trade organizations, and other applicable governmental authorities with the opportunity to provide comments. The Level 3 Alert, incorporating received feedback, will be provided to the Board prior to publication on May 4, 2026.

## Essential Actions

The Level 3 Alert consists of seven Essential Actions, summarized as follows:

1. TPs and PCs should develop a detailed list of modeling data, settings, and parameters needed from computational loads and distribute this to TOs in their footprint.
2. TPs and PCs should study the stability margin in their area at least annually for areas with computational loads.
3. PCs should revise their definition of “qualified change” that triggers a review of local area protection, stability limits, and other reliability studies to account for computational load.
4. TOs should establish a commissioning process for computational loads.
5. TPs and PCs should study and implement System-side corrective actions with TOs to ensure no loss of firm load for computational load from normally cleared faults.
6. TOs should install and utilize dynamic fault recording devices to capture and share computational load facility electrical performance during System Disturbances.
7. TOPs, RCs, and BAs should establish Interpersonal Communication capabilities with computational loads to improve their situational awareness.

These actions are further explained in the text of the Level 3 Alert.

## Proposed Timing:

The Level 3 Alert timeline is as follows:

- Draft distributed to RSTC, trade groups/forums, FERC: April 7, 2026
- Comments requested from RSTC, trade groups/forums, and FERC: April 14, 2026
- Publishing date: May 4, 2026
- Distribution: TPs, TOs, PCs, RCs, BAs, TOPs
- Response: Reporting required by Midnight Eastern on August 3, 2026

The Alert seeks responses from entities registered as a TP, TO, PC, RC, BA, or TOP. These entities are asked a total of 29 multiple choice and 1 open text response questions to evaluate the implementation of the Essential Actions in the Level 3 Alert. Since no data submissions are required, NERC staff expects this alert to be much less time-consuming and resource-intensive

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<sup>2</sup> For a comprehensive set of known risks, see *Characteristics and Risks of Emerging Large Load* available here: [https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/3\\_doc\\_white-paper-characteristics-and-risks-of-emerging-large-loads.pdf](https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/3_doc_white-paper-characteristics-and-risks-of-emerging-large-loads.pdf)

than prior alerts. NERC will compile and submit a report to FERC within 30 days of the deadline to respond (i.e., August 3) in accordance with the Rules of Procedure.

NERC Management is seeking Board approval to issue this Level 3 Alert Essential Actions on May 4, 2026 in substantially the form presented with updates approved by the NERC Chief Executive Officer and President. Out of an abundance of caution, delegation of the Board of Trustees' authority to approve any updates to the Level 3 Alert prior to publication that are made in response to recommendations RSTC, industry trade groups, forums, or FERC in April 2026 to the NERC Chief Executive Officer and President.

# Level 3 Alert

# Essential Actions to Industry

Computational Load Modeling, Studies, Instrumentation,  
Commissioning, Operations, Protection, and Control

Board of Trustees Meeting

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Latrice Harkness, Director, Engineering and Security Integration  
Darrell Moore, Director Reliability, Risk, Management

April 16, 2026

## Purpose

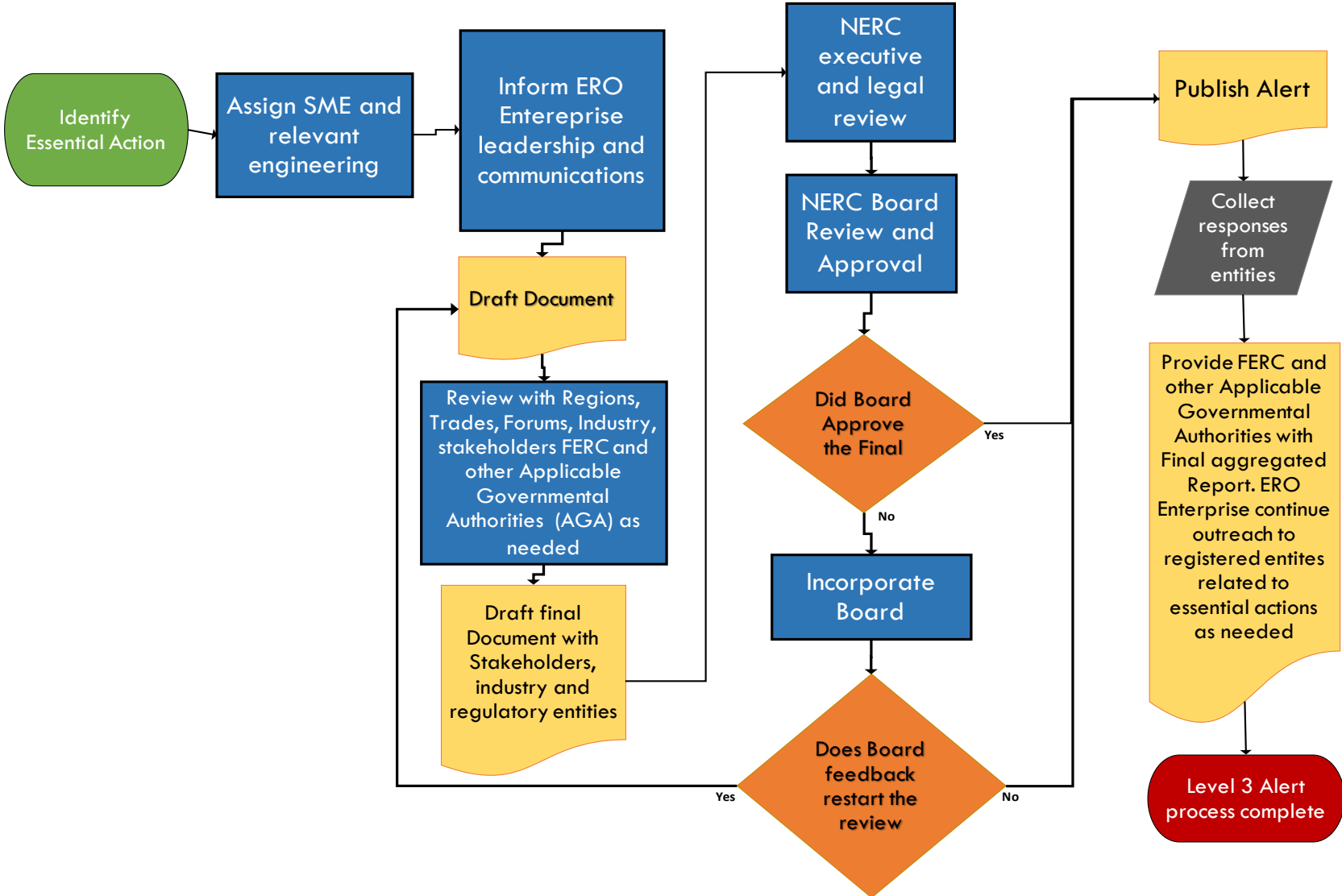
# Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control

The purpose of this alert is to ensure essential actions are taken by Registered Entities to address the risks posed by computational loads interacting with the bulk power system (BPS).

NERC issued a previous Level 2 Alert Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations that discussed the recommended practices NERC deemed to address the emerging risks from “Large Loads”.

In the responses to the Alert, NERC found that entities generally did not have sufficient processes, procedures, or methods to address emerging computational loads while reiterating historic experience with traditional non-power electronic non-computational load.

# High Level Diagram of Level 3 Alert Process





Essential Actions are specific actions that NERC has determined to be essential for certain segments of owners, operators, or users of the BPS to undertake to ensure the Reliable operation of the BPS.

There are 7 essential actions.



Under the ROP Board approval is required prior to issuance of a level 3 alert Essential Actions to industry.



This would be the Third level 3 essential actions alert issued by NERC.



NERC Management is seeking Board Approval to issue this Level 3 Alert Essential Actions to Industry Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control.

A light blue map of the United States is shown in the background. A vertical bar on the left side of the image transitions from dark blue at the top to a teal color at the bottom. The text 'NERC' is written in a bold, dark blue, sans-serif font on the left side of the map.

**NERC**

**Discussion**

## **DRAFT** Essential Action to Industry

Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control

Initial Distribution: May 4, 2026

**The purpose of this alert is to ensure essential actions are taken by registered entities to address the risks posed by computational loads interacting with the bulk power system (BPS).**

**NERC issued a previous Level 2 Alert Industry Recommendation: *Large Load Interconnection, Study, Commissioning, and Operations* that discussed the recommended practices NERC deemed to address the emerging risks from “Large Loads.” In the responses to the Alert, NERC found that entities generally did not have sufficient processes, procedures, or methods to address emerging computational loads while reiterating historical experience with traditional non-power electronic non-computational load. As seen in the released public report on these responses, NERC has found specific deficiencies with the treatment of computational load that includes artificial intelligence training, cryptocurrency mining, and traditional data center uses.**

**From the Level 2 Alert responses and seen in the subsequently released public report, NERC has determined a set of immediate actions that registered entities should take to reduce the risk to the BPS and warrant issuance via a Level 3 Alert. These actions relate to the modeling, study, installed fault recording or instrumentation, commissioning, operation, protection, and control of computational load.**

**NERC issues this Level 3 Alert for entities to implement specific changes to handle critical risks. Additional actions are discussed as part of NERC’s Large Loads Action Plan and include the draft registry criteria and Standard Authorization Request (SAR) for computational load posted in parallel path on NERC’s website on April 1, 2026. Responses will also help inform potential future standards revisions developed in coordination with NERC’s Large Loads Working Group of the Reliability and Security Technical Committee.**

[Why am I receiving this? >>](#)

[About NERC Alerts >>](#)

**Status:**

Acknowledgement Required by Midnight Eastern on May 11, 2026  
Reporting Required by Midnight Eastern on August 3, 2026



**PUBLIC:** No Restrictions  
[More on handling >>](#)

**Instructions:**

This Level 3 NERC Alert provides specific Essential Actions that NERC registered entities should consider in response to a particular issue. Pursuant to Rule 810 of NERC's Rules of Procedure,<sup>1</sup> NERC registered entities shall (1) acknowledge receipt of this advisory within the NERC Alert System, and (2) report to NERC on the status of their activities in relation to this Essential Action (as provided below). For United States entities, NERC will aggregate the responses and provide an anonymized report to FERC.

This Level 3 NERC Alert is not the same as a Reliability Standard, and it does not create a mandatory obligation to take the Essential Actions. Your organization will not be subject to penalties for failure to implement the Essential Actions. Issuance of this Essential Action, however, does not alter the requirements of any approved Reliability Standard nor excuse the failure to follow the practices discussed in the Essential Action if such failure constitutes a violation of a Reliability Standard. Registered entities must continue to comply with applicable Reliability Standards.

**Distribution:**

**Initial Distribution:** Transmission Planner (TP), Planning Coordinator (PC), Transmission Owner (TO), Balancing Authority (BA), Reliability Coordinator (RC), and Transmission Operator (TOP)

[Who else will get this alert? >>](#)

**Primary Interest Groups:**

Transmission Planning, System Operators, System Operators – System Protection, System Operators – Transmission Engineering

**Essential Action:**

Essential Actions are specific actions that NERC has determined to be essential for certain segments of owners, operators, or users of the BPS to undertake to ensure the Reliable Operation of the BPS. Pursuant to Rule 810 of NERC's Rules of Procedure (ROP),<sup>2</sup> NERC registered entities shall (1) acknowledge receipt of these Essential Actions within the NERC Alert System, and (2) report to NERC on the status of their activities in relation to these Essential Actions (as provided below). Confidential Information shall be protected in accordance with the provisions of Section 1500 of the ROP. As emphasized in Section 810, for example, NERC's report to FERC regarding actions taken in response to this Alert will include "appropriate protection for Confidential Information or Critical Energy Infrastructure Information."<sup>3</sup>

<sup>1</sup> <https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx>

<sup>2</sup> [NERC Rules of Procedure](#)

<sup>3</sup> Section 810(5) of the ROP.

Similarly, any public report with findings from this Alert will ensure appropriate protections under Section 1500 of the ROP.

**Essential Action #1:** TPs and PCs should develop a detailed list of modeling data, settings, and parameters needed from computational loads and distribute this to TOs in their footprint. TOs should reflect this in their facility interconnection requirements.<sup>4</sup> TPs and PCs should use the *PERC1* (Power Electronic Reconnecting and Ceasing)<sup>5</sup> model, or a model with equivalent or better capabilities, at minimum, as a base for these requirements.<sup>6</sup> Additionally, power electronic drives supplying cooling loads should also be represented with an appropriate model. Additionally, TPs and PCs should do the following:

1. Model the computational load records separate from other industrial loads. Additionally, model the computational load facility's Information Technology (IT) load separate from the non-IT load (see item 2.c. below).
2. Collect the following data from the computational load entity:
  - a. **Electrical Size and Power Factor**– Expected MW for minimum and maximum consumption, as well as expected power factor. If the computational load facility is expected to grow, include forecasted values for future-year studies.
  - b. **Dynamic Characteristics** – Collect the parameters for the dynamic representation of the computational and cooling loads response as well as control actions<sup>7</sup> expected to operate during simulated Disturbances.
  - c. **Composition** – Percentage of IT load versus non-IT load (e.g., cooling/motor load).<sup>8</sup> This percentage should be used to allocate the percentage of electronic load models (e.g., PERC1 modeled load) versus traditional load models for this facility in simulation models.
  - d. **Expected Ramp Rate** – Expected maximum rate (MW/min) in down-ramp and up-ramp.

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<sup>4</sup> Some computational load entities seek to interconnect at pre-existing generation sites. TOs should reflect their appropriate interconnection requirements for computational loads for instances where these are directly connecting to the BPS as well as through a Generator Owner's Facility.

<sup>5</sup> More information on the PERC1 model can be found here: [Load Characteristic Model: PERC1](#)

<sup>6</sup> For more modeling information beyond this action, see NERC's [Dynamic Modeling Recommendations](#).

<sup>7</sup> NERC Incident Review [Considering Simultaneous Voltage-Sensitive Load Reductions](#)

<sup>8</sup> Sometimes referred to as the power utilization effectiveness (PUE). PUE calculates the expected ratio of the load composition supporting the IT load. When using PUE ratios, submitting entities are encouraged to also include the type of non-IT loads to ensure proper motor load representation of the load facility.

- e. **Protective Devices** – TPs and PCs should represent the actions of protection and control devices at the point of common coupling with the computational load with standalone models or integrated into equipment models. These models should represent voltage and frequency parameters and relays that could isolate this load from the BPS or reduce the facility's demand. TPs and PCs should also collect the reconnecting voltage and timing for when the computational load facility would be expected to reconnect to the System. These protection models should also represent relevant relays or control hardware that could "trip" and restore the facility<sup>9</sup> or switch to and from backup power.
  - f. **On-Site Generation** – Information regarding on-site generation for when the facility is expected to transfer to on-site generation or utilize the on-site generation for Demand Response or other controlled interactions. Full generation representation should be pursued if the generation source (inclusive of Battery Energy Storage Systems) plans to be operated in parallel with the BPS.
  - g. **Facility Use** – Information on what the facility will be used for (e.g., traditional compute and storage, AI training, or cryptocurrency mining). This may include percentages for each use-case when the facility has multiple use-cases.
3. Implement processes and procedures to require specific modeling information from computational load entities during interconnection and throughout the operational lifecycle of the data center, including model updates when a qualified change to the facility occurs.

**Essential Action #2:** TPs and PCs should study the stability margin in their area at least annually for areas with computational loads (e.g., as part of TPL-001 studies). These studies should do the following:

1. Evaluate System Operating Limits or similar operating envelope limitations for additional load to connect to the area before voltage or frequency instability. This may include P-Q and P-V analysis or transient domain limits.
2. Identify areas vulnerable to instabilities due to computational loads and develop appropriate mitigation measures in accordance with established planning criteria.
3. Identify credible Contingencies<sup>10</sup> where the aggregate loss or reduction (including customer-initiated load reductions) of computational loads

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<sup>9</sup> For example, a relay model that includes parameters for a 0.85 p.u. voltage for 30 seconds would "trip" the load model in simulation.

<sup>10</sup> The definition of Contingency is available in the *NERC Glossary of Terms used in Reliability Standards* here:

[https://www.nerc.com/globalassets/standards/reliability-standards/glossary\\_of\\_terms.pdf](https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms.pdf)

are expected to cause planning criteria violations and update Contingency files accordingly.<sup>11</sup> The amount of load loss involved with these Contingencies should also be communicated to BAs and Resource Planners (RP).

**Essential Action #3:** PCs should revise their definition of “qualified change” that triggers a review of local area protection, stability limits, and other reliability studies to account for computational load. This definition should include language to account for the following:

1. Growth of the computational load.
2. Changes to settings, parameters, or configuration of the computational load electrical supply equipment and end-use equipment.
3. Repurposing<sup>12</sup> of computational load for a significantly different application.

**Essential Action #4:** TOs should establish a commissioning process for computational loads. Some items in the commissioning process may need to be repeated when a significant change to the facility occurs. This process should include all items required for operational readiness, including the following:

1. Processes to evaluate the “as-built” load facility model, including processes to assess model quality and for performing model verification and model validation.
2. Processes to notify owners of affected nearby systems (e.g., generation facilities) of planned load commissioning tests, in instances where the nearby system uses the same or electrically close point of common coupling to the BPS.
3. Where possible, a full facility load and no-load test of the facility and tests of applicable electrical control modes<sup>13</sup> of operation. Additionally, if possible, at least a 10% change in voltage should be performed with individual phase currents captured at the Point of Measurement.<sup>14</sup> The full load, no-load, and voltage change testing should be performed with the facility’s computational equipment installed and operational.

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<sup>11</sup> The Contingency definition (i.e., elements affected) should be updated for all planning studies where the Contingency is credible.

<sup>12</sup> For example, altering the computational load facility from a data warehouse or crypto mining facility to an AI training facility.

<sup>13</sup> For example, switching from an “eco” mode on the UPS to supplying through on-site Battery Energy Storage Systems. These tests should be unique to the planned operation of the constructed facility.

<sup>14</sup> One possible method for performing this test is to change the tap setting on the step-down transformer to adjust the voltage on the low side of the transformer.

4. Processes to ensure that communication and testing coordination capabilities are coordinated between the utility and computational load customer.
5. A coordinated commissioning checklist between the TO and the computational load customer for reviewing and testing the functional performance of the facility before energization. This checklist should also be coordinated with the relevant RCs, TOPs, and BAs. The checklist should include items for the following:
  - a. Switching
  - b. Design Prints
  - c. Functionally test electrical supply ac/dc protection circuitry
  - d. Functionally test electrical supply protection system settings
  - e. Functionally test supervisory control and data acquisition (SCADA) points
  - f. Functionally test electrical equipment including circuit breakers, transformers, and onsite generation (if operated in parallel with the Bulk Electric System (BES))
  - g. In-service load and protection coordination checks
6. Verification after energization that all parties have the same or consistent data needed for the following:
  - a. SCADA systems;
  - b. As-built diagrams, ratings, and information; and
  - c. One-lines identifying responsibilities of utility and computational loads.

**Essential Action #5:** TPs and PCs should study and implement System-side corrective actions with TOs to ensure no loss of firm load for computational load from normally cleared faults.<sup>15,16</sup> Loss of firm load can also be Non-Consequential load loss but does not include customer-initiated load reductions.<sup>17</sup>

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<sup>15</sup> NERC Incident Review [Considering Simultaneous Voltage-Sensitive Load Reductions](#)

<sup>16</sup> See TPL-001 Table 1 – Steady State & Stability Performance Planning Events for the events for which non-consequential load loss should not occur. In very limited and rare instances, some normally cleared faults may interrupt firm electric service. Table 1 and the surrounding TPL-001 requirements explicitly detail the performance expectations. Available here: [TPL-001-5.1](#)

<sup>17</sup> Non-Consequential load loss is defined in the NERC Glossary of Terms, available: [https://www.nerc.com/globalassets/standards/reliability-standards/glossary\\_of\\_terms.pdf](https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms.pdf). Non-Consequential load loss occurs when load is isolated from the BPS that is not part of removing the faulted equipment.

1. Entities should acquire the necessary facility-level relaying and protection settings, files, or configurations from the computational load entities.
2. Entities should use that information to evaluate the response of the computational loads protection and control systems to normally cleared faults.
3. TOs should coordinate with computational load customers, where possible, on customer-side improvements to maximize the computational load facility-level “ride-through” performance up to equipment capability to increase stability margins.

**Essential Action #6:** TOs should install and utilize dynamic fault recording devices to capture and share computational load facility electrical performance during System Disturbances. This action could be accomplished through collaboration with the computational load owner to install, or grant access to existing, dynamic fault recording devices. TOs may coordinate with the RC to determine at which computational load facilities these devices should be installed. This should include digital Disturbance recording and fault recording technology for continuous recording at lower resolution and trigger-based recording at higher resolution (e.g., digital fault recorders). TOs should supply the data from these devices<sup>18</sup> as required by TPs, PC, RCs, Regional Entities, or the Electric Reliability Organization (ERO) to aid in event analysis and root-cause analysis for System Disturbances.

**Essential Action #7:** TOPs, RCs, and BAs should establish Interpersonal Communication capabilities with computational loads to improve their situational awareness. TOPs, RCs, and BAs should issue operating instructions or similar information to computational load entities through voice, SCADA, or other communication platforms to prevent BES Emergencies. Computational load entities that receive operating instructions should comply with the instructions within the limits of their equipment.

**Reporting  
Instructions:**

Initial acknowledgement of receipt is required by **May 11, 2026**, Midnight Eastern via the NERC Alert System. Responses to the questions below are required to be submitted via the NERC Alert System by **August 3, 2026**, Midnight Eastern.

<sup>18</sup> These specifications on sample rate, recording retention window, and specific triggers will be custom to the facility. Some information can be found in [PRC-028](#) and [PRC-002](#). See the Additional Information section below for a Reliability Guideline that also includes information on how to specify.

A valid response in the NERC Alert System consists of the following three steps by the submitting entity:

- Acknowledgement of Alert
- Submission of Response
- Approval of Response

The NERC Alert System contains menu options for each of the above commands that are available to authorized individuals upon login. A response will not be considered valid until all three steps have been completed.

All registered entities belonging to the TP, PC, TO, BA, RC, and TOP functional groups are required to acknowledge receipt of this Alert and respond, as applicable.

All registered entities covered by this Essential Action are required to provide an approved response as defined above to the following questions:

### **Questions**

**All Entities answer the following Questions:**

1. Select the option to describe the workload required to implement Essential Action 1:
  - A. Low effort to implement changes
  - B. Significant effort to implement changes
  - C. Cumbersome workload and effort to implement changes
2. Select the option to describe the workload required to implement Essential Action 2:
  - A. Low effort to implement changes
  - B. Significant effort to implement changes
  - C. Cumbersome workload and effort to implement changes
3. Select the option to describe the workload required to implement Essential Action 3:
  - A. Low effort to implement changes
  - B. Significant effort to implement changes
  - C. Cumbersome workload and effort to implement changes

4. Select the option to describe the workload required to implement Essential Action 4:
    - A. Low effort to implement changes
    - B. Significant effort to implement changes
    - C. Cumbersome workload and effort to implement changes
  5. Select the option to describe the workload required to implement Essential Action 5:
    - A. Low effort to implement changes
    - B. Significant effort to implement changes
    - C. Cumbersome workload and effort to implement changes
  6. Select the option to describe the workload required to implement Essential Action 6:
    - A. Low effort to implement changes
    - B. Significant effort to implement changes
    - C. Cumbersome workload and effort to implement changes
  7. Select the option to describe the workload required to implement Essential Action 7:
    - A. Low effort to implement changes
    - B. Significant effort to implement changes
    - C. Cumbersome workload and effort to implement changes
  8. Select the option to describe the level of external action required to implement the Essential Actions:
    - A. Requires coordination with an external commercial entity
    - B. Requires action by an external regulatory agency
    - C. Requires no external coordination to implement
  9. Please include additional information that you wish to provide to help understand your response to the Alert in the free text box below.
- TP and PC only**
10. Do your modeling requirements include the actions in Essential Action 1?
    - A. Yes
    - B. No, however, we plan to modify our requirements to include
    - C. No, and we have no plans to modify our requirements

11. If you answered “No, however, we plan to modify our requirements to include” when do you plan to implement changes to your modeling requirements to align with Essential Action 1?
  - A. 2026
  - B. 2027
  - C. 2028
  - D. Beyond 2028
12. If you answered “No, and we have no plans to modify our requirements,” please explain in the free text field below.
13. Does your annual study process include the actions in Essential Action 2?
  - A. Yes
  - B. No, however, we plan to modify our requirements to include
  - C. No, and we have no plans to modify our requirements
14. If you answered “No, however, we plan to modify our requirements to include,” when do you plan to implement changes to your modeling requirements to align with Essential Action 2?
  - A. 2026
  - B. 2027
  - C. 2028
  - D. Beyond 2028
15. If you answered “No, and we have no plans to modify our requirements,” please explain in the free text field below.
16. Do your studies evaluate and provide mitigations for the items discussed in Essential Action 5?
  - A. Yes
  - B. No, however, we plan to modify our requirements to include
  - C. No, and we have no plans to modify our requirements
17. If you answered “No, however, we plan to modify our requirements to include,” when do you plan to implement changes to your modeling requirements to align with Essential Action 5?
  - A. 2026
  - B. 2027
  - C. 2028
  - D. Beyond 2028

18. If you answered “No, and we have no plans to modify our requirements,” please explain in the free text field below.

**PC only**

19. Does your definition of “qualified change” include the items discussed in Essential Action 3?

- A. Yes
- B. No, however, we plan to modify our requirements to include
- C. No, and we have no plans to modify our requirements

20. If you answered “No, however, we plan to modify our requirements to include,” when do you plan to implement changes to your modeling requirements to align with Essential Action 3?

- A. 2026
- B. 2027
- C. 2028
- D. Beyond 2028

21. If you answered “No, and we have no plans to modify our requirements,” please explain in the free text field below.

**TO Only**

22. Do your commissioning practices include the items discussed in Essential Action 4?

- A. Yes
- B. No, however, we plan to modify our requirements to include
- C. No, and we have no plans to modify our requirements

23. If you answered “No, however, we plan to modify our requirements to include,” when do you plan to implement changes to your modeling requirements to align with Essential Action 4?

- A. 2026
- B. 2027
- C. 2028
- D. Beyond 2028

24. If you answered “No, and we have no plans to modify our requirements,” please explain in the free text field below.

25. Do your protection and coordination practices include the items discussed in Essential Action 5?
- A. Yes
  - B. No, however, we plan to modify our requirements to include
  - C. No, and we have no plans to modify our requirements
26. If you answered “No, however, we plan to modify our requirements to include,” when do you plan to implement changes to your modeling requirements to align with Essential Action 4?
- A. 2026
  - B. 2027
  - C. 2028
  - D. Beyond 2028
27. If you answered “No, and we have no plans to modify our requirements,” please explain in the free text field below.

**TOPs, RCs, BAs Only**

28. Do your operating practices include the Interpersonal Communication practices discussed in Essential Action 7?
- A. Yes
  - B. No, however, we plan to modify our requirements to include
  - C. No, and we have no plans to modify our requirements
29. If you answered “No, however, we plan to modify our requirements to include,” when do you plan to implement changes to your modeling requirements to align with Essential Action 7?
- A. 2026
  - B. 2027
  - C. 2028
  - D. Beyond 2028
30. If you answered “No, and we have no plans to modify our requirements,” please explain in the free text field below.

**Additional Information:**

The rapid increase of computational loads continues to evolve. NERC has identified other risks, gaps, and materials that would be useful for recipients of

this Alert to follow. The following links provide additional information and best practices:

- [Large Load Action Plan](#) – NERC’s plan for further actions associated with computational loads. This link also contains information about the draft registry criteria and standards project referenced in the Alert.
- [Characteristics and Risks of Emerging Large Loads](#) – Highlights the risks and characteristics with large loads, including computational loads.
- [Assessment of Gaps in Existing Practices, Requirements and Reliability Standards for Emerging Large Loads](#) – Highlights the gaps in utility practices, NERC Reliability Standards, and other industry work related to large loads, including computational loads.
- **[Reliability Guideline: Risk Mitigation for Emerging Large Loads]** – Highlights the best practices to enhance entity practices to resolve gaps for large loads, including computational loads.
- [Data Center Information Collection Questionnaire](#) – For the purposes of data center modeling in transmission studies, this questionnaire helps TPs model data centers using key information gathered from large loads.

**Contact:**

For clarification or content-related questions, contact:

[Engineering@nerc.net](mailto:Engineering@nerc.net)

For login/account/registration issues, contact:

[nerc.alert@nerc.net](mailto:nerc.alert@nerc.net)

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North American Electric Reliability Corporation

[www.nerc.com](http://www.nerc.com)

**NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION**

**Proposed Resolution for Agenda Item 1: Level 3 Alert – Large Loads**

**Board of Trustees Meeting**

**April 16, 2026**

**WHEREAS**, since 2022, NERC has analyzed numerous load loss events across both the Eastern Interconnection and the Texas Interconnection resulting from unexpected disconnection of computational loads, losses which were not predicted through the current planning studies;

**WHEREAS**, in September 2025, NERC published a Level 2 Alert: Large Load Interconnection, Study, Commissioning, and Operations, and the responses to this Level 2 Alert showed that computational loads such as those at data centers could increase exponentially in the next four years, and that there are significant risks that need to be addressed through immediate industry actions spanning power system modeling, studies, commissioning, and operations;

**WHEREAS**, the Board has the authority under Section 800 of the NERC Rules of Procedure to approve the issuance of Essential Actions to Industry, containing specific actions that NERC has determined are essential for certain segments of owners, operators, or users of the bulk power system to take to ensure the reliability of the bulk power system;

**WHEREAS**, the Board has determined that it is essential to ensure the reliability of bulk power system for registered entities Transmission Owners, Transmission Planners, and Planning Coordinators to take certain steps to enhance technical minimum requirements, study processes, and modeling accuracy to predict and mitigate risks posed by large computational loads;

**NOW, THEREFORE, BE IT RESOLVED**, that the Board hereby approves the Level 3 Alert Essential Actions to Industry: Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control, substantially in the form presented to the Board at this meeting, together with such changes as are approved by NERC's Chief Executive Officer based on stakeholder feedback.

## **Amendment to Nova Scotia Memorandum of Understanding**

### **Action**

Approve the Amendment to the 2010 Memorandum of Understanding between Nova Scotia Power, NERC, and NPCC on substantially the terms and conditions presented to the Board, and delegate authority to NERC's President and CEO, or their delegate, to finalize and execute the proposed Amended MOU on behalf of NERC.

### **Background**

NERC and the Regional Entities have Memorandum of Understandings (MOUs) with Canadian provincial authorities or electric utilities that define the applicability of NERC Reliability Standards and the scope of Compliance Monitoring and Enforcement Program (CMEP) activities in the respective provinces.

In Nova Scotia, NERC and the Nova Scotia Utility and Review Board (NSUARB) entered into a MOU in 2006 (2006 MOU). The 2006 MOU included acknowledgement that NERC had been certified as the Electric Reliability Organization (ERO) in the United States and that NSUARB has regulatory authority over electric utilities operating in Nova Scotia. The 2006 MOU also establishes expectations regarding NERC filing proposed Reliability Standards with the NSUARB for approval, mandatory compliance with NSUARB-approved Reliability Standards in Nova Scotia and sharing of compliance information and recommendations where appropriate, and funding of NERC and associated Regional Entities.

NERC and the Northeast Power Coordinating Council (NPCC) entered into an MOU with Nova Scotia Power, Inc. (Nova Scotia Power) in 2010 (2010 MOU). The 2010 MOU establishes that Nova Scotia Power will comply with NSUARB-approved NERC Reliability Standards, establishes a mechanism for review, comment, and approval of NERC Reliability Standards in Nova Scotia, and subjects Nova Scotia Power to NERC's CMEP as implemented by NPCC. Nova Scotia Power has historically been the only entity subject to NSUARB-approved Reliability Standards in Nova Scotia.

### **2024 Changes in the Nova Scotia Regulatory Structure**

In 2024, the Nova Scotia Energy Reform Act (Energy Reform Act) received Royal Assent. The Energy Reform Act included the More Access to Energy Act 2024 (MAEA), which created the Nova Scotia Independent Energy System Operator (IESO-NS), which was established in February 2025. The MAEA set up this new entity to take over long-term electricity system planning, procurement of new energy resources, and transmission grid operations from Nova Scotia Power. On December 1, 2025, IESO-NS began performing the Planning Coordinator/Planning Authority, Resource Planner, and Transmission Planner functions. IESO-NS is expected to begin performing the Transmission Operator and Balancing Authority functions in Q2 2027.

The Energy Reform Act also included the Energy and Regulatory Boards Act (ERBA), which created a new Nova Scotia Energy Board (NSEB), transferred certain regulatory responsibilities previously exercised by the NSUARB to the NSEB, and provided the NSEB with the authority to adopt, monitor, and enforce NERC Reliability Standards in Nova Scotia. The ERBA authorizes the NSEB

to contract with a compliance body to assist with performing compliance monitoring and enforcement activities. NPCC is expected to serve as that compliance body.

### **Regulations Under Development**

There are currently no regulations in place under the ERBA for the NSEB or NPCC to begin performing these activities in Nova Scotia. Therefore, compliance monitoring and enforcement activities under the new regulatory structure cannot formally begin until such regulations are adopted. The regulations are being developed and are intended to provide NSEB with authority to (1) adopt NERC Reliability Standards, (2) create a registry of entities required to comply with NERC Reliability Standards, (3) conduct compliance monitoring and enforcement activities, including issuing sanctions for violations, and (4) contract with a compliance body to assist with the compliance monitoring and enforcement activities. The regulations are also anticipated to create a Nova Scotia-specific CMEP procedure. NSEB is working collaboratively with NPCC to enable NPCC to perform compliance monitoring and enforcement activities under the ERBA. The timeline for finalizing these regulations remains uncertain.

### **Proposed Amendment to 2010 MOU**

After adoption of regulations under the ERBA, NERC, NPCC, and NSEB would seek agreement on a new MOU under the new regulatory structure. Until that occurs, the parties to the 2010 MOU and IESO-NS have negotiated an amendment to the 2010 MOU (Amended MOU) to include IESO-NS in the existing construct.

The proposed Amended MOU amends the existing 2010 MOU between NERC, NPCC, and Nova Scotia Power by:

1. Adding IESO-NS as a party to the MOU;
2. Providing a mechanism and structure for NPCC to perform compliance monitoring and enforcement activities with respect to NERC Reliability Standards applicable to IESO-NS;
3. Replacing references to the NSUARB with references to the NSEB; and
4. Updating points of contact for the parties.

NERC staff seeks the Board's approval of the Amend MOU and the Board's delegation of authority to the President and CEO, or their delegate, to finalize and execute the proposed Amended MOU on behalf of NERC.

# Amendment to Nova Scotia MOU

Board of Trustees Meeting

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Howard Gugel  
Senior Vice President, Regulatory Oversight

April 16, 2026

# Nova Scotia Energy Reform



# Amendment to Memorandum of Understanding



## IESO-NS to existing 2010 MOU

NPCC to perform compliance monitoring and enforcement activities



## Nova Scotia developing regulations

NSEB with authority to:

- Adopt NERC Reliability Standards
- Create a compliance registry
- Conduct compliance monitoring and enforcement activities
- Contract with a compliance body
- Anticipated Nova Scotia-specific CMEP procedure



## Next steps

NSEB and NPCC to enable NPCC to perform compliance monitoring and enforcement activities

NERC, NPCC, and NSEB to seek agreement on a new MOU under the new regulatory structure

A light blue map of the United States is shown in the background. A vertical bar on the left side of the image transitions from dark blue at the top to a teal color at the bottom. The text 'NERC' is written in a bold, dark blue, sans-serif font on the left side of the map.

**NERC**

**Discussion**

This **AMENDMENT** to the Memorandum of Understanding made as of the 9<sup>th</sup> day of May 2010 (the "**Amendment**").

**Between:**

**Nova Scotia Power Incorporated ("NS Power")**

-and-

**The Northeast Power Coordinating Council Inc. ("NPCC")**

-and-

**The North American Electric Reliability Corporation ("NERC")**

-and-

**Nova Scotia Independent Energy System Operator ("IESO NS")**

Collectively referred to as (the "**Parties**")

**WHEREAS** pursuant to a Memorandum of Understanding dated May 9, 2010 (as amended, modified or supplemented from time to time, the "**MOU**"), by and among NS Power, NPCC, and NERC agreed to matters of importance respecting NERC and NPCC's development and application of Reliability Standards and Regional Reliability Criteria (the "**Standards**");

**AND WHEREAS** the MOU supports the December 22, 2006 Memorandum of Understanding between the Nova Scotia Utility and Review Board ("UARB") and NERC;

**AND WHEREAS** pursuant to the *Energy and Regulatory Boards Act* ("**ERBA**"), the UARB was continued as the Energy and Regulatory Boards Tribunal (the "Tribunal"), and the Nova Scotia Energy Board ("**NSEB**") was established as a division of the Tribunal;

**AND WHEREAS** the NSEB was granted authority under the ERBA to regulate a broad range of energy matters previously regulated by the UARB, including regulation of IESO NS;

**AND WHEREAS** the *More Access to Energy Act* ("**MAEA**") created the IESO NS with a statutory mandate that includes, among other objects, administering the bulk power system, system planning, managing wholesale electricity markets, managing transmission interconnection, undertaking capacity

procurement functions and real time dispatch operations, and other compliance obligations in Nova Scotia;

**AND WHEREAS** IESO NS's statutory mandate includes some responsibilities currently held by NS Power subject to oversight by NERC and NPCC;

**AND WHEREAS** the Parties wish to add IESO NS as a Party to the MOU for the purpose of ensuring NERC and NPCC compliance;

**AND WHEREAS** the Parties have agreed to amend certain terms of the MOU;

**AND WHEREAS** unless specifically defined herein, all capitalized terms used in this Amendment have the same meaning as the capitalized terms in the MOU;

**NOW THIS AMENDMENT WITNESSETH THAT** for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the parties agree as follows:

## **ARTICLE 1 – AMENDMENTS**

### **1.1 Regulator**

The Parties agree to amend the MOU by deleting and replacing any references to the “UARB” with the NSEB or the “Board”. The Parties agree to read in all necessary corresponding spelling and grammatical changes to the MOU arising from this amendment.

### **1.2 IESO NS**

- A) The Parties agree to add IESO NS as a Party to the MOU, and IESO NS shall be bound by all obligations that bind NS Power under the terms and conditions of the MOU.
- B) The Parties agree to amend the MOU by adding “and/or IESO NS” after every reference to NS Power as appropriate, saving and excepting for the references to NS Power in Article 1 - The Signatories. The Parties agree to read in all necessary corresponding spelling and grammatical changes to the MOU arising from this amendment.
- C) The Parties agree that NS Power and IESO NS shall determine, as between themselves, which entity shall be responsible for each obligation under the MOU that is currently assigned to NS Power. In the event that NS Power and IESO NS are unable to reach agreement on

the allocation of any such obligation, and subject to any applicable provisions of the *MAEA* or jurisdiction of the Board, NS Power and IESO NS shall defer to a neutral arbitrator to determine which of NS Power, IESO NS, or both, shall be responsible for the relevant obligation.

D) In the event of a violation of a NERC Reliability Standard requirement that NS Power and IESO NS were unable to reach agreement on the allocation of such obligation, both NS Power and IESO NS shall be jointly and severally responsible for ensuring that all required mitigation, remediation, and corrective actions are commenced within a timeframe directed by NPCC and completed as soon as practicable. Once compliance is restored, NS Power and IESO NS shall allocate costs and responsibility between themselves in accordance with paragraph C above.

### **1.3 AMENDMENT AND TERMINATION**

The Parties agree to amend Article 4 of the MOU to say:

This MOU shall remain in effect until it is amended or replaced by agreement of the Parties. Any Party may withdraw from this MOU by providing not less than thirty (30) days' prior written notice to the other Parties. The withdrawal of any Party shall not affect the continuing validity or enforceability of the MOU as between the remaining Parties. The Parties agree to read in all necessary corresponding spelling and grammatical changes to the MOU arising from any such withdrawal or amendment.

### **1.4 POINTS OF CONTACT**

The Parties agree to amend Article 5 of the MOU to add the following point of contact for IESO NS:

David Luther  
General Counsel  
Nova Scotia Independent Energy System Operator  
1010 TD Tower, 1791 Barrington Street  
(437) 385-4445  
[David.luther@ieso-ns.ca](mailto:David.luther@ieso-ns.ca)

The Parties agree to amend Article 5 of the MOU to add the following point of contact for NSPI:

Natasha Flynn  
Senior Compliance Engineer  
Nova Scotia Power Incorporated  
1223 Lower Water St

Halifax, NS B3J 3S8  
Natasha.flynn@nspower.ca

And

Blake Williams  
Senior Director, Regulatory Affairs  
Nova Scotia Power Incorporated  
1223 Lower Water St  
Halifax, NS B3J 3S8  
[Blake.williams@nspower.ca](mailto:Blake.williams@nspower.ca)

The Parties agree to amend Article 5 of the MOU to remove the existing NPCC contact add the following point of contact for NPCC:

Damase Hebert  
Senior Vice President and Chief Legal Officer  
Northeast Power Coordinating Council, Inc.  
1040 Avenue of the Americas, 4<sup>th</sup> Floor  
New York, NY 10018  
[dhebert@npcc.org](mailto:dhebert@npcc.org)

The Parties agree to amend Article 5 of the MOU to remove the existing NERC contact add the following point of contact for NERC:

Sonia Rocha  
Senior Vice President, General Counsel, and Corporate Secretary  
North American Electric Reliability Corporation  
1401 H Street NW, Suite 410  
Washington, DC 20005  
[sonia.rocha@nerc.net](mailto:sonia.rocha@nerc.net)

## **ARTICLE 2 – GENERAL**

### **2.1 Ratification**

Except as otherwise provided in this Amendment, all terms and conditions of the MOU shall continue in full force and effect.

### **2.2 Further Assurances**

The Parties shall, with reasonable diligence, do all such things and provide all such further documents or instruments required by any other party as may be reasonably necessary or desirable to effect the purpose of this Amendment and carry out its provisions.

**2.3 Successors and Assigns**

This Amendment shall enure to the benefit of and be binding upon the parties and their respective successors and permitted assigns.

**2.4 Governing Law**

This Amendment shall be governed by, and interpreted and enforced in accordance with, the laws in force in the Province of Nova Scotia.

**2.5 Counterparts**

This Amendment and any amendment, restatement, supplement or other modification hereto or waiver hereunder, (a) may be executed in any number of counterparts, each of which will be deemed to be an original copy of this Amendment and all of which, when taken together, will be deemed to constitute one and the same agreement, and (b) to the extent signed and delivered by means of scanned pages or DocuSign, shall be treated in all manner and respect as an original contract and shall be considered to have the same binding legal effects as if it were the original signed version thereof delivered in person.

**[SIGNATURE PAGE FOLLOWS]**

**IN WITNESS WHEREOF, the Parties have caused this Amendment to be executed and delivered as of the latest date below written.**

**NOVA SCOTIA POWER INCORPORATED**

Per: \_\_\_\_\_

**Name, Title**

Date: \_\_\_\_\_

**THE NORTHEAST POWER COORDINATING COUNCIL INC.**

Per: \_\_\_\_\_

**Name, Title**

Date: \_\_\_\_\_

**THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION**

Per: \_\_\_\_\_

**Name, Title**

Date: \_\_\_\_\_

**NOVA SCOTIA INDEPENDENT ENERGY SYSTEM OPERATOR**

Per: \_\_\_\_\_

**Name, Title**

Date: \_\_\_\_\_

**NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION**

**Proposed Resolution for Agenda Item 2: Amendment to the 2010 Memorandum of Understanding between Nova Scotia Power Incorporated, the North American Electric Reliability Corporation, and the Northeast Power Coordinating Council, Inc.**

**Board of Trustees Meeting**

**April 16, 2026**

**WHEREAS**, the Nova Scotia Utility and Review Board (NSUARB) was charged under Nova Scotia law with authority over all electric utilities within Nova Scotia, pursuant to the Nova Scotia Public Utilities Act, and the NSUARB and NERC memorialized an agreement in 2006 with respect to NSUARB's adoption of NERC-approved Reliability Standards and mandatory compliance with NSUARB-approved Reliability Standards in Nova Scotia;

**WHEREAS**, Nova Scotia Power Incorporated (Nova Scotia Power), a public utility in Nova Scotia, NERC, and NPCC memorialized an agreement in 2010 with respect to the development and application of NSUARB-approved NERC Reliability Standards in Nova Scotia and that Nova Scotia Power Incorporated, as a registered entity, would be subject to NERC's Compliance Monitoring and Enforcement Program (CMEP), as implemented by NPCC;

**WHEREAS**, the 2010 Memorandum of Understanding is the main governing document setting forth Nova Scotia Power's, NPCC's, and NERC's roles and responsibilities regarding Reliability Standard and CMEP activities in Nova Scotia;

**WHEREAS**, the Nova Scotia More Access to Energy Act created the Nova Scotia Independent Energy System Operator (IESO-NS) with a statutory mandate that includes performing reliability functions that were previously performed by Nova Scotia Power in Nova Scotia;

**WHEREAS**, the Energy and Regulatory Boards Act created the Nova Scotia Energy Board (NSEB), which assumed certain regulatory responsibilities previously held by the NSUARB with respect to NERC Reliability Standards in the Province of Nova Scotia;

**WHEREAS**, the reliability functions that have been or will be transferred from Nova Scotia Power to the IESO-NS have been subject to oversight by NPCC, and the evaluation of IESO-NS's compliance in the performance of the reliability functions is a key reliability objective;

**WHEREAS**, Nova Scotia Power, NERC, and NPCC seek to revise the 2010 Memorandum of Understanding to add IESO-NS as a party to the agreement and to replace references to the NSUARB with references to the NSEB;

**NOW, THEREFORE, BE IT RESOLVED**, that the NERC Board of Trustees (Board) hereby approves the Amendment to the 2010 Memorandum of Understanding between Nova Scotia Power, NERC,

and NPCC on substantially the terms and conditions presented to the Board, together with such changes as are approved by NERC's President and Chief Executive Officer.

**BE IT FURTHER RESOLVED**, that each of NERC's President and Chief Executive Officer and General Counsel, are hereby authorized to execute and deliver, on behalf of NERC, the Amendment to the 2010 Memorandum of Understanding.