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Request IR-1:

Refer to the Application cover letter p. 2, which states

“The Parties hosted a stakeholder session, led by Power Advisory, on May 14, 2026. On July 23, the Parties hosted an additional stakeholder engagement session.”

(a) Please confirm whether any party other than REI—including other prospective or existing LRSs, net metering customers, distribution-connected generation developers, or IESO Nova Scotia—participated in either session.

(b) Please provide any written comments or feedback received from attendees other than REI.

(c) If not, please explain why broader stakeholder input was not sought, given that the resulting tariffs will apply to all LRSs and RtR Customers, not solely REI.

Response IR-1:

(a) Other than NS Power and REI, the stakeholder sessions held May 14 and July 23, 2026 were attended by customer representatives/advocates. The sessions were conducted as part of the collaborative process undertaken in response to the Board’s direction in M12339.

(b) No comments or submissions were requested or received from attendees in connection with the stakeholder sessions. The sessions were intended to facilitate discussion of potential tariff amendments, identify issues, and obtain stakeholder input through the engagement process. Feedback was considered through stakeholder discussions during the sessions and the subsequent collaborative work undertaken by NS Power and REI.

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1 (c) The stakeholder engagement process was conducted in response to the Board's directive in
2 M12339, which required NS Power to engage with REI in the development of tariffs,
3 procedures, or standards of conduct necessary to enable distribution-connected generation
4 and net billing within the RtR market. Consistent with that direction, the Company retained
5 Power Advisory and worked collaboratively with REI throughout the development of the
6 proposed amendments. The resulting Application reflects that collaborative process. While
7 the proposed tariff framework is intended to apply more broadly within the RtR market, it
8 has been developed in the context of a market that remains in the early stages of
9 development and for which there is currently limited operational experience. As experience
10 is gained with the operation of the framework, the proposed Distribution-connected
11 Aggregation Service (DAS) Tariff provides for a review at the end of 2028, at which time
12 any potential revisions may be considered and, if appropriate, brought before the Board for
13 approval.

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Request IR-2:

Refer to the Application cover letter p. 4, which states

“The Parties are proposing no changes to the annual cost base which underpins the pricing of EBS Tariff top-up and spill amounts as this is an issue that remains under review in accordance with the Board’s direction in the Company’s 2026 AAR Application (M12551) and is subject to change.”

(a) Please explain the interrelationship between this Application and the Board's ongoing review of the EBS Tariff pricing in NS Power's 2026 AAR Application (M12551).

(b) How does NS Power propose to coordinate the two proceedings to avoid inconsistent outcomes?

Response IR-2:

(a) The scope of this Application and the review directed by the Board in NS Power’s 2026 Annually Adjusted Rate (AAR) Application (M12551) are distinct. This Application addresses the tariff provisions associated with enabling distribution-connected generation and net billing within the RtR market in accordance with the Board’s direction in M12339 (Renewall Energy Inc. – Request for Tariffs for the RTR Market). The review directed by the Board in M12551 relates to issues raised by Renewall Energy Inc. (REI) concerning the implementation of monthly marginal cost pricing, a potential true-up mechanism, and the annual cost base used to determine Energy Balancing Service (EBS) Tariff top-up and spill pricing. As described in this Application and in the Company’s August 31, 2026 correspondence under M12551, NS Power is not proposing changes relative to the annual cost base currently used to determine EBS Tariff top-up and spill pricing, as those matters remain under review with REI and may be subject to change.

(b) This Application addresses tariff provisions associated with enabling distribution-connected generation and net billing within the RtR market, whereas the review directed

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1 in M12551 relates to the costing and pricing of existing RtR tariffs. Any costing or pricing
2 changes arising from the review directed in M12551 can be accommodated through the
3 applicable AAR process without requiring amendments to the tariff provisions proposed in
4 this Application. The tariff amendments proposed in this Application may be considered
5 independently of the outcome of the review directed in M12551.

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Request IR-3:

Refer to the Attachment 2 Appendix section, pp. 30-39. The jurisdictional scan shows approaches to charging distribution-connected generation for grid use ranging from no charge (most of Canada) to fixed monthly account-related charges (e.g., Ontario, roughly \$87-\$266/month) to per-MW system-operator contribution charges (e.g., Alberta: \$10,000-\$50,000/MW).

(a) Please explain how the proposed DAS Tariff's administration-only charge was benchmarked against these comparators.

(b) Please explain whether NS Power anticipates proposing a distinct distribution-use charge (above administration-only) in the future, and under what circumstances.

(i) What data will be collected to inform the development of these charges?

Response IR-3:

(a) The proposed Distribution-connected Aggregation Service (DAS) Tariff administration charge was developed as part of the broader framework designed to enable distribution-connected generation and net billing within the RtR market. In developing that framework, the Company considered Power Advisory's jurisdictional scan to better understand how similar services have been implemented in other jurisdictions. The scan identified a range of approaches, including no charge, fixed administrative charges, and charges intended to recover broader system costs. However, these approaches reflect differing market structures, regulatory frameworks, participation models, and cost recovery arrangements. Accordingly, the jurisdictional scan was used to inform the development of the proposed framework rather than to establish a direct benchmark. As described in the Application, the administration charge will be developed for inclusion in the 2027 Annually Adjusted Rate

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1 (AAR) Application and is intended to recover the administrative costs associated with
2 operating the service.

3
4 (b) The Company is not proposing a distribution-use charge under the DAS Tariff as part of
5 this Application. As described in the Application, the proposed DAS Tariff proposes a
6 review of the operation of the DAS tariff and broader RtR construct at the end of 2028 in
7 recognition of the uncertain pace and scope of RtR market development and the uncertain
8 implications of distribution-connected generation in that context. Accordingly, the
9 Company expects any future consideration of additional charges would be informed by the
10 experience gained through the implementation and operation of the proposed framework.

11
12 (i) The specific information or data requirements, if any, would depend on the issues
13 identified through the review described above, and in the Application. More
14 generally, areas of consideration for this review may include market participation,
15 customer adoption, distribution-connected generation characteristics, operational
16 impacts, administrative requirements, and other information relevant to the operation
17 of the DAS Tariff and the broader RtR construct. Should revisions be identified
18 through that review process, any such amendments would be proposed for the Board's
19 review and approval.

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Request IR-4:

Refer to Attachment 3, p. 8, which notes that, unlike NS Power's net metering construct, there is no prohibition on RtR distribution-connected generation exceeding load.

(a) Please describe any analysis NS Power has undertaken, or intends to undertake, of the potential for reverse power flow, feeder overloading, or protection coordination issues arising from this design choice.

(b) Please identify what interconnection study thresholds or triggers would prompt further technical review.

Response IR-4:

(a-b) For distribution-connected generation, NS Power evaluates the potential impacts of a proposed interconnection on the distribution system through its existing interconnection processes. Depending on the size, location, and characteristics of a proposed facility, this review may consider matters such as reverse power flow, feeder overloading, protection coordination, and other technical requirements necessary to maintain the safe and reliable operation of the system. As part of the interconnection process, NS Power identifies and implements appropriate mitigation measures where required.

This Application does not propose changes to the existing interconnection processes. Rather, as part of the updates to RtR market elements in accordance with the Board's direction in M12339, the Company has added Section 13.0 (Technical Requirements for Interconnection of RtR Behind-the-Meter and Distribution-Connected Generation) to the Licensed Retail Supplier Terms and Conditions.¹ This section provides the framework for assessing and mitigating potential system impacts associated with generation

¹ Refer to Attachment 12, Section 13.0 (page 16 of 26) of the Application.

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interconnections within the context of the RtR market, consistent with the established interconnection requirements and applicable technical standards.

Consistent with the Company's existing processes for interconnecting generation facilities, the level of technical review is determined based on the size and characteristics of the proposed facility and the potential impacts on the distribution system, as outlined below:

Distribution-Connected Generator Size	Technical Assessment Requirement
Less than 27 kW	Plans review by NS Power Electrical Inspection
27 kW to less than 100 kW	Class 1 Interconnection Requirements ²
100 kW to 1,000 kW (limited to 1,000 kW for NS Power's Commercial Net Metering program but no upper limit for the RtR Market)	Class 2 Interconnection Requirements ³

This tiered approach ensures that the technical review process remains proportionate to the size and potential system impact of the generation facility while maintaining the safety, reliability, and operational integrity of the distribution system.

² Class 1 Interconnection Requirements are found on the Open Access Same-time Information System website at this link: https://www.nspower.ca/docs/default-source/pdf-to-upload/dsir---100-kw-and-below---.pdf?sfvrsn=1f13667a_6&_gl=1*1ann4id*_gcl_au*MTE5Njk2MTk5NC4xNzQxNzk4MjMz

³ Class 2 Interconnection Requirements are found on the Open Access Same-time Information System website at this link: https://www.nspower.ca/docs/default-source/pdf-to-upload/interconnection-requirements-generating-facilities-above-100kw.pdf?sfvrsn=fc0424ee_20

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Request IR-5:

Refer to Attachment 4, p. 1, which states

“Customer exports will be tracked and reported to the LRS to support the LRS’ commercial arrangement with the LRS’ customer and will serve as an input to the generation amount applicable to the LRS under the Standby Service, Energy Balancing Service and RTR Transition tariffs.”

(a) Please confirm that customer exports are a proxy for total behind the meter generation of a resource.

(b) Why is self-consumption (generation consumed by on-site load) not incorporated into the generation total for a BTM resource? In other words, if some generation is consumed on-site, shouldn’t this generation amount accrue to LRS entity? Please explain.

(c) Has NS Power considered use of production meters to measure generation of BTM resources? Why or why not? Could LRS entities install production meters to measure generation of BTM resources?

Response IR-5:

(a) Not confirmed. Customer export represents excess generation produced by the customer’s behind-the-meter generator but not consumed by the customer’s load. Customer export is the generation that flows back onto the distribution system.

(b) In matter M06214 concerning the Sale of Renewable Low-Impact Electricity generated within Nova Scotia by a Retail Seller to a Retail Customer pursuant to the Electricity Act, the Board ruled on the issue of Generation behind the Meter in section 3.7 of its March 23, 2016 Decision; reproduced in part as follows:

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1 [...] an arrangement whereby a person generates electricity for their own
2 use behind the NSPI meter is not subject to regulation by the Board under
3 the *Public Utilities Act*. Likewise, if a third party constructs a generator on
4 or adjacent to the property of that person, and supplies that customer
5 exclusively, that transaction is not subject to the *Public Utilities Act* so long
6 as it occurs behind the meter.

7
8 Consequently, behind-the-meter renewable generation arrangements fall outside the RtR
9 market framework.

10
11 (c) No. NS Power has not considered the use of meters to measure the generation of behind-
12 the-meter resources because this area falls outside the scope of the RtR market.

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Request IR-6:

Refer to Attachment 4, p. 1, which states,

“The LRS’ Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.”

(a) Please describe and define what is meant by “necessary arrangements.”

(b) Will written operating agreements be approved by the Board?

(c) Is there a dispute process to resolve disagreements about the written operating agreements, and if so, what is it?

(d) Please describe and define what is meant by “unduly deteriorate.” For example, if there is a temporary power quality issue does this qualify, but if not, what does? Please explain.

(e) What is the process if there is a dispute between an LRS and NS Power regarding what constitutes a “necessary arrangement?” Where is this described or laid out?

(f) Shouldn’t power system issues due to generation be addressed in the interconnection process? Please explain the interplay between this clause and interconnection studies accomplished by NS Power, if any.

(g) Please provide references and a brief explanation of the interconnection process for different sized systems to NS Power’s distribution system.

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1 **(h) Please explain the process if power system issues occur after a generator has**
2 **interconnected to the system.**

3
4 **(i) Please state whether any distribution-level costs caused by distribution-connected**
5 **generation (e.g., incremental losses, voltage management) are being recovered from**
6 **any customer class prior to the post-2028 review, and if so, from which class(es).**
7 **Please provide a citation to the amount of these costs over the last five years.**

8
9 Response IR-6:

10
11 (a) The term “necessary arrangements” refers to compliance with the technical requirements
12 of the interconnection process. Please refer to Synapse IR-4, part (a-b).

13
14 (b) No. Operating agreements between NS Power and interconnection customers participating
15 in the RtR market will not require Board approval, as they are intended to address only the
16 technical and operational aspects of interconnection.

17
18 In alignment with operating agreements for NS Power Commercial Net Metering:

- 19
20 • For generating facilities larger than 100 kW, the applicable agreement will be the
21 Standard Small Generator Interconnection and Operating Agreement (SSGIA).
22
23 • For generating facilities larger than 27 kW and up to 100 kW, customers will be
24 required to execute an operating agreement that contains technical and operational
25 requirements like the corresponding provisions in the Commercial Net Metering
26 Participant Agreement.

27
28 (c) Yes. For generating facilities greater than 100 kW, Article 8 of the SSGIA describes the
29 applicable dispute-resolution process. For generating facilities larger than 27 kW and up to

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1 100 kW, the operating agreement will contain a dispute resolution process like that found
2 in the corresponding provisions of the Commercial Net Metering Participant Agreement.

3
4 (d) The term “unduly deteriorate” refers to impacts to the integrity of the power supply system,
5 including the considerations listed in Special Condition (3). Whether an impact unduly
6 deteriorates the system would be assessed against NS Power’s applicable distribution
7 system interconnection requirements.

8
9 (e) Disputes between an LRS and NS Power regarding what constitutes a “necessary
10 arrangement” would be addressed under the applicable dispute-resolution provisions of the
11 LRS Terms and Conditions and agreements between the LRS and NS Power. Where the
12 dispute concerns the technical requirements applicable to a specific generating facility, it
13 would be addressed with the Interconnection Customer through the applicable
14 interconnection process and operating agreement.

15
16 (f) Power system issues due to distribution-connected generation are addressed in operating
17 agreements (described in part (b) above) and interconnection requirements associated with
18 the distribution interconnection processes (described in Synapse IR-4, part (a-b)).

19
20 The referenced clause is found as Special Condition (2) of the proposed Distribution-
21 connected Aggregation Service tariff. This special condition is intended to reinforce the
22 requirements of the operating agreements and technical requirements of the
23 interconnection processes.

24
25 (g) Facilities of 27 kW or less will follow a process consistent with NS Power’s Self-
26 Generating Option, including electrical plans review and inspection.

27
28 Facilities greater than 27 kW and not exceeding 100 kW will follow a process similar to
29 the existing Class 1 Commercial Net Metering process, including an interconnection

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1 application, electrical plans review and inspection, and execution of an operating
2 agreement similar to the CNMP Participant Agreement.

3
4 Facilities greater than 100 kW will follow the Distribution Generator Interconnection
5 Procedures (DGIP), including a preliminary assessment, Distribution System Impact
6 Study, electrical plans review and inspection, and execution of an SSGIA before
7 operation.

8
9 Please refer to Synapse IR-4, part (a-b) for additional details about the interconnection
10 processes.

11
12 (h) If power system issues occur after interconnection, NS Power will assess whether the
13 generating facility is complying with the applicable Distribution System Interconnection
14 Requirements and operating agreement. The Interconnection Customer will be notified of
15 any required corrective action and provided a reasonable opportunity to correct the issue,
16 consistent with the nature and severity of the condition. If the issue is not corrected, NS
17 Power may disconnect the generating facility. Where immediate action is required to
18 protect safety or system reliability, NS Power may temporarily disconnect the facility
19 without prior notice. For facilities subject to an SSGIA, these provisions are described in
20 Article 4.4.

21
22 (i) In accordance with the Board's direction in M12339, the Company has proposed a
23 framework to enable distribution-connected generation and net billing within the RtR
24 market. As part of that framework, the effect of distribution-connected generation on
25 system losses and other potential system impacts has been identified for review at the end
26 of 2028, once operational experience has been gained with the market. In light of the early
27 stage of RtR market development, the Company has not quantified distribution-level costs
28 specifically attributable to distribution-connected generation. Accordingly, the Company
29 cannot provide the requested five-year history of such costs. Any future proposals arising
30 from the post-2028 review would be subject to the Board's review and approval.

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Request IR-7:

Refer to Attachment 4, pp. 2-3.

- (a) Please provide NS Power's current estimate of forecast administration costs underlying the DAS Administration Charge, broken down by cost category (e.g., metering/settlement systems, IT, incremental labor), together with the assumed "forecast number of LRS' subscribed" denominator.**
- (b) Please also explain how the charge would be calculated if, initially, only one LRS (i.e., REI) is subscribed to the service.**
- (c) Please confirm whether the DAS Administration Charge is intended to recover only costs incremental to the aggregation / export-tracking function, or whether it also recovers costs already embedded in the Distribution Tariff rates paid by the RtR Customer for Distribution System Access. Explain the safeguard against double-recovery of the same cost between the two tariffs.**

Response IR-7:

- (a) The Distribution-connected Aggregation Service (DAS) Administration Charge has not yet been developed. Accordingly, the Company cannot provide the requested forecast cost breakdown. As described in the Application, subject to a Board determination in this matter, the proposed figure will be included in the 2027 Annually Adjusted Rates (AAR) Application. The development of the DAS Administration Charge through the AAR process will be informed by the requirements of the approved tariff framework and the Company's best available information at that time regarding implementation and administration costs.**

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1 (b) As the DAS Administration Charge has not yet been developed, the Company has not
2 established assumptions regarding the number of participating Licensed Retail Suppliers
3 (LRS) for the purposes of calculating the charge. As noted above, the charge will be
4 developed and included in the 2027 AAR process and will be based on the approved
5 methodology and the Company's best available information at that time. The Company
6 notes that, in light of the early stage of RtR market development, evolving system
7 requirements, and implementation and administration costs identified to date, the resulting
8 DAS Administration Charge may differ materially from the administration charges
9 currently applicable under existing RtR tariffs.

10
11 (c) The DAS Administration Charge is intended to recover the costs associated with
12 administering the DAS Tariff. The specific costs to be recovered through the charge have
13 not yet been determined and will be developed as part of the 2027 AAR process. It is
14 anticipated that, at least initially, the DAS Administration Charge will cover incremental
15 costs. As the market develops, this will be subject to change. Any proposed charge will be
16 supported by the appropriate cost information filed with that application and will be subject
17 to the Board's review and approval.

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1 **Request IR-8:**

2
3 **Refer to Attachment 4, p. 3, which states**

4
5 **“In light of the early stages of RtR market development in general and, in**
6 **particular, Distribution connected Generation market development following**
7 **2028, a review of the operation of this tariff and the broader RtR construct**
8 **will be undertaken by NS Power and submitted to the Board for its review.”**
9

10 **Please also refer to Attachment 3, p.4, which states that “REI expects to enter the**
11 **market December 1, 2026, and complete entrance by COD date for Mersy Wind, Q1**
12 **2027.”**
13

14 **(a) Please provide the expected timeline and process for the 2028 review referenced in**
15 **the DAS Tariff Review section, including whether stakeholders including REI will**
16 **have an opportunity for input.**
17

18 **(b) Please describe the specific data NS Power intends to collect over the interim period**
19 **to inform its review of the tariff.**
20

21 **(c) Please explain why an approximately two-year period was selected given REI’s stated**
22 **intention to enter the market by December 1, 2026 and to have distribution-connected**
23 **generation online by 2027.**
24

25 **(d) Will LRS entities be held responsible for costs incurred before the development of**
26 **charges associated with RtR market? If so, when and how will these costs be**
27 **collected?**
28

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1 Response IR-8:

2
3 (a) As described in the Application,¹ the proposed review would occur following 2028 and
4 would consider the operation of the DAS Tariff and the broader RtR construct. While the
5 specific timing and process for that review have not been established, the Company expects
6 the scope and timing of the review would be informed by the pace and scope of RtR market
7 development. Consistent with the collaborative approach that has informed the
8 development of this Application, NS Power will engage REI and stakeholders as part of
9 this review process.

10
11 (b) The scope of information collected for the review will be informed by the development of
12 the RtR market and the issues identified through operation of the proposed framework, as
13 described on page 4 of the Application. The review is expected to leverage operational
14 experience with the DAS Tariff and the broader RtR construct, including market
15 participation levels, customer adoption trends, net billing activity, distribution-connected
16 generation characteristics, administration and settlement requirements, and other
17 implementation-related considerations. NS Power anticipates collecting hourly interval
18 data for net billing customers and distribution-connected generation during the review
19 period, which will be incorporated into the analysis.

20
21 (c) The two-year review period was selected in consultation with REI. In addition, the
22 proposed framework is being implemented within a market environment that continues to
23 evolve, including the early stage of RtR market development, potential changes in
24 technology and participation levels, and the transition to the Nova Scotia Independent
25 Energy System Operator. As such, the Company considers it important that a reasonable
26 basis of operational experience be obtained before undertaking a review of the DAS Tariff
27 and broader RtR construct.

¹ Refer to pages 3-4 of the Application.

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- 1 (d) As described in the Application and related filings, certain costs associated with the
2 development and implementation of RtR market elements may be addressed through the
3 applicable Annually Adjusted Rates process. The timing, amount, and method of any such
4 recovery would be proposed in a future application and would be subject to the Board's
5 review and approval.

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Request IR-9:

Refer to Attachment 5, p. 2, which describes the Energy Balancing Service Tariff’s top-up and spill quantities as adjusted by “transmission losses” and “transmission locational losses, as applicable to the geographic zone in which the generating facility is interconnected.”

(a) Please clarify how this loss adjustment applies (or does not apply) to a Distribution-connected Generation facility that has no transmission zone designation, and identify what loss factor, if any, is applied to such a facility's output in the top-up/spill calculation.

Response IR-9:

(a) Transmission locational losses are not applicable to distribution-connected generation as it is assumed that the Licensed Retail Supplier’s distribution-connected generation will be consumed within the same distribution zone. This assumption will be revisited following 2028, when a review of the operation of this tariff and the broader RtR construct will be undertaken by NS Power and submitted to the Board for its review.

Distribution losses for the output of a distribution-connected generation facility are accounted for when that output energy is delivered to an RtR customer of the Licensed Retail Supplier. All end-customer metered load is adjusted for distribution losses through the application of a distribution loss factor in the calculation of Top-up and Spill energy under the Energy Balancing Service Tariff.

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Request IR-10:

Refer to Attachment 5, p. 2, and Attachment 7, p. 2. The EBS and Standby Service Administration Charges are each set at \$414.63 per month.

(a) Please confirm that an LRS taking either service must also take the other.

(b) Please explain how double-counting of shared administrative costs (e.g., account management) is avoided across the two charges.

Response IR-10:

(a) Confirmed.

(b) As provided in response to Synapse IR-2, costing and pricing matters associated with existing RtR tariffs are addressed through the Annually Adjusted Rates (AAR) process. The proposed amendments in this Application do not include changes to the methodology used to determine the Energy Balancing Service (EBS) or Standby Service (SS) tariff administration charges. Accordingly, the Company is not proposing changes through this Application that would affect the recovery of administrative costs through those tariffs. It is expected that NS Power would calculate the total tariff operating and administration costs for RtR tariffs, then allocate the approved monthly cost-recovery amount between the EBS Tariff and SS Tariff administration charges. However, RtR tariff operating and administration costs will be reviewed through the 2027 Annually Adjusted Rates process and are subject Board approval.

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Request IR-11:

Refer to Attachment 5, p. 3.

(a) Please explain the rationale for excluding fixed cost adder from the spill credit.

(b) Please confirm whether the energy charge components listed in Attachment 5 reflect any incremental costs of system benefits (e.g., reduced losses) attributable specifically to distribution-connected generation. If not, indicate when such effects are expected to be studied and potentially reflected in rates.

Response IR-11:

(a) The purpose of the spill credit is to compensate an LRS for the value of surplus energy delivered to NS Power's system. While that energy may offset variable energy-related costs, it does not reduce the fixed costs associated with maintaining firm capacity and other fixed system costs recovered through the EBS fixed cost adder. Accordingly, the spill credit reflects only the value of the energy supplied to the system and does not include the fixed cost adder. The Spill pricing construct was approved by the Board under matter M06214 concerning the Sale of Renewable Low-Impact Electricity generated within Nova Scotia by a Retail Seller to a Retail Customer pursuant to the Electricity Act, the Board Decision for which was dated March 23, 2016.

(b) The energy charge components reflected in Attachment 5 do not include adjustments specific to potential system benefits associated with distribution-connected generation, such as reduced losses. In accordance with the Board's direction in M12339, this Application proposes a framework to enable distribution-connected generation and net billing within the RtR market. The proposed framework includes a review following 2028 to assess the operation of the DAS Tariff and broader RtR construct based on actual market experience. As experience is gained with the implementation of distribution-connected

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1 generation in the RtR market, that review will provide an opportunity to consider whether
2 any amendments to the framework, including pricing-related matters, should be proposed.
3 Any such pricing proposals would be subject to the Board's review and approval.

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Request IR-12:

Refer to Attachment 6, pp. 10-11, Section 11.

(a) Please confirm that Distribution Tariff energy and demand charges apply only to the RtR Customer's metered imports (exports excluded).

(b) Please explain who bears any incremental distribution system costs associated with accommodating bidirectional flows at RtR Customer premises (e.g., feeder upgrades, protection equipment, voltage regulation costs attributable to distribution-connected generation).

Response IR-12:

(a) Confirmed.

(b) Incremental distribution system upgrade costs associated with accommodating bidirectional flows at RtR customer premises would be assessed through the interconnection process and recovered from the interconnection customer.

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Request IR-13:

Refer to Attachment 6, Section 11.3 and Attachment 8, Section 15.4.1. The Distribution Tariff states that Real Power Losses are incorporated into Distribution Tariff rates and that the RtR Customer is responsible for such losses, and the LRS Terms and Conditions provide that RtR Customer load (imports) is adjusted for distribution losses using established average annual rate class losses.

(a) Please confirm whether an equivalent, symmetric loss adjustment is applied to distribution-connected generation exports.

(b) If not, quantify the potential for under- or over-recovery of system costs this asymmetry could create.

Response IR-13:

(a) Please refer to Synapse IR-9.

(b) Please refer to CA IR-4.

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Request IR-14:

Refer to Attachment 7, pp. 2-5.

- (a) Please describe how the Effective Load Carrying Capability (ELCC) methodology will be applied in practice to small (1-5 MW), potentially non-dispatchable, distribution-connected renewable resources, including: (1) The granularity (system-wide, zonal, or feeder-level) at which ELCC values will be determined, and (2) Whether/how an LRS may challenge or seek reconsideration of an assigned ELCC value.**
- (b) Please provide a numerical example of the Monthly Standby Contract Demand (MSCD) calculation for a hypothetical LRS with a mix of BTM customer-owned generation and contracted distribution-connected generation, showing how CMPFD, CMDAFi, CCi, GCi, and PR interact. Confirm how the "exports only" treatment of surplus purchased from Distribution-connected Generation customers is incorporated into GCi.**
- (c) Please explain the rationale for the failure-to-deliver remedy in Special Condition (6) (payment of NS Power's cost to procure or self-supply undelivered capacity, net of charges already paid), including whether any cap, force majeure exclusion, or liquidated-damages treatment applies, and how this remedy compares to the equivalent default provisions in the Wholesale Market BUTU Tariff.**

Response IR-14:

- (a) The Effective Load Carrying Capability (ELCC) is currently being evaluated as part of the Integrated Resource Plan (IRP) conducted by the IESO Nova Scotia (IESO-NS) and will continue to be evaluated periodically by the IESO-NS as the planning environment changes. The ELCC assessment considers the forecasted Nova Scotia electricity system,**

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1 including expected load growth, the evolving generation resource mix, and the contribution
2 of both dispatchable and non-dispatchable resources over the study period and how those
3 resources contribute to system needs during normal and contingency conditions (peak
4 periods, weather events).

5
6 ELCC values are determined at the bulk system level rather than for individual projects,
7 feeders, or distribution zones. The studies evaluate the incremental reliability contribution
8 of resource classes, such as solar, wind, storage, and demand response, to overall system
9 adequacy and establish technology-specific ELCC values based on their ability to reduce
10 reliability risk under forecast system conditions.

11
12 As the generation portfolio, load characteristics, and renewable penetrations change over
13 time, the ELCC of each resource type is expected to evolve and is therefore reassessed
14 periodically.

15
16 For behind-the-meter, non-dispatchable solar resources, the ELCC is anticipated to be zero
17 or near zero for capacity accreditation purposes, as these resources are not directly
18 dispatchable by the system operator and their output during system reliability events cannot
19 be relied upon with a high degree of certainty. While such resources may provide energy
20 and reduce customer load, their contribution to firm system capacity is expected to be
21 limited.

22
23 The Licensed Retail Supplier may seek reconsideration of an assigned ELCC value through
24 an application to the Nova Scotia Energy Board.

25
26 (b) Please refer to Attachment 1.

27
28 (c) Special Condition (6) of the Standby Service Tariff was adopted from the Wholesale
29 Market BUTU Tariff, but does not specify treatment for cap, force majeure exclusion, or
30 liquidated damages.

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1 The rationale for this remedy is discussed in the Board Decision on matter M09940, an
2 Application by Nova Scotia Power Incorporated to amend its Wholesale Market Backup /
3 Top-up (BUTU) Service Tariff at section 3.7 Proposed Special Conditions, paragraph 166,
4 second bullet. In brief, the remedy compensates NS Power for replacement energy for the
5 energy that was not supplied by the tariff subscriber receiving capacity credit when
6 requested to do so by the System Operator during a period of resource adequacy need.

Hypothetical Sample Calculation for Monthly Standby Contract Demand (MSCD)**Class Monthly Peak Firm Demand (CMFPD) from Distribution Loss Adjusted Customer Meter Data Aggregated by Class for the CP Hour of the Billing Month**

Customer Class	CMFPD (MW)
DOMESTIC	10.233
SMALL GENERAL	3.824
GENERAL	18.468
LARGE GENERAL	2.487
SMALL INDUSTRIAL	7.945
MEDIUM INDUSTRIAL	8.129
LARGE INDUSTRIAL	12.542
LARGE INDUSTRIAL (TRANSMISSION CONNECTED)	3.492
OUTDOOR RECREATIONAL LIGHTING	0.000
UNMETERED SERVICE RATES	0.000

Class Monthly Demand Adjustment Factors (CMDAF) for Billing Month

Customer Class	CMDAF (From the Standby Service Tariff)
DOMESTIC	1.27
SMALL GENERAL	1.21
GENERAL	1.12
LARGE GENERAL	1.05
SMALL INDUSTRIAL	1.06
MEDIUM INDUSTRIAL	1.14
LARGE INDUSTRIAL	1.10
LARGE INDUSTRIAL (TRANSMISSION CONNECTED)	1.10
OUTDOOR RECREATIONAL LIGHTING	8.24
UNMETERED SERVICE RATES	8.24

Determine the LRS Winter Peak Firm Demand (LWPFDF) by Multiplying CMFPD by CMDAF

Customer Class	Resultant
DOMESTIC	12.996
SMALL GENERAL	4.627
GENERAL	20.684
LARGE GENERAL	2.611
SMALL INDUSTRIAL	8.422
MEDIUM INDUSTRIAL	9.267
LARGE INDUSTRIAL	13.796
LARGE INDUSTRIAL (TRANSMISSION CONNECTED)	3.841
OUTDOOR RECREATIONAL LIGHTING	0.000
UNMETERED SERVICE RATES	0.000
Σ	76.24 MW LWPFDF

Capacity Contribution Factor

	Generator Capacity (GCI) (MW)		Capacity Contribution Factor [ELCC] (CCI) (%)				TOTAL Capacity Contribution
Wind Farm	100	X	10%	X	=		10.00
BTM Net Billing Spill	3	X	0%	X	=		0.00
Distr.-Conn. Solar Generator	5	X	8%	X	=		0.40
					TOTAL:		10.40 MW

Planning Reserve Margin

PRM	PRM	=	20%	(As determined by NS Power/IESO-NS System Planning)
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LRS Winter Peak Firm Demand (LWPFDF)

LWPFDF	=	76.24 MW	(As determine through Standby Service Tariff calculations above)
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Monthly Standby Contract Demand (MSCD)

LWPFDF	-	Min (LWPFDF, TOTAL Capacity Contrib./((1 + Planning Reserve Margin)))	=	MSCD
76.24	-	8.67	=	67.58 MW

Disclaimer:

- For illustrative purposes only.
- Energy, Demand, and Other values are for illustrative purposes only and do not reflect expected quantities.

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Request IR-15:

Refer to Attachment 8, pp. 16-17, Section 14.1.2.

(a) Please provide an estimate of the total incremental cost involved with AMI metering necessary to interconnect a generator to the distribution system.

(b) Please clarify how the incremental AMI metering and communications costs required to separate hourly import and export channels are recovered (e.g., through general distribution rates, through the DAS Administration Charge, or as an incremental metering charge to the RtR Customer, under LRS Terms and Conditions?)

Response IR-15:

(a) The incremental cost of providing AMI metering for a generator interconnected to the distribution system, relative to a residential load customer, can range from zero to tens of thousands of dollars. Costs vary based on several factors, including generator size, with larger generators often requiring more complex and costly metering arrangements, whether metering is installed on the primary or secondary system, and the availability of AMI communications coverage. In areas where communications coverage is insufficient, an alternative communication backhaul solution may be required, resulting in additional costs.

(b) Incremental AMI metering and communications costs are recovered through the interconnection process.

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Request IR-16:

Refer to Attachment 10, redlined language for the definition of “Distribution System Access.”

(a) Do these changes have any implications for cost allocation? Please explain.

Response IR-16:

(a) Yes. The introduction of the Distribution-connected Aggregation Service (DAS) is expected to result in incremental costs related to the aggregation and settlement of generation resources connected to the distribution system. The Company intends to seek recovery of these costs through a tariff charge in its 2027 Annually Adjusted Rates application, which is scheduled to be filed in November 2026.

Given the early stage of RtR market development, the Company expects to reassess the tariff charge as part of its proposed post-2028 review.

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Request IR-17:

Refer to Attachment 11, pp. 4-5, Condition 5 and sub-parts.

(a) Please describe the process and timeline by which an LRS is expected to “demonstrate” compliance with items (i) through (vi) to NS Power’s satisfaction.

(b) Are these standards expected to be met prior to operation or during? Please explain.

(c) Is there a right of appeal or independent review if NS Power determines the LRS has not met this standard? Please explain.

(d) Regarding part (iii) how are “critical times of the year” determined? Does this refer to a specific type of event?

(e) Are these conditions appropriate for a small-scale resource like BTM solar? Please confirm that a BTM resource could not generally meet these conditions, or what NS Power’s expectation is for smaller, BTM resources.

(f) Would it be more appropriate for these conditions to apply to larger and/or FTM distribution-connected resources? Why or why not?

(g) If a capacity contribution factor for a BTM resource is zero, will it still be incorporated into NS Power resource planning?

Response IR-17:

(a-b) Please refer to the table below.

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Proposed Standby Service Tariff Special Condition (5)	Compliance Process and Timeline
(i) If the LRS' resource is dispatchable, that it can start up and deliver energy contracted to, but unused by, the LRS to NS Power, if directed to do so by the NSPSO, in the event of a resource adequacy need;	Initial and periodic verification testing with first test occurring during generator commissioning.
(ii) If the LRS' resource is non-dispatchable, that it makes its full output for which it is provided an ELCC value contracted to, but unused by, the LRS available to deliver energy to NS Power, in the event of a resource adequacy need;	Initial and periodic verification testing with first test occurring during generator commissioning.
(iii) The LRS' resource will remain available for dispatch, if called upon by the NSPSO, by coordinating with the NSPSO and refraining from taking planned outages during certain critical times of the year, as determined by the NSPSO;	Planned outage work will be scheduled in accordance with Market Rules Chapter 3: Reliability Planning Requirements, Section 3.5 – Outage Management. The timeline for compliance would be the first and every subsequent outage request for planned maintenance.
(iv) Any export transactions utilizing energy from the LRS' resource will be recallable by the NSPSO, up to the amount contracted to the LRS, for delivery to the NS Power system in the event of a resource adequacy need;	The LRS would be required to provide evidence of commercial recall rights between the LRS in Nova Scotia and the buyer. The timeline for compliance would be the first and every subsequent sale arranged.
(v) The LRS' resource, as applicable, will perform as needed to meet NS Power's reliability requirements; and	Initial and periodic testing to ensure adequate response to dispatch directives, to meet the reliability needs of the system operator, with first test occurring during generator commissioning.
(vi) The capacity derived based on the capacity contribution factor is procured and available to the LRS on a minimum three-year forward basis, unless this requirement is waived by NS Power.	The LRS would be required to provide evidence that the capacity derived based on the capacity contribution factor is procured and available to the LRS on a minimum three-year forward basis prior to approval of the capacity contribution factor by NSPSO.

- (c) In the event NS Power determines that a Licensed Retail Supplier (LRS) has not satisfied one or more of the requirements set out in Special Condition (5), the Company would expect to engage with the LRS to understand the circumstances and seek to resolve the matter. The Wholesale and Renewable to Retail Market Advisory Committee may also

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1 provide an opportunity for discussion of implementation or operational issues. If the matter
2 remains unresolved, the LRS may seek recourse to bring the matter forward to the Nova
3 Scotia Energy Board.

4
5 (d) In accordance with Market Rules Chapter 3: Reliability Planning Requirements, Section
6 3.5 – Outage Management, planned outage work shall be coordinated with and approved
7 by the system operator. As part of the assessment, the system operator will determine if the
8 outage can be granted without compromising the reliability of the bulk power system.

9
10 (e) Small-scale renewable resources such as behind-the-meter solar are not likely to be
11 awarded a capacity contribution factor because the Effective Load Carry Capability
12 (ELCC) of these resources is expected to be zero, or near zero (subject to the most currently
13 available ELCC study).

14
15 (f) The application of a capacity contribution factor is only possible if a resource can meet the
16 requirements noted under Special Condition (5). Essentially, a capacity contribution factor
17 can only be applied if the full capacity of the resource can be called upon and utilized by
18 the System Operator in the event of a resource adequacy need. This is independent of the
19 location and size of the resource. In general, it is more likely these provisions could be
20 fulfilled by a larger generator.

21
22 (g) No.

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Request IR-18:

Refer to Attachment 12, p. 12, Section 9.8.

(a) Please provide the specific language in the Electricity Act referenced.

(b) Why would a customer be “de-rated?” How would this, in practice, be accomplished? Please provide an illustrative example of a customer who is de-rated and how this impacts the customer’s bills, as well as any other consequences of de-rating.

(c) What recourse, if any, would a customer have if they were not adequately informed of the de-rating risk by the LRS?

(d) What constitutes whether an LRS has “informed” a customer of this provision?

Response IR-18:

(a) Please refer to the following sections of the [Electricity Act](#).

Requirement	Section	Provision
Compensation limit for ≤ 27 kW customers	s. 7(4)	Compensation capped at customer annual consumption
Compensation limit for > 27 kW program participants	s. 6(6)	Compensation capped at customer annual consumption

(b) Please refer to NSEB IR-11 part (a). De-rating a behind-the-meter generator can be achieved by implementing output limits within the generator’s control system to ensure its output does not exceed a specified level. For a behind-the-meter solar generator, de-rating can also be accomplished by removing solar panels from service to reduce the generator’s maximum output capability.

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1 NS Power does not have visibility into the billing arrangements between a Licensed Retail
2 Supplier (LRS) and customers participating in the LRS' net billing offering and, therefore,
3 cannot comment on any resulting billing impacts.
4

5 (c) NS Power does not have visibility into the contractual arrangements between an LRS and
6 customers participating in the LRS' net billing offering. Any concerns regarding those
7 arrangements could potentially be brought before the Nova Scotia Energy Board (NSEB)
8 by the customer.
9

10 (d) This would be a matter between the LRS and customers participating in the LRS' net billing
11 offering.

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Request IR-19:

Refer to Attachment 12, p. 16, Section 13.

(a) Please clarify how a distribution-connected generator sized above net-metering limits will be technically evaluated for interconnection. Please also describe what protections exist against adverse impacts on feeder capacity or other customers served on the same feeder.

(b) Regarding the sentence that states “For clarity, sizing limits applicable to NS Power’s net metering programs do not apply.” Please explain this sentence.

(i) Do the sizing limits not apply to both BTM and FTM resources?

(c) Please confirm there is no maximum energy or capacity amount an RtR Customer or LRS may interconnect.

Response IR-19:

(a) Please refer to Synapse IR-4, part (a-b).

(b) Sizing limits imposed on the NS Power Commercial Net Metering program require that the generator be sized to meet, but not exceed, the customer’s expected annual electricity consumption. The referenced sentence is intended to clarify that this net-metering sizing limitation does not apply to resources participating in the RtR market for net billing or distribution-connected generation.

(c) There is no legislated or regulatory limit on the amount of annual energy production or capacity of a resource that an RtR Customer or LRS may interconnect to the distribution system. Any limitation would be determined by the technical capability of the distribution

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1 system to accommodate the interconnection as established through existing distribution
2 generation interconnection procedures.

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Request IR-20:

Refer to the 2026 NS Power Load Forecast Report, Section 4.8. Specifically, refer to lines 11-12, which states

“The peak forecast remains unchanged as NS Power is required to serve the full peak of these customers if needed.”

(a) Please explain how the peak contribution of RtR resources will be accounted for in NS Power’s planning to meet peak load.

(b) Will the contribution of RtR resources in meeting peak load reduce NS Power’s capacity needs? Please explain.

(c) Please explain how this influences cost allocation.

Response IR-20:

(a) For any Renewable to Retail (RtR) resource which meets the Special Condition (5) of the revised Standby Service (SS) Tariff and is awarded a Capacity Contribution Factor (CCF) as determined by its Effective Load Carrying Capability (ELCC), that CCF can be counted toward the long-term capacity planning to meet peak load plus the Planning Reserve Margin.

(b) Yes. As part of the value exchange, the Licensed Retail Supplier (LRS) will receive a CCF credit for its resource. In return, the Independent Energy System Operator – Nova Scotia may count that capacity toward its long-term resource planning.

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1 (c) As described in the stakeholder materials included with the Application,¹ the RtR Energy
2 Balancing Service (EBS), SS, and Renewable to Retail Market Transition (RTT) tariffs are
3 currently costed and priced based on NS Power customer class costs and load profiles, with
4 tariff pricing applied to actual LRS load and generation. This Application does not propose
5 changes to that existing costing construct. While eligible RtR resources may contribute
6 toward resource adequacy planning through the CCF framework, no corresponding
7 changes to cost allocation are proposed as part of this Application. Given the early stage of
8 RtR market development and the limited operational experience available, the Company
9 expects this approach to remain unchanged through the proposed review period, with the
10 operation of the Distribution-connected Aggregation Service (DAS) Tariff and broader
11 RtR construct subject to review following 2028. Should future changes to RtR costing or
12 pricing be proposed, they would be subject to the applicable regulatory review and
13 approval process.

¹ Refer to Attachment 3.