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January 22, 2020

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Re: Dry Bridge Solar 1, LLC, et. al Petition for Dispute Resolution – Docket No. 5103

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid (the Company), enclosed for filing are six copies of the Company's Redacted Exhibit 1 of its Response to the Petition for Dispute Resolution filed by Dry Bridge Solar 1, LLC, in Dry Bridge Solar 2, LLC, Dry Bridge Solar 3, LLC and Dry Bridge Solar 4, LLC the above-referenced matter, and a motion for protective treatment of the same. These materials were electronically filed on this date.

Thank you for your attention to this matter. Please contact me if you have any questions.

Sincerely,

John K. Habib

John K. Habib, Esq.

Enclosures

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

Dry Bridge Solar 1, LLC, Dry Bridge Solar 2, LLC, Dry Bridge Solar 3, LLC and Dry Bridge Solar 4, LLC Petition for Dispute Resolution	)	Docket No. 5103

NATIONAL GRID'S PETITION
FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission (PUC) provide confidential treatment and grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by PUC Rule 1.3(H) and R.I.G.L. § 38-2-1, *et seq.* National Grid further requests that, pending entry of findings pursuant to these provisions, the PUC preliminarily grant National Grid's request for confidential treatment pursuant to Public Information, PUC Rule 1.3(H)(2).

I. BACKGROUND

On January 7, 2021, Dry Bridge Solar 1, LLC, Dry Bridge Solar 2, LLC, Dry Bridge Solar 3, LLC and Dry Bridge Solar 4, LLC (together, Dry Bridge or Customer) filed a petition for dispute resolution in the above-captioned matter concerning terms of a Conditional Interconnection Service Agreement (ISA) executed by National Grid and Exeter. In accordance with Section 9 of National Grid's Standards for Connecting Distributed Generation, RIPUC No. 2180, National Grid is submitting a response to Exeter's Petition on January 22, 2021. Together with its response, National Grid is submitting as Exhibit 1 a draft version of the applicable

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

Distribution System Impact Study (DSIS) for the Dry Bridge projects.

Exhibits 1 of National Grid's response contains certain information regarding Dry Bridge's projects, including single line diagrams and other engineering documents, which may be considered confidential customer information. Accordingly, National Grid requests that the PUC give the information contained in the un-redacted versions of Exhibit 1 confidential treatment.

II. LEGAL STANDARD

The PUC's Rule 1.3(H) provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I.G.L. §38-2-1 *et seq.*

Under the APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I.G.L. §38-2-2(4). Therefore, to the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information to be confidential and to protect that information from public disclosure. In that regard, R.I.G.L. §38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The exception "protects persons who submit financial or commercial data to government agencies from the competitive disadvantages which would result from its publication." Critical Mass Energy Project v. Nuclear Regulatory Commission, 975 F.2d 871, 873 (D. D.C. Cir. 1992); see also Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I. 2001) (adopting Critical Mass). The Rhode Island Supreme Court has held that this confidential

information exemption applies where disclosure of information would be likely to either: (1) impair the Government's ability to obtain necessary information in the future; or (2) cause substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal, 774 A.2d at 47 (emphasis added).

The second prong of the Providence Journal test has been interpreted to not require "a sophisticated economic analysis of the likely effects of disclosure." New Hampshire Right to Life v. US Dept. of Health and Human Services, 778 F. 3d 43, 50 (1st. Cir. 2015) (quoting Pub. Citizen Health Research Grp., 704 F. 2d 1280, 1291 (1983)). The party opposing disclosure must establish "actual competition and a likelihood of substantial competitive injury" to bring the information under the confidential exemption. Id. In determining whether information is confidential the court should not limit its assessment of bidding information in a singular ad-hoc manner, but rather should acknowledge the likelihood of additional bids in the future. Id., at 51. As discussed further below, the Confidential Information here should be protected because it is commercial or financial information that, if disclosed, would be likely to cause substantial harm to the competitive position of the persons from whom the information was obtained.

III. BASIS FOR CONFIDENTIALITY

Exhibit 1 of National Grid's response to Dry Bridge's Petition consists of the draft DSIS for Dry Bridge's project. Appendix C of the DSIS includes customer site and single line diagrams prepared by Dry Bridge and submitted to National Grid in connection with Dry Bridge's interconnection application. Section 10 of the Conditional ISA executed by the parties provides that National Grid "shall maintain confidentiality of all Interconnecting Customer confidential and proprietary information except as otherwise required by applicable laws and regulations, the Interconnection Tariff, or as approved by the Interconnecting Customer in the

Simplified or Expedited/Standard Application form or otherwise." See Dry Bridge Petition, Exhibit C, at 5. To comply with this provision and protect proprietary customer information, National Grid respectfully requests confidential treatment of Exhibit 1.

IV. CONCLUSION

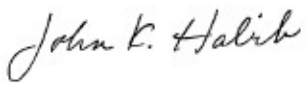
Accordingly, the Company requests that the PUC grant protective treatment above-listed confidential information.

WHEREFORE, the Company respectfully requests that the PUC grant its Petition for Protective Treatment as stated herein.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

By its attorney,



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Dated: January 22, 2021

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

Dry Bridge Solar 1, LLC, Dry Bridge Solar 2, LLC, Dry Bridge Solar 3, LLC and Dry Bridge Solar 4, LLC Petition for Dispute Resolution	)	Docket No. 5103

THE NARRAGANSETT ELECTRIC COMPANY'S RESPONSE TO PETITION

The Narragansett Electric Company d/b/a National Grid (TNEC), pursuant to Section 9.2 of the Standards for Connecting Distributed Generation, R.I.P.U.C. No. 2180 (the Interconnection Tariff), hereby responds to the Petition for Dispute Resolution (Petition) filed by Dry Bridge Solar 1, LLC, Dry Bridge Solar 2, LLC, Dry Bridge Solar 3, LLC and Dry Bridge Solar 4, LLC (together, Dry Bridge or Customer) in the above-captioned matter.[1]

I. INTRODUCTION

This dispute concerns whether Dry Bridge should be required to pay a Direct Assignment Facility Charge (DAF) assessed to TNEC by TNEC's transmission service provider, New England Power (NEP), in accordance with NEP's FERC-approved tariff, Schedule 21-NEP to the ISO-NE Open Access Transmission Tariff (OATT). The DAF charge will be assessed by NEP because Dry Bridge's proposed 40 MW of solar projects in North Kingston (Projects) together with a related 10 MW solar energy project in Exeter, Rhode Island being developed by a previously-affiliated entity, Exeter Renewables 1 LLC (Exeter), require construction of a new substation

[1] Section 9.2(a) of the Tariff provides that "within ten business days after the written request to the Commission for dispute resolution, the other party shall also submit a summary of the situation to the Commission and provide a copy of the summary to the Requesting Party." For organizational purposes, TNEC has set forth its specific response to each of the factual allegations stated in the Petition.

served from the transmission system in order to be safely interconnected to TNEC's distribution system. The new substation will include transmission assets at or above 69kV, which will be operated and maintained by NEP. The DAF is a FERC-approved means by which NEP may recover certain costs of operating transmission assets from specific transmission customers.

The issues raised in Dry Bridge's petition are nearly identical to the issued raised by Exeter's petition for dispute resolution filed on November 18, 2020 and currently under consideration in Docket 5090.[2] Accordingly, TNEC largely adopts the substance of its December 3, 2020 response in Docket 5090 in this response.

Like Exeter, Dry Bridge attempts to frame this dispute as a simple matter of contract law. Dry Bridge argues that the terms of Conditional Interconnection Services Agreements (Conditional ISAs) approved by the Rhode Island Public Utilities Commission (PUC or Commission) in Docket 4956 and subsequently executed by the parties bars TNEC from passing through NEP's DAF charges. Dry Bridge's narrow reading of the preliminary Conditional ISA overlooks the plain language of Section 5.1 of the Conditional ISA, which provides that "[t]he Interconnecting Customer shall be responsible for the actual Affected System operator costs, including operation and maintenance costs, and any additional Company costs necessitated as a result of the Affected System operator requirements, **none of which shall be subject to any cost caps or limitations**." Conditional ISA, Section 5.1 (emphasis added).

More importantly, Dry Bridge's Petition fails to acknowledge that DAF charges are assessed by NEP under FERC-approved tariffs, which cannot be challenged here. The filed rate doctrine prohibits the PUC from reviewing the propriety of FERC-approved rates and requires that the PUC allow TNEC full recovery of costs properly assessed by NEP to TNEC under FERC-

[2] TNEC understands that Dry Bridge and Exeter's petitions will proceed under separate dockets but will be coordinated and considered together.

approved tariffs. Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, 962, 106 S.Ct. 2349 (1986); Petition of the Episcopal Diocese of Rhode Island, Docket No. 4981, Order 23811 (2020). Though it improperly attempts to do so in its Petition, Dry Bridge cannot argue away the DAF charges. If the PUC were to accept Dry Bridge's argument that it is not responsible for paying DAF charges under the Conditional ISAs, the result would be that the DAF charges are instead passed through to all Rhode Island retail customers under TNEC's Transmission Service Cost Adjustment Provision, RIPUC No. 2198. Therefore, the question actually presented in this case is whether DAF charges should be paid for by the companies that have caused the need for these transmission upgrades and that will profit from the operation of these large-scale 40 MW solar facilities, or if the costs should instead be paid for by all Rhode Island customers, who are already supporting renewable energy development through their electric rates. The terms of the Interconnection Tariff, the negotiated provisions of the Conditional ISAs, traditional cost causation principles and the PUC's recent decision in Docket No. 4981 all lead to the answer that Dry Bridge is responsible for these costs.

II. RESPONSE TO STATEMENT OF FACTS

TNEC responds to Dry Bridge's "Statement of Facts" in its Petition, as follows:

1. TNEC does not dispute that Petitioners are the owners of the Projects, which are four related solar distributed generation projects being built in North Kingston, Rhode Island.

2. TNEC does not dispute that Brown University has agreed to purchase the power generated by the Projects.

3. TNEC does not dispute the contents of Exhibit A of the Petition.

4. TNEC does not dispute that the Projects must be interconnected to the electric power system to be operational. However, the Wickford Junction substation is not yet constructed.

The Projects are four of fourteen solar projects with an aggregate capacity of 108 MW that will share in the construction, cost and use of a common double circuit 34.5kV distribution feeder and a new 115kV/34.5kV substation referred to as the Wickford Junction substation. Construction of the new Wickford Junction substation includes the following transmission-level upgrades: (1) installation of 115kV loop tap to the new Wickford Substation; (2) installation of 115kV ring bus including breaker, disconnect switches, bus, bus insulators and wave trap, and associated site-work, grounding, foundations, structures and associated protection and control; and (3) installation of a 115kV 4-Breaker Ring Bus with protection and control, including but not limited to site work, grounding and conduits.

5. The agreements entered between Dry Bridge and TNEC in November 2019 are Conditional ISAs, which Dry Bridge requested TNEC issue prior to the completion of all required interconnection analyses and studies. TNEC does not dispute that Exhibits C, D, E and F are true and correct copies of the Conditional ISAs executed by the parties.

6. TNEC does not dispute that it presented the Conditional ISAs to the PUC for approval as part of a dispute resolution process under Docket No. 4956. TNEC does not dispute the contents of Exhibit G to the Petition.

7. TNEC disputes that the Conditional ISAs reflect all costs that TNEC will incur in making the upgrades to its electric power system needed to interconnect the Projects. First, the Conditional ISAs clearly provide that, at time of execution, required interconnection studies for the Projects were not complete and additional System Modifications could be identified. Second, the Conditional ISAs do not identify DAF charges, which represent additional costs that TNEC will incur for transmission-level upgrades required at the new Wickford Junction substation.

8. TNEC does not dispute that Section 5 of the Conditional ISAs notes that the Projects required additional studies and that Dry Bridge could incur additional costs as a result.

9. TNEC does not dispute the contents of Exhibit H of the Petition.

10. TNEC does not dispute that Section 5 of the Conditional ISAs provides that "Subject to Section 14, upon the request of the Interconnecting Customer, or at the Company's discretion, the Company shall amend this Agreement and any attachments to incorporate the results of any final Impact Study, Detailed Study, ISRDG and/or ASO study." TNEC does not dispute that Section 14 of the Conditional ISAs provides that "No amendment or modification of this Agreement shall be binding unless in writing and duly executed by both Parties." TNEC further states for clarity that Final Distribution System Impact Study (DSIS) was not complete for the Projects at the time of executing the Conditional ISAs. The Final DSIS was issued on July 14, 2020.

11. TNEC disputes that "there were no 'results of any final Impact Study Detailed Study, ISRDG and/or ASO study' that justified any amendment under Section 5 of the [Conditional] ISA." The Conditional ISAs were based on the Draft DSIS with non-binding good faith cost planning grade estimates. The Final DSIS was issued on July 15, 2020. TNEC further disputes Dry Bridge's allegation that the Projects "are not responsible for any transmission level modifications." The Draft DSIS clearly identified transmission-level line work and transmission-level substation work required to interconnect the Projects. The Draft DSIS is provided as **Exhibit 1** hereto.

12. TNEC disputes Dry Bridge's allegation that the Projects would not require any ASO Upgrades. ISO-NE reviewed the Projects inclusive of the transmission-level upgrades at the newly proposed Wickford Junction substation, identified in paragraph 4, above. Those

transmission-level upgrades, once constructed, will be operated by NEP, an Affected System operator.

13. TNEC does not dispute that the Western RI Area ASO Study Results found that the Projects would not have any adverse impacts on NEP or other transmission owners. As noted in paragraph 12, above, this determination was made by ISO-NE based on the System Modifications identified in the DSIS, including the transmission-level upgrades associated with the newly proposed 115kV/34.5kV Wickford Junction substation.

14. TNEC does not dispute the contents of Exhibits K, L, M and N of the Petition. However, as noted in paragraphs 12 and 13, above, ISO-NE's determinations were based on the System Modifications identified in the DSIS, including the transmission-level upgrades associated with the newly proposed 115kV/34.5kV Wickford Junction substation.

15. TNEC takes no position as to Dry Bridge's judgement to move forward with the Projects based on the Conditional ISAs, which were not final and remained subject to possible revision.

16. TNEC does not dispute that Dry Bridge has made more than $14 million of milestone payments to TNEC and have arranged to maintain a letter of credit valued at more than $16 million. TNEC has no knowledge of other investments made on the Projects and therefore takes no position on Dry Bridge's remaining statement. TNEC notes, however, that none of these payments have gone towards DAF charges. Under the proposed Final ISAs, the initial four months of DAF payments is required 30 days prior to the in-service date, anticipated February 2022.

17. TNEC does not dispute that it submitted Final Interconnection Services Agreements to Dry Bridge on or around August 12, 2020, as contained in Exhibits O, P, Q and R of the Petition. The Final ISAs identify NEP's carrying charge as 5.21% of actual transmission

Gross Plant Investment, which is subject to change in accordance with NEP's FERC-approved tariffs. The Final ISAs note that the DAF charge is an estimate and will be recalculated based on the actual reconciled costs of the transmission-level upgrades.

18. TNEC does not dispute the contents of the Final ISAs.

19. TNEC does not dispute that the transmission-level upgrades were listed in the Conditional ISAs as "National Grid System Modifications." However, the System Modifications were at all times known to include transmission-level upgrades and were clearly identified as such in the Draft DSISs. The Final ISAs were issued based on the understanding of the parties that the Conditional ISA was an interim document provided at Dry Bridge's request that would become final once amended to include additional terms and conditions associated with TNEC, and if applicable, Affected System operator costs and payment terms. The System Modifications in Attachment 2 and Attachment 3 were listed separately based on the classification of distribution level and transmission level work, in the same manner as identified in the Draft DSIS and Final DSIS. Identifying the transmission level upgrades as "Affected System Operator Upgrades" is consistent with the Interconnection Tariff definition of "Affected System" as "[a]ny neighboring transmission or distribution EPS not under the control of the Company (e.g., a municipal utility, or other regulated distribution or transmission utility, which may include Affiliates, or ISO-NE, as defined herein)." Interconnection Tariff, Section 1.2. Regardless of ownership, all transmission assets will be controlled and operated by NEP, as TNEC's transmission provider. The PUC has determined clearly that "New England Power Company has always been an Affected System under each version of the Distributed Generation Standards for Interconnection tariffs." Order 23811 at 13-14.

20. TNEC does not dispute the contents of Attachment 2 of the Conditional ISAs.

21. For the reasons stated in paragraph 19, above, TNEC disputes Dry Bridge's allegation that the transmission-level upgrades "cannot be an ASO Upgrade."

22. TNEC disputes Dry Bridge's allegation that transmission-level upgrades were described in the Final ISAs as "ASO Upgrades" for the purpose of imposing DAF charges. Regardless of the descriptive headings applied in the attachments to the Conditional ISAs or Final ISAs, the transmission-level upgrades associated with the new 115kV/34.5kV Wickford Substation will, as a matter of fact, be transmission assets that will be operated by NEP as TNEC's transmission provider. NEP will assess DAF charges to TNEC for those transmission assets regardless of how the Conditional ISA or Final ISA characterizes those costs. Nevertheless, TNEC maintains that for the reasons identified in paragraph 19, above, the organization of costs identified in the Final ISAs is appropriate.

23. TNEC disputes Dry Bridge's allegations. Even as presented in the Conditional ISAs, the transmission-level upgrades for the new 115kV/34.5kV Wickford Junction substation will result in NEP assessing DAF charges. Under Section 5.1 of the Conditional ISA, NEP's DAF charges are not subject to any cost cap or other limitation and are therefore properly passed through to Dry Bridge: "[t]he Interconnecting Customer shall be responsible for the actual Affected System operator costs, including operation and maintenance costs, and any additional Company costs necessitated as a result of the Affected System operator requirements, none of which shall be subject to any cost caps or limitations." Conditional ISA, Section 5.1. This provision is consistent with Section 5.4 of the Interconnection Tariff, which provides that "Interconnecting Customers shall be directly responsible to any Affected System operator for the costs of any system modifications necessary to the Affected Systems."

24. TNEC disputes Dry Bridge's allegations. The DAF charges will be assessed by NEP in accordance with its FERC-approved tariffs. The justness and reasonableness of the DAF charges cannot be challenged before the PUC, as the PUC lacks jurisdiction to review NEP's tariffs and is obligated to accept those charges and allow TNEC to recover those costs under the filed rate doctrine. Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, 962, 106 S.Ct. 2349 (1986); Petition of the Episcopal Diocese of Rhode Island, Docket No. 4981, Order 23811 (2020).

25. TNEC does not dispute that the transmission-level updates associated with the new 115kV/34.5kV Wickford Junction substation were identified as such in the Draft DSIS, Conditional ISAs and Final DSIS. Dry Bridge's obligation to pay for DAF charges associated with those transmission assets is consistent with Section 5.4 of the Interconnection Tariff and Section 5.1 of the Conditional ISAs.

26. As noted in paragraphs 12, 13, and 14 above, ISO-NE's determinations were based on review of the Projects inclusive of the System Modifications identified in the DSIS, including the transmission-level upgrades associated with the newly proposed 115kV/34.5kV Wickford Junction substation.

27. TNEC disputes Dry Bridge and Exeter's allegation that "as a matter of law under the Interconnection Tariff, all of the System Modifications are Company EPS that is not subject to DAF charges." TNEC identified all transmission-level upgrades associated with the new 115kV/34.5kV Wickford Junction substation. The transmission assets will be operated by NEP, an Affected System operator. The transmission assets are therefore subject to DAF charges in accordance with NEP's FERC-approved tariff.

28. TNEC disputes Dry Bridge's allegation that "there can be no basis under the ISO-NE OATT for New England Power to impose DAF Charges…" As discussed further below, NEP

operates all transmission assets owned by TNEC. In accordance with Schedule 21-NEP, Attachment DAF, NEP charges TNEC for the costs associated with its provision of transmission service, including costs associated with new transmission facilities constructed for specific transmission customers, and on-going charges associated with the operation and maintenance of those assets.[3] In any event, Dry Bridge cannot challenge the legal basis for the assessment of DAF charges here, as the PUC is required to respect NEP's FERC-approved tariff and is prohibited from setting rates that would have the effect of trapping costs incurred by TNEC as a result of those tariffs. Nantahala, 476 U.S., at 968, 970.

29. TNEC disputes Dry Bridge's allegation for the reasons stated in paragraph 28, above.

30. TNEC disputes Dry Bridge's allegation for the reasons stated in paragraph 28, above. Additionally, "Affected System" is defined in the Interconnection Tariff as "[a]ny neighboring transmission or distribution EPS **not under the control of the Company** (e.g., a municipal utility, or other regulated distribution or transmission utility, which may include Affiliates, or ISO-NE, as defined herein)." Interconnection Tariff, Section 1.2 (emphasis added). The PUC has determined clearly that "New England Power Company has always been an Affected System under each version of the Distributed Generation Standards for Interconnection tariffs." Order 23811 at 13-14.

31. TNEC disputes Dry Bridge's allegation. The Projects require transmission-level upgrades associated with the construction of the new 115kV/34.5kV Wickford Junction substation. Those transmission assets will be operated by NEP following construction, and NEP will assess DAF charges on those assets in accordance with its FERC-approved tariff, Schedule 21-NEP,

[3] See Schedule 21-NEP, Attachment DAF, *available at* https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/sch21/sch_21_nep.pdf.

Attachment DAF; a legal conclusion that cannot be challenged here. Dry Bridge's obligation to pay for DAF charges associated with those transmission assets is consistent with Section 5.4 of the Interconnection Tariff and Section 5.1 of the Conditional ISA, as discussed further below.

32. TNEC disputes Dry Bridge's allegation for the reasons stated in paragraph 31, above.

33. TNEC disputes that Dry Bridge "rightly rejected" to sign the Final ISAs, for the reasons stated in paragraph 31, above.

34. TNEC does not dispute that Dry Bridge initiated disputes resolution on or about September 2, 2020 and that the parties have been unable to resolve the dispute.

35. TNEC does not dispute that Dry Bridge made additional payments of more than $8 million to TNEC after commencing this dispute.

36. TNEC does not dispute that this matter is ripe for mediation/non-binding arbitration under Section 9.2 of the Interconnection Tariff. TNEC disputes that Dry Bridge's requests for certain declaratory judgments by the Commission is procedurally appropriate under the same provision. TNEC further disputes Dry Bridge's request for attorneys' fees, as no such relief is afforded under the Interconnection Tariff and its request therefore lacks any legal basis.

III. RESPONSE TO DISPUTED ISSUES

A. DAF Charges Are Assessed By NEP Pursuant To FERC-Approved Tariffs And Should Be Passed On To Dry Bridge As The Entities Causing Such Costs.

Dry Bridge's Petition mischaracterizes the transmission facilities required to reliably interconnect its project. TNEC is not attempting to transfer or shift any transmission assets associated with the Projects to its transmission affiliate, NEP. Rather, TNEC has appropriately identified portions of the new substation and related equipment needed to interconnect the Projects as transmission assets.[4] Once constructed, those transmission assets will be operated by NEP, in accordance with its role as TNEC's transmission provider. Dry Bridge's focus on ownership of the assets and description in the Conditional ISAs as "National Grid System Modifications" is irrelevant - the costs charged by NEP to TNEC associated with the transmission facilities required for the Projects are properly assessed by NEP under its FERC-approved tariff. Moreover, TNEC's allocation of those costs as Affected System Operator costs to Dry Bridge are appropriate under the Interconnection Tariff and consistent with PUC precedent regarding cost causation and allocation (see Order #23811 in Docket No. 4981, Petition of the Episcopal Diocese of Rhode Island).

NEP operates transmission facilities that it owns directly, as well as certain transmission facilities owned by its distribution affiliates in New England, including TNEC. TNEC is a wholesale transmission customer of NEP and FERC-approved Schedule 21-NEP to the ISO-NE OATT provides the mechanisms by which NEP allocates and recovers from its transmission customers certain costs associated with its provision of transmission service, including costs

[4] For new substations containing assets operating below 69kV and at or above 69kV, as is the case here, equipment rated at 69kV or higher is generally booked as a transmission asset, while equipment below 69kV is booked as a distribution asset. TNEC identified the System Modifications required for the Projects consistent with this approach, identifying System Modifications at the 115kV level as transmission assets.

associated with new transmission facilities constructed for specific transmission customers, and on-going charges associated with the operation and maintenance of those assets.[5]

Under Parts II and III of the Federal Power Act (FPA), the rates and services for electric transmission in interstate commerce and electric wholesale power sales in interstate commerce are the exclusive jurisdiction of the FERC. New York v. FERC, 535 U.S. 1, 122 S.Ct. 1012, (2002). Pursuant to the filed rate doctrine, rates filed with or fixed by FERC must be given binding effect by state utility commissions determining intrastate rates. Entergy Louisiana, Inc. v. Louisiana Public Service Commission et al., 539 U.S. 39, 47 123 S.Ct. 2050, 2056 (2003); Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, 962, 106 S.Ct. 2349 (1986). "When the filed rate doctrine applies to state regulators, it does so as a matter of federal pre-emption through the Supremacy Clause." Entergy Louisiana, 539 U.S., at 47.

Applying the filed rate doctrine, the Supreme Court has held that state regulators are barred from setting rates that would have the effect of trapping costs by categorically excluding costs under a FERC tariff from recovery through retail rates. Entergy Louisiana, 539 U.S., at 39; Nantahala, 476 U.S., at 968, 970. "Such a 'trapping' of costs is prohibited." Nantahala, 476 U.S., at 970.

In its April 14, 2020 written decision in Order 23811, the PUC agreed that "[t]he PUC is prohibited from reviewing the propriety of FERC-approved rates" and that "[i]t must allow Narragansett full recovery of costs properly assessed by New England Power or ISO-NE to Narragansett under FERC-approved tariffs." Order 23811 at 6-7. However, it is within the PUC's jurisdiction to determine how costs incurred under FERC-approved transmission tariffs should be recovered in retail rates. Id. at 7.

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[5] See Schedule 21-NEP, Attachment DAF, *available at* https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/sch21/sch_21_nep.pdf.

The PUC indicated that transmission charges for transmission facilities that serve all retail customers are collected through a base transmission charge and a transmission service cost adjustment provision based on cost allocation principles. Order 23811 at 8. Where transmission charges are necessary to serve a distributed generation customer's interconnection request, the Interconnection Tariff provides that "[t]he Interconnecting Customer will be directly responsible to the potentially Affected System operators for all costs of any additional studies required to evaluate the impact of the interconnection on the potentially Affected Systems" and that "Interconnecting Customers shall be directly responsible to any Affected System operator for the costs of any system modifications necessary to the Affected Systems." Order 23811 at 11. Moreover, the PUC found that "New England Power Company has always been an Affected System under each version of the Distributed Generation Standards for Interconnection tariffs." Order 23811 at 13-14. Therefore, the PUC found that "recovering the costs caused by a distributed generation interconnecting customer is consistent with well-established principles of cost causation." Id. at 14.

The PUC's decision in Order 23811 controls here as well. Construction of the new 115kV/34.5kV Wickford Substation is required only to serve the proposed aggregate 50MW of new distributed generation projects proposed by Dry Bridge and Exeter, and the 58MW of new distributed generation proposed by Green Development at this time. The new 115kV/34.5kV Wickford Substation would not be built absent these projects, as it is not currently needed to serve other retail customers. The new Wickford Substation will include equipment greater than 69kV, which will be classified as transmission assets. Those transmission assets will be managed by NEP within its role as the FERC-jurisdictional provider of transmission services to TNEC. As a result, NEP will assess TNEC an Annual Facilities Charge for the transmission assets in

accordance with Schedule 21-NEP, Attachment DAF. This FERC-approved charge must be considered just and reasonable by the PUC, and the PUC must allow TNEC full recovery of those costs. Because these costs are being incurred solely because of the proposed Exeter and Dry Bridge projects, those interconnecting customers should pay for the costs consistent with the PUC's longstanding cost-causation principles and its Order 23811. In the event the new 115kV/34.5kV Wickford Substation is later used to serve another distributed generation project or the Company determines that the use of some portion of the capacity of the new substation will be used by other Company non-DG customers, TNEC will reevaluate whether the DAF charge should be shared by any additional distributed generation facilities or amongst all customers of TNEC that benefit from the construction and operation of the substation.

B. The Assessment Of DAF Charges Is Consistent With The Conditional ISA.

Dry Bridge argues that the Conditional ISA cannot be revised to include the DAF charges because the DAF charges are related to System Modifications identified in the Conditional ISAs and not resulting from additional Affected System operator studies. Dry Bridge's position is inconsistent with the plain language of the Conditional ISAs, as well as provisions of the Interconnection Tariff and the PUC's Order 23811.

Under the Conditional ISAs, the parties agreed to the following cost adjustment procedures in Section 5.1:

> 5.1 Cost or Fee Adjustment Procedures. The Company will, in writing, advise the Interconnecting Customer in advance of any expected cost increase for work to be performed up to a total amount of increase of 10% only. Any such changes to the Company's costs for the work shall be subject to the Interconnecting Customer's consent. The Interconnecting Customer shall, within thirty (30) days of the Company's notice of increase, authorize such increase and make payment in the amount up to the 10% increase cap, or the Company will suspend the work and the corresponding agreement will terminate. The foregoing cost adjustment procedures shall only apply to the Company System Modification costs in Section 5(a) above, as detailed in the Impact Study, Detailed Study as necessary and/or ISRDG

> completed as of the date this Agreement is issued in executable form. The Interconnecting Customer shall be responsible for the actual Affected System operator costs, including operation and maintenance costs, and any additional Company costs necessitated as a result of the Affected System operator requirements, none of which shall be subject to any cost caps or limitations.

Dry Bridge expressly agreed to pay for actual Affected System operator costs, including operation and maintenance costs, without limitation. This clause was specifically added to the Conditional ISAs and was important to include because the final details and final cost estimates for any additional required system modifications to Affected Systems or the distribution system were not known at the time of executing the Conditional ISAs. The Conditional ISAs were always intended to be interim documents, produced to aid Dry Bridge in obtaining financing while additional studies and cost estimates were prepared. The Conditional ISAs were intended to be replaced with a final ISA after all such costs were identified.

Importantly, the PUC approved the revised terms of the Conditional ISAs (including Section 5.1 revisions) upon staff's recommendation that it "does not appear they shift the risk from the customer to ratepayers as compared to the form ISA contained in the Tariff as Attachment H. In fact, it appears the developer (interconnecting customer) has taken on additional risk in the form of unknown costs." Petition, Exhibit H at 3.

The PUC also found that the cost responsibility in the Conditional ISAs is consistent with the Interconnection Tariff. Section 5.4 of the Interconnection Tariff provides that "Interconnecting Customers shall be directly responsible to any Affected System operator for the costs of any system modifications necessary to the Affected Systems." Petition, Exhibit H at 4-5. More specifically, the PUC found that preserving the ten percent cap on currently known costs but lifting the cap on unknown System Modification costs that arise from the results of Affected System Operator studies "appropriately balances the interest of the Interconnecting Customer in cost controls over

currently known System Modifications while protecting National Grid and its ratepayers from increased costs that arise in the future due to other entities' studies." Petition, Exhibit H at 6.

Under the Conditional ISAs, Dry Bridge assumed the risk that additional costs related to Affected System operators could be identified after the Conditional ISAs were executed and agreed that the ISAs would be amended to reflect such costs. Moreover, Dry Bridge expressly agreed to new language in the Conditional ISAs providing that Dry Bridge "shall be responsible for the actual Affected System operator costs, including operation and maintenance costs, and any additional Company costs necessitated as a result of the Affected System operator requirements, none of which shall be subject to any cost caps or limitations." Conditional ISAs, Section 5.1.

DAF charges were not identified in the SIS or Conditional ISAs because those charges were not known to TNEC at the time. The cost estimate in the DSIS is a "planning grade estimate" that is "prepared using historical cost data from similar projects." However, TNEC has not historically encountered generation projects of this scale (i.e., an aggregate of 50 MW proposed by Dry Bridge and Exeter). Nor has TNEC had prior instances in which interconnection of such generation requires construction of a new substation and associated transmission line facilities, with substation equipment to be operated by NEP over the life of the assets. The cost estimates contained in the DSIS were carried over into the Conditional ISAs, with the understanding that the Conditional ISAs were not a reflection of final costs, and that Dry Bridge unequivocally agreed to "be responsible for the actual Affected System operator costs, **including operation and maintenance costs**, and any additional Company costs necessitated as a result of the Affected System operator requirements, **none of which shall be subject to any cost caps or limitations**. Conditional ISA, Section 5.1 (emphasis added).

The DAF charges are not TNEC System Modification costs – they are charges assessed by NEP, an Affected System operator, to cover the annual costs of operating transmission assets.[6] The DAF charges are assessed pursuant to Schedule 21-NEP of the OATT, which has been approved by FERC and cannot be challenged before the PUC. If the PUC were to accept Dry Bridge's argument and subject the DAF charges to the ten percent cost cap, the PUC would be required to allow recovery of the DAF charges from all retail customers through the transmission service cost adjustment provision. This is exactly the type of cost shifting the PUC sought to avoid when it approved the Conditional ISAs. Therefore, the PUC should reject Dry Bridge's argument and find that Dry Bridge must pay the DAF charges consistent with the plain language of Section 5.1 of the Conditional ISAs, Section 5.4 of the Interconnection Tariff, the Staff Report and Recommendation in Docket No. 4956, and Order 23811.

IV. CONCLUSION

As detailed above, NEP, an Affected System operator, will charge TNEC DAF charges to cover the annual costs of operating the transmission assets that are required to be constructed to interconnect Dry Bridge's Project. The DAF charges are assessed pursuant to Schedule 21-NEP of the OATT, which has been approved by FERC and cannot be challenged before the PUC. Consistent with the PUC's long-standing cost causation principles, as recently affirmed in Order 23811, Dry Bridge should be responsible for those costs as they would not be incurred but for its proposed projects. Moreover, the addition of DAF charges in the Final ISAs is consistent with the terms of the Conditional ISAs, in which Dry Bridge agreed to be responsible for all Affected System operator costs, including operation and maintenance costs, without any cost caps or

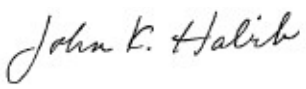
[6] See Schedule 21-NEP, Sec. 24.6.

limitations. For those reasons, Dry Bridge should be responsible for the DAF charges as presented in the Final ISAs.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID

By its attorney,



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John K. Habib
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99 High Street, Suite 2900
Boston, Massachusetts 02110
(617) 951-1400

Dated: January 22, 2021

System Impact Study
For Distributed Generation Interconnection to National Grid's 34.5 kV System

DG WR:	RI-24926794	RI-24926796	RI-24926798	RI-24926805
Applicant:	Dry Bridge Solar LLC	Dry Bridge Solar LLC	Dry Bridge Solar LLC	Dry Bridge Solar LLC
Address:	471 Dry Bridge Rd	471 Dry Bridge Rd	471 Dry Bridge Rd	471 Dry Bridge Rd
City:	North Kingstown, RI	North Kingstown, RI	North Kingstown, RI	North Kingstown, RI
DG kW/kVA:	10,000 kW/10,000 kVA	10,000 kW/10,000 kVA	10,000 kW/10,000 kVA	10,000 kW/10,000 kVA
DG Type:	Inverter-Based Photovoltaic	Inverter-Based Photovoltaic	Inverter-Based Photovoltaic	Inverter-Based Photovoltaic
Feeder:	Lafayette New Circuit	Lafayette New Circuit	Lafayette New Circuit	Lafayette New Circuit

nationalgrid	DISTRIBUTION PLANNING DOCUMENT Interconnection Study	Doc. RI-24926794_6796_6798_6805 Page 2 of 42
	Complex Generating Facility - R.I.P.U.C. 2163	Version 2.0 08/23/2019
	Dry Bridge Solar LLC 40,000 kW / kVA AC Inverter-Based Photovoltaic 471 Dry Bridge Rd, North Kingstown RI	Draft

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List of Tables

Definitions

The following is a list of acronyms/synonyms used in this Interconnection Study:

Company – National Grid

Customer – The interconnecting customer of this project

DG – Distributed Generation

DTT – Direct Transfer Trip

EPS – Electrical Power System

ESB – National Grid's Electrical Service Bulletin

Facility – The distributed generating facility for this project, including all related appurtenances and equipment.

IA – Interconnection Application

Interconnecting Circuit – Circuit to which the Facility will connect

ISA – Interconnection Service Agreement

ISO-NE – Independent System Operator of New England

NPCC – Northeast Power Coordinating Council

PCC – Point of Common Coupling (point of demarcation between the Customer and Company facilities)

Project – The interconnection of the Facility to the Company electrical power system.

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Executive Summary

The Company has completed the Impact Study, for the interconnection of Dry Bridge Solar LLC, ("Customer") 40,000 kW / 40,000 kVA combined total, inverter-based photovoltaic ("the Facility"), to its 34.5 kV sub transmission system, ("the Project"), and presents the conclusions of the study herein.

The interconnection requirements specified are inclusive to this project and the following projects 26003838, 26003990, 25814950, 26004136, 26004235, 26004367, 26004536, 26004727, 26004875, 26012283. Requirements are based upon the most recent information submitted by the Customer, which is attached for reference in Appendix C. Any further design changes made by the Customer post IA without the Company's knowledge, review, and/or approval will render the findings of this report null and void.

The interconnection requirements specified are exclusive to this project and are based upon the most recent information submitted by the Customer, which is attached for reference in Appendix C. Any further design changes made by the Customer post IA without the Company's knowledge, review, and/or approval will render the findings of this report null and void.

System Modifications

In general, the Project was found to be feasible with certain modifications to the existing Company System and operating conditions, which are described in detail in the body of this Study. Significant modifications include:

1. Installation of 115 kV loop tap off the L190 to new Wickford Substation, consisting of breaking the L190 line at structure #143 and installing two new spans of wire between the existing transmission line and the substation busses. New steel three pole structures on concrete caisson foundation will be required. Structure #123 on the adjacent 34.5 kV, 3311 line will need to be replaced to support the L190 construction. Install ~150' of three phase overhead 795 ACSR from Pole #13-53 to proposed Pole #13-56.

2. Installation of 115 kV four (4) breaker ring bus including breakers, disconnect switches, bus, bus insulators and wave trap; and associated site-work, grounding, foundations, structures, and associated protection and control.

3. Installation of two (2) 33/44/55 MVA Wye-Wye transformers and two (2) 34.5 kV feeders with protection and control, including but not limited to site work, grounding, conduits, fencing and driveway from the street.

4. Installation of 8,000 circuit feet of two (2) sets of underground 3-1/C 1000 SCU EPR cables from pole #9121 in the right-of-way outside Wickford Substation to man hole located at the intersection of South County Trail and Ten Rod Road. Customer is responsible for installation of Man hole and Duct civil work.
5. Install 7,800 circuit feet of 3-795 ACSR overhead conductors from existing Pole #5 South County Trail to proposed Pole # 13-50 Dry Bridge Road (Section 2.2). The proposed overhead line extension will overbuild an existing 15 kV class circuit.
6. Install ~150' circuit feet of three phase overhead 795 ACSR from Pole #13-50 to proposed Pole #13-53 and 100' of 1/0 AAAC from Pole #13-53 to proposed Pole #13-53-2 (Figure B-1).

7. Install a loadbreak switch on proposed Pole #13-51 (Figure B-1).
8. Install a recloser on proposed Pole #13-52 (Figure B-1).
9. Install a three-phase disconnect switch on proposed Pole #13-53-1 (Figure B-1).
10. Install a primary meter on proposed Pole #13-53-2. (Figure B-1)
11. Install ~100' of three phase overhead 1/0 AAAC from Pole #13-54 to proposed Pole #13-54-2
12. Install a disconnect switch on Pole #13-54-1.
13. Install a primary meter on Pole #13-54-2.
14. Install ~100' of three phase overhead 1/0 AAAC from Pole #13-55 to proposed Pole #13-55-2.
15. Install a disconnect switch on Pole #13-55-1.
16. Install a primary meter on Pole #13-55-2.
17. Install ~100' of three phase overhead 1/0 AAAC from Pole # 13-56 to proposed Pole #13-56-2.
18. Install a disconnect switch on Pole #13-56-1.
19. Install a primary meter on Pole #13-56-2.

Customer Document Revisions

The Customer is requested to provide the following additional and/or revised documentation as required. All revised drawings shall be stamped and signed by an Electrical Professional Engineer licensed in the same state as the Project location. The following list is intended as a convenient summary of documents for re-submission, however the Customer is required to comply with all items listed and discussed in this document. Omission of an item from the following summary list that is referenced elsewhere in this document does not release the Customer from providing the necessary documents:

1. Load Rejection Overvoltage Mitigation documentation required (Section 3.3).

2. Customer's Manual Generator Disconnecting Means are not acceptable as shown (Section 6.4)

3. Customer proposed Secondary Overcurrent Relay Elements are not acceptable as shown (Section 6.6.2)

4. Customer proposed interconnecting transformers are not acceptable as shown (Section 6.3).

5. Customer's proposed DG interrupting device is not acceptable as shown (Section 6.6).

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Cost Estimate

Refer to the Cost Estimate table in Section 9.0 for a listing of major modifications and associated costs. The total estimated planning grade cost of the work associated with the interconnection of the Facility, is $25,383,342 +/-25% and includes Company EPS modifications, Customer interconnection, and taxes. An estimated construction schedule will be provided in the Interconnection Service Agreement. Applicable cost sharing allocations, if any, will be calculated by the Company and provided in the Interconnection Service Agreement.

Note: This study does not include any potential costs associated with the ongoing Transmission System Impact Study.

The transmission line and substation modifications and costs reflected in the distribution impact study are for the full build-out of a two transformer four-ring bus substation. If all projects move forward cost sharing will be applicable. Costs do not include distribution line modifications on Ten Rod Road and at the PCC of the Exeter Renewables 1 project (26012283).

1.0 Introduction

The Customer has requested interconnection of a Facility to the Company's existing infrastructure.

The analysis utilized Customer provided documentation to examine the effects on the Company system when the new Facility is connected. The results identify required modifications to the Customer one line diagram(s) and Company infrastructure in order to accommodate the interconnection. As such, the interconnection of the Facility has been evaluated under specific conditions. Should the Customer make any changes to the design, other than those identified in this study, it may require additional time for review, and possibly additional cost.

In accordance with the R.I.P.U.C. No. 2163 tariff and the Company's ESB series, the Company has completed an Impact Study to determine the scope of the required modifications to its EPS and/or the Facility for providing the requested interconnection service.

Analysis will be performed in accordance with applicable reliability standards and study practices, and in compliance with the applicable codes, standards, and guidelines listed in the Company's *Electric System Bulletin No. 756 Appendix D: Distributed Generation Connected to National Grid Distribution Facilities Per The Rhode Island Standards for Interconnecting Distributed Generation ("ESB756D")* to determine the incremental impact and any potential adverse impacts associated with the interconnection of the Facility to the EPS.

2.0 Project Description

2.1 Customer Facility

RI-24926794

The Customer proposes to install the following:

- Five (5) Customer owned, SMA 2500-EV-US inverters factory limited to 2,000 kW / kVA(10,000 kW / kVA total)
- Two (2) Customer owned 4,000 kVA, 34.5 kV wye-grounded primary, with a fully insulated and isolated neutral bushing, 550 V delta secondary, and 550 V delta tertiary interface transformers, Z of 6%, X/R of 7.5
- One (1) Customer owned 2,000 kVA, 34.5 kV wye-grounded primary, with a fully insulated and isolated neutral bushing, and 550 V delta secondary interface transformer, Z of 6%, X/R of 7.5
- One (1) Customer owned 50-ohm neutral reactor
- One (1) Customer owned 35 kV pad-mount G&W Viper switchgear and SEL 651R relay assembly

- One (1) Customer owned, S & C Omni-rupter, Model #147513, 35 kV gang-operated airbreak switch, with visible blades accessible to utility

RI-24926796

The Customer proposes to install the following:

- Five (5) Customer owned, SMA 2500-EV-US Factory Limited to 2,000 kW/kVA inverters @ 35°Celsius (C)
- Two (2) Customer owned 4,000 kVA, 34.5 kV wye-grounded primary, with a fully insulated and isolated neutral bushing, 550 V delta secondary, and 550 V delta tertiary interface transformers, Z of 6%, X/R of 7.5
- One (1) Customer owned 2,000 kVA, 34.5 kV wye-grounded primary, with a fully insulated and isolated neutral bushing, and 550 V delta secondary interface transformer, Z of 6%, X/R of 7.5
- One (1) Customer owned 35 kV pad mount G&W Viper switchgear and SEL 651R relay assembly
- One (1) Customer owned 50-ohm neutral reactor
- One (1) Customer owned, S & C Omni-rupter, Model #147513, 35 kV gang-operated airbreak switch, with visible blades accessible to utility

RI-24926798

The Customer proposes to install the following:

- Five (5) Customer owned, SMA 2500-EV-US Factory Limited to 2,000 kW/kVA inverters @ 35°Celsius (C)
- Two (2) Customer owned 4,000 kVA, 34.5 kV wye-grounded primary, with a fully insulated and isolated neutral bushing, 550 V delta secondary, and 550 V delta tertiary interface transformers, Z of 6%, X/R of 7.5
- One (1) Customer owned 2,000 kVA, 34.5 kV wye-grounded primary, with a fully insulated and isolated neutral bushing, and 550 V delta secondary interface transformer, Z of 6%, X/R of 7.5
- One (1) Customer owned 35 kV pad mount G&W Viper switchgear and SEL 651R relay assembly
- One (1) Customer owned 50-ohm neutral reactor
- One (1) Customer owned, S & C Omni-rupter, Model #147513, 35 kV gang-operated airbreak switch, with visible blades accessible to utility

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RI-24926805

The Customer proposes to install the following:

- Five (5) Customer owned, SMA 2500-EV-US Factory Limited to 2,000 kW/kVA inverters @ 35°Celsius (C)
- Two (2) Customer owned 4,000 kVA, 34.5 kV wye-grounded primary, with a fully insulated and isolated neutral bushing, 550 V delta secondary, and 550 V delta tertiary interface transformers, Z of 6%, X/R of 7.5
- One (1) Customer owned 2,000 kVA, 34.5 kV wye-grounded primary, with a fully insulated and isolated neutral bushing, and 550 V delta secondary interface transformer, Z of 6%, X/R of 7.5
- One (1) Customer owned 35 kV pad mount G&W Viper switchgear and SEL 651R relay assembly
- One (1) Customer owned 50-ohm neutral reactor
- One (1) Customer owned, S & C Omni-rupter, Model #147513, 35 kV gang-operated airbreak switch, with visible blades accessible to utility

A copy of the Customer one lines are provided in Appendix C, illustrating the Customer's proposed design and proposed interconnection to the area EPS. The Customer documents are not binding and shall require modifications and/or clarification as identified herein.

The following parameters were assessed as part of the Project evaluation:

1. The voltage and frequency trip settings as shown on the one line (dated 04-09-2019).

Any advanced inverter functionality other than that specifically called out on the Customer documentation and/or outlined herein shall be subject to additional study before being enabled.

2.1.1 Assumptions

For certain components, data was not provided by the Customer, or was physically not available at the time of this Study. In order to proceed with the analysis certain assumptions were made based on past experience and engineering judgment. Assumptions are summarized in the following list. Should any of these assumptions be incorrect, the Customer must advise the Company immediately, as reevaluation of the Impact Study results may be required:

1. The analysis in this Study assumed a neutral reactor sized at 50 ohms at each of the interface transformers

2. 115 kV-34.5 kV supply transformer is required to be installed at a proposed 115 kV-34.5 kV Wickford substation to accommodate the Project. The circuit proposed to serve this Project will be served by this newly installed transformer.
3. The 115 kV/34.5 kV supply transformer at the proposed Wickford Substation was assumed to be a 33/44/55 MVA transformer with Z = 10.1% and X/R = 23.91
4. Assumed that the generators will not exceed 2,000 kW / kVA.
5. The customer cable length between each interface transformer was assumed to be 500 feet long.

2.2 Company Area EPS

The area EPS was evaluated, and it was determined that the most viable interconnecting option is a 34.5 kV regulated, three-phase, 4 wire, wye, effectively-grounded, radial distribution circuit that will originate out of the Company's proposed Wickford Junction Substation, in North Kingstown, RI (the "Interconnecting Circuit"). Modifications include:

1. Installation of 115kV loop tap off the L190 to new Wickford Substation, consisting of breaking the L190 line at structure #143 and installing two new spans of wire between the existing transmission line and the substation busses. New steel three pole structures on concrete caisson foundation will be required. Structure #123 on the adjacent 34.5kV, 3311 line will need to be replaced to support the L190 construction.
2. Installation of 115kV four (4) breaker ring bus including breakers, disconnect switches, bus, bus insulators and wave trap; and associated site-work, grounding, foundations, structures, and associated protection and control.
3. Installation of two (2) 33/44/55 MVA Wye-Wye transformer and two (2) 34.5kV feeders with protection and control, including but not limited to site work, grounding, conduits, fencing and driveway from the street.
4. Installation of 8,000 circuit feet of two (2) sets of underground 3-1/C 1000 SCU EPR cable from pole #9121 in the right-of-way outside Wickford Substation to man hole located at the intersection of South County Trail and Ten Rod Road. Customer is responsible for installation of Man hole and Duct civil work.
5. Install 7,800 circuit feet of 3-795 ACSR overhead conductors from existing Pole #5 South County Trail to proposed Pole # 13-50 Dry Bridge Road. The proposed overhead line extension will overbuild an existing 15 kV class circuit.

In order to accommodate the interconnection of the aggregate 40 MW DG, two (2) new 33/44/55 MVA transformers, 115 kV-34.5 kV, are planned to be installed at a new

substation adjacent to the existing Lafayette 34.5 kV-12.47 kV substation. The circuit proposed to serve this Project will be served out of the new transformers.

The ability to generate is contingent on this Facility being served by the Interconnecting Circuit during normal operating conditions. Therefore, if the Interconnecting Circuit is out of service, or if abnormal operating conditions of the area EPS are in effect, the Company reserves the right to direct the Customer to disengage the Facility.

The Interconnecting Circuit has the following characteristics:

- Refer to Section 3.0 for circuit loading characteristics.
- The existing and in-process generation at the substation and on the interconnecting circuit is summarized in Table 1. Values shown are based on full nameplate DG output:

Feeder	Generation installed and operating at time of study (kW)	Generation in process at time of study (kW)	Generation proposed for this Project (kW)	*TOTAL* (kW)
30T1	-	40,000	10,000	*50,000*
30T2	-	58,080	-	*58,030*
TOTAL	-	*98,080*	*10,000*	**108,030**

Table 1: Generation at the Substation and Interconnecting Circuit

-
- There are no capacitor banks on the circuit.

- Voltage regulation at the proposed Wickford Junction 115 kV / 34.5 kV substation will be accomplished by means of an LTC transformer. Refer to Section 3 for further discussion on any required modifications.

Location	Status
Lafayette New 115 kV / 34.5 kV LTC Transformer	Proposed

Table 2: LTC location

2.3 Interconnection

Refer to the interconnection diagram in Appendix B for approximate PCC location.

Should the Customer elect to move forward with the Project, the Company's Design Personnel will specify the exact location of the Company's facilities and installation details. The Customer shall be responsible for obtaining all easements and permits

required for any line extension not on public way in accordance with the Company's requirements.

The Customer shall provide unencumbered direct access to the Company's facilities along an accessible plowed driveway or road, where the equipment is not behind the Customer's locked gate. In those cases where Company equipment is required to be behind the Customer's locked gate, double locking, with both the Company's and Customer's locks shall be employed.

For this Project, the PCC for RI-24926794 is defined as Pole #13-53-2. The PCC for RI-24926796 is defined as Pole #13-54-2. The PCC for RI-24926798 is defined as Pole #13-55-2. The PCC for RI-24926805 is defined as Pole #13-56-2. The Customer must install their facilities up to the Company revenue meter. The Customer must provide sufficient conductor to allow the Company to make final connections at each meter pole. The Company will provide final connection of the Customer conductors to each Company meter.

The customer will be responsible for the installation of the additional manholes and duct system from the substation to the existing manhole built for the 84T3 extension. The customer shall provide manhole and duct layout drawings to be approved by the Company.

If National Grid right of way (R.O.W) is involved, then the Customer shall provide detailed drawings of any planned construction within any National Grid R.O.W., for the Company's review and subsequent approval, showing elevation grades of all phases of construction within the R. O. W. before any construction may begin. Plans and drawings must be submitted that meet all the Company's requirements before the interconnection process can move forward. These plans shall be submitted to National Grid's R.O.W./Real-Estate group and the Transmission R.O.W. Engineering and construction group for review and comment before any construction can be allowed to move forward. There may be additional costs and subsequent delays involved with the review, and, or oversight of any construction in, or adjacent to, the Company's R.O.W., and if any Company owned facilities need modification as a result of the Customer's proposed construction. These costs will be in addition to, and outside of the scope of, this SIS. Failure of the Customer to reimburse the Company for these costs may delay or negate the interconnection process.

3.0 Power Flow Analysis

The power flow analysis was substantially performed using electrical system modeling software. A model of the Interconnecting Circuit, as described in Section 2.2, was developed based on data extracted from the Company's Global Information System ("GIS"). A field review of the feeder was performed on April 16th, 2018.

There exists a lack of capacity and utility infrastructure to feasibly interconnect the Project. Therefore, a new substation and circuit is required to interconnect the Project. No load is expected on the proposed circuit.

3.1 Reverse Power Flow at Substation

The possibility of the Facility causing reverse power flow through the Company's substation transformer was reviewed.

Reverse Power Flow was not found to be a concern on the distribution level, however the Transmission study may require additional upgrades should these projects create problems.

3.2 Interconnecting Circuit Load Flow Analysis

The area EPS was examined with and without the Facility operating at full output. The analysis demonstrated that the addition of the Facility will not create thermal loading problems on the Interconnecting Circuit, or the associated substation. The substation and circuit are being designed with ratings to withstand power output from the Project.

Specifically, no conductor, transformer, or voltage regulator overloads occur as a result of this interconnection. All Company owned mainline conductor and distribution facilities are thermally large enough to accommodate the proposed generation.

3.3 Interconnecting Circuit Voltage Analysis

The Company is obligated to hold distribution voltages at customer service points to defined limits in ANSI Standard C84.1- 2006. Range A of the ANSI standard requires the Company to hold voltage within +/- 5% of nominal at the PCC.

Under emergency conditions, voltage on the system could reach 90% of nominal prior to corrective action being taken. The Customer is advised to consider this in

planning their system requirements and equipment settings, however, no warranties or guarantees are implied.

Under normal operating conditions it is expected that the Company will be able to meet its obligations for ANSI C84.1 with the system generation at full power. The Customer must maintain voltage at the PCC at +/- 5% of nominal under normal conditions. Also, the PV interconnection shall not contribute to greater than a 3.0% change in voltage on the EPS under any conditions.

The analysis of this facility determined that when the Facility generation is at full output at **unity power factor**, the voltage range at the PCC was within acceptable limits.

Customer has not provided manufacturer's test reports have been reviewed for 1.4PU pickup values with 1ms or less total clearing time. Customer needs to provide acceptable documentation.

Due to potential high generation to load ratios on the feeder and possible Load Rejection Over Voltage (LROV), the Customer must provide details, documentation, and any factory tests or pre-certifications for the mitigation of this condition. The Company reserves the right to request additional equipment on the Customer's Facility if required and/or Over Voltage set point or a modification of an existing setting to mitigate this condition. The clearing/de-energization time must satisfy the Transient Over Voltage Tolerance Curve in Figure 1.

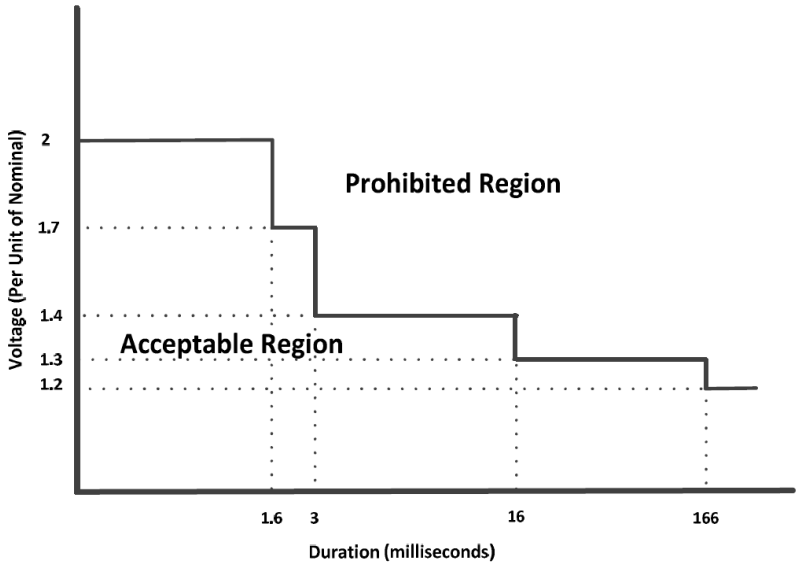

Figure 1: Transient/Temporary Overvoltage Tolerance Curve

The Company will not be held liable for any power quality issues that may develop with the Customer or any other customers as result of the interconnection of this generation.

3.4 Flicker Analysis

The IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems, IEEE Std. 1453-2004 was used as a basis for flicker and voltage fluctuation analysis.

This Facility was modeled using the Long Term Dynamics module of CYME[1]. A long term dynamic profile for the Facility was used that simulates the voltage fluctuation of the site over a 6 hour period. Other significant DG existing or in process ahead of this Project were modeled at full output, and modeled with the appropriate voltage fluctuation curve to simulate normal cloud passage.

The long term dynamic DG profile used is based on live metered data from a PV site that is similar in size to this Project. The data is intended to simulate a typical day with cloud cover passing over the site, resulting in a varied output from the PV.

Given the nature of flicker, it is impossible to predict the true Facility fluctuation and results of how this Facility will interact with other DG on the circuit under all conceivable environmental conditions. Therefore, the flicker results are used as a metric to evaluate whether or not there is a readily apparent concern related to voltage flicker.

The Company will not be held liable for any power quality issues that may develop with the Customer or any other customers as result of the interconnection of this generation.

Analysis shows that the predicted flicker and voltage fluctuations are expected to be acceptable, provided that the following conditions are met:

- The system modifications identified elsewhere in this study are implemented
- The reactive contribution of the PV at the PCC operates at 100% power factor at all times.

[1] CYME Power Engineering Software, Version 7.1, Revision 02, Build 99, Copyright © 1986-2014, Cooper Industries, Ltd.

4.0 Risk of Islanding

4.1 Islanding Analysis (ESB 756D Section 7.6.12)

The project was screened for the potential of islanding risk. Per IEEE 1547 *section 4.4.1 Unintentional Islanding*, for an unintentional island in which the DG energizes a portion of the Area EPS through the PCC, the DG interconnection system shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island.

Based on known in-service and in-progress projects at the time of study, the generation shown in Table 3 was considered on this feeder. Three-phase projects greater than 25kW are listed individually. All other projects below 25kW are listed as a single line item.

Project Size (kW)	Certified / Non-Certified
40,000	Certified
10,000	Certified

Table 3: Generation Considered for Risk of Islanding Analysis

Analysis indicates that the overall ability of this Facility to island more than 2.0 seconds is considered likely event. As a result, PCC recloser with reclose blocking will be required.

4.2 Direct Transfer Tripping (DTT)

A DTT system is not required by the Company for this interconnection provided the Customer can provide a stamped one-line and documentation that certifies the inverters are UL 1741-2005/IEEE 1547 compliant and have an acceptable means of active islanding detection, refer to Section 4.0.

Although DTT is not required for the Distribution system, DTT may be required on a Transmission level and will be evaluated in the Transmission Study.

The Customer is responsible for all initial and recurring costs associated with the communication line for the DTT circuit. The Customer is responsible for communication with Local Telecommunications Provider to secure the line, and to coordinate scheduling with Local Telecommunications Provider for installation of the line prior to interconnection of the DG. The Company has no control over the Local Telecommunications Provider's process or schedule. The Customer is advised to

contact Local Telecommunications Provider as soon as possible to assure that the communication circuit is in place before the interconnection due date.

4.2.1 Direct Transfer Trip Requirements

The specifications given in this section are for copper based, leased line communication. Should the Customer prefer to use fiber-based communication, the Company's specifications will be provided upon request. For Customers using direct fiber-based DTT, the Customer is responsible for all installation and maintenance costs and coordination, including having the installing entity follow the Company's third-party attachments policy where attaching fiber to Company structures. The Customer is additionally responsible for all initial and recurring costs associated with third party attachments.

Copper based, leased line DTT requirements are as follows:

- The Company's Standard RFL is model S00763PF which uses the Guard Before Trip feature for DTT applications.
- The breakers being controlled must be tripped for relay/breaker Loss of Potential (LOP), Relay failure, loss of Guard signal, and receipt of the trip signal. Relay failure, LOP and loss of guard signal shall have a 30 second delay to trip the breaker. This is to avoid nuisance tripping due to the system transients.
- Since the Company does not specify the relay type, any timer that is equivalent to an ABB RXKL1 is acceptable.
- When the order actually takes place, both the transmitter and receiver must be ordered from RFL as a package.
- Even if there are different orders for the transmitter and the receiver (i.e. the receiver order from the Customer and the transmitter order from the Company), RFL must be informed of this to insure that the two devices are compatible. RFL will test them together before shipping.
- The Company will also specify all trip and guard frequencies. The Company uses default settings of the groups 3 and 5 to set the guard and trip frequencies.
    - Group 3:
      Tone 1 Tx: 1540Hz (trip) 1690Hz (Guard)
      Tone 1 Rx: 2030Hz (Trip) 1880Hz (Guard)
    - Group 5:

Tone 2 Tx: 2220 Hz (Trip) 2370 Hz (Guard)
Tone 2 Rx: 2710Hz (Trip) 2560 Hz (Guard)

The Customer is responsible for all initial and recurring costs associated with the leased communication line for DTT circuit. The Customer is advised to establish communication with The Local Telecommunications Provider to place order for the leased-line for DTT to make sure that the communication circuit is in place in-time before the interconnection.

5.0 Short Circuit and Protection Analysis Company Facilities

The Company performed a review of the Project relative to the short circuit and protective device impacts on the Interconnecting Circuit. This review identifies EPS enhancements that are necessary to complete the Project and its ability to meet Rhode Island R.I.P.U.C. 2163 interconnection tariff and the requirements of the Company's ESB 756D. The Interconnecting Circuit, including all relevant DG was modeled in a software package called ASPEN OneLiner[2]. The model was developed using Company records for feeder characteristics, and Customer provided documentation. Refer to Section 2.1.1 for any assumptions made in the model.

5.1 Fault Detection at Substation

Addition of generation sources to distribution feeders can result in the backfeeding of the substation transformers, effectively turning a station designed for load into a generation step-up transformer. The Company's typical 115kV-34.5kV class substation transformer has a delta connection on the transmission side and wye-grounded connection on the distribution side. Due to the transformer's configuration, it cannot contribute zero sequence ground fault current to single line to ground faults on a transmission line, and the voltage on the unfaulted phases rises significantly and rapidly. These overvoltages have potential to exceed insulation levels of the station and transmission line equipment, and maximum continuous operating voltage of surge arresters. Zero sequence voltage protection (commonly referred to as "$3V_0$") on the primary side of the transformer is required in order to detect these overvoltage conditions. This $3V_0$ protection will disconnect the generation from the substation transformer, and stop the generation and transformer from contributing to the transmission-side overvoltage condition.

Detailed analysis was completed to determine whether the interconnection of the Facility, in conjunction with existing connected facilities, may pose significant risk of causing temporary over-voltage conditions to develop on the system during line to

[2] ASPEN OneLiner V12.5, Build: 19177 (2015.01.28), Copyright © 1987-2013 ASPEN.

ground faults on the high side of the substation transformer. The load to generation match at the substation has been evaluated assuming minimum load, maximum generation, and one feeder out of service in order to determine if substation modifications are required.

For this Project, results indicate that the Facility poses a significant risk of causing temporary overvoltage to develop on the primary side of the substation transformer. Consequently, 3V0 will be required at the substation's T1, 115kV Grd-Y – 34.5kV Grd-Y, supply transformer.

It is not possible for the Customer to reduce to a lower Project size in order to avoid 3V0.

5.2 PCC Impedance

The Interconnecting Circuit impedance is shown below in per unit at the PCC for the proposed Facility, using a 100 MVA base. The PCC location is shown in Appendix B. These values take into account proposed system conditions, but not the impact of the Customer's new Facility.

Pre-Project

System Impedance at PCC

Z1 = 0.03134+j0.25033 p.u.

Z0 = 0.08801 +j0.43072 p.u

5.3 Fault Current Contributions

Table 4 summarizes the Facility's effect on fault current levels at the PCC. The equipment at Lafayette substation should be rated to withstand the fault currents shown in Table 4.

The Customer is responsible for ensuring that their own equipment is rated to withstand the available fault current according to the NEC and National Grid ESB 750, which specifies that the fault current should be no more than 80% of the device interrupting rating.

Any assumptions made in calculating the fault current shown in Table 4 are identified in Section 2.1.1.

PRE PROJECT	Wickford Bus Amps @ 34.5 kV	PCC Amps @ 34.5 kV
3-phase (LLL)	6516	4920
Phase-Ground (LG)	7365	4493

POST PROJECT	Wickford Bus Amps @ 34.5 kV	PCC Amps @ 34.5 kV	Wickford Bus Amps @ 34.5 kV	DELTA I_{fault} @ PCC
3-phase (LLL)	7509	5913	15.24%	20.2%
Phase-Ground (LG)	8891	6201	20.72%	38.01%

Table 4: Fault Duty

5.4 Substation Protective Device Modifications

This study proposes new device settings for the circuit breaker. These device settings and associated time-current curves were evaluated for protective devices at the substation. The new substation device should be set according to the proposed settings in this Study.

5.5 Area EPS Protective Device Coordination

The Project will require a Company owned recloser at the PCC

6.0 Customer Equipment Requirements

The following Section discusses requirements for Customer owned equipment, which are further outlined in detail in ESB 756D. References to ESB 756D are provided in each sub-section below. It is the Customer's responsibility to comply with all requirements of ESB 756D. Please note that applicable sections of ESB 756D are referenced for information purposes and may not comprise the entirety of applicable sections.

In general, the Customer Facility shall have the capability to withstand voltage and current surges in accordance with the environments defined in IEEE Standard C62.41.2-2002 or IEEE Standard C37.90.1-2002 as applicable.

6.1 Revenue Metering Requirements (ESB 756D Section 7.2.2 and 7.2.3)

For systems greater than 25kW, Interconnecting Customer shall provide a means of communication to the National Grid revenue meter. This may be accomplished with an analog/POTS (Plain Old Telephone Service) phone line (capable of direct inward dial without human intervention or interference from other devices such as fax machines, etc.), or, in locations with suitable wireless service, a wireless meter.

Feasibility of wireless service must be demonstrated by Interconnecting Customer, to the satisfaction of National Grid. If approved, a wireless-enabled meter will be installed, at the customer's expense. If and when National Grid's retail tariff provides a mechanism for monthly billing for this service, the customer agrees to the addition of this charge to their monthly electric bill. Interconnecting Customer shall have the option to have this charge removed, if and when a POTS phone line to National Grid's revenue meter is provided.

Refer to *Appendix A Figures A-1 and A-2 - Revenue Meter Phone Line Installation Guide).*

The Customer is advised to contact Generation and Load Administration (NewGenCoord@iso-ne.com) at ISO New England regarding all metering, communications circuits, remote access gateway (rig), financial assurance, paperwork, database updates, etc. that may be required for this Facility.

6.2 Interconnecting Transformer (ESB 756D Section 7.3)

The documentation provided states that the interconnecting transformers are two (2) Customer owned pad-mounted 4,000 kVA, 34.5 kV wye ground primary / 550 V delta secondary and 550 V delta tertiary interface transformers with a H-X impedance of 6% and X/R ratio of 7.5, H-Y impedance of 6% and X/R ratio of 7.5 and X-Y impedance of 12% and a X/R ratio of 12.

One (1) 2,000 kVA, 34.5 kV wye-grounded primary and 550 V delta secondary with Z=6.0 and X/R= 7.5.

The proposed transformers satisfy the requirements of the ESB 756D.

6.3 Effective Grounding (ESB 756D Section 7.3.2.1)

The Company requires DG installations to be effectively grounded, which is defined in IEEE C62.92.1 section 7.1. Additionally, the Company requires that DG installations do not raise the overvoltage above 125% on the unfaulted phases during ground faults on the distribution circuits. Refer to IEEE C62.92.1 sections 6.3 and 7.1 for further details.

The proposed configuration will satisfy the effective grounding requirements for the system. The model was run with a neutral grounding reactor impedance of 50 ohms, which yielded satisfactory effective grounding results.

The proposed grounding reactor is recommended to have a continuous current rating of no less than 100A.

The Customer must provide a revised one-line diagram, proposing a means of effective grounding that is acceptable to the Customer's system.

6.4 Manual Generator Disconnecting Means (ESB 756D Section 7.4)

The Customer provided documents do not satisfy the requirement of this Section of ESB 756D.

6.5 Primary Protection (ESB 756D Section 7.6 & 7.8)

The following section relates to the primary means of protection by the Customer. This includes the inverter relay functionality.

6.5.1 Primary Protective Relaying (ESB 756D Section 7.6.1, 7.6.2, 7.6.11, & 7.8)

The Customer provided documents indicate that the generator/inverter will be provided with an internal relay that will trip the generator interrupting device. Proposed settings for the 27, 59, 81O/U functions have been provided for review.

All inverter-based DER projects are required to have voltage and frequency settings and ride-through capability described in ESB 756D Section 7.6.11 and 7.8.

6.5.2 Primary Frequency Protection (ESB 756D Section 7.6.8, 7.6.11.1, and 7.8)

Frequency elements trip settings for primary relaying are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.8, 7.6.11, and 7.8.

The R.I.P.U.C No. 2180, requires that, the DER cease to energize the area EPS within 2 seconds, refer to IEEE1547 and UL1741.

The Customer provided documents showing acceptable internal relay setting in accordance with the aforementioned requirements.

6.5.3 Primary Voltage Relay Elements (ESB 756D Section 7.6.7, 7.6.11.1, and 7.8)

Voltage relay elements trip settings are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.11 and 7.8.

The Customer provided documents show undervoltage (27) and overvoltage (59) elements that satisfy the requirements of this Section of ESB 756D.

6.6 Secondary Protection

The following section relates to the secondary means of protection, also referred to as redundant relaying.

6.6.1 Generator Interrupting Device (ESB 756D Section 7.5)

A Company owned recloser is required at the PCC, which will contain utility facing protective elements (27, 59, 81O/U). A Generator Interrupting Device shall be installed for site protection, with overcurrent functionality. The Customer design shows a switchgear for site protection.

The Customer provided documents indicate an interrupting device on the High side (Utility 34.5kV side) of the interconnecting transformer, which satisfies the requirements of ESB 756D.

6.6.2 Secondary Overcurrent Relay Elements (ESB 756D Section 7.6.10)

Customer proposed settings are provided on the Customer drawings, as attached in Appendix C.

The Customer's provided relay settings do not provide sufficient coordination with other devices on the EPS. The following are minimum

values that would be acceptable for coordination. Values are provided here for informational purposes only. The Customer must provide revised settings for review by the Company:

RI-24926796, RI-24926798, RI-24926805:

51C – Phase

Customer Proposed: 60 A primary amps pickup, 2.0 Time Dial, U4 curve

Customer 51C-Phase relay elements trip settings are required to comply with ISO-NE ride-through requirements. This requirement is not met. Customer proposed 51C element must be removed.

51GC – Ground

Customer Proposed: 35 A primary amps pickup, 1.5 Time Dial, U4 curve

Customer 51CG-Ground relay elements trip settings are required to comply with ISO-NE ride-through requirements. This requirement is not met. Customer proposed 51GC element must be removed.

51G – Ground

Customer Proposed: N/A

Company Suggested: 50 A primary amps pickup, 1.0 Time Dial, U1 curve

The above is provided for informational purposes only. It is the Customer's responsibility to provide revised settings that will be sufficient to trip the Customer's interrupting device for faults on the Company system as well as for faults within the Facility. The Company will evaluate for coordination with EPS protective devices.

Note that the pickup values that allow for proper protective settings may not be possible with the proposed CT ratio.

6.6.3 Secondary Protective Relaying (ESB 756D Section 7.6.3)

The Customer provided documents indicate that a redundant utility grade relay is provided that will trip the generator interrupting device. Relay make/model is included on the Customer single line.

The Customer provided documents do not satisfy this Section of ESB 756D.

6.6.4 Secondary Frequency Protection (ESB 756D Section 7.6.8, 7.6.11.1, and 7.8)

Frequency elements trip settings for primary relaying are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.8, 7.6.11, and 7.8.

The R.I.P.U.C. No. 2180, requires that, the DER cease to energize the area EPS within 2 seconds, refer to IEEE1547 and UL1741.

The Customer provided documents do not show acceptable redundant relay settings in accordance with the aforementioned requirements.

6.6.5 Secondary Voltage Relay Elements (ESB 756D Section 7.6.7, 7.6.11.1, and 7.8)

Voltage relay elements trip settings are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.11 and 7.8.

The Customer provided documents show undervoltage (27), overvoltage (59) and neutral overvoltage (59N) elements that satisfy the requirements of this Section of ESB 756D.

6.6.6 Current Transformers (“CT”) (ESB 756D Section 7.6.4.1)

The Customer provided documents satisfy this section of ESB 756D.

6.6.7 Voltage Transformers (“VT”) and Connections (ESB 756D Sections 7.6.4.2)

The Customer provided documents show wye-grounded/wye-grounded VT’s and show the VT ratio, which satisfies this Section of ESB 756D.

6.6.8 Protective Relay Hard-Wiring (ESB 756D Section 7.6.5)

The Customer provided documents call for hardwiring of the redundant relaying trip circuits, therefore satisfies the requirements of this section of ESB 756D.

6.6.9 Protective Relay Supply (ESB 756D Section 7.6.5 and 7.6.6)

The Customer has proposed a DC power supply. The Customer shall demonstrate in the witness test that the relay will trip if the DC voltage goes out of the normal operating range.

It is recommended that the power DC power supply be connected to the utility (source) side of the interrupting device in order to ensure power availability to close the interrupting device after an extended outage. This is a recommendation, for consideration by the Customer. It is not a requirement by the Company.

6.6.10 Utility Restoration Detection (ESB 756A Section 4.5.2.7)

Following a trip of the protective relay, a Utility Restoration Detection function shall prevent manual and automatic reclosing of the Customer's DG intertie device until the Customer's relay has detected that the Utility EPS has been within the voltage and frequency windows identified by IEEE 1547 section 4.2.6 for a minimum of five minutes. The five-minute time interval is required to restart if the utility voltage or frequency falls outside of this window.

All the devices associated with five-minute timing must meet IEEE C37.90 standard and be capable of withstanding voltage and current surges.

The Customer's one-line diagram shows utility grade devices and settings to satisfy this requirement

6.6.11 Relay Failure Protection (ESB 756D Section 7.6.3)

For all required tripping functions, either redundant relaying or relay failure protection, where a hardware or power supply failure for the redundant relay automatically trips and blocks close of the associated breaker, is required.

The Customer's one-line diagram shows devices and settings to satisfy this requirement

6.7 Synchronizing Devices (ESB 756D Section 7.6.9 and 7.6.11.2)

Project is inverter based; therefore, synchronizing devices are not required.

6.8 Customer Cabling

The Customer must provide a means for primary protection between the Generator disconnect switch and Customer owned transformer to protect the Customer cable. The Company is not responsible for the protection of the Customer cable and primary protection for the Customer cable must be provided at the change of ownership.

6.9 Additional Requirements

The Facility may be required to use high-speed protection if time-delayed protection would result in degradation in the existing sensitivity or speed of the protection systems on the Company's EPS.

7.0 Telemetry and Telecommunications

The Customer is advised to communicate with ISO-New England for any telemetry requirement as ISO-NE may require real-time monitoring between ISO-NE EMS and the DG site. The Customer shall refer to the ISO-NE website and ISO-NE customer service help desk for details.

This project is considered an independent power producer (IPP), an RTU for telecommunication will not be required by the Company.

8.0 Inspection, Compliance Verification, Customer Testing, and Energization Requirements

8.1 Inspections and Compliance Verification

A municipal electrical inspection approval certificate from the local authority having jurisdiction is required of the Customer's Facilities (i.e. primary service entrance conduit, primary switchgear, wiring, and generation equipment). The Company must receive the Customer's Draft set of Project documentation and test plan for the

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functional verification tests at least four (4) weeks before the Company's field audit. Documentation from the customer must include, but not be limited to:

- Equipment cut sheets and shop drawings for all major equipment
- Inverter manufacturer cut sheet including method of island detection and UL certification
- Inverter protective relay settings
- Settings for any other Customer relay related to the Project
- The most recent version of the single line diagram and site plan, reflecting all modifications required in this Impact Study
- Single line diagram of the Facility
- Site diagram of the Facility
- A 3-line diagram and DC schematic illustrating the protection and control scheme
- The proposed testing procedure
- The proposed energization plan
- All provided Customer drawings shall be stamped and signed by an Electrical Professional Engineer that is licenses in the state where the Facility is located.

The DG Customer shall adhere to all other Company related verification and compliance requirements as set forth in the applicable ESB 750 series documents. These and documented acceptance testing requirements of these facilities will be specified during the Draft design review of the Project prior to the Company's field audit and energization.

8.2 Testing and Commissioning

The Customer shall submit initial relay settings to the Company no later than twenty-one (21) calendar days following the Company's acceptance of the Facility's service connection's Draft RI state licensed professional engineer sealed design. If changes/updates are necessary, the Company will notify the Customer three (3) business days after the initial relay settings were received, and the Customer shall submit the revised settings within seven (7) calendar days from such notification. Within three (3) business days of receipt of the proposed Draft relay settings, the Company shall provide comments on and/or acceptance of the settings. If the process must continue beyond the above evolution due to errors in the relay settings, the Company retains the right to extend the Testing and Commissioning process, as needed, to ensure the Draft relay settings are correct.

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Assuming no major issues occurring with the relay settings, the Customer shall submit a Testing and Commissioning Plan (TCP) to the Company for review and acceptance, no later than forty-five (45) calendar days following the Company's acceptance of the Facilities Draft design. The TCP must be drafted, including Company acceptance, no later than six (6) weeks prior to functional testing. The Company requires a minimum of 5 business days for review of any submitted documentation.

8.3 Energization and Synchronization

The "Generator Disconnect Switch" at the interconnection point shall remain "open" until successful completion of the Company's field audit and witness testing.

Prior to the start of construction, the DG Customer shall designate an Energization Coordinator (EC), and prepare and submit an Energization Plan (EP) to the Company for review and comment. The energization schedule shall be submitted to the Company and communicated with the Company's local Regional Control Center at least two (2) weeks in advance of proposed energization. Further details of the EP and synchronization requirements will be specified during the Draft design review of the Project.

The Customer shall submit as-built design drawings to the Company 90 days following commercial operation of their DG Facility.

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9.0 Cost Estimate

The non-binding good faith cost planning grade estimate for the Company's work associated with the interconnection of this Facility to the EPS, as identified in this report, is shown below in **Error! Reference source not found.**5:

National Grid	Conceptual Cost +/-25% Planning Grade Cost Estimate not including Tax Liability				Associated Tax Liability Applied to Capital	Total Customer Costs includes Tax Liability on Capital Portion
NECO - Line Work, Customer Property	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**11.08%**	**Total**
Equipment at Point of Common Coupling - See Note #1	$370,108	$370,108	$0	$0	$41,008	$411,116
SUBTOTAL	**$370,108**	**$370,108**	**$0**	**$0**	**$41,008**	**$411,116**

NECO - Line Work, Mainline	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
New 34.5kV Circuit #2. UG From Lafayette - Customer POI. See Note #2	$3,719,368	$3,643,448	$44,659	$31,261	$403,694	$4,123,063
SUBTOTAL	**$3,719,368**	**$3,643,448**	**$44,659**	**$31,261**	**$403,694**	**$4,123,063**

NECO -Line Work - Transmission Level	Pre-Tax Total	Capital	O&M	Removal	9.90%	Total
New 115 kV Transmission Line Tap, See Note #3	$1,819,463	$1,777,063	$8,623	$33,777	$172,197	$1,991,661
SUBTOTAL	**$1,819,463**	**$1,777,063**	**$8,623**	**$33,777**	**$172,197**	**$1,991,661**

NECO - Substation Work (Distribution Level)	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
New 115 kV/34.5 kV Distribution Substation, See Note #4	$2,926,437	$2,926,437	$0	$0	$324,249	$3,250,687
SUBTOTAL	**$2,926,437**	**$2,926,437**	**$0**	**$0**	**$324,249**	**$3,250,687**

NECO - Substation Work Non - PTF (Transmission Level)	Pre-Tax Total	Capital	O&M	Removal	9.69%	Total
New 115 kV/34.5 kV Transmission Substation, See Note #5	$10,523,563	$10,523,563	$0	$0	$1,019,733	$11,543,297
SUBTOTAL	**$10,523,563**	**$10,523,563**	**$0**	**$0**	**$1,019,733**	**$11,543,297**

NECO - Substation Work PTF (Transmission Level)	Pre-Tax Total	Capital	O&M	Removal	9.90%	Total
New 115 kV/34.5 kV Transmission Substation, See Note #6	$3,697,468	$3,697,468	$0	$0	$366,049	$4,063,518
SUBTOTAL	**$3,697,468**	**$3,697,468**	**$0**	**$0**	**$366,049**	**$4,063,518**

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	Pre-Tax Total	Capital	O&M	Removal	Tax	Total
Totals	$23,056,407	$22,938,087	$53,282	$65,038	$2,326,931	$25,383,342

Notes

1. Installation of pole mounted equipment including (4) primary meters, Installation of (12) poles, (1) recloser, and (5) gang operated load breaks. Installation of approximately 150' circuit feet of 795 ACSR and 300' circuit feet of 1/0 AAAC overhead conductor.
2. Install 8,000 circuit feet of two (2) sets of underground 3-1/C 1000 SCU EPR cable from P9121 in the right-of-way outside Wickford Junction Substation to existing Pole #5 South County Trail. Install 7,800 circuit feet of 3-795 ACSR overhead conductors from existing Pole #5 South County Trail to proposed Pole # 13-50 Dry Bridge Road. The proposed overhead line extension will overbuild an existing 15 kV class circuit.
3. Installation of 115kV loop tap off the L190 to new Wickford Substation, consisting of breaking the L190 line at structure #143 and installing two new spans of wire between the existing transmission line and the substation busses. New steel three pole structures on concrete caisson foundation will be required. Structure #123 on the adjacent 34.5kV, 3311 line will need to be replaced to support the L190 construction.
4. Install two (2) 34.5kV feeder positions with protection and control, including but not limited to site work, grounding, conduits, fencing and driveway from the street.
5. Install 115kV ring bus including breaker, disconnect switches, bus, bus insulators and wave trap; and associated site-work, grounding, foundations, structures, and associated protection and control.
6. Install 115kv 4-Breaker Ring Bus with protection and control, including but not limited to site work, grounding and conduits.
7. Costs do not include distribution line modifications on Ten Rod Road West of the South County Trail intersection and at the PCC of the Exeter Renewable project (26012283).

Table 5: Cost Estimates

The planning grade estimate provided in is based on information provided by the Interconnecting Customer for the study, and is prepared using historical cost data from similar projects. The associated tax effect liability included is the result of an IRS rule, which states that all costs for construction collected by the Company, as well as the value of donated property, are considered taxable income.[3] This estimate is valid for ninety (90) calendar days from the issuance of this report, after which time it becomes void. If the Interconnection Customer elects to proceed with this project after the ninety (90) calendar days, a revised estimate may be required.

The estimated duration for the Company to complete construction of the System Modifications will be identified in the Interconnection Service Agreement.

The project schedule may be impacted by the ability to have planned outages to allow work to take place on the distribution system. Outages will be contingent on the ability to support the load normally supplied by affected circuits. The schedule can also be impacted by unknown factors over which the Company has no control. The interconnection schedule is contingent on the Interconnecting Customer's successful compliance with the requirements outlined in this report and timely completion of its obligations as defined in *ESB756D, Exhibit 2: Company Requirements for Projects Not Eligible for the Simplified Process*. The schedule for the Company's work shall be addressed during the development, or after the execution, of the Interconnection Agreement

[3] Actual charges shall include the tax rate in effect at the time the charges are incurred.

10.0 Conclusion

The project was found to be feasible. It will be allowed to interconnect with certain system modifications and additions to the local Company EPS. Associated costs are provided in Section 9.0. Applicable cost sharing allocations, if any, will be calculated by the Company and provided in the Interconnection Service Agreement.

The Customer must submit revised documentation as identified herein, to the Company for review and approval before an ISA can move forward.

A milestone schedule shall be included in the ISA and shall be reflective of the tasks identified in ESB756D, Exhibit 2. Upon execution of the ISA, and prior to advancing the project, the Customer shall provide a detailed project schedule, inclusive of the Exhibit 2 tasks referenced above. After completion of final design and all associated applications, fees, permitting and easement requirements are satisfied, System Modifications for this Project will be placed in queue for construction.

If a Customer fails to meet the R.I.P.U.C No 2163, Section 3.1 & RI SCDG Time Frames and does not provide the necessary information required by the Company within the longer of 15 days or half the time allotted to the Company to perform a given step, or as extended by mutual agreement, then the Company may terminate the application and the Customer must re-apply.

Note: Authorization for parallel operation will not be issued without a fully executed Interconnection Agreement, receipt of the necessary insurance documentation, and successful completion of the Company approved witness testing. Such authorization shall be provided in writing.

11.0 Revision History

Version	Date	Description of Revision
1.0	06/08/2018	Issue to Customer
2.0	08/23/2019	Issue to Customer

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Appendix A Revenue Metering Phone Line Requirements

An analog phone line to National Grid's revenue meter shall be provided by the Customer. The analog phone line must be capable of direct inward dial without human intervention or interference from other devices such as fax machines, etc. The phone line can be a phone (extension) off the customers PBX phone system, or it may be a separate dedicated phone line as provided by the Telephone Company. The following is to be used as a guide, please contact the Company if additional information is required. The most common installations are outlined below, Wall mounted Meter Installation, Outdoor Padmount Transformer Meter Installation, and Outdoor Pole Mounted Meter Installation.

1) WALL MOUNTED METER INSTALLATION
If the meter is wall mounted indoor or outdoor the customer shall provide a telephone line within 12" of the meter socket and additional equipment as described and shown below in figures 1A & 1B. National Grid will connect the meter to the customer provided phone line.

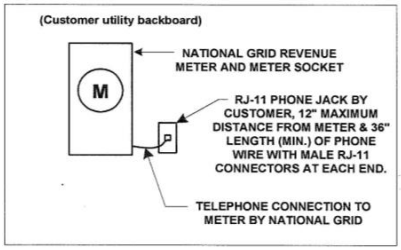

Figure 1A – Indoor Meter Installation
not to scale

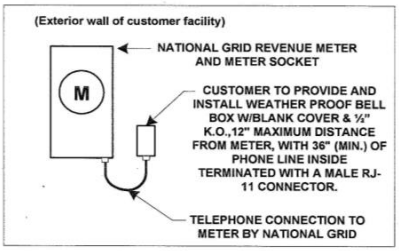

Figure 1B – Outdoor Meter Installation
not to scale

2) OUTDOOR PADMOUNT TRANSFORMER METER INSTALLATION
If the meter is mounted outside on the secondary compartment of the padmount transformer as shown below the conduit shall stub up and roughly line up with the bottom or side knock out of the meter socket and terminate into a weatherproof box or fitting. A liquid tight flexible conduit whip with end bushing and locknut of sufficient length to reach and terminate at the knockout location of the meter socket with three feet of telephone wire coiled (and terminated with a male RJ-11 connector) at its end shall be connected to the weatherproof box or fitting. National Grid will connect the conduit whip to the meter socket and terminate the telephone wire to the meter (see figure 2 below).

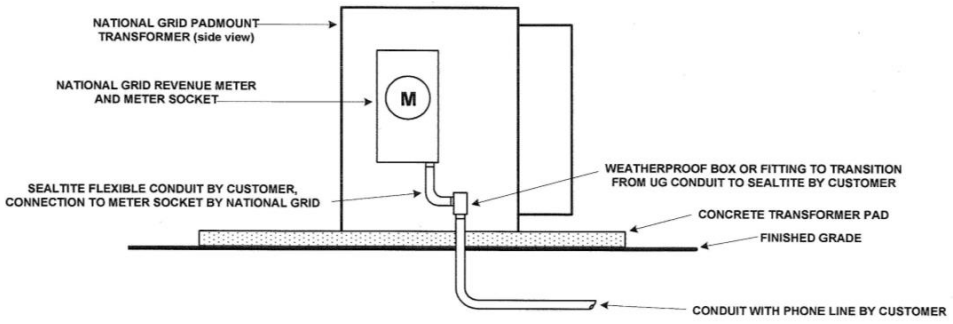

Figure A- 1: Revenue Meter Phone Line Installation Guide

3) OUTDOOR POLE MOUNTED METER INSTALLATION

If the meter is located outdoor on a Company owned utility pole as part of a primary metering installation the Customer will install and connect a phone line from the Telephone Company provided termination interface box, the line shall be terminated with a RJ-11 male connector and be of sufficient length to reach the meter socket and create a drip loop, as well as additional line for final connection to the meter. The customer is responsible for the Telephone Company phone line installation. (see figure 3 below).

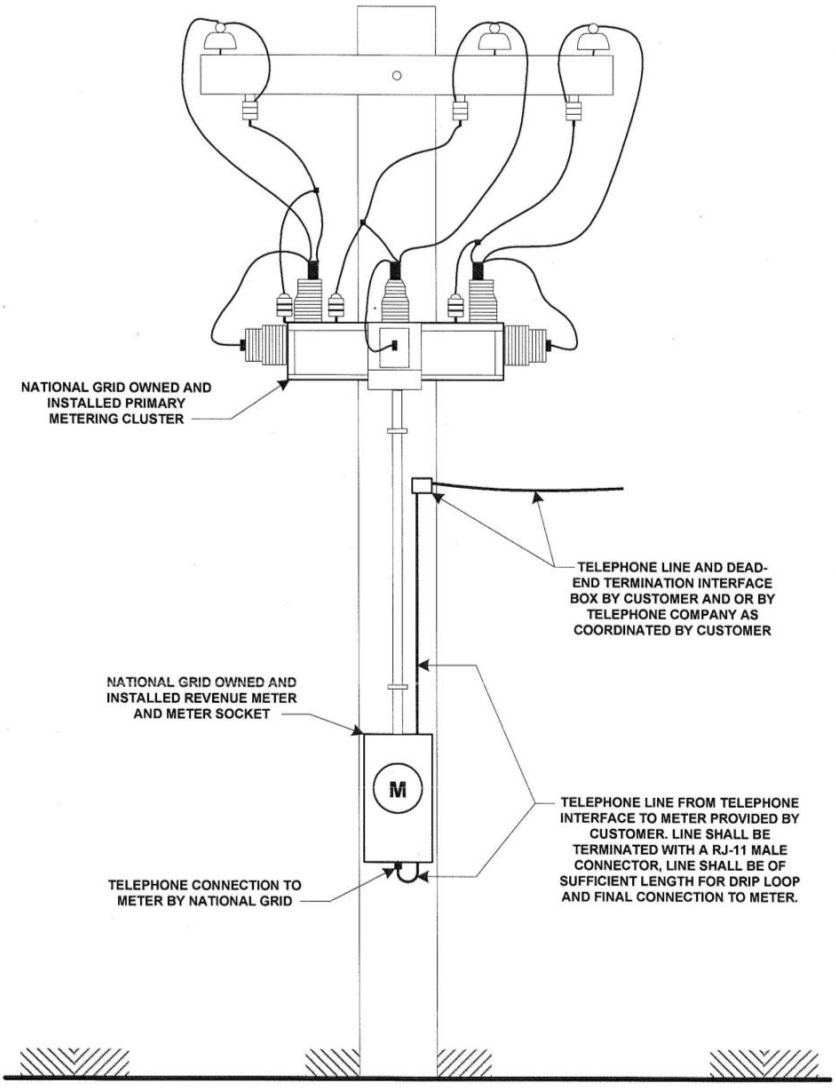

Figure A- 2: Revenue Meter Phone Line Installation Guide

Appendix B System Modification Diagrams

Note: Company EPS modification diagrams provided in this Appendix are intended as a diagrammatic reference of work required to be completed before this Facility may interconnect. The Company will be performing a detailed design following this Impact Study, should the Customer elect to move forward with the interconnection process. At that time, the Company will determine exact locations and requirements for system modification designs. Refer to the body of this Impact Study for further discussion regarding specific EPS modifications that are required for the interconnection of this Facility.

[redacted]

Appendix C Customer Site and Single Line Diagram

[redacted]

[redacted]

[redacted]

[redacted]