nationalgrid

Jennifer Brooks Hutchinson
Acting Assistant General Counsel and Director

November 20, 2020

VIA ELECTRONIC MAIL

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

RE: Docket 4770 – Electric Earnings Sharing Mechanism
Earnings Report - Twelve Months Ended December 31, 2019
<u>Responses to PUC Data Request – Set 4</u>

Dear Ms. Massaro:

On behalf of National Grid[1] I have enclosed an electronic version of the Company's responses to the Public Utilities Commission's Fourth Set of Data Requests in the above-referenced matter.[2]

The Company received an extension to November 25, 2020 to respond to the following data requests in this set: PUC 4-3, 4-4, 4-5, 4-6, 4-7, 4-8, 4-9 and 4-10.

Thank you for your attention to this transmittal. If you have any questions regarding this filing, please contact me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: Docket 4770 Service List
John Bell, Division
Christy Hetherington, Esq.
Leo Wold, Esq.

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

[2] Per Commission counsel's update on October 2, 2020, concerning the COVID-19 emergency period, the Company is submitting an electronic version of this filing. The Company will provide the Commission Clerk with a hard copy and, if needed, additional hard copies of the enclosures upon request.

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

____________________________________ November 20, 2020

National Grid Docket No. 4770 (Rate Application) & Docket No. 4780 (PST)
Combined Service list updated 9/18/2020

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PUC 4-1

Request:

Referring to Attachment 3-3-1-A and the FERC letter provided as Attachment 3-3-1-H, the filing and the letter indicate that the ISO believed that the original filing was "non-conforming." Please explain the issue of non-conformance referenced in the filing and the FERC letter.

Response:

The agreements referenced in Attachment PUC 2-2-1-A and Attachment PUC 3-3-1-H (NEP-TSA-83 and NEP-TSA-86) are Local Service Agreements (LSAs) under Attachment A to Schedule 21-Common of the ISO-NE OATT. LSAs that strictly follow the terms of a *pro forma* from a FERC approved tariff need not be filed with FERC. However, according to well-established FERC precedent, agreements that vary from a *pro forma* agreement previously filed at FERC must be filed with FERC for approval before going into effect. For example, FERC has stated:

> First, public utilities that have standard forms of agreements in their transmission, cost-based power sales tariffs, or tariffs for other generally applicable services will no longer file conforming agreements with the Commission. The filing requirements of FPA section 205(c) will be satisfied by the standard forms of agreements and by the electronic filing of Electric Quarterly Reports. Electric Quarterly Reports will be filed with the Commission, and the Commission will post them on FERC's Internet web site.
>
> Second, agreements for transmission, cost-based power sales, and other generally applicable services that do not conform to an applicable standard form of agreement in a public utility's tariff, including agreements with individualized terms and conditions or unexecuted agreements for any service, must continue to be filed with the Commission for approval before going into effect.

Revised Public Utility Filing Requirements, Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at PP 18-19 (2002).

As stated in the filing letter (Attachment PUC 3-3-1-A), NEP believed the LSAs conformed to the Form of LSA contained in Attachment A to Schedule 21-Common of the ISO-NE OATT, and, thus, did not need to be filed. ISO-NE, however, believed that the provisions in the LSAs regarding the BITS Surcharge may have rendered the LSAs non-conforming. In other words, ISO-NE did not view these charges as inappropriate, they merely thought that they technically

PUC 4-1, page 2

varied from the terms of the *pro forma*. Out of an abundance of caution, NEP agreed to file the agreements with FERC and FERC accepted those agreements as reflected in Attachment PUC 3-3-1-H.

PUC 4-2

Request:

Refer to the response to PUC 3-10(d) which acknowledges that the Company has the discretion to re-classify an asset from distribution to transmission, and paragraph 9 of Attachment PUC 3-10 (i.e., the New England Transmission-Distribution Classification of Assets Rules Document) which states:

> "There are exceptions to any set of rules and unique or unusual configurations may arise that will require special determination concerning the classification of National Grid's assets. To ensure appropriate classification of assets consistent with regulatory intent, these situations should be addressed at the appropriate senior management level. Currently known major exceptions are listed below and special rules apply:
>
> A. EUA Substations (Appendix A)
> B. MECo Transmission Lines (Appendix B)
> C. Sub-Transmission Lines
> D. BITS (Block Island Transmission System) – Details TBD."

a. Please explain the exception relating to the BITS that is referenced in these classification rules and why an exception apparently was made.

b. When was this reference to a BITS exception written into in the Rules Document? Please provide copies of all prior versions of the Rules Document.

Response:

a. BITS was included in the "exception" section of the New England Transmission-Distribution Classification of Assets Rules Document (the "Asset Rules Document") because, at the time, it was not clear what the classification of the BITS assets would ultimately be. Following that version of the Asset Rules Document, the decision was made to classify the BITS assets as Distribution. Updated versions of this Asset Rules Document should remove this as an exception as the classification of the BITS assets has now been determined.

b. This reference was added in version 3 of the Asset Rules Document. Attachment PUC 4-2-1 represents version 1 of this Asset Rules Document from 2016, and Attachment PUC 4-2-2 represents version 2 of this Asset Rules Document from 2017. Please note that on page 2 of PUC Attachment 4-2-2 it incorrectly states that it was issued September 1, 2016. The date was not updated when issued in 2017.

Prepared by or under the supervision: Michael Artuso

New England Electric Transmission-Distribution

Classification of Assets Rules Document

Department approvals:

Name	Role	Approval (Y/N)	Date
Sharon Partridge	VP US Financial Controller		
Patrick Tarmey	Senior Counsel – FERC Regulatory		
James Holodak	VP Regulatory Strategy & Integrated Analytics		
Carol Sedewitz	VP Electric Asset Management		
John Gavin	VP Electric Systems Engineering		

Classification Rules for New England Transmission and Distribution Electric Assets
Issue Date September 1, 2016

This document is the work product of a Process Excellence (PEx) Team charged with the responsibilities to:

- investigate past historic practices for the:
  - classification of New England electric assets as either transmission or distribution plant, and
  - classification of transmission assets as either Pool Transmission Facilities (PTF) or Non-PTF.
- establish appropriate classification rules that will be used on a going-forward basis.

This document incorporates inputs from:

- Transmission Planning and Asset Management – New England
- Distribution Planning and Asset Management – New England
- Substation Engineering and Design
- Transmission Line Engineering
- Regulatory
- Legal
- Plant Accounting

A. General points:

1. These rules apply only to National Grid's operations in New England.
2. FERC provides general guidance for classifying assets as either transmission or distribution in its Uniform System of Accounts. Included in 'PART 101—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR PUBLIC UTILITIES AND LICENSEES SUBJECT TO THE PROVISIONS OF THE FEDERAL POWER ACT - General Instructions - Electric Plant Instructions', dated August 1, 2016, is the following statement:

   14. Transmission and Distribution Plant.

   For the purpose of this system of accounts:

   A. Transmission system means:
      (1) All land, conversion structures, and equipment employed at a primary source of supply (i.e., generating station, or point of receipt in the case of purchased power) to change the voltage or frequency of electricity for the purpose of its more efficient or convenient transmission;
      (2) All land, structures, lines, switching and conversion stations, high tension apparatus, and their control and protective equipment between a generating or receiving point and the entrance to a distribution center or wholesale point*; [National Grid Note: This instruction would apply to NEP-owned Massachusetts substations which change electricity from transmission to distribution voltage because NEP is a wholesale transmission provider and the entrance or wholesale point for NEP's transmission service is at the low side of a NEP-owned step-down transformer.]* and
      (3) All lines and equipment whose primary purpose is to augment, integrate or tie together the sources of power supply.

   B. Distribution system means all land, structures, conversion equipment, lines, line transformers, and other facilities employed between the primary source of supply (i.e., generating station, or point of receipt in the case of purchased power) and of delivery to customers, which are not includible in transmission system, as defined in paragraph A, whether or not such land,

structures, and facilities are operated as part of a transmission system or as part of a distribution system.
NOTE: Stations which change electricity from transmission to distribution voltage shall be classified as distribution stations. *[National Grid Note: This instruction would apply to ownership of substations by National Grid distribution affiliates MECO and NECO.]*

C. Where poles or towers support both transmission and distribution conductors, the poles, towers, anchors, guys, and rights of way shall be classified as transmission system. The conductors, crossarms, braces, grounds, tiewire, insulators, etc., shall be classified as transmission or distribution facilities, according to the purpose for which used.
D. Where underground conduit contains both transmission and distribution conductors, the underground conduit and right of way shall be classified as distribution system. The conductors shall be classified as transmission or distribution facilities according to the purpose for which used.
E. Land (other than rights of way) and structures used jointly for transmission and distribution purposes shall be classified as transmission or distribution according to the major use thereof.

3. For new assets and asset replacements, the rules presented in this document are intended to remain consistent with historical regulatory precedents as codified by the restructuring settlements of the former NEES and EUA companies in the late 1990s.
4. There are historic reasons for the differences in asset classification:
   a. By state
   b. Between transmission and distribution assets owned by National Grid's predecessors, the former EUA and NEES companies.
   c. The former NEES companies classified substation assets owned by its MECo (Massachusetts Electric Company) and NECo (Narragansett Electric Company) distribution affiliates, differently from the equivalent assets owned by NEP based on NEP's (New England Power) role as the FERC jurisdictional provider of transmission services to its distribution affiliates.
   d. Nantucket Electric follows the same rules as MECo.
5. When replacing existing assets on a one-for-one (replacement of specific individual pieces of equipment due to damage or failure, such as a circuit breaker) or functional basis (e.g., replacing a transformer to increase its rating from 10 MVA to 20 MVA capability or replacing all insulators of a specific type based on asset condition), the existing designation of the assets as transmission or distribution and PTF or Non-PTF will remain unchanged unless there is a system re-configuration that dictates a change in functional classification.
6. These rules are intended to ensure consistent treatment in the classification of "shared assets" for new substation construction, including, but not limited to, land, site preparation, fencing, control house, yard lighting, station service transformer, battery/charger system, etc., consistent with the FERC Uniform System of Accounts.
7. For rate recovery purposes, if assets are installed to satisfy NERC Reliability Standards, then the assets will be PTF transmission assets. Includes assets to satisfy CIP Standards for Cyber and Physical Security of the substation.
8. When building a new substation in Massachusetts, it must be determined which National Grid operating company, NEP or MECo, will own the substation. Ownership of the new substation will be based on which company, MECo or NEP, owns the transmission line that will interconnect the new substation to the transmission system.
9. It must also be recognized that there are exceptions to any set of rules and unique or unusual configurations may arise that will arise that will require a special determination concerning the classification of National Grid's assets. To ensure appropriate classification of assets consistent with regulatory intent, these situations should be addressed at the appropriate senior management level as part of the existing project sanctioning process.

10. Formal accountability is assigned to the New England Transmission Planning and Asset Management department to ensure that PTF and Non-PTF designations of assets are appropriate and that National Grid's PTF catalogs are updated annually and reported to ISO New England in accordance with operating agreements with the ISO.

B. Lines Ownership Classification Rules and PTF Determination

1. NEP, MECo and NECo all own transmission lines.
2. Lines are generally defined as 'transmission' if they are rated 69 KV and higher, except for:
    a. The Narragansett-owned #63 69 KV RI circuit between Jepson and Gate II substations which was defined as a distribution circuit by EUA.
    b. Both MECo and NECo own lower voltage (less than 69 KV) line assets booked as 'transmission' assets based on historic installations but these assets now serve a 'primary distribution function'.
    c. NEP owns transmission lines that are rated less than 69 KV based on historic hydro power water rights agreements or purchase of assets from other utilities, including the former Boston Edison Company (now part of EverSource).
3. Where poles or towers support both transmission and distribution conductors, the poles, towers, anchors, guys, and rights of way shall be classified as transmission system. The conductors, crossarms, braces, grounds, tiewire, insulators, etc., shall be classified as transmission or distribution facilities, according to the purpose for which used.
4. Where underground conduit contains both transmission and distribution conductors, the underground conduit and right of way shall be classified as distribution system. The conductors shall be classified as transmission or distribution facilities according to the purpose for which used.
5. All new Massachusetts transmission lines will be owned by NEP.
6. All new radial taps into a substation are to be their own PowerPlant 'major location' and not included in the main line 'major location'. Ownership will be determined by which company - NEP/MECo/NECo – owns the existing transmission line.
7. The ISO-NE PTF Catalog, updated yearly, identifies all PTF transmission lines currently in service.
8. PTF is a defined by Section II. 49 and the Attachment F Implementation Rule in the ISO-NE Tariff. Transmission Line Engineering's reference document is *Pool Transmission Facilities.*

C. Rhode Island Substation Ownership Classification Rules

1. Narragansett Electric owns all assets
    a. required by RI State laws
    b. only exception is NEP owning 90% of the 115 KV Manchester St ring bus by special RI law

2. When replacing existing assets on a one-for-one or functional basis, the existing designation of the assets as transmission or distribution and PTF or Non-PTF will remain unchanged unless there is a system re-configuration that dictates a change in functional classification. Any classification change must be explicitly approved through the project approval and sanctioning process.

3. For new substations:
    a. Any NECo substation where all primary equipment (including circuit breakers and transformers but excluding auxiliary equipment) is operated at 69 KV or higher is defined as a 'transmission'
    b. Any NECo substation where all primary equipment (including circuit breakers and transformers but excluding auxiliary equipment) is operated below 69 KV is defined as a 'distribution' substation
    c. For any NECo substation that contains assets operating below 69kV and at 69kV and above:
        i. equipment rated at 69 KV or higher will be booked as 'transmission' assets
        ii. equipment rated at below 69 KV will be booked as 'distribution' assets
        iii. all power transformer with two terminals operating at 69 KV or higher will be booked as a 'transmission' asset (including 3 winding transformers)
        iv. all 2 winding step-down transformers with both terminals operating below 69 KV will be booked as a NECo 'distribution' asset
        v. all 2 winding step-down transformers with a terminal operating below 69 KV will be booked as a NECo 'distribution' asset
    d. Shared assets for new substation construction will be classified as:
        i. NECo Distribution if majority of Total Major Equipment investment is for equipment operating at less than 69 KV.
        ii. Otherwise, NECo Transmission

D. <u>Massachusetts Substation Ownership Classification Rules</u>

1. Classification depends on if the substation is a former EUA or NEES substation. A list of former EUA substations with transmission assets is maintained by both the Transmission and Distribution Planning and Asset Management.
2. Existing substations:
    a. When replacing existing assets on a one-for-one or functional basis, the existing company ownership; designation of the assets as transmission or distribution; and the PTF or Non-PTF classification will remain unchanged unless there is a system re-configuration that dictates a change in functional classification. Any classification change must be explicitly approved through the project approval and sanctioning process.
    b. If all substation equipment is owned by MECO, (former EUA substations and a few former NEES substations) - all 2 winding step-down transformers with a terminal operating below 69 KV are booked as MECo distribution asset. Existing transformer ownership should be verified via a PowerPlant query.
    c. If all substation equipment is solely owned by NEP, all 2 winding step-down transformers with a terminal operating at 69 KV or greater are booked as transmission.

   d. There will be no transfer of asset ownership between MECo and NEP due to any asset replacement program.
   e. All capital projects connected to a MECo transmission line will be MECo assets

3. For new substations:
   a. Classification depends on if the substation is to be connected to a MECo or NEP transmission line. The list of MECo owned transmission lines is maintained by Transmission Planning and Asset Management.
   b. <u>Connected to MECo transmission line:</u>
      i. New substation will be a MECo facility.
      ii. Any substation where all primary equipment (including circuit breakers and transformers but excluding auxiliary equipment) is operated at 69 KV or higher is defined as a 'transmission' substation.
      iii. Any substation where all primary equipment (including circuit breakers and transformers but excluding auxiliary equipment) is operated below 69 KV is defined as a 'distribution' substation.
      iv. For any substation that contains both transmission and distribution assets based on the voltage rating of equipment:
         1. book equipment rated to operate at 69 KV or higher as 'transmission' assets
         2. equipment rated at below 69 KV will be booked as 'distribution' assets
         3. all power transformer with two terminals operating at 69 KV or higher will be booked as a MECo 'transmission' asset
         4. all 2 winding step-down transformers with both terminals operating below 69 KV will be booked as a MECo 'distribution' asset
         5. all 2 winding step-down transformers with a terminal operating below 69 KV will be booked as a MECo 'distribution' asset
      v. Shared assets for new substation construction will be classified as:
         1. MECo Distribution if majority of Total Major Equipment investment is for equipment operating at less than 69 KV.
         2. Otherwise, MECo Transmission.

   c. <u>Connected to NEP transmission line:</u>
      i. New substation may have both NEP and MECo assets
      ii. Any substation where all primary equipment (including circuit breakers and transformers but excluding auxiliary equipment) is operated at 69 KV or higher is defined as NEP transmission.
      iii. Any substation where all primary equipment (including circuit breakers and transformers but excluding auxiliary equipment) is operated below 69 KV is defined as MECo distribution.
      iv. For any substation that contains both transmission and distribution assets based on the voltage rating of equipment:
         1. book equipment rated to operate at 69 KV or higher as NEP 'transmission' assets
         2. equipment rated at below 69 KV will be booked as MECo 'distribution' assets
         3. all power transformer with two terminals operating at 69 KV or higher will be booked as a NEP 'transmission' asset

4. all 2 winding step-down transformers with a terminal operating at 69 KV or higher will be booked as a NEP 'transmission' asset unless MECo decides to own the transformer then it will be booked as a MECo 'distribution' asset
5. all 2 winding step-down transformers with both terminals operating below 69 KV will be booked as a MECo 'distribution' asset

v. Shared assets for new substation construction will be classified as:
   1. MECo Distribution if majority of Total Major Equipment investment is for equipment operating at less than 69 KV.
   2. Otherwise, NEP Transmission.

E. Substation Asset PTF Determination

1. The determination of whether a substation asset – circuit breaker, disconnect switch or transformer – is determined by terms defined in Section II.49 –Definition of PTF of the *ISO-NE Open Access Transmission Tariff (OATT).* Refer to *Attachment 1 to Appendix A to Attachment F Implementation Rule* for examples of what equipment is considered PTF under various substation configurations.

2. Substation Engineering presents similar information in its document *Allocation of Costs on Projects Involving PTF*

New England Substation Asset Transmission vs Distribution Ownership Classification Decision Table

		Equipment to be Classified (1) (2)					
	Substation Fed from Transmission System (>69 KV)	**Major Equipment =/> 69 KV (3)**	**Major Equipment < 69 KV (4)**	**2–winding Transformer With 1 winding < 69 KV**	**3-winding Transformer with 2 windings >= 69 KV**	**3-winding Transformer with 2 windings < 69 KV**	**Shared Assets (5) (6)**
Adding assets to or modifying assets at an existing substation in both MA and RI		As general rule, classification of assets being installed to replace assets on a one-for-one basis will be classified as the asset being replaced. Review Plant Accounting records to determine actual Plant Accounting for the asset in question. Should the replacement/construction activities include an expansion of existing facilities, need to verify that the re-configuration activities do not change the classification of assets. If uncertain of classification, consult with Transmission Planning and Asset Management –New England (TP&AM-NE).					
New substation--Massachusetts	MECo Owned Transmission Line	MECo-owned: Transmission	MECo-owned: Distribution	MECo-owned: Distribution	MECo-owned: Transmission	MECo-owned: Distribution	**MECo Distribution** if majority of total Major Equipment investment is < 69 KV. Otherwise **MECo Transmission**
	NEP Owned Transmission Line	NEP- owned: Transmission	MECo-owned: Distribution	NEP-owned Transmission (7)	NEP-owned: Transmission	NEP-owned: Transmission (7)	**MECo Distribution** if majority of total Major Equipment investment is < 69 KV. Otherwise **NEP Transmission**
New substation—Rhode Island	NECo Owned Transmission Line – Only Option	NECo-owned: Transmission	NECo-owned: Distribution	NECo-owned: Distribution	NECo-owned: Transmission	NECo-owned: Transmission	**NECo Distribution** if majority of total Major Equipment investment is < 69 KV. Otherwise **NECo Transmission**

Notes:

1. This table presents general guidelines for determining the classification of substation assets as either transmission or distribution.
2. If one has questions on the proper classification of an asset, they should ask Transmission Planning & Asset Management for guidance.
3. The term 'Major Equipment =/> 69 KV' includes all substation equipment operating at a primary voltage of 69 KV or higher and/or is used in support of the primary voltage rated equipment that is capable of conducting significant current flow, including circuit breakers or circuit switchers, and their associated dis-connect switches.
4. The term 'Major Equipment < 69 KV' includes all substation equipment operating at distribution system voltage that is less than 69 KV and/or is used in support of the distribution voltage rated equipment that is used to serve MECo and NECo retail customers.
5. 'Shared Assets' refers to those assets that serve both transmission and distribution equipment, including, but not limited to, land, site preparation, fencing, grounding grid, yard lighting, station service transformer, station battery and its charging system and the control building. Land will be classified in the same manner as other Shared Assets per the FERC Uniform System of Accounts instructions.
6. If source line voltage is less than 69 KV, then the new substation is classified as a distribution substation unless special approval is provided through the project sanctioning process and senior management acknowledgement.
7. NEP-owned transmission asset UNLESS MECo decides to own the transformer as MECo-owned distribution asset under terms of the NEP Wholesale transmission tariff.

New England Electric Transmission-Distribution

Classification of Assets Rules Document

Department approvals:

Name	Role	Approval (Y/N)	Date
Sharon Partridge	VP US Financial Controller		
Patrick Tarmey	Senior Counsel – FERC Regulatory		
James Holodak	VP Regulatory Strategy & Integrated Analytics		
Carol Sedewitz	VP Electric Asset Management		
John Gavin	VP Electric Systems Engineering		

Classification Rules for New England Transmission and Distribution Electric Assets
Issue Date September 1, 2016

This document is the work product of a Process Excellence (PEx) Team charged with the responsibilities to:

- investigate past historic practices for the:
    - classification of New England electric assets as either transmission or distribution plant, and
    - classification of transmission assets as either Pool Transmission Facilities (PTF) or Non-PTF.
- establish appropriate classification rules that will be used on a going-forward basis.

This document incorporates inputs from:

- Transmission Planning and Asset Management – New England
- Distribution Planning and Asset Management – New England
- Substation Engineering and Design
- Transmission Line Engineering
- Regulatory
- Legal
- Plant Accounting

A. General points:

1. These rules apply only to National Grid's operations in New England.
2. FERC provides general guidance for classifying assets as either transmission or distribution in its Uniform System of Accounts. Included in 'PART 101—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR PUBLIC UTILITIES AND LICENSEES SUBJECT TO THE PROVISIONS OF THE FEDERAL POWER ACT - General Instructions - Electric Plant Instructions', dated August 1, 2016, is the following statement:

> 14. Transmission and Distribution Plant.
>
> For the purpose of this system of accounts:
>
> A. Transmission system means:
> (1) All land, conversion structures, and equipment employed at a primary source of supply (i.e., generating station, or point of receipt in the case of purchased power) to change the voltage or frequency of electricity for the purpose of its more efficient or convenient transmission;
> (2) All land, structures, lines, switching and conversion stations, high tension apparatus, and their control and protective equipment between a generating or receiving point and the entrance to a distribution center or wholesale point*; [National Grid Note: This instruction would apply to NEP-owned Massachusetts substations which change electricity from transmission to distribution voltage because NEP is a wholesale transmission provider and the entrance or wholesale point for NEP's transmission service is at the low side of a NEP-owned step-down transformer.]* and
> (3) All lines and equipment whose primary purpose is to augment, integrate or tie together the sources of power supply.
>
> B. Distribution system means all land, structures, conversion equipment, lines, line transformers, and other facilities employed between the primary source of supply (i.e., generating station, or point of receipt in the case of purchased power) and of delivery to customers, which are not includible in transmission system, as defined in paragraph A, whether or not such land, structures, and facilities are operated as part of a transmission system or as part of a distribution system.

NOTE: Stations which change electricity from transmission to distribution voltage shall be classified as distribution stations. *[National Grid Note: This instruction would apply to ownership of substations by National Grid distribution affiliates MECO and NECO.]*

C. Where poles or towers support both transmission and distribution conductors, the poles, towers, anchors, guys, and rights of way shall be classified as transmission system. The conductors, crossarms, braces, grounds, tiewire, insulators, etc., shall be classified as transmission or distribution facilities, according to the purpose for which used.

D. Where underground conduit contains both transmission and distribution conductors, the underground conduit and right of way shall be classified as distribution system. The conductors shall be classified as transmission or distribution facilities according to the purpose for which used.

E. Land (other than rights of way) and structures used jointly for transmission and distribution purposes shall be classified as transmission or distribution according to the major use thereof.

3. For new assets and asset replacements, the rules presented in this document are intended to remain consistent with historical regulatory precedents as codified by the restructuring settlements of the former NEES and EUA companies in the late 1990s.
4. There are historic reasons for the differences in asset classification:
    a. By state
    b. Between transmission and distribution assets owned by National Grid's predecessors, the former EUA and NEES companies.
    c. The former NEES companies classified substation assets owned by its MECo (Massachusetts Electric Company) and NECo (Narragansett Electric Company) distribution affiliates, differently from the equivalent assets owned by NEP based on NEP's (New England Power) role as the FERC jurisdictional provider of transmission services to its distribution affiliates.
    d. Nantucket Electric follows the same rules as MECo.
5. When replacing existing assets on a one-for-one (replacement of specific individual pieces of equipment due to damage or failure, such as a circuit breaker) or functional basis (e.g., replacing a transformer to increase its rating from 10 MVA to 20 MVA capability or replacing all insulators of a specific type based on asset condition), the existing designation of the assets as transmission or distribution and PTF or Non-PTF will remain unchanged unless there is a system re-configuration that dictates a change in functional classification.
6. These rules are intended to ensure consistent treatment, in line with the FERC Uniform System of Accounts, in the classification of "shared assets" for new substation construction, including, but not limited to, land, site preparation, fencing, control house, yard lighting, station service transformer, battery/charger system, etc. that support both T/D pieces of equipment.
7. Assets that affect/support the PTF system and that are identifiable as serving a PTF function—classified as "other facilities" in the OATT—which are being installed/modified should be classified as PTF. This applies to such things as CIP physical security projects.
8. When building a new substation in Massachusetts, it must be determined which National Grid operating company, NEP or MECo, will own the substation. Ownership of the new substation will be based on which company, NEP or MECo, owns the transmission line that will interconnect the new substation to the transmission system.
9. There are exceptions to any set of rules and unique or unusual configurations may arise that will require a special determination concerning the classification of National Grid's assets. To ensure appropriate classification of assets consistent with regulatory intent, these situations should be addressed at the appropriate senior management level as part of the existing project sanctioning process.

10. Formal accountability is assigned to the New England Transmission Planning and Asset Management department to ensure that PTF and Non-PTF designations of assets are appropriate and that National Grid's PTF catalogs are updated annually and reported to ISO New England in accordance with operating agreements with the ISO.

B. Lines Ownership Classification Rules and PTF Determination

1. NEP, MECo and NECo all own transmission lines.
2. Lines are generally defined as 'transmission' if they are rated 69 KV and higher, except for:
    a. The Narragansett-owned #63 69 KV RI circuit between Jepson and Gate II substations which was defined as a distribution circuit by EUA.
    b. Both MECo and NECo own lower voltage (less than 69 KV) line assets booked as 'transmission' assets based on historic installations but these assets now serve a 'primary distribution function'.
    c. NEP owns transmission lines that are rated less than 69 KV based on historic hydro power water rights agreements or purchase of assets from other utilities, including the former Boston Edison Company (now part of EverSource).
3. Where poles or towers support both transmission and distribution conductors, the poles, towers, anchors, guys, and rights of way shall be classified as transmission system. The conductors, crossarms, braces, grounds, tiewire, insulators, etc., shall be classified as transmission or distribution facilities, according to the purpose for which used.
4. Where underground conduit contains both transmission and distribution conductors, the underground conduit and right of way shall be classified as distribution system. The conductors shall be classified as transmission or distribution facilities according to the purpose for which used.
5. All new Massachusetts transmission lines will be owned by NEP.
6. All new radial taps into a substation are to be their own PowerPlant 'major location' and not included in the main line 'major location'. Ownership will be determined by which company - NEP/MECo/NECo – owns the existing transmission line.
7. The ISO-NE PTF Catalog, updated yearly, identifies all PTF transmission lines currently in service.
8. PTF is a defined by Section II. 49 and the Attachment F Implementation Rule in the ISO-NE Tariff. Transmission Line Engineering's reference document is *Pool Transmission Facilities.*

C. Rhode Island Substation Ownership Classification Rules

1. Narragansett Electric owns all assets
    a. required by RI State laws
    b. only exception is NEP owning 90% of the 115 KV Manchester St ring bus by special RI law

2. When replacing existing assets on a one-for-one or functional basis, the existing designation of the assets as transmission or distribution and PTF or Non-PTF will remain unchanged unless there is a system re-configuration that dictates a change in functional classification. Any classification change must be explicitly approved through the project approval and sanctioning process.

3. For new substations:
    a. Any NECo substation where all primary equipment (including circuit breakers and transformers but excluding auxiliary equipment) is operated at 69 KV or higher is defined as a 'transmission' substation
    b. Any NECo substation where all primary equipment (including circuit breakers and transformers but excluding auxiliary equipment) is operated below 69 KV is defined as a 'distribution' substation
    c. For any NECo substation that contains assets operating below 69kV and at 69kV and above:
        i. equipment rated at 69 KV or higher will be booked as 'transmission' assets
        ii. equipment rated at below 69 KV will be booked as 'distribution' assets
        iii. all power transformers with all terminals operating at 69 KV or higher will be booked as a NECo 'transmission asset'
        iv. all power transformers with all terminals operating below 69 KV will be booked as a NECo 'distribution asset'
        v. all 2 winding step-down transformers with 1 terminal operating below 69 KV will be booked as a NECo 'distribution' asset
        vi. all 3 winding step-down transformers with 2 terminals operating at or above 69 KV will be booked as a NECo 'transmission asset'
        vii. all 3 winding step-down transformers with 2 terminals operating below 69 KV will be booked as a NECo 'distribution asset'
    d. Shared assets for new substation construction will be classified as:
        i. Transmission or Distribution based on whichever business segment has greater major equipment investment; typically, shared assets are classified as:
            1. **NECo-owned Distribution for construction with :**
                a. 2-Winding Transformers with 1 winding < 69kV
                b. 3-Winding Transformer with 2 windings < 69kV
            2. **NECo-owned Transmission for construction with :**
                a. 3- Winding Transformer with 2 windings >= 69kV
        ii. Note that power transformer ownership is currently typically used as a basis for "major equipment investment" due to its relatively high cost/value, which often tips the scale of "major equipment investment" to the owner of the power transformer. However, major equipment investment in a new substation can be dictated by investment in assets other than power transformers.

D. <u>Massachusetts Substation Ownership Classification Rules</u>

1. Classification depends on whether the substation is a former EUA or NEES substation. A list of former EUA substations with transmission assets is maintained by both the Transmission and Distribution Planning and Asset Management.

2. Existing substations:
   a. When replacing existing assets on a one-for-one or functional basis, the existing company ownership, designation of the assets as transmission or distribution, and the PTF or Non-PTF classification will remain unchanged unless there is a system re-configuration that dictates a change in functional classification. Any classification change must be explicitly approved through the project approval and sanctioning process.
   b. If all substation equipment is owned by MECO, (former EUA substations and a few former NEES substations) - all 2 winding step-down transformers with a terminal operating below 69 KV are booked as MECo distribution asset. Existing transformer ownership should be verified via PowerPlan's Continual Property Records.
   c. If all substation equipment is solely owned by NEP, all 2 winding step-down transformers with a terminal operating at 69 KV or greater are booked as NEP transmission.
   d. There will be no transfer of asset ownership between MECo and NEP due to any asset replacement program.
   e. All capital projects connected to a MECo transmission line will be MECo assets.

3. For new substations:
   a. Classification depends on whether the substation is to be connected to a MECo or NEP transmission line. The list of MECo owned transmission lines is maintained by Transmission Planning and Asset Management with the support of Transmission Line Engineering.
   b. <u>Connected to MECo transmission line:</u>
      i. Any new substation will be a MECo facility.
      ii. Any substation where all primary equipment (including circuit breakers and transformers but excluding auxiliary equipment) is operated at 69 KV or higher is defined as a 'transmission' substation.
      iii. Any substation where all primary equipment (including circuit breakers and transformers but excluding auxiliary equipment) is operated below 69 KV is defined as a 'distribution' substation.
      iv. For any substation that contains both transmission and distribution assets based on the voltage rating of equipment:
         1. equipment rated to operate at 69 KV or higher will be booked as 'transmission' assets;
         2. equipment rated at below 69 KV will be booked as 'distribution' assets;
         3. all power transformers with all terminals operating at 69 KV or higher will be booked as MECo 'transmission' assets ;
         4. all power transformers with all terminals operating below 69 KV will be booked as MECo 'distribution' assets ;
         5. all 2 winding step-down transformers with 1 terminal operating below 69 KV will be booked as MECo 'distribution' assets;
         6. all 3 winding step-down transformers with 2 terminals operating at or above 69 KV will be booked as MECo 'transmission assets';
         7. all 3 winding step-down transformers with 2 terminals operating below 69 KV will be booked as MECo 'distribution assets'.

v. Shared assets for new substation construction will be classified as:
   1. Transmission or Distribution based on whichever business segment has greater major equipment investment. Typically, shared assets are classified as:
      a. **MECo-owned Distribution for construction with :**
         i. 2-Winding Transformer with 1 winding < 69kV
         ii. 3-Winding Transformer with 2 windings < 69kV
      b. **MECo-owned Transmission for construction with :**
         i. 3- Winding Transformer with 2 windings >= 69kV
   2. Note that power transformer ownership is currently typically used as a basis for "major equipment investment" due to its relatively high cost/value, which often tips the scale of "major equipment investment" to the owner of the power transformer. However, major equipment investment in a new substation can be dictated by investment in assets other than power transformers.

c. <u>Connected to NEP transmission line:</u>
   i. Any new substation may have both NEP and MECo assets.
   ii. Any substation where all primary equipment (including circuit breakers and transformers but excluding auxiliary equipment) is operated at 69 KV or higher is defined as NEP transmission.
   iii. Any substation where all primary equipment (including circuit breakers and transformers but excluding auxiliary equipment) is operated below 69 KV is defined as MECo distribution.
   iv. For any substation that contains both transmission and distribution assets based on the voltage rating of equipment:
      1. equipment rated to operate at 69 KV or higher will be booked as NEP 'transmission' assets;
      2. equipment rated at below 69 KV will be booked as MECo 'distribution' assets;
      3. all power transformers with two terminals operating at 69 KV or higher will be booked as NEP 'transmission' asset;
      4. all power transformers with all terminals operating below 69 KV will be booked as MECo 'distribution' assets;
      5. all 2 winding step-down transformers with a terminal operating at 69 KV or higher will be booked as NEP 'transmission' assets unless MECo decides to own the transformer in which case it will be booked as a MECo 'distribution' asset;
      6. all 3 winding step-down transformers with at least 1 terminal operating 69 KV or above will be booked as NEP 'transmission' assets.
   v. Shared assets for new substation construction will be classified as:
      1. Transmission or Distribution based on whichever business segment has greater major equipment investment.
      2. Typically, shared assets are NEP-owned Transmission except in cases where MECo decides to own the power transformer, in which case shared assets would be MECo-owned Distribution. See where this applies in the Classification Decision Table as noted by note (7).

3. Note that power transformer ownership is currently typically used as a basis for “major equipment investment” due to its relatively high cost/value, which often tips the scale of “major equipment investment” to the owner of the power transformer. However, major equipment investment in a new substation can be dictated by investment in assets other than power transformers.

E. Substation Asset PTF Determination

1. The determination of whether a substation asset – circuit breaker, disconnect switch or transformer – is PTF is determined by terms defined in Section II.49 –Definition of PTF of the *ISO-NE Open Access Transmission Tariff (OATT).* Refer to *Attachment 1 to Appendix A to Attachment F Implementation Rule* for examples of what equipment is considered PTF under various substation configurations.

2. Substation Engineering presents similar information in its document *Allocation of Costs on Projects Involving PTF*.

New England Substation Asset Transmission vs Distribution Ownership Classification Decision Table

	Substation Fed from Transmission System (>69 KV)	Equipment to be Classified (1) (2)					
		Major Equipment =/> 69 KV (3)	**Major Equipment < 69 KV (4)**	**2–winding Transformer With 1 winding < 69 KV**	**3-winding Transformer with 2 windings >= 69 KV**	**3-winding Transformer with 2 windings < 69 KV**	**Shared Assets (5) (6)**
Adding assets to or modifying assets at an existing substation in both MA and RI		As a general rule, classification of assets being installed to replace assets on a one-for-one basis will be classified as the asset being replaced. Review Plant Accounting records to determine actual Plant Accounting for the asset in question. Should the replacement/construction activities include an expansion of existing facilities, it is necessary to verify that the re-configuration activities do not change the classification of assets. If uncertain of classification, consult with Transmission Planning and Asset Management –New England (TP&AM-NE).					
New substation--Massachusetts	MECo Owned Transmission Line	MECo-owned: Transmission	MECo-owned: Distribution	MECo-owned: Distribution	MECo-owned: Transmission (8)	MECo-owned: Distribution	**MECo-owned Distribution for construction with :** • 2-Winding Transformers with 1 winding < 69kV • 3-Winding Transformer with 2 windings < 69kV **MECo-Owned Transmission for construction with :** • 3- Winding Transformer with 2 windings >= 69kV
	NEP Owned Transmission Line	NEP-owned: Transmission	MECo-owned: Distribution	NEP-owned Transmission (7)	NEP-owned: Transmission	NEP-owned: Transmission (7)	**NEP-owned Transmission**
New substation—Rhode Island	NECo Owned Transmission Line – Only Option	NECo-owned: Transmission	NECo-owned: Distribution	NECo-owned: Distribution	NECo-owned: Transmission (8)	NECo-owned: Distribution	**NECo-owned Distribution for construction with :** • 2-Winding Transformers with 1 winding < 69kV • 3-Winding Transformer with 2 windings < 69kV **NECo-Owned Transmission for construction with :** • 3- Winding Transformer with 2 windings >= 69kV

Notes (continued on next page):
1. This table presents general guidelines for determining the classification of substation assets as either transmission or distribution.
2. If one has questions on the proper classification of an asset, they should ask Transmission Planning & Asset Management for guidance.

New England Substation Asset Transmission vs Distribution Ownership Classification Decision Table

3. The term 'Major Equipment =/> 69 KV' includes all substation equipment operating at a primary voltage of 69 KV or higher and/or is used in support of the primary voltage rated equipment that is capable of conducting significant current flow, including circuit breakers or circuit switchers, and their associated dis-connect switches.
4. The term 'Major Equipment < 69 KV' includes all substation equipment operating at distribution system voltage that is less than 69 KV and/or is used in support of the distribution voltage rated equipment that is used to serve MECo and NECo retail customers.
5. "Shared Assets" for new substation construction includes, but is not limited to, land, site preparation, fencing, control house, yard lighting, station service transformer, battery/charger system, etc. that support both T & D pieces of equipment simultaneously. Classification of Shared Assets fall under ownership of the operating company that has the most major equipment investment.
6. If source line voltage is less than 69 kV, then the new substation is classified as a distribution substation unless special approval is provided through the project sanctioning process and senior management approval.
7. NEP-owned transmission asset UNLESS MECo decides to own the transformer as MECo-owned distribution asset under terms of the NEP Wholesale transmission tariff.
8. This is to account for the fact that a 3-winding Transformer with 2 windings >= 69 kV could be classified as PTF; PTF is only captured by the Transmission businesses of the NE Operating companies.

Version 1 – 9/1/16 – Initial rollout
Version 2 – 3/1/16 – Updated with shared asset details and other minor word changes
Next review of document: 9/1/17

<u>PUC 4-11</u>

<u>Request</u>:

Referring to Attachment PUC 3-15-1, column (C), please identify all Narragansett-owned assets in Rhode Island that tie to the calculations reflected in that column.

<u>Response</u>:

Please see Attachment PUC 4-11. Page 1 of the attachment provides a breakout in columns D and E of the IFA Transmission-related Integrated Facilities Credit between Narragansett Electric and Massachusetts Electric. Starting on page 2 of the attachment is a list of all Narragansett-owned assets in Rhode Island that are used to calculate its portion of the Transmission related Integrated Facilities Credit.

Line	Month	(A) = (B) + (C) LNS Transmission Revenue Requirement	(B) NEP-specific Revenue Requirement (a)	(C) IFA Transmission related Integrated Facilities Credit	(D) Revenue requirement that is derived from distribution facilities	(E) Revenue requirement that is derived from transmission facilities	(F) = MECO Portion of (D) MECO Transmission related Integrated Facilities Credit	(G) = NECO Portion of (D) NECO Transmission related Integrated Facilities Credit
1	Jan-2019	13,755,401	424,695	13,330,706	1,696,758	11,633,947	1,200,393	12,130,313
2	Feb-2019	6,864,143	(6,852,007)	13,716,150	1,727,685	11,988,465	1,430,268	12,285,882
3	Mar-2019	10,277,037	(3,834,521)	14,111,558	1,723,678	12,387,880	1,532,257	12,579,301
4	Apr-2019	12,456,550	(664,168)	13,120,719	1,754,401	11,366,318	1,287,110	11,833,609
5	May-2019	15,755,837	1,697,347	14,058,490	1,727,437	12,331,053	1,734,755	12,323,735
6	Jun-2019	17,258,391	5,055,948	12,202,443	1,729,552	10,472,891	2,009,967	10,192,476
7	Jul-2019	8,345,073	(3,906,988)	12,252,061	1,729,887	10,522,174	1,188,231	11,063,830
8	Aug-2019	3,403,821	(10,479,361)	13,883,182	1,554,721	12,328,462	1,434,615	12,448,568
9	Sep-2019	2,702,781	(10,415,607)	13,118,387	1,657,976	11,460,412	2,458,808	10,659,579
10	Oct-2019	11,830,804	(1,999,026)	13,829,830	1,665,088	12,164,742	1,596,581	12,233,250
11	Nov-2019	12,141,494	(1,320,545)	13,462,039	1,667,879	11,794,160	1,727,670	11,734,369
12	Dec-2019	13,842,743	(465,815)	14,308,559	1,666,905	12,641,654	1,550,962	12,757,597
13	**Total**	**128,634,074**	**(32,760,049)**	**161,394,124**	**20,301,968**	**141,092,156**	**19,151,616**	**142,242,508**

Notes

(a) NEP's revenue requirement includes revenue credits associated with revneues received through ISO-NE Regional Network Service

Attachment PUC 4-11
Page 2 of 2

Company	Major Location Description	Amount in CY2019
NECO	SOUTH STREET GENERATING STATION	2,398,031
NECO	SOUTH STREET 115KV TRANSMISSION SUB	25,079,947
NECO	SUB #11 FRANKLIN SQUARE TRANS	10,232,498
NECO	SUB #9 ADMIRAL STREET TRANS	573,449
NECO	SUB #14 DRUMROCK TRANS	25,958,348
NECO	SUB #15 HOPE	991
NECO	SUB #6 OLNEYVILLE	991
NECO	ADMIRAL ST TERMINAL STATION CARRIER	731,128
NECO	SUB #26 WOONSOCKT TRANS	6,576,504
NECO	SUB #19 WOLF HILL TRANS	83,363
NECO	SUB #62 WEST KINGSTON TRANS	8,982,185
NECO	PUTNAM PIKE SUB TRANS	220,287
NECO	SUB #50 CENTERDALE	991
NECO	SUB #57 LAKEWOOD	991
NECO	SUB #18 JOHNSTON TRANS	23,992
NECO	SUB #20 PHILLIPSDALE TRANS	1,666,699
NECO	SUB #22 KENT COUNTY TRANS	77,781,021
NECO	SUB #77 EAST GEORGE STREET	991
NECO	SUB #21 WEST CRANSTON TRANS	163,328
NECO	SUB #23 FARNUM PIKE TRANS	110,027
NECO	SUB #59 PEACEDALE	991
NECO	SUB #27 PONTIAC TRANS	194,997
NECO	SUB #85 WOOD RIVER TRANS	1,854,498
NECO	MELROSE SERVICE STATION	266,806
NECO	SUB #13 CLARKSON STREET TRANS	224,575
NECO	SUB #35 HARTFORD AVE	16,145,311
NECO	SUB #76 POINT STREET TRANS	3,616,491
NECO	MANCHESTER STREET SWITCHYARD - JO W	3,165,527
NECO	SUB #87 KILVERT STREET (Trans)	3,145,261
NECO	SUB #88 TOWER HILL (TRANMISSION)	1,816,590
NECO	RIDGEWOOD 124 SWITCHYARD	261,010
NECO	SUB #68 KENYON	786,640
NECO	SUB #155 CHASE HILL HOPKINTON TRANS	173,126
NECO	SUB #84 DAVISVILLE TRANS	189,248
NECO	SUB #24 SOCKANOSSET TRANS	297,367
NECO	SUB #72 LINCOLN AVE TRANS	181,957
NECO	SUB #48 WAMPANOAG TRANS	2,162,870
NECO	SUB #46 OLD BAPTIST ROAD TRANS	210,656
NECO	SUB #33 TIVERTON #2 TRANS	537,349
NECO	SUB #51 BRISTOL #1-GOODING AVE TRAN	91,555
NECO	SUB #5 WARREN TRANS	413,184
NECO	BLOCK ISLAND SUBSTATION	14,246,590

NECO	SPARE EQUIPMENT FED RI	27,259
NECO	LAKE ROAD POWER INTERCONNECTION	139,817
NECO	SUB #200 HIGHLAND PARK TRANSMISSION	3,340,119
NECO	SUB #128 SHUN PIKE TRANS	1,261,703
NECO	WASHINGTON SUB 13.8KV TRANS	866,785
NECO	STAPLES SUB TRANS 13.8KV -- PTF	1,408,901
NECO	SHERMAN RD 345 KV -- PTF	27,427,557
NECO	OSP INTERCONNECT 1990 ADDITIONS 34	7,070,809
NECO	MANCHESTER ST STATION UNIT COMMON	132,267
NECO	SUB #105 FARNUM TRANS	32,437
NECO	WEST FARNUM SUB TRANS -- PTF	73,903,217
NECO	WEST FARNUM 115KV GAS CIRCUIT BREAK	368,512
NECO	345/115 KV AUTOTRANSFORMER	3,086,374
NECO	NASONVILLE SUB TRANS 115KV	30,398
NECO	PAWTUCKET #1, PAWTUCKET TRAN 13.8KV	5,397,846
NECO	DEXTER SUB TRANS 115KV -- PTF	2,685,099
NECO	JEPSON SUB TRANS -- PTF	1,474,347
NECO	CANONICUS SUB -- PTF	193,704
NECO	VALLEY SUB 13.8KV TRANS	2,863,065
NECO	RIVERSIDE SUB TRAN 13.8KV -- PTF	7,812,917
NECO	165T1 34.5 SUBMARINE CABLE	78,876,067
NECO	165T1 34.5 CRSCNT BCH-BLOCK ISL SUB	4,062,809
NECO	160T1 34.5 BLCK ISL SUB-CRSCNT BCH	2,806
NECO	T172S TAP TO NEW LONDON AVE #150	578,458
NECO	H17 TAP LINE TO SUB #105 FARNUM 115	19,414
NECO	3302 34.5KV LAFYETE-WICKFRD & WAKEF	19,249,549
NECO	3304 34.5KV DRUMROCK SUB. WRK - WES	283,481
NECO	3306 34.5KV -W.KINGSTON-KENYON-WOOD	252,407
NECO	33046 34.5KV WESTLY SUB WES-STRCTRE	76,331
NECO	3312 34.5KV KENT CNTY SUB-DIV ST-WI	176,529
NECO	33204 34.5KV UG FR DQ SUB PRV-WELLI	85,378
NECO	E183 & F184 115KV M/RI LINE WAR-WAR	1,824,279
NECO	Q143/R144 MA/RI LN TO FRANKLN SQ	9,934,957
NECO	S171/T172 LINE WOONSOCKET-DRUMROCK	1,135,785
NECO	V148 115KV WOONS. SUB NSM LINCOLN J	4,817,543
NECO	F184 115KV WARREN SUB WAR-BRISTOL #	2,276,816
NECO	FRANKLIN SQ SUB TRANS-SOUTH ST 115K	263,812
NECO	Q143 MA/RI ST LINE TO FRANKLN SQ	19,393,630
NECO	R144 MA/RI ST LINE TO FRANKLN SQ	13,497,300
NECO	S171 115KV WOONSOCKET SUB. NSM DRUM	59,289,789
NECO	T172 115KV WOONSOCKET SUB. NSM DRUM	77,034,571
NECO	S171N 115KV TAP - WOLF HILL #19 SUB	244,879
NECO	3308 34.5KV W.KINGS. SUB-KINGS. & W	5,143,002
NECO	J188 115KV SOCKANOSSET-DRUMROCK SU	2,194,098
NECO	CLP 57 34.5KV WESTERLY SUB-CT/R.I.L	969
NECO	G185 115KV DRUMROCK SUB-WEST KINGS.	27,228,367

NECO	V148/L1 LINCOLN JCT.-M/R.I. LINE	180,314
NECO	115KV TAP OFF X-3 LINE PAWT.-PHILLI	349,613
NECO	E183 115KV M/R.I. LINE - FRAN. SQ.S	1,905,823
NECO	1870 115KV W.KINGS. SUB - WESTERLY	9,420,139
NECO	3310 34.5KV KENT CTY SUB-3304 U.S N	651,075
NECO	3305 34.5KV W.KINGSTON-KENYON-WOOD	438,444
NECO	3311 34.5KV KENT CTY-DIV.ST.-LAFAYE	330,922
NECO	S171N 115KV TAP T0 FARNUM PIKE #105	216,290
NECO	3307&3308 34.5KV TAP - PEACEDALE SU	252,263
NECO	E183 115KV TAP - PHILLIPSDALE SUB.	1,625,850
NECO	S171N 115KV TAP TO WEST FARNUM #17	1,154,304
NECO	K189 115KV LINE DRUMROCK-KENT COUNT	1,574,098
NECO	315 LINE M/RI LINE STR.341-RIVERSID	2,980,850
NECO	I187 115KV DRUMROCK SUB-SOCKANOSSET	1,735,261
NECO	332 LINE 345KV KENT CNTY - W. FARNU	16,637,975
NECO	3307 LINE 34.5KV W.KINGS-WAKEFIELD	355,878
NECO	M13/L14 MA LN - SUB#33 TVRTN 115KV	3,446,794
NECO	I187/J188 TAP WARWICK-PONTIAC 115KV	809,878
NECO	J188 115KV DRUMROCK - SOCKANOSSET S	1,190,330
NECO	115KV TAP FROM 1870 LINE - WOOD RIV	75,183
NECO	33A LINE QUONSET POINT 34.5KV	55,643
NECO	33C LINE QUONSET POINT 34.5KV	11,700
NECO	L190 115KV KENT CTY-W KNGSTN SUB	11,312,211
NECO	G185 SOUTH TAP OLD BAPTIST RD 115KV	516,367
NECO	G185 TAP BAPTIST TO DAVISVLL 115K	1,726,713
NECO	L190 TAP OLD BAPTIST TO DAVISVL 115	1,513,216
NECO	E183 TAP TO WAMPANOAG SUB 115KV	214,930
NECO	115KV UG BLKBURN #80 - WARWICK #60	66,105
NECO	M13 TAP 115KV INTERCONNECT TO EMI-T	252,596
NECO	L14 TAP 115KV INTERCONNECT TO EMI-T	243,667
NECO	E105 F106 MANCHESTER ST SUB-HARTFOR	25,274,747
NECO	M13/L14 MA/RI LINE TO DEXTER SUB 11	28,164,143
NECO	61 LINE - DEXTER TO JEPSON - 69KV	623,751
NECO	62 LINE - DEXTER TO JEPSON - 69KV	669,552
NECO	T2 TAP TO POINT STREET SUB - 115KV	1,934,756
NECO	S-171S 115KV TAP - FPLE-RISEP PLANT	540,582
NECO	T172S 115KV TAP TO FPLE-RISEP PLAN	542,546
NECO	S-171S TAP TO JOHNSTON #18 SUB	1,511,805
NECO	T172S 115KV TAP TO JOHNSTON #18 SU	1,044,770
NECO	315 LINE WEST FARNUM TO RIVERSIDE J	3,030,795
NECO	328 LINE WEST FARNUM TO SHERMAN RD	27,920,140
NECO	347 LINE SHERMAN RD TO RI/CT STATE	8,602,850
NECO	B23 LINE WEST FARNUM TO NASONVILLE	2,543,645
NECO	H17 LINE WEST FARNUM TO FRANUM TO R	5,137,599
NECO	P11/X3 PAWTUCKET SUB TO MA/RI LN	2,097,649
NECO	P11/R9 VALLEY SUB TO MA/RI LINE	244,750

NECO	R9/Q10 MA/RI LN TO STAPLES SUB	2,860,996
NECO	R9/J16 STAPLES TO RIVERSIDE 115KV-	6,762,184
NECO	T7 SOMERSET TO PAWTUCKET (RI PORTIO	3,859,889
NECO	T3 115KV TAP LINE TO POINT ST SUB	302,318
NECO	I187 115KV TAP LINE TO KILVERT ST	143,468
NECO	366 LINE MA/RI ST LN-W FARNUM 345KV	31,408,291
NECO	341 LN W FARNUM-RI/CT ST LN 345KV	56,938,112
NECO	359 LN W FARNUM-KENT COUNTY 345KV	88,520,617
NECO	T172N 115KV TAP TO WEST FARNUM #17	804,736
NECO	T172N 115KV TAP T0 FARNUM PIKE #105	29,252
NECO	S171S 115KV TAP - WEST CRANSTON #2	222,432
NECO	T172S 115KV TAP - WEST CRANSTON #2	312,644
NECO	T172N 115KV TAP TO PUTNAM PIKE #38	51,797
NECO	T172N 115KV TAP TO WOLF #19	22,326
NECO	S171N 115KV TAP - PUTNAM PIKE #38	268,026
NECO	333LINE OSP- SHERMAN RD 345KV LINE	1,259,608
NECO	3361 LINE INTO SHERMAN RD. 345KV	1,315,276

PUC 4-12

Request:

Referring to PUC 3-5,

a. Please explain why "[t]he application of NEP's carrying charge to a NECO owned asset, even hypothetically, does not provide an accurate comparison for review of the existing calculation of the BITS surcharge."

b. Referring to the statement: "there is no formula for calculating a transmission carrying charge specific to NECO in Schedule 21-NEP or in NEP's Tariff No.1," please explain why the Company believes it was important to make this observation in the response, given the question that was asked in PUC 3-5.

c. Please provide schedule(s) showing how the hypothetical carrying charge used in Attachment 3-5-1 was determined and calculated.

Response:

a. The application of NEP's carrying charge to a NECO-owned asset does not provide an accurate matching of assets and costs because the cost of service for a transmission asset to NEP is unlikely to match the cost of service for a transmission asset to NECO given differences in capital structure and borrowing costs, as well as other considerations such as overhead rates. The BITS assets are owned by NECO and the cost of service associated with those assets is reflected on the books and records of NECO. The response was noting that it is more accurate to utilize the cost of service of NECO for the comparison.

b. The Company believes it was important to make the observation quoted above because the absence of a NECO transmission carrying charge formula applicable to the BITS surcharge in Schedule 21-NEP and NEP Tariff No.1 further supported the Company's determination that the BITS assets were intended to be treated as distribution assets recovered through transmission rates.

c. Please see Attachment PUC 4-12 for the calculation on how the hypothetical NECO transmission carrying charge was calculated.

Prepared by or under the supervision: Michael Artuso

The Narragansett Electric Company
Integrated Facilities Agreement
Summary of BITS Surcharge
For Costs in Calendar Year 2019

Line	Month	Gross Plant	Carrying Charge (a)	BITS Surcharge (b)
1	January	113,500,009	13.91%	1,315,552
2	February	113,523,131	13.91%	1,315,820
3	March	113,855,096	13.91%	1,319,668
4	April	113,912,570	13.91%	1,320,334
5	May	113,928,017	13.91%	1,320,513
6	June	113,947,385	13.91%	1,320,738
7	July	113,971,509	13.91%	1,321,017
8	August	113,981,288	13.91%	1,321,131
9	September	113,995,356	13.91%	1,321,294
10	October	114,103,482	13.91%	1,322,547
11	November	114,122,449	13.91%	1,322,767
12	December	114,160,806	13.91%	1,323,211
13	**Total Calendar Year 2019**			**15,844,593**

Notes

(a) The Narragansett Electric Company's 2019 carrying charge calculated using transmission revenue requirements as per annual IFA filing

(b) As per PUC 3-5, the calendar year 2019 BITS Surcharge is recalculated using a hypothetical Narragansett Electric Company transmission carrying charge as opposed to the FERC approved Primary Distribution System Carrying Charge set forth in Schedule III-B to NEP's FERC Electric Tariff No. 1

Narragansett Electric Company
Integrated Facilities Agreement
Annual True-up
CY 2019

Line No.		(A) 1st Quarter FF1 CY 2019	(B) 2nd Quarter FF1 CY 2019	(C) 3rd Quarter FF1 CY 2019	(D) 4th Quarter FF1 CY 2019	(E) [Col (A) + (B) + (C) +(D)]/4 Annual FERC Form 1 Revenue Requirement	(F) [Page 2, Col. D] CY 2019 Actual Monthly Billing	(G) Reconciliation (Over)/Under	Tariff Reference
	Transmission Investment Base:								
1	Transmission Plant	$894,777,746	$908,050,705	$921,978,153	$927,077,457	$912,971,015	$914,379,347	($1,408,332)	Section III-B (B) (A) (1) (a)
2	Transmission General Plant	$6,483,596	$6,526,534	$6,559,952	$6,637,875	$6,551,989	$5,102,869	$1,449,121	
3	Transmission Plant Held for Future Use	$12,532,019	$12,532,019	$12,532,019	$12,532,019	$12,532,019	$12,531,980	$39	
4	NEEWS-Related CWIP	$0	$0	$0	$0	$0	$0	$0	
5	Sub-Total Transmission Plant	$913,793,360	$927,109,257	$941,070,124	$946,247,351	$932,055,023	$932,014,196	$40,827	
6									
7	Transmission Depreciation Reserve	($125,214,347)	($128,212,841)	($132,590,277)	($136,322,738)	($130,585,051)	($130,988,401)	$403,350	
8	Transmission Accumulated Deferred Taxes	($140,017,869)	($140,691,316)	($139,915,390)	($138,533,254)	($139,789,457)	($146,256,823)	$6,467,366	
9	Transmission Loss on Reacquired Debt	$863,052	$844,722	$829,141	$810,565	$836,870	$837,403	($533)	
10	Transmission Prepayments	$1,084,834	$1,685,395	$1,116,190	$509,697	$1,099,029	$1,124,948	($25,919)	Section III-B (B) (L) (1)
11	Transmission Materials & Supplies	$2,949,928	$2,994,625	$2,933,793	$2,865,867	$2,936,053	$2,946,906	($10,853)	
12	Transmission Cash Working Capital	$3,116,316	$3,116,316	$3,116,316	$3,116,316	$3,116,316	$2,912,027	$204,289	
13	**Total Transmission Investment Base**	**$656,575,276**	**$666,846,158**	**$676,559,897**	**$678,693,805**	**$669,668,784**	**$662,590,257**	**$7,078,527**	
14									
15	Average Return and Associated Income Taxes (%)	9.632%	9.604%	9.629%	9.645%	9.656%			
16									
17	**Transmission Revenue Requirement:**					CY2019 Actual			
18	Return and Associated Income Taxes	$63,483,080	$64,248,210	$65,314,994	$65,617,475	$64,665,940	$64,272,167	$393,772	
19	Transmission Depreciation & Amortization Expense					$20,590,467	$20,555,897	$34,570	Section III-B (B) (K)
20	Transmission Amortization of Loss on Reacquired Debt					$62,693	$62,909	($216)	
21	Transmission Amortization of Investment Tax Credits					($530)	($533)	$3	
22	Transmission Municipal Tax Expense					$16,162,255	$16,162,255	$0	
23	Payroll Taxes					$573,072	$582,961	($9,889)	
24	Transmission Operation and Maintenance Expense					$9,805,203	$21,887,673	($12,082,470)	Section III-B (B) (I)
25	Transmission Administrative and General Expense					$15,125,328	$1,408,545	$13,716,784	
26	Direct Assignment Facilities Credit - Attachment 6h					$1,606,304	$1,606,304	$0	
27	Integrated Facilities Credit - BITS Surcharge					$18,948,602	$19,207,600	($258,998)	
28	Billing Adjustment					$0	($1,345,858)	$1,345,858	
29	Billing Adjustment Prior Year True-up					($2,157,412)	($2,157,412)	$0	
30	**Total Transmission Revenue Requirement**					**$145,381,922**	**$142,242,508**	**$3,139,415**	
31									
32	**Interest- Attachment 3**							**$76,116**	Section III-B (B) (L) (1)
33									Section III-B (B) (L) (3)
34	**Total CY19 True Up with Interest - Attachment 3**							**$3,215,531**	

Section III-B (B) (A) (1) (a): Total Transmission Investment Base shall be defined as a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Land Held for Future Use, plus (d) Transmission Related Construction Work In Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital.

Section III-B (B) (L) (1): The Annual True-up will reconcile any differences between a recalculation of the costs for the Service Year based on actual data reported in Customer's Quarterly FERC Form l's as compared to the monthly actual costs invoiced. The recalculation of the costs for the Service Year will be done using the average quarterly balances for all balance sheet items used in the formula (i.e. Plant, Depreciation Reserve, Deferred Taxes). Expenses will be those Service Year expenses reported in Customer's 4th Quarter FERC Form 1.

Section III-B (B) (K): Billing Adjustments shall be plus or minus any billing adjustments from the prior transmission billing periods. Billing adjustments shall include, but not be limited to, adjustments due to corrections to any value included in this formula, including, but not limited to, corrections to the FERC Form 1.

Section III-B (B) (I): Direct Assignment Facilities Credit shall equal the monthly revenue received by NEP for service provided to any of NEP's wholesale customers that utilize directly assigned transmission, distribution and/or generator interconnection facilities owned by Customer. Such NEP revenue is defined as any revenue NEP receives for Direct Assignment Facilities under the ISO-NE OATT or any interconnection-related charges for Customer-owned and/or maintained facilities under FERC jurisdictional agreements where NEP is the party to the agreement.

Section III-B (B) (L) (1), Section III-B (B) (L) (3): The Annual True-up Adjustment will be adjusted for interest, whether positive or negative, accrued monthly from December 31 of the Service Year to the end of the calendar month in which the Annual True-up Adjustment will be applied to a monthly billing. Interest shall accrue pursuant to the rate specified in the Commission's regulations 18 C.F.R §35.19a.

Line	**Hypothetical NECO Transmission Carrying Charge**	
35	Revenue Requirement (Sum Lines 18 thru 25)	$126,984,428
36	Transmission Plant (Line 1)	$912,971,015
37	Carrying Charge (Line 35 / Line 36)	13.91%

PUC 4-13

Request:

Refer to the following response to PUC 3-26, which states: "[I]t is expected that the revenue recovered through the application of the carrying charge is fairly in line with the actual O&M and A&G costs incurred over the life of the asset."

(a) Please define the phrase "fairly in line with."
(b) Please provide quantitative evidentiary support for the Company's expectation that the revenue recovered from the carrying charge, as it relates to the imputed A&G costs, will be fairly in line with actual A&G cost incurrence over the life of the asset, including a reasonable forecast of annual A&G cost incurrence and expected annual revenue based on best information available to the Company today.
(c) Please also include an explanation supporting the forecasted quantitative analysis.

Response:

(a) The phrase "fairly in line with" is meant to convey that the revenue recovered is a close proxy for actual costs, but recognizes that it does not track actual dollar-for-dollar costs, because it is difficult to forecast actual O&M and A&G expenses with certainty. Under the circumstances, the Company believes that application of the carrying charge is the best approach.

(b) Although the Company believes that revenue recovered from the carrying charge is fairly in line with actual costs, the Company cannot provide quantitative support that, over the life of an asset, imputed A&G costs will be in line with actual A&G costs because of how A&G costs are incurred. Specifically, A&G costs are typically allocated from the Service Company to the Operating Company level and are not typically identified as supporting a specific project or asset. In the carrying charge approach, the imputed A&G is calculated based on the average amount of A&G for every dollar of plant. The challenge of tracking A&G costs described above illustrates the appropriateness of the application of the carrying charge approach. The Company is unable to forecast annual A&G cost incurrence associated with the asset.

(c) Please see the response to subpart (b) above, explaining the rationale for using imputed A&G costs.

Prepared by or under the supervision: Michael Artuso

PUC 4-14
DUPLICATE OF PUC 4-13

Request:

Refer to PUC 3-26, which states: "[I]t is expected that the revenue recovered through the application of the carrying charge is fairly in line with the actual O&M and A&G costs incurred over the life of the asset."

(a) Please define he phrase "fairly in line with."
(b) Please provide quantitative evidentiary support for the Company's expectation that the revenue recovered from the carrying charge, as it relates to the imputed O&M costs, will be fairly in line with actual O&M cost incurrence over the life of the asset, including a reasonable forecast of annual O&M cost incurrence and expected annual revenue based on best information available to the Company today.
(c) Please also include an explanation supporting the forecasted quantitative analysis.

Response:

This request is a duplicate of PUC 4-13. Please see the Company's response to PUC 4-13.

PUC 4-15

Request:

Please provide a forecast of the net present value of the total revenue that will be recovered through the BITS surcharge over the next 20 years, based on the best information available to the Company today.

Response:

The forecasted net present value of the total revenue that will be recovered through the BITS surcharge over the next 20 years totals $233.7 million. Please refer to the calculation provided at Attachment PUC 4-15 which is based on the Company's best available information as of September & October 2020.

The Narragansett Electric Company
Integrated Facilities Agreement
BITS Surcharge Estimated Revenue

Line	(A) G/L Month	(B) Service Month	(C) Gross Plant	(D) Carrying Charge	(E) Revenue
2	Feb-20	Jan-2020	$114,160,806	16.63%	$1,582,433
3	Mar-20	Feb-2020	$114,168,145	16.63%	$1,582,535
4	Apr-20	Mar-2020	$114,198,676	16.63%	$1,582,958
5	May-20	Apr-2020	$114,426,011	16.63%	$1,586,109
6	Jun-20	May-2020	$114,456,270	16.63%	$1,586,529
7	Jul-20	Jun-2020	$114,464,924	16.63%	$1,586,649
8	Aug-20	Jul-2020	$114,466,787	15.40%	$1,469,276
9	Sep-20	Aug-2020	$114,476,590	15.40%	$1,469,402
10	Oct-20	Sep-2020	$114,527,764	15.40%	$1,470,059
11	Nov-20	Oct-2020	$114,527,764	15.40%	$1,470,059
12	Dec-20	Nov-2020	$114,527,764	15.40%	$1,470,059
13	Jan-21	Dec-2020	$114,527,764	15.40%	$1,470,059
14	CY	2020			$18,326,126
15	Feb-21	Jan-2021	$114,527,764	15.40%	$1,470,059
16	Mar-21	Feb-2021	$114,527,764	15.40%	$1,470,059
17	Apr-21	Mar-2021	$114,527,764	15.40%	$1,470,059
18	May-21	Apr-2021	$114,527,764	15.40%	$1,470,059
19	Jun-21	May-2021	$140,592,764	15.40%	$1,804,625
20	Jul-21	Jun-2021	$144,189,764	15.40%	$1,850,795
21	Aug-21	Jul-2021	$145,036,764	15.40%	$1,861,667
22	Sep-21	Aug-2021	$145,046,764	15.40%	$1,861,796
23	Oct-21	Sep-2021	$145,056,764	15.40%	$1,861,924
24	Nov-21	Oct-2021	$145,066,764	15.40%	$1,862,052
25	Dec-21	Nov-2021	$145,066,764	15.40%	$1,862,052
26	Jan-22	Dec-2021	$145,066,764	15.40%	$1,862,052
27	CY	2021			$20,707,200
28	CY	2022	$145,066,764	15.40%	$22,344,629
29	CY	2023	$145,066,764	15.40%	$22,344,629
30	CY	2024	$145,066,764	15.40%	$22,344,629
31	CY	2025	$145,066,764	15.40%	$22,344,629
32	CY	2026	$145,066,764	15.40%	$22,344,629
33	CY	2027	$145,066,764	15.40%	$22,344,629
34	CY	2028	$145,066,764	15.40%	$22,344,629
35	CY	2029	$145,066,764	15.40%	$22,344,629
36	CY	2030	$145,066,764	15.40%	$22,344,629
37	CY	2031	$145,066,764	15.40%	$22,344,629
38	CY	2032	$145,066,764	15.40%	$22,344,629
39	CY	2033	$145,066,764	15.40%	$22,344,629
40	CY	2034	$145,066,764	15.40%	$22,344,629
41	CY	2035	$145,066,764	15.40%	$22,344,629
42	CY	2036	$145,066,764	15.40%	$22,344,629
43	CY	2037	$145,066,764	15.40%	$22,344,629
44	CY	2038	$145,066,764	15.40%	$22,344,629
45	CY	2039	$145,066,764	15.40%	$22,344,629
46	**Total 20 - year revenue total**				**$441,236,643**
47					
48	**20-year NPV**				**$223,725,512**

Notes

Column (C) - represents actual BITS plant in service through October 2020; remainder is estimated based on capital forecast.

Column (D) - 16.63% actual Distribution Carrying Charge based on CY 2018 FERC Form 1 data; 15.40% actual Distribution Carrying Charge based on CY 2019 FERC Form 1 data

Column (E) - Lines 1 through 26 : Column C times Column D/12 ; Lines 28 through 45: Column C times Column D

Line 48 - assumes discount rate of 7.66% representing the after-tax weighted average cost of capital used in the calculation of the CY 2019 Distribution Carrying Charge

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PUC 4-16

Request:

Referring to Attachment PUC 1-1, page 24 (Division Informal 1-2), please provide a more complete explanation of how the delay in the IFA billing reconciliation caused a significant change in A&G expenses from 2018 to 2019.

Response:

New England Power Company (NEP) files the IFA Annual True-Up Informational Filing (Annual True-up) under its FERC Electric Tariff Number 1 Integrated Facilities Provisions. The filing deadline is 90 days after The Narragansett Electric Company's FERC Form No.1 (FF1) is available. The FF1 reporting deadline is generally in mid-April; the Annual True-up filing is normally filed around the end of June. In a calendar year, there are 12 monthly IFA billings and a prior year IFA true-up billing. The monthly billing is based on monthly GAAP financial statements, while the FERC formula rates are based on FF1 financials in accordance with the tariff. Due to differences between GAAP and FERC financial statements, the annual IFA true-up includes a significant reclassification between O&M and A&G expenses. Due to the timing of the IFA annual reconciliation, the IFA adjustments made to the electric earnings reports are comprised of the 12 monthly billings issued in the current calendar year and the prior year true-up which is billed in the June/July timeframe of the current calendar year. From January 2020 and forward, the monthly IFA billing has been based on interim FERC financial statements as an improvement made to FERC reporting. The true-up adjustments are expected to be much smaller in the future.

Please refer to Attachment PUC 4-16, which is a supplement to Attachment DIV Informal 1-2. In the revised CY 2018 Electric Earnings Report, the 2017 IFA annual true-up was included in the IFA O&M expense adjustment on a net basis which reduced IFA O&M expense by $1.5 million and, therefore, increased distribution O&M expense by $1.5 million.

In the revised CY 2019 Electric Earnings Report, the 2018 IFA annual true-up was included in the IFA adjustments on an item-by-item basis. The reclassification between A&G and O&M in the 2018 annual true-up is picked up by IFA adjustments. This resulted in $11 million of IFA O&M expense and $11 million in IFA A&G expense. The distribution A&G expense was $115 million, as shown on Line 1, Column (f).

As mentioned above, the total net CY 2017 annual IFA true-up of negative $1.5 million was included in IFA O&M expense. By removing the net negative $1.5 million IFA true-up from the IFA O&M expense and itemizing the 2017 true-up into its individual cost of service line items,

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IFA O&M expense decreased by $10 million (add back $1.5 million for the net true-up less $11.7 million for the annual true-up O&M expense) and the IFA A&G expense increased by $9 million, as shown in Column (g), Line 8 and Line 7, respectively. The distribution A&G expense became $116 million, as shown on Line 7, Column (h). Overall, if the annual true-up is reflected in IFA adjustments on an item-by-item basis, in both calendar years, 2018 and 2019, there is no significant change in distribution A&G expenses from 2018 to 2019. As explained in Lines 15 through 37, major variances are in distribution O&M expense.

THE NARRAGANSETT ELECTRIC COMPANY
Operation and Maintenance Analysis
Twelve Months Calendar 2019 vs Calendar 2018
($ milions)

		Per FERC Form 1	Less: Integrated Facilities Agreement (IFA) and Block Island Transmission System (BITS) Amounts Billed to New England Power Co.	Other Adjustments	Electric Distribution Amount	Add: Block Island Transmission System (BITS) O&M Amounts	Revised Electric Distribution Amount	Remove net CY 2017 IFA True-up from O&M and itemize	Revised Electric Distribution Amount
		(a)	(b)	(c)	(d) = (a)-(b)+(c)	(e)	(f) = (d)+(e)	(g)	(h) = (f)-(g)
1	**Changes in "Genl & Admin. O&M" and "All Other Operation & Maintenance ("O&M") expense"**								
2	**4770-CY2019-Electric Earnings (PUC 5-6-20)**								
3	Genl & Admin. O&M	$126	$17	$0	$109	$6	$115		$115
4	All Other Operation & Maintenance ("O&M") expense	$193	$14	$1	$180	$3	$183		$183
5	**Total of Line 9 and Line 10**	$319	$31	$1	$288	$9	$298	$0	$298
6	**4323/4770-CY2018-Electric Earnings (PUC 5-1-19)**								
7	Genl & Admin. O&M	$124	$2	$3	$125		$125	$9	$116
8	All Other Operation & Maintenance ("O&M") expense	$168	$31	$2	$139	$9	$148	($10)	$158
9	**Total of Line 9 and Line 10**	$293	$33	$5	$264	$9	$273	($1)	$274
10	**Variance**								
11	Genl & Admin. O&M	$2	$15	($3)	($16)	$6	($10)	($9)	($1)
12	All Other Operation & Maintenance ("O&M") expense	$24	($17)	($1)	$40	($6)	$35	$10	$24
13	**Total Variance CY2019 vs CY2018**	$26	($2)	($4)	**$24**	$0	**$24**	$1	**$23**
14									
15	**Explanation of Variances**								
16	**Increase in Genl & Admin. O&M**								
17	Increase in A&G Consultant expense								$1
18	Decrease in Injuries and damages								($3)
19	Increase in Pension/PBOP expense								$3
20	Decrease in Regulatory Commission expense								($1)
21	**Total Increase in Genl & Admin. O&M**								($1)
22									
23	**Increase in All Other Operation & Maintenance ("O&M") expense**								
24	Increase in Energy Efficiency related expenses								$9
25	Increase in customer outreach, mostly EV Incentive								$1
26	Decrease in Electric Maintenance & Construction								($2)
27	Increase in US IT, cyber security for GBE project								$2
28	Increase in Vegetation Management								$3
29	Increase in US Engineering due to Grid Mod program								$2
30	Amortization of Excess ADIT from Service Company								$1
31	Increase in Capital related Operation and Maintanance Expense								$2
32	Net Increase in Non-deferrable Storms and Amortization of Storm Fund Deferral								$3
33	Decrease in IFA adjustment								$1
34	Other								$1
35	**Total Increase in All Other Operation & Maintenance ("O&M") expense**								$24
36									
37	**Total Increase**								**$23**

Column Notes:

(g) New England Power Company CY 2017 Annual True-Up Informational Filing

Line Notes:

3	4770-CY2019-Electric Earnings (PUC 5-6-20) Report Revised, Page 3, Line 9	11	Line 3 - Line 7
4	4770-CY2019-Electric Earnings (PUC 5-6-20) Report Revised, Page 3, Line 10	12	Line 4 - Line 8
5	Line 3 + Line 4	13	Line 5 - Line 9
7	CY2018-Electric Earnings (PUC 5-1-19) Report Revised, Page 3, Line 9	21	Sum of Line 17 through Line 20
8	CY2018-Electric Earnings (PUC 5-1-19) Report Revised, Page 3, Line 10	35	Sum of Line 24 through Line 34
9	Line 7 + Line 8	37	Line 21 + Line 35

PUC 4-17

Request:

For each of the following three calendar years, 2017, 2018, and 2019, please provide a schedule showing

(i) the total amount of actual A&G expenses allocated to Narragansett Electric,
(ii) the total amount of actual A&G expenses allocated to the Narragansett Electric distribution business,
(iii) the total amount of actual A&G expenses allocated to Narragansett Electric's transmission business that the Company considers to be FERC-jurisdictional and subject to the IFA (excluding the BITS), and
(iv) the total amount of actual A&G expenses allocated to the BITS.

Response:

Please see the schedule below for actual A&G expenses recorded to the Electric business, the Electric distribution business, the Transmission business subject to the IFA (excluding BITS), and the BITS assets.

Administrative & General expenses are recorded through allocations and direct charges. Depending on the nature of the expense, some A&G expenses are recorded at project level, while some A&G expenses of a back-office nature, such as accounting and finance, legal or regulatory support, cannot be directly attributed to individual projects or assets. As stated in the response to PUC 4-13, the Company cannot quantify the total actual IFA A&G costs. Therefore, the A&G expense charged to Narragansett Electric's transmission business as shown in the table below represents the annual imputed A&G expense based on the IFA formula rate. The actual A&G expense charged to BITS shown below reflects direct project charges only. Total A&G expense charged to the Naragansett Electric is per the respective calendar year's FERC Form 1. The A&G expense charged to Narragansett Electric Distribution is the result of total Narragansett Electric A&G expense (i) less Transmission (iii) and BITS (iv).

Item	A&G expense charged to:	2017	2018	2019
(i)	Narragansett Electric	$118,555,926	$124,218,360	$126,300,232
(ii)	Narragansett Electric Distribution	$107,318,936	$112,379,935	$111,174,904
(iii)	Narragansett Electric Transmission	$11,229,360	$11,838,425	$15,125,328
(iv)	BITS - Direct Charges	$7,630	-	-

Prepared by or under the supervision: Melissa A. Little

PUC 4-18

Request:

Referring to Attachment 3-19, it shows total net IFA A&G to be $17,955,634 in 2017, dropping to $1,915,222 in 2018, and then for 2019, PUC 1-2 shows the total net IFA rising to $11,331,740. Please explain these wide variations from year to year.

Response:

As stated in the response to PUC 4-16, IFA adjustments in a calendar year include 12 monthly billings and a prior year true-up. In the revised CY 2017 and CY 2019 Earnings Reports, the prior year IFA true-up adjustments were included in the total IFA adjustments on an item by item basis. The CY 2017 IFA A&G expense of $17,955,634 includes the CY 2016 IFA True-up reclassification between A&G and O&M of $16 million. The 2019 IFA A&G expense of $11,331,740 includes CY 2018 IFA reclassification between A&G and O&M of $10 million.

In the CY 2018 earnings report, the $1,915,222 of IFA A&G expense is the total A&G expense reflected in the 12 monthly billings. The total net CY 2017 IFA true-up was reflected in the IFA O&M expense line. If the presentation of the CY 2017 true-up were to be changed such that it was included in the IFA adjustments on an itemized basis, the CY 2018 IFA A&G expense would increase to $11 million through a $9 million reclassification between A&G and O&M. Therefore, the actual variance in IFA A&G expense from year to year is not as significant. The variations are caused by the differing presentation of the IFA annual true-ups in the earnings reports.

PUC 4-19

Request:

Referring to page 3 of 7 of Schedule 1 of the Revised Earnings estimate filed on June 24, in column (b), line 9, there is a total of A&G expenses of $17,404,000. The Company removed $6,073,000 from this total which it has previously represented were imputed A&G expenses related to BITS. In column (e), this results in a net total of $11,331,000 of A&G expense that the Company removed from the distribution cost of service. PUC 3-17 contains the statement: "The A&G expense billed and recovered from NEP through the IFA would be considered imputed." Why are the IFA imputed A&G costs not treated in the Earnings Report in the same way as the imputed A&G costs attributable to the BITS?

Response:

As stated in the response to PUC 4-13, A&G costs by nature are not usually specifically identified as supporting a specific project or asset. By applying a salary & wage allocator to total Electric A&G expense, the IFA imputed A&G costs represent a reasonable estimate of the actual A&G costs incurred on Transmission assets.

As stated in the response to PUC 1-2, the BITS Distribution Carrying Charge is determined based on the annual revenue requirement of all the Company's distribution assets as a percentage of Distribution plant. Due to the uniqueness of BITS assets, the actual BITS A&G costs do not incur evenly, and, therefore, the imputed BITS A&G costs do not represent the actual BITS A&G costs in a particular year. As such, the Company believes it is more appropriate to exclude the actual A&G and O&M expenses incurred on BITS assets from the annual Earnings Report.

PUC 4-20

Request:

Referring to the response to PUC 3-24, part "a" states in part: "For Distribution ratemaking purposes subject to State jurisdiction, the assets and related revenues were removed from the revenue requirement and treated as stand-alone assets as opposed to reducing base distribution revenue requirements due to concerns about substantial increases in costs in later years and due to the fact that the costs are recovered through transmission rates." Please identify and explain the concerns about substantial increases in costs in later years.

Response:

As stated in the response to PUC 1-2, the BITS facilities include 20 miles of submarine cable, two substations, as well as the overhead and underground infrastructures connecting the cable with the substation. Due to the unique location of the submarine cable and the involvement of two substations, the repair costs, which may involve a repair crew with specialized skills and a vessel, can be substantial--up to the tens of millions of dollars-- as noted in the response to PUC 1-2. If distribution customers were to receive the benefit of the BITS revenue in the future through reduced distribution base rates, they would bear the risk of funding any significant BITS repair costs in the future.

Prepared by or under the supervision: Melissa Little

PUC 4-21

Request:

Refer to the response to PUC 3-18, which states in part: "[i]n making this decision as to whether to include the actual or imputed expenses for depreciation and municipal taxes, the Company noted the relatively small impact to ROE as stated above… and that reducing depreciation expense by the imputed BITS related amount of $3.4 million would benefit customers by reducing distribution-related depreciation expense and, thereby, increasing income available for earnings." It appears from this response that the Company made a conscious business decision to include the imputed expenses identified in the response in the distribution cost of service in the 2019 Earnings Report.

(a) When was the decision made and who were the primary decisionmakers?
(b) Why did the Company not disclose the inconsistency with the treatment of depreciation and municipal taxes compared to other imputed expenses when it filed the corrected earnings reports?

Response:

As stated in the response to PUC 3-18, at the time the original Earnings Reports and the revised Earnings Reports were submitted, it was believed that the imputed BITS-related depreciation and municipal taxes are approximately the same as the actual BITS-related depreciation and municipal taxes. When the Company was working on the responses to PUC Set 3, the difference between the imputed and actual BITS-related municipal taxes was discovered.

(a) The Company calculated the impact on the revised CY 2019 electric distribution earnings if the imputed BITS-related expenses were replaced by the actual BITS-related depreciation and actual municipal tax (based on the erroneous calculation). These revisions had no impact on earnings sharing with customers. The primary decision maker was Melissa Little, Director of Revenue Requirements for the Company's distribution businesses in Rhode Island. The Company plans to make all corrections in a compliance filing upon the conclusion of the Commission's review of earnings in this docket.

(b) As stated above, at the time the revised Earnings Reports were submitted, it was believed that the imputed BITS-related depreciation and municipal taxes were approximately the same as the actual BITS-related depreciation and municipal taxes and that using the higher imputed amounts was a conservative approach that increased distribution earnings to customer's benefit. Therefore, the Company did not identify any inconsistencies to disclose; however, as discussed above, once the Company determined that there was, in

PUC 4-21, page 2

fact, a larger difference between the imputed and actual municipal taxes than originally thought, during the preparation of the responses to PUC Set 3, the Company disclosed this difference in its response to PUC 3-18.

Prepared by or under the supervision: Melissa A. Little

PUC 4-22

Request:

Please provide schedules for each of the years 2017, 2018, and 2019, showing the difference between actual costs occurred from the BITS (as such costs were itemized in the attachments to PUC 3-19) to actual revenue received from the BITS surcharge to recover the costs of the respective itemized components.

Response:

Please see the schedule below for the difference between actual costs occurred from the BITS to actual revenue received from the BITS surcharge.

			2017	2018	2019
			(a)	(b)	(c)
1	Total BITS Surcharge		$23,501,173	$20,115,480	$19,207,600
2	Less: Return and Associated Income Taxes		$7,868,649	$5,942,259	$4,839,760
3	Amount included in BITS Surcharge to Recover Costs		$15,632,524	$14,173,221	$14,367,840
4					
5	Less: Actual Costs				
6	Depreciation & Amortization Expense		$2,320,929	$2,411,743	$2,588,717
7	Municipal Tax Expense		$146,010	$337,785	$340,922
8	Operation & Maintenance Expense		$1,480	$189,702	$114,936
9	Administrative & General Expense	*	$7,630	$0	$0
10	Total Actual Costs		$2,476,049	$2,939,230	$3,044,575
11					
12	Difference between Actual Cost and the Amount included in BITS Surcharge to Recover Costs		$13,156,475	$11,233,991	$11,323,265

* Depending on the nature of the expense, some A&G expenses are recorded at the project level, while those of a back-office nature cannot be directly attributed to individual projects or assets. The actual A&G expense charged to BITS as shown in the table above reflects direct project charges only.

Line Notes

1 & 2 Per the Company's responses to PUC 2-2 and PUC 3-19
6 & 7 Per the Company's response to PUC 3-20
8 Per the Company's response to PUC 3-22
9 Per the Company's response to PUC 3-21

Prepared by or under the supervision: Melissa A. Little

PUC 4-23

Request:

Referring to the response to PUC 3-18, which contains the statement: "the Company recently discovered during preparation of the responses to the third set of data requests that the calculation of BITS property tax previously provided appears to have included duplicative assets in the assessment base, thereby overstating the calculation of actual property tax expense related to BITS assets incurred in each period."

(a) Please explain why this error occurred.
(b) Is the "assessment base" an account used only for regulatory accounting purposes, or is it used in financial accounting as well?
(c) Were there any other impacts on the Company's financials or regulatory accounts from this error, other than the impact on the earnings report?
(d) Has the Company performed any check to determine if the assessment base and the distribution cost of service contains any other overstatement of municipal tax expenses from 2017 through 2019? If so, what was the result of the review?
(e) Was this duplicative asset issue present in any prior earnings reports for 2017 and 2018 or the cost of service used in the rate case?

Response:

(a) Each municipality provides the Company a combined, total assessed value of the equipment and assets located in its territory on a single tax bill. There is no asset by asset assessment detail provided on the actual tax bill. The Company, therefore, takes the total assessed value of the property in each municipality and the corresponding tax, and allocates those values across the plant located in those municipalities. The information used to do this allocation comes from the fixed asset register, which allocates the assessed values and municipal tax expense as billed across the Company's assets by municipality and major location. To calculate the actual BITS-related Municipal Taxes, the Company extracted data from the fixed asset register for assets located in the applicable municipalities (New Shoreham, Narragansett and South Kingstown), and then based on work order narrowed the extracted asset base down to those assets associated with BITS. Using that group of assets, and their allocated assessed value, the municipal tax was calculated. The error occurred when extracting the information from the fixed asset register; certain major locations were extracted multiple times resulting in duplicative assets included in the calculation of BITS-related municipal tax. In responding to the Commission's inquiries in Set 3, the calculation was then revised and compared with the total assessed values and corresponding tax for the associated municipalities to ensure reasonability.

(b) The above-mentioned BITS-related Municipal Tax calculation is used for the electric earnings reports only. The calculated Municipal Tax, or the assessment base, were not used for any financial accounting or regulatory accounting purposes.

(c) As mentioned in (b) above, there are no impacts on the Company's financials or regulatory accounts from this error.

(d) The above-mentioned BITS-related Municipal Tax calculation is used for the electric earnings reports only. There are no errors in the municipal tax expenses recorded in Company books.

(e) In the CY 2017 and CY 2018 earnings reports, the imputed BITS-related municipal tax expenses were used in the calculation; therefore, the duplicative asset issue was not present in those filings. The updated actual BITS-related municipal tax expenses will be used in the compliance filing.

In the Company's current distribution cost of service, the assessed value for the property associated with BITS assets was removed from the total assessment base upon which distribution-related municipal taxes were calculated. The resulting pro forma rate year distribution municipal taxes do not include municipal taxes related to BITS, and no duplicative asset issue was present in the Docket 4770 cost of service.

Prepared by or under the supervision: Melissa A. Little