STATE OF CONNECTICUT
PUBLIC UTILITIES REGULATORY AUTHORITY

November 4, 2022

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Connecticut Public Utilities Regulatory Authority
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Submit to: The Department of the Treasury and the Internal Revenue Service

RE: Request for Comments on Certain Energy Generation Incentives (IRS Notice 2022-49)

The Connecticut Public Utilities Regulatory Authority (PURA or the Authority) appreciates the opportunity to submit the following comments in response to the request for comments issued by The United States Department of the Treasury (Treasury Department) and the Internal Revenue Service (IRS).

Introduction

The tax incentives for clean and renewable energy as provided by the Internal Revenue Code (Code) have been instrumental in deploying these resources throughout the country since their original enactment in 1992. The amendments to the Code, made by the Inflation Reduction Act of 2022 (IRA), will provide greater certainty in renewable energy investment economics for years to come.

PURA's role and statutory responsibilities

The Authority is statutorily charged with ensuring that Connecticut's investor-owned utilities, including the state's electric distribution companies (EDCs), natural gas, water, and telecommunications companies, provide safe, clean, reliable, and affordable utility service and infrastructure. PURA's mission is essential to advancing the state's energy, economic, and environmental goals and is critical to maintaining public health and safety, as well as a robust economy.

PURA is a quasi-judicial agency that interprets and applies the statutes and regulations governing all aspects of Connecticut's utility sector. Among other things, PURA sets the rates charged by investor-owned utilities, advances the modernization of the electric distribution system, regulates the retail electric supplier market, implements federal requirements for natural gas pipeline safety, ensures adequate water system infrastructure investments, reviews mergers

and acquisitions, provides education and outreach for consumers, and regulates the expansion of telecommunications infrastructure.

PURA also oversees the tariff design structures and implementation of the State's multiple renewable energy deployment programs. Connecticut currently has programs that allow for annual capacity additions of 160MW for non-residential solar and clean energy facilities, and unlimited residential deployment. The tax incentives established and amended by the IRA will help improve the cost-effectiveness of solar and other renewable technology investment by Connecticut ratepayers, and further allocate benefits to underserved communities. The responses below reflect PURA's relevant lessons learned and best practices in designing and deploying the various clean energy programs statewide.

PURA Responses

.01 IRA Changes to the Renewable Electricity Production Credit (§ 45)

1. Section 45(e)(13) provides that electricity produced by a taxpayer will be treated as sold by such taxpayer to an unrelated person during the taxable year if (A) such electricity is used during such taxable year by the taxpayer or a person related to the taxpayer at a qualified clean hydrogen production facility (as defined in § 45V(c)(3)) to produce qualified clean hydrogen (as defined in § 45V(c)(2)), and (B) such use and production is verified (in such form or manner as the Secretary may prescribe) by an unrelated third party.
    a. What existing industry standards, if any, should the Treasury Department and the IRS consider in establishing guidelines for how an unrelated third party will verify that electricity produced by a facility for which the taxpayer is claiming the § 45 credit has been used to produce qualified clean hydrogen?

Connecticut requires that all electric providers serving customers in state must meet a certain percentage of the energy that they sell or generate with renewable energy. This requirement is called the Renewable Portfolio Standard (RPS), and the percentage increases each year by statute. See Conn. Gen. Stat. § 16-245a. Electric providers meet the annual RPS requirement by purchasing renewable energy certificates (RECs) from certified renewable energy resources. A REC represents the property rights to the environmental attributes of one megawatt-hour (MWh) of energy produced by a renewable energy generator.

An electric supplier may either purchase the RECs it needs through a regional market, or contract directly with a generator to receive either "bundled" energy -- meaning the supplier receives both the electricity and the RECs; or "unbundled" where they only purchase the RECs from a certified renewable generator. Either way, holding RECs allows a supplier to demonstrate that it has met its RPS requirement.

In the context of the § 45 credit that a taxpayer tries to claim for producing qualified clean hydrogen, the IRS and Treasury Department could require the taxpayer to demonstrate that they produced and sold or used at least the

equivalent amount of RECs as MWh used to produce the clean hydrogen. This could be accomplished through a completed contract agreement between the taxpayer generating the clean electricity, and the facility owner producing the clean hydrogen for the purpose of that production. However, if the Treasury Department and the IRS decide to use RECs to verify that the electricity used to produce hydrogen is "clean", they will also need to consider the following issues:

a. Not all states recognize RECs as a legal tool for tracking ownership of renewable generation on the grid, though multiple Federal agencies do, and U.S. case law also supports the legal basis of RECs as attributes and property rights.[1]
b. Should there be a limit on the distance between where the REC was generated, and where the clean hydrogen is being produced?
c. Should RECs be from a renewable energy source that is on-site with the hydrogen production?
d. Should RECs be a sufficient indicator that "clean" electricity was used in producing the hydrogen, or should the taxpayer be required to contract for "bundled" service, as described above?

b. The term "unrelated person" is used in section 45 (as well as other provisions discussed in this notice that were added or amended by the IRA). Is guidance needed to clarify the meaning of the term "unrelated person"? If so, how should that term be clarified?

The change to section 45(e)(13) makes this issue irrelevant because the primary question is around the verification of whether the electricity was used to generate hydrogen; not whether it was sold to an "unrelated person." For this reason, PURA does not expect that guidance is needed to clarify the term "unrelated person."

.02 The Energy Investment Credit (§ 48)

1. IRA Changes to the Energy Investment Credit (§ 48)
   a. The IRA expanded the definition of energy property to include electrochromic glass, energy storage technology, qualified biogas property, and microgrid controllers.
      i. What should the Treasury Department and the IRS consider in determining what types of technologies are included in the definitions of these new types of energy property?

Connecticut has existing definitions for these terms in statute and programs that the Treasury Department and the IRS may wish to consider.

[1] Center for Resource Solutions, *The Legal Basis for Renewable Energy Certificates,* June 17, 2015, *available at:* https://resource-solutions.org/wp-content/uploads/2015/07/The-Legal-Basis-for-RECs.pdf.

In Connecticut, the following definitions are used for energy storage technologies; qualified biogas property; and microgrid controllers:

1. "Energy Storage Technology" is defined by the Energy Storage Solutions Program as:[2]

    A. "Storage technologies shall be considered (and approved or not approved) for inclusion as eligible based on their ability to satisfy program requirements and objectives, including, but not limited to, the following:

        1. Commercially available technologies with appropriate technical certifications, reflecting adequate capabilities, testing and quality control with respect to industry standards;[3]

        2. Ability to meet the passive and active dispatch needs of the Program, including existing or intended software integration with dispatch platforms utilized in the program, and ability for technology to receive remote software upgrades;

        3. Safety considerations, and other characteristics including:

            1. 70% roundtrip efficiency or greater;
            2. 10-year warranty or equivalent; and,
            3. 10-year system life or equivalent.

        4. Customer service and technical support provided by battery manufacturer.

2. "Biogas" under Conn. Gen. Stat. § 16-1(20) and § 22a-174-31 of the Regulations of Connecticut State Agencies means primarily methane and CO2 resulting from the landfill methane gas, anaerobic digestion, or technology that produces biogas from biological resources.

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[2] Connecticut PURA, Decision, Docket No. 17-12-03RE03 – PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Electric Storage, July 28, 2021, *available at:* https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/6991ef77ba07bae185258752007994f7/$FILE/171203RE03-072821.pdf

[3] In determining availability, the EDCs may consider the list of batteries approved by the California Energy Commission. See https://www.energy.ca.gov/programs-and-topics/programs/solar-equipment-lists.

3. "Microgrid" per Conn. Gen. Stat. § 16-243y means "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and that connects and disconnects from such grid to enable it to operate in both grid-connected or island mode"

b. Section 48(a)(8) provides that for certain energy property amounts paid or incurred for qualified interconnection property may be included in basis.
   i. For interconnection property, what types of additions, modifications, or upgrades to the transmission or distribution system are required for the purpose of accommodating interconnection?

Connecticut has been working on addressing interconnection issues for various types and sizes of distributed energy resources (DERs) in PURA Docket No. 17-12-03RE06, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Interconnection Standards and Practices. In June 2022, PURA issued interrogatories to Connecticut's two investor-owned utilities, Connecticut Light and Power Company d/b/a Eversource Energy (Eversource) and The United Illuminating Company (UI), requesting data on the most common distribution grid infrastructure upgrades triggered by DER interconnection projects and their costs. Eversource and UI reported the following data:

Table 1: Eversource[4]

System Upgrade or Modification	Typical Cost Range
Transformer upgrades, residential, overhead	$1,000 - $3,000
New three-phase service	$150,000 - $200,000
Three-phase overhead line extension	$900,000 - 1.7 million per mile
Overhead line extension: single-phase to three-phase	$600,000 - 1.3 million per mile
Conductor upgrade/reconductoring	$1 - 1.3 million per mile
Upgrade/install/replace distribution line regulators	$50,000 - 200,000

Table 2: United Illuminating[5]

[4] CL&P dba Eversource Energy, Response to Interrogatory RSR-012, PURA Docket No. 17-12-03RE06 – PURA Investigation into Distribution Planning of the Electric Distribution Companies – Interconnection Standards and Practices, July 13, 2022, *available at:* https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/cc01915fe1d538c58525887e004b5079?OpenDocument

[5] The United Illuminating Company, Response to Interrogatory RSR-012, PURA Docket No. 17-12-03RE06 – PURA Investigation into Distribution Planning of the Electric Distribution Companies – Interconnection Standards

Design Scope	**Estimated Total Cost Range**
Upsize a pole-mounted service transformer	$2,000 to $8,000
Install/remove secondary break points	$250 to $750
Install new pole-mounted service transformer and secondary break points	$5,000 to $15,000
Extend primary wire and install new pole-mounted service transformer and secondary break points	$10,000 to $30,000

The Treasury Department and the IRS may also find Eversource and UI's responses to interrogatories issued in another proceeding, Docket No. 22-06-29, PURA Investigation into Distributed Energy Resource Interconnection Cost Allocation, helpful in response to this question. PURA has attached those interrogatory responses to the end of this document.

ii. For interconnection property, what type of documentation, in addition to interconnection agreements and cost certification reports, is readily available for a taxpayer to demonstrate that they have paid or incurred interconnection costs?

Per Eversource and UI's responses to interrogatory RSR-28 in Docket No. 22-06-29, the two companies record and track customer payments for DER interconnection related system upgrades or modifications. As stated by Eversource:

> "Customer payments for DER interconnection-related system upgrades and / or modifications are typically in the form of a contribution in aid of construction (CIAC). These dollars received are identified as a contribution for a specific capital project / work order. Under Generally Accepted Accounting Principles (GAAP), CIAC funds are not subject to the FASB Accounting Standards Codification (ASC) 606, *Revenue Recognition Guidance,* and are presented as either an offset to construction work in progress (CWIP) (FERC Account 107) or a liability balance, depending on the funded status of the project. This accounting is also consistent with FERC accounting guidance. As many of the DER projects can span multiple years, these CIAC funds are typically presented as a liability and reclassified to CWIP (FERC Account 107) as capital dollars are spent. The CIAC funds are not subject to carrying costs and do not

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and Practices, July 12, 2022, *available at:* https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/dcb2c3658af1ecc18525887d005ab423?OpenDocument

earn a return. In addition, because the CIAC funds are not recognized as revenue, these funds do not apply to revenue decoupling."[6]

.06 IRA Addition of Special Programs for Certain Facilities Placed in Service in Connection with Low-income Communities (§§ 48(e) and 48E(h))

In addition to its comments below, PURA also notes that it supports the responses submitted by the Connecticut Green Bank to the questions related to §§ 48(e) and 48E(h).

1. Sections 48(e)(4)(A) and 48E(h)(4)(A) require the Secretary to establish a program to allocate amounts of environmental justice capacity limitation to applicable facilities. In establishing such program, the Secretary must provide procedures to allow for an efficient allocation process.
   a. What should the Treasury Department and the IRS consider in providing guidance regarding the application process for taxpayers seeking an allocation of the environmental justice capacity limitation?

      The Treasury Department and the IRS may want to consider holding "office hours" or creating a resource where interested taxpayers can discuss their project with a live representative. Not all taxpayers have experience or background in applying for federal programs, and creating a human, conversational resource where participants can ask questions or explain portions of their application can help make the program more accessible.

   b. How can the application procedures and application process be made accessible to taxpayers?

      As stated in PURA's response to question 1a above, the Treasury Department and the IRS should consider opportunities to support applying taxpayers in ensuring their application is prepared correctly. This can help adjust for experience discrepancies, making the process more accessible and equitable.

   c. How can the process incorporate community input, engagement, and benefit for projects seeking an allocation of the environmental justice capacity limitation?

      Connecticut's Shared Clean Energy Facilities (SCEF) program bid submittal requirements were updated in 2021 through the Decision in Docket 21-08-04, Annual Review of Statewide Shared Clean Energy Facility Program Requirements – Year 3 such that bidders would be required to provide documentation of outreach conducted to the intended host-community and any

[6] CL&P dba Eversource Energy, Response to Interrogatory RSR-028, PURA Docket No. 22-06-29 – PURA Investigation into Distributed Energy Resource Interconnection Cost Allocation, August 16, 2022, *available at:* https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/27225721d6b75743852588a0004b53ce?OpenDocument

plans for continued education and outreach efforts to that community if the project was selected. This could include written correspondence with local municipal officials or community leaders; evidence of in-person or virtual meetings with those individuals; or other documentation that demonstrates outreach.[7] The Treasury Department and the IRS could consider a similar requirement for taxpayers seeking an allocation of the environmental justice capacity limitation to demonstrate substantial efforts to receive community input.

.03 What methods currently exist or need to be designed for a taxpayer to certify that a project is being built in a low-income community, on Indian land, or as part of a low-income residential building project or a qualified low-income economic benefit project?

There are multiple mechanisms that the Treasury Department and the IRS can use including Census tract data, DOE's Low-Income Energy Affordability Data (LEAD) TOOL, or demonstrating that a certain percentage of building occupants meet a low-income threshold.

.04 What mechanisms exist for a taxpayer to demonstrate that the financial benefits of the electricity produced by an applicable facility are allocated equitably among the occupants of a low-income residential building project and do not impact the occupants' eligibility for their housing? Similarly, what mechanisms exist for a taxpayer to demonstrate that at least 50 percent of the financial benefits of electricity produced by an applicable facility which is part of a low-income economic benefit project are provided to households within certain income thresholds?

Since 2019, Connecticut has been operating the SCEF Program which is an annual procurement of Class I renewable energy resources for development in the state, where selected bids provide a $0.025/kWh credit to subscribed participants. Subscribed participants must be low-income customers, moderate-income customers, small business customers, state or municipal customers, commercial customers, or non-low or moderate income customers that reside in a property where the Customer does not control the property's roof, or do control the property's roof but have proof that they are unable to install solar panels on their roof.[8] The program requires subscriptions to be allocated as follows:

i. 20% low income customers;
ii. 20% small business customers;

[7] CT Department of Energy & Environmental Protection, Year 3 – Exhibit B SCEF Appendix B Redlines, PURA Docket No. 21-08-04 – Annual Review of Statewide Shared Clean Energy Facility Program Requirements – Year 3, September 10, 2021, *available at:* https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/0144e5c7e1c2fdfa8525874c0065c8b9?OpenDocument

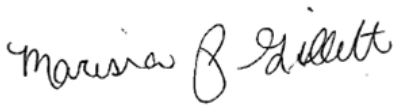
[8] Connecticut PURA, Decision, Docket No. 19-07-01 – Review of Statewide Shared Clean Energy Facility Program Requirements, December 18, 2019, *available at:* https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/2c2724a6374a05a3852584d4006bd716?OpenDocument

iii. 40% low-to-moderate customers, affordable housing facilities; or customers who qualify for low-income services; and
iv. 20% to other eligible customers.

Taxpayers could consider a similar subscription model to demonstrate how their electricity generation is allocated to various communities.

PURA greatly appreciates the opportunity to submit a response to this request for comments and looks forward to further opportunities to contribute.

Sincerely,



Marissa P. Gillett
Chairman
Public Utilities Regulatory Authority

Attachments

Date Filed: August 02, 2022

Witness: Ferrante, David A
Request from: Public Utilities Regulatory Authority

Question:
Eversource and UI Response to RSR-12 in Docket No. 17-12-03RE06. Provide a typical scenario(s) under which each of the system upgrades or modifications listed in RSR-12 would be necessary. Provide this separately for residential interconnection projects (<25 kW) and commercial projects (>25 kW) where appropriate. Describe what interconnection issues these upgrades solve and explain how they solve it.

Response:

1. Transformer upgrades, residential, overhead ($1,000 - $3,000): These costs are limited to residential projects less than 25 kW.

   Scenario 1 - Aggregate generation exceeds transformer name plate rating:
   The existing Eversource pole-mounted transformer is rated 25 kVA with five customers and two photovoltaic (PV) systems online with an aggregate generation equal to 20 kW. A new interconnection application was received for a 15 kW photovoltaic system. The maximum aggregated output of 35 kW for the PV interconnected to the existing 25 kVA transformer will exceed the transformer's thermal nameplate rating. A new 50 kVA transformer and a new pole will allow all generation to be safely and reliably interconnected while allowing addition load such as EV charging and additional PV systems to be connected. This scenario will cost on average $3,000.

   Scenario 2 – Same as scenario 1 but the existing pole can be re-used. This will cost on average $1000.

2. New three-phase service ($150,000 - $200,000):

   Scenario - A new interconnection application is received for a 3 MW photovoltaic system. The site is located 500 feet from the road that has an existing three-phase, 23 kV circuit. An impact study was conducted and determined that the proposed project has no adverse impact on the distribution system. However, the site has no existing service so a primary 23 kV service will be needed. The new service will consist of a conductor from the existing circuit to the property line, 2 poles with one recloser and primary metering.

3. Three-phase overhead line extension ($900,000 - 1.7 million per mile):

   Scenario - A new interconnection application is received for a 3 MW photovoltaic system. The site is located on a road with no existing electrical

infrastructure. The closest three-phase circuit is approximately one mile away. The impact study was conducted and determined that the proposed project has no adverse impact on the distribution system, but a three-phase overhead one-mile line extension is required. This scenario will also require a new three-phase service and primary meter.

4. Overhead line extension: single-phase to three-phase ($600,000 - 1.3 million per mile):
   Scenario - A new interconnection application is received for a 3 MW photovoltaic system. The site is located on a road with a single-phase 23 KV circuit. A 3 MW interconnection project cannot be interconnected to a single-phase circuit and the closest three-phase circuit is approximately one mile away. The impact study was conducted and determined that the proposed project has no adverse impact on the distribution system, but the existing single-phase line will need to be upgraded to a three-phase overhead circuit This scenario will also require a new three-phase service and primary meter.

5. Conductor upgrade/reconductoring ($1 - 1.3 million per mile):
   Scenario - A new interconnection application is received for a 3 MW photovoltaic system. The site is located on a road with an existing three-phase 23 KV circuit with 2/0 conductors. The impact study was conducted and determined that output from the proposed project during light load periods could increase the voltage on the circuit above 5% of nominal, even with application of Volt/VAr control measures. Approximately one mile of existing 2/0 conductor will need to be replaced with 556 TW conductor to keep the voltage rise below 5%. This scenario will also require a new three-phase service and primary meter.

6. Upgrade/install/replace distribution line regulators ($50,000 - 200,000):
   Scenario - A new interconnection application was received for a 1 MW photovoltaic system located behind a customer meter with a peak load of 500 kW and a minimum load of 150 kW. The customer is located approximately 4 miles from the substation at the end of the feeder and there are no other commercial customers in the area. An existing three-phase line regulator had been installed to ensure that the voltage in the area remain within standard limits. During off-peak times, the proposed photovoltaic system will export up to 350 KW. However, with no large load in the area, most of the export will backfeed the line regulator. The line regulator cannot support reverse flow and will keep trying to regulate voltage up until it reaches the maximum voltage tap significantly increasing the voltage in the area. The cost varies depending on whether the regulator needs to be replaced or if the controls can be retrofitted.

Date Filed: August 02, 2022

Witness: Ferrante, David A
Request from: Public Utilities Regulatory Authority

Question:
Eversource and UI Response to RSR-12 in Docket No. 17-12-03RE06. Describe any co-benefits provided by the system upgrades or modifications listed in RSR-12 (e.g., new or enhanced accommodation of EV charging at a
given location on a circuit from a new transformer, etc.).

Response:

1. Transformer upgrades, residential, overhead ($1,000 - $3,000): Co-benefits provided by the system upgrades will be primarily limited to the residential customers connected to the same transformer. Additional load (such as EV) and generation (such as PV) can be connected to the new transformer only limited by the size of the new transformer and service conductor size and length.

2. New three-phase service ($150,000 - $200,000): Co-benefits provided by the system upgrades will be primarily limited to the project needing the three-phase service. The benefits include the ability to add load behind the new three-phase service provided that no other constraints exist on the distribution or transmission systems such as capacity or thermal limits. Aggregate output from a significant number of these projects across the system could reduce system demand during high-export periods, possibly shaving or shifting the local peak, depending on coincidence.

3. Three-phase overhead line extension ($900,000 - 1.7 million per mile): The addition of new electrical infrastructure may be able to provide co-benefits including additional generation and load provided that no other constraints exist on the distribution or transmission systems such as capacity or thermal limits. Aggregate output from a significant number of new PV projects across the system could reduce system demand during high-export periods, possibly shaving or shifting the local peak, depending on coincidence.

4. Overhead line extension: single-phase to three-phase ($600,000 - 1.3 million per mile):
Refer to response in bullet 3 above.

5. Conductor upgrade/reconductoring ($1 - 1.3 million per mile):
Refer to response in bullet 3 above.

6. Upgrade/install/replace distribution line regulators ($50,000 - 200,000): Line regulators are replaced specifically to provide voltage regulation of a circuit, mitigating excessive voltage drop or voltage rise due to load or generation on the circuit. Therefore, line

regulator upgrades may provide voltage regulation benefits for existing customers on the circuit and enable additional generation or load to be accommodated without violation of standard voltage limits.

In general, upgrades to the distribution system to accommodate generation, can result in co-benefits with the understanding that the level of benefits will vary depending on aggregate generation, existing and/or future load, the load profile (time of day/year) and the distribution and transmission system limitation(s) on the circuit and/or the substation. Many standalone photovoltaic systems are sited in rural areas where land is available. However, since load is typically low in these areas during seasonal periods, this can cause thermal and voltage limits to be exceeded. In most cases a site-specific or group study may be required to assess actual benefits and impacts to DER and loads.

RSR-020 Q:

Eversource and UI Response to RSR-12 in Docket No. 17-12-03RE06. Provide a typical scenario(s) under which each of the system upgrades or modifications listed in RSR-12 would be necessary. Provide this separately for residential interconnection projects (<25 kW) and commercial projects (>25 kW) where appropriate. Describe what interconnection issues these upgrades solve and explain how they solve it.

RSR-020 A:

Residential Interconnection Projects

1) Upsize a pole-mounted service transformer ($2,000-$8,000)
   a) The typical scenario resulting in this infrastructure work scope would be a new PV project with a system size of 10kW is proposing to interconnect. This customer is fed by a 25kVA transformer, which already has two existing 10kW PV projects approved and online. The maximum total PV output of 30kW (20kW existing + 10kW new) exceeds the transformer's thermal nameplate rating (technical screen 2.5.1 in the residential Guidelines for Interconnection document). UI would replace the 25kVA transformer with a 37.5 kVA transformer, which is the smallest standard size transformer to allow for a safe and reliable interconnection.

2) Install/remove secondary break points ($250-$750)
   a) Same scenario as in #1a. In reviewing infrastructure options to resolve the issue, it is identified that by relocating secondary break points and transferring the customer with the new 10kW PV project to a neighboring transformer that has sufficient hosting capacity available, the issue will be resolved with a lower-cost solution.

3) Install new pole-mounted service transformer and secondary break points ($5,000-$15,000)
   a) The typical scenario resulting in this infrastructure work scope would be a new PV project with a system size of 15kW is proposing to interconnect. This customer is a significant distance from the 25kVA service transformer, which has an existing 10kW PV system already installed. Although the transformer nameplate rating is not exceeded, the large proposed system size along with the significant distance from the transformer is found to causing voltage rise above the acceptable +5% threshold (technical screen 2.5.4 in the residential Guidelines for Interconnection document). UI would install a new service transformer closer to the new 15kW PV system to minimize the voltage rise impact.

4) Extend primary wire and install new pole-mounted service transformer and secondary break points ($10,000-$30,000)

5) Same scenario as in #3a. The customer proposing the new 15kW PV system does not have primary along the pole line feeding their house. UI would extend primary wire and install a new service transformer closer to the new PV system. Commercial Interconnection Projects Although there were no details included in the RSR-12 response for non-residential interconnection projects due to the significant amount of site-specific variables (primary vs secondary service, location/configuration of main switchgear, shared or dedicated transformer, etc.), the overall approach of designing infrastructure solutions is consistent as above for similar scenarios

RSR-021 Q:

Eversource and UI Response to RSR-12 in Docket No. 17-12-03RE06. Describe any co-benefits provided by the system upgrades or modifications listed in RSR-12 (e.g., new or enhanced accommodation of EV charging at a given location on a circuit from a new transformer, etc.).

RSR-021 A:

1) Upsize a pole-mounted service transformer ($2,000-$8,000) The possible co-benefits of this infrastructure scope of work are additional capacity for new loads (i.e. EV charging) or generation, so long as no other system/equipment constraints are exceeded. Also, these benefits would only be applicable to the customers fed from this service transformer.

2) Install/remove secondary break points ($250-$750)
    a. Same as #1. However, in this scenario, these benefits would be applicable to the customers fed from the two service transformers involved with transferring customers.

3) Install new pole-mounted service transformer and secondary break points ($5,000-$15,000)
    a. Same as #1. However, in this scenario, these benefits would be applicable to the customers fed from the new service transformer and any neighboring transformer involved with transferring customers.

4) Extend primary wire and install new pole-mounted service transformer and secondary break points ($10,000-$30,000)
    a. Same as #3. Overall, it is possible for co-benefits to be realized as a result of infrastructure upgrades required for safe and reliable generator interconnections. However, the benefits are contingent on various other factors, such as amount of existing voltage constraint(s) as a result of system configuration, equipment rating limitation(s), aggregate generation, amount of current load, coincidence of load (time of day, time of year), and future load growth.