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CT GENERAL STATUTES – SECTION 16A-3A 2025 INTEGRATED RESOURCES PLAN

Transmission Solutions White Paper

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I. Introduction

Connecticut is served by a regional electric grid consisting of a network of power plants that are connected by a transmission system, including high-voltage power lines and associated infrastructure, that spans the six New England states. The transmission system is a high voltage backbone that delivers electricity generated by the region's power plants to the local areas where this electricity is needed to serve power demand in homes and businesses. As this transmission infrastructure ages, and as electricity demand grows in Connecticut and New England, investments to maintain and expand the transmission system are increasingly needed to ensure power flows affordably and reliably in our region. New England's independent regional transmission operator, ISO New England (ISO-NE), projects that our region's electricity demand will grow over the next ten years due to economic growth as well as increased adoption of electric vehicles and heat pumps.[1] ISO-NE anticipates regional electricity demand could double by 2050. In addition to ensuring that our existing transmission system continues to be reliable, new transmission infrastructure and upgrades to existing infrastructure are needed to access new sources of low-cost generation both within New England and from other regions.

Connecticut and our sister New England states have made substantial progress in the last five years to address these needs, by ensuring that ISO-NE conducts long-term transmission planning; identifying "no regrets" upgrades to unlock new generation supply; establishing a mechanism to procure and fund proactive upgrades; and securing unprecedented federal funding to make these upgrades even more affordable. This White Paper details these efforts, including anticipated progress in 2025 on an ISO-NE-administered competitive regional transmission procurement to unlock new sources of low-cost power for the region in northern Maine.

While transmission investments to unlock new generation are needed and gaining momentum, ratepayer costs associated with reliably maintaining New England's existing, aging transmission infrastructure—through "asset condition" and "local transmission service" projects—are mounting. Between 2016 and 2024, the New England region's TOs invested more than $9 billion in transmission projects to address reliability needs identified by ISO-NE and replace aging transmission infrastructure.[2] Since 2015, annual transmission costs as a whole have grown by 72% and now make up 10-11% of the typical Connecticut residential customer's monthly electricity bill. New England is projected to invest another $6.5 billion in asset condition and reliability transmission projects through 2030.[3] Transparency and rigorous oversight of projects are needed to ensure they are necessary and warrant the enormous ratepayer costs involved. While the costs of building and maintaining our region's transmission system are regulated by the Federal Energy Regulatory Commission (FERC), this White Paper suggests key state-jurisdictional reforms that would better enable Connecticut to effectively engage in the FERC processes that regulate the project costs embedded in the transmission rates our residents and businesses pay and highlights other regional reform efforts that DEEP is participating in.

This White Paper also discusses other issues implicating the transmission system and ratepayer costs. Some issues, like supply chains that have not fully recovered from the pandemic are hard for states to

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[1] The ISO's latest demand forecast numbers for the next ten years, which includes a new methodological approach as compared to prior iterations, will be published on May 1, 2025.

[2] The actual spend on new transmission buildout in the region is even higher because these numbers do not include the costs of a subset of asset condition projects (discussed further below) that individually cost less than $5 million each or local transmission projects (also discussed more below).

[3] Overall transmission costs will be higher than this $6.5 billion as more reliability projects are identified and because this $6.5 billion estimate excludes other categories of transmission spending.

solve absent federal assistance, though DEEP highlights exploratory work with other states to tackle this issue. In other areas, states could play a central role, such as addressing barriers to transmission deployment through state siting and permitting reforms that encourage Transmission Owners (TOs) to more effectively consider advanced transmission technologies, like advanced conductors and grid enhancing technologies, which show promise in reducing costs for ratepayers. States could also consider streamlining siting and permitting processes for projects that further policy goals and increase affordability for ratepayers.

II. Background: New England's Transmission System

New England's transmission system includes approximately 9,000 miles of high-voltage (69,000 volts or higher) power lines, substations, and associated infrastructure. The transmission system moves electricity over longer distances from the power plants where it is generated to the areas where it is needed. Before reaching homes or businesses, the transmission system connects to separate lower voltage distribution systems, which ultimately deliver electricity over distribution power lines to individual consumers. While lower voltage distribution systems are regulated by states—the Public Utilities Regulatory Authority (PURA) in Connecticut—the high-voltage transmission system, which crosses state lines, is regulated primarily by FERC.

As part of an interconnected grid, as opposed to a single-state grid that ends at our borders, Connecticut must work with many other decisionmakers in managing our grid, including FERC, ISO-NE, and the other New England states. Our state receives significant benefits by being part of a regional grid. This regional system avoids duplicative investment, allows individual transmission and generation assets to be used more efficiently, and boosts reliability such as by providing multiple pathways to flow electricity across the region in response to generator retirements, weather events, outages, and other contingencies. The interconnected regional grid also facilitates access to a lower-cost, larger, and more diverse portfolio of generation resources than is available within Connecticut alone, including resources located in our region and in neighboring regions like New York and Canada. This enables Connecticut to source competitive generation from across a broader market, and to keep the lights on even when in-state generation resources go offline for both planned (*e.g.*, scheduled maintenance) and unplanned reasons.

New England's high-voltage transmission system is owned by a variety of independent TOs, which include utilities like Eversource and United Illuminating (UI). Under the terms of a FERC-approved Transmission Operating Agreement, the TOs cede to the region's grid operator—ISO-NE—operational control over the transmission system, but the TOs still own and continue to have an obligation to maintain these transmission assets. The TOs' costs to maintain these transmission assets—including operation and maintenance, repairs, and costs of new projects and upgrades—as well as ISO-NE's costs to plan and operate the system, are recovered from the New England states' electric ratepayers according to each state's proportional shares of regional electric load (*i.e.*, the percent of load that each state represents on the regional grid, which for Connecticut is approximately 25 percent). These costs are recovered pursuant to transmission service rates approved by FERC.[4] Under the Federal Power Act,

[4] While most transmission costs are shared regionally, some costs are paid only by ratepayers in a single state or even a single service territory. If a TO owns transmission facilities that are necessary to serve the reliability needs of a given area of a state, but do not serve broader regional reliability benefits, these transmission facilities will only be paid for by the ratepayers in that service territory. These projects are known as local transmission service projects. If a state's siting process results in a change to a proposed transmission project that is based on non-reliability focused reasons (*e.g.*, undergrounding the transmission line where not necessary but for aesthetic reasons), then ratepayers in that state alone will pay for the incremental expense of requiring the change.

FERC has exclusive jurisdiction over setting transmission rates and states are prohibited from taking actions to regulate these rates.

A. Regulation and Costs

New England's transmission costs are the highest in the country. New England spends $5.90 on transmission for every MWh of demand served, which is higher than in any other U.S. region. Florida was the least costly at 17 cents spent on transmission per MWh of demand served.[5] Factors contributing to these higher costs include our region's higher cost of labor, as well as geographic limitations such as mountainous terrain and large swaths of forest, which impact the design characteristics of and access to transmission corridors, and the density of population centers along our region's coastline. Another contributing factor is the profit that TOs earn on transmission investments through their collection of a return on equity (ROE) that has been set by FERC.

FERC has approved an ROE on transmission investments in New England of 11.07%, which is almost 2% higher than ROEs PURA has approved for distribution system investments by Connecticut's electric distribution companies. TOs earn the 11.07% FERC-approved ROE on the transmission capital investments that they make—*i.e.*, the transmission lines, substations, and transformers they develop. This ROE-based approach means TOs realize larger profits, in total dollars, on larger capital investments. This creates a potential incentive for TOs to prioritize higher capital cost solutions to transmission needs, as opposed to lower-cost solutions, which heightens the need for oversight of proposed transmission projects. The 11.07% ROE also includes a 0.5% bonus for voluntarily participating in the ISO-NE regional transmission organization. Some states have required their TOs to participate in an RTO and at least one court has found that such laws make a TO ineligible for the 0.5% bonus.[6]

PURA's regulation of the electric utilities' distribution system investments differs fundamentally from FERC's regulation of the TOs' transmission system investments. For the distribution system, PURA conducts in depth rate proceedings where the electric distribution companies (Eversource and UI) bear the burden of proving that their investments are prudent and, therefore, appropriate to recover from the state's ratepayers. FERC takes a significantly different and less rigorous approach by utilizing a "formula-based" approach to setting transmission rates. Essentially, each TO has a preapproved formula rate on file with FERC that contains various inputs (*e.g.*, approved ROE, depreciation expenses, operation and maintenance expenses, taxes, *etc.*) that the TO fills in during an annual proceeding to update its transmission rates for the next year. Unlike at PURA, FERC presumes that a TO's expenditures, as entered into its formula rate, are prudent. It falls to a challenger, such as a state or individual ratepayer, to mount a challenge to demonstrate to FERC's satisfaction that there is "serious doubt" that a TO's expenditures were prudent before FERC requires proof from the TOs as to the prudency of those expenditures. The requirement to demonstrate serious doubt is a difficult hurdle for challengers to clear, given the amount of information and data that goes into these formulas and the overall complexity involved.[7] Unless a challenger is able to demonstrate serious doubt, FERC will not scrutinize a

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[5] *See* U.S. Dept. of Energy, National Transmission Needs Study at p. 50 (Oct. 2023), available at https://www.energy.gov/sites/default/files/2023-10/National_Transmission_Needs_Study_2023.pdf.

[6] *See* https://www.utilitydive.com/news/appeals-court-ferc-roe-transmission-adder-aep-duke-firstenergy/737791/. For clarity, the 0.5% bonus is included within the 11.07% approved ROE.

[7] Opportunities exist through FERC's formula rate process to request data and information from TOs. However, the TOs each file thousands of pages of information. The information exchange period (*i.e.*, the time during which parties can ask questions) is only three months, which is short considering the length and complexity of the filing.

TO's costs further and will allow these costs to automatically flow into the transmission rates paid by the region's ratepayers.

B. Types of Transmission

Different types of transmission projects are subject to varying levels of oversight, and thus raise unique concerns when it comes to protecting Connecticut ratepayers. This section provides a high-level overview of four types of transmission projects: new regional transmission, asset condition projects, local transmission service projects, and "right sizing" projects.

1. New Regional Transmission

Unlocking New Supply with New Transmission

New England's transmission grid grew organically around large power plants located near the region's urban areas. As the region's electricity demands grow, and as our generation mix diversifies to include more decentralized generation resources, like solar, wind, and hydropower, which can be located further from load centers or in other regions, we will need to build new transmission to connect these new resources to the grid.

When new transmission is needed to unlock new sources of supply, there can be a disincentive for a generation developer to be the "first mover" into an area. The initial transmission upgrades needed to connect the first project are often higher than the costs to connect subsequent projects in the same area.[8] In other words, subsequent projects in the same area can make use of the transmission upgrades paid for by the first project, leading to lower overall costs for these subsequent projects. In recent years, ISO-NE has adopted planning reforms, at FERC's direction, that are intended to more fairly share new transmission costs between "clusters" of new resources looking to interconnect in a particular area. Connecticut and our sister New England states are also working with ISO-NE to proactively deploy transmission in areas where upgrades could enable the development of new, lower cost sources of supply.

Ensuring Reliability with New Transmission

New transmission is also needed to ensure grid reliability and resiliency by providing redundancy during times of high demand and unexpected events (*e.g.*, an outage on a particular transmission line or at a generator). Reliability projects, which are projects required to address load growth and maintain appropriate system conditions, are a second subcategory of new transmission builds. In some cases, reliability projects must be developed in new transmission corridors; however, some projects are able to utilize space within existing rights of way by upgrading existing transmission lines.

ISO-NE is responsible for assessing the reliability of the transmission system regularly, and where deficiencies are identified, pursuing reliability solutions to address the need. ISO-NE plays an active role in evaluating and overseeing the need for and scope of proposed reliability projects, which helps assure ratepayer interests are protected. Under its FERC approved tariff ISO-NE must procure project solutions through a competitive bidding process, assuming the identified need is far enough in the future to allow for such a procurement. If an identified need is required sooner, the incumbent TO(s) where the need was identified are tasked with solving the problem. To date, there has only been one such competitive RFP in New England. Going forward DEEP expects that ISO-NE will ensure this competitive RFP process is

[8] This same phenomenon can also occur later once a given area becomes saturated with generation resources and new transmission upgrades are again needed for additional generation to come online.

the norm and not the exception, which should help further protect ratepayers by ensuring the most cost-effective solutions are selected.

Interregional Transmission

Interregional transmission is transmission that electrically connects regions that are otherwise mostly distinct transmission grids (e.g., ISO-NE with New York). Such transmission can provide value by supplementing and complementing the energy resources located within a single region, helping to maintain reliability and lower electricity costs. For example, weather patterns in one region can differ from weather patterns in another region, especially as the distance between the two regions increases. This allows one region that might have an excess amount of generation at a given moment in time (*e.g.*, if it is particularly windy or sunny in that region) to send that electricity that might otherwise be wasted to another region and vice versa.

2. Asset Condition Projects

Asset condition projects involve rebuilding existing transmission infrastructure that is deteriorating or otherwise in need of repair. These projects, where warranted, are critical to maintaining the reliability of the transmission grid. Unlike reliability projects, the TOs exercise their own judgment on the need for, timing, and scope of asset condition project. These projects are currently subject to effectively no oversight at either ISO-NE or FERC, which raises ratepayer cost concerns. The costs of asset condition projects are entered into TOs' annual formula rates and are presumed by FERC to be prudent unless a challenger can demonstrate "serious doubt". As discussed above, this is an almost impossible burden for a challenger to meet, exposing the region's ratepayers to a significant risk of over- or unnecessary spending, such as where a TO proposes to replace transmission infrastructure before it is needed or in a manner beyond what is necessary (*i.e.,* gold plating).

TOs' spending on asset condition projects in New England has grown significantly in recent years and is expected to continue to grow, heightening these concerns. Since 2018, TOs have invested approximately $4.1 billion in asset condition projects, compared to $2.2 billion spent on new reliability projects. Looking ahead, based on TOs' current proposals, New England ratepayers can expect the TOs to invest at least an additional $5.4 billion on asset condition projects through 2030, significantly outpacing spending on currently planned new reliability projects through that year. This is not just a New England problem: in late 2024, a nationwide consortium of large industrial energy users filed a complaint at FERC challenging FERC's approach to oversight for asset condition and local transmission service projects (discussed in next section). DEEP has intervened in this challenge and plans to work with our sister agencies in Connecticut and other states in this proceeding.

3. Local Transmission Service Projects

Local transmission service projects suffer from similar process and oversight deficiencies as asset condition projects. Local transmission service projects are transmission projects that do not serve regional needs but instead are needed to address local reliability concerns in a specific TO's service territory. Ratepayers in the service territory where a local transmission service project is located pay for the entire cost of these local projects; the costs are not shared with other states in the region or even other transmission ratepayers within the same state.

Similar to asset condition projects, and unlike regional reliability projects, ISO-NE exercises only limited authority and oversight over the need for, timing, and scope of local transmission projects. Each TO plans and develops local transmission projects to solve needs identified by the TO itself at its local level. These projects are then incorporated into a local system plan developed by the TO, which is presented to stakeholders at a TO-led forum known as the Transmission Owner Planning Advisory Committee (TOPAC) meeting for feedback. As with asset condition projects, FERC presumes the costs of local transmission projects to be recovered from ratepayers are prudent unless a challenger can demonstrate "serious doubt."

4. "Right Sizing" Projects

A "right sizing" project is effectively a combination of a new transmission build and an asset condition project. A right sizing project will usually start out as an asset condition project before being expanded to address or prepare for projected future demands on the transmission system (*e.g.*, by rebuilding an existing transmission line to a higher capacity level than the original line). Right sizing is likely to increase the costs of implementing an asset condition project on its own but could lower eventual transmission costs and save ratepayers money overall by proactively addressing challenges and reducing the need for later, potentially more costly investments in additional or duplicative transmission infrastructure.

For example, assume there is a transmission line that must be replaced due to legitimate asset condition concerns. Next, assume that ISO-NE modeling demonstrates a high likelihood that this same line will need to be rebuilt to a higher capacity within ten years of the replacement line entering service due to expected demand growth. In this situation, it would likely be less costly for ratepayers to replace the line once at a higher capacity, as opposed to replacing the line first at its current capacity and then rebuilding it again to a higher capacity ten years later. While the additional capacity might not be needed right away, it could save ratepayers money because the transmission infrastructure will not be replaced twice. Such right sizing could also limit disruptions to local communities by only requiring one construction period rather than two.

The potential benefits of right sizing depend significantly on whether the initial asset condition project is justified. If such asset condition rebuild is not needed, ratepayers may not benefit from right sizing—and may instead be harmed—by expanding the scope of an unnecessary project and rebuilding a line at a higher capacity before such capacity is needed.

III. New Transmission Projects: Critical Progress Towards Regional Investment in Removing Barriers to Needed Electricity Supply

Over the last five years, the New England states and ISO-NE have made significant progress in advancing long-term planning and improved procurement processes for new transmission in the region. In 2020, the New England states issued a Vision Statement calling on ISO-NE to develop a proactive approach to transmission planning to ensure a reliable and cost-effective transition of the region's energy system. In response, ISO-NE undertook the region's first long-term transmission planning exercise, a 2050 Transmission Study, which modeled electricity demand and potential generation mixes in the region in 2035, 2040, and 2050. The 2050 Transmission Study provides a roadmap for "no regrets" transmission, identifying areas that will likely need to be upgraded as economic growth drives electricity demand. These include (1) areas where new transmission is likely needed to solve long-term needs cost-effectively, as well as (2) opportunities for "right sizing," where existing transmission lines could be expanded to meet long-term needs more efficiently than building new transmission in new rights of way.

The New England states and ISO-NE have further developed a framework, approved by FERC in 2024, to advance the transmission needs identified in the 2050 Transmission Study. The framework includes a competitive procurement process administered by ISO-NE in consultation with the states;[9] and a landmark agreement among the six states to fairly allocate by load share the costs of transmission projects procured through this process if the projected economic and reliability benefits from such projects exceed their anticipated costs over their first 20 years (transmission infrastructure typically has an expected useful life of 60 or more years).[10] This benefits analysis focuses on whether such transmission will lead to lower costs (*e.g.*, through access to cheaper generation resources) and/or contribute to increased reliability for the region.

ISO-NE recently launched the first procurement under this framework, which will focus on addressing transmission needed to access low-cost onshore wind in northern Maine. The new framework provides a mechanism to regionally invest in these transmission upgrades to reduce the cost to interconnect new generation in Maine, which will provide reliability and cost saving benefits across the region. Individual states would still need to procure the wind generation, and likely some level of transmission upgrades as well, but regionalization of a significant portion of these transmission costs will substantially reduce the costs of such future state procurements. This will lead to direct savings for states like Connecticut that procure this generation to meet our states' needs, as well as savings for all six states by enabling the connection of new generation resources that can lower wholesale energy and capacity costs in ISO-NE. Relatedly, FERC issued two orders, Order Nos. 1920 and 1920-A in 2024, which require transmission providers like ISO-NE to establish a long-term transmission planning process similar to the process described above in New England.

ISO-NE's 2050 Transmission Study also identified opportunities for transmission right sizing. As discussed above, right sizing is a potential strategy to lower transmission costs in the long-term by proactively addressing challenges and reducing the need for later, more costly investments. However, right sizing is not yet a commonplace strategy in New England, due to concerns that the lack of oversight by ISO-NE and FERC of asset condition projects, which would underlie a right sizing proposal, hampers the ability of states and stakeholders to assess these proposals. To support a right sizing proposal, DEEP must be confident consumers will realize efficiencies and benefits, requiring meaningful reforms to asset condition oversight first.

DEEP is further working to identify and break down barriers to interregional transmission development through our participation in the ten-state Northeast States Collaborative on Interregional Transmission. Interregional transmission has the potential to reduce costs and increase reliability for ratepayers in Connecticut and New England broadly. For example, New England and New York currently have approximately 2,000 MW of transmission interconnections between our two grids. A study by Lawrence Berkeley National Lab found that expanding these connections by half (1,000 MW) could create between $137 million and $189 million in cost savings per year, shared between New York and New England.[11] While there are clear potential benefits of interregional transmission, development of such transmission is complicated by the need to coordinate across regional grid operators and determine how to allocate the costs of such projects between regions. FERC has taken some steps to encourage further coordination between regional grid operators in a recent transmission planning order (Order No.

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[9] While the procurement process is run by ISO-NE, the New England states are in the lead in identifying the initial need for such procurement and the framework allows the states to collectively end a procurement process if the states do not think a resulting project identified by ISO-NE is in the best interest of our ratepayers.
[10] Previously, the costs of new transmission needed to unlock new sources of supply would typically fall to the state(s) procuring the generation that needed the transmission upgrades.
[11] *See* Empirical Estimates of Transmission Value using Locational Marginal, available at https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf.

1920). Through the Northeast States Collaborative on Interregional Transmission, Connecticut and other states are also working to develop a strategic plan that will outline steps that states can take in the near- and medium-term to help address barriers to deploying interregional transmission. DEEP expects this plan to be released in the first half of this year.

IV. Transmission Concerns and Areas for Further Action

DEEP has identified several areas where reforms are needed to ensure beneficial transmission investments and avoid unnecessary costs to Connecticut ratepayers. This section identifies these areas, discusses existing efforts by DEEP, and discusses areas where potential actions by the Connecticut General Assembly might be warranted to provide DEEP or other Connecticut state agencies with additional tools to protect and benefit ratepayers.

A. Asset Condition and Local Transmission Service Projects: Bolster state oversight over these projects to the extent allowable under federal law, while continuing to pursue reforms at FERC to provide greater federal oversight over and scrutiny of asset condition and local transmission service projects.

Due to large investments in New England's transmission system over the past 50 years as well as proactive replacement of aging infrastructure, New Englanders have historically enjoyed a robust and reliable transmission system. Routine maintenance of existing transmission, through asset condition and local transmission service projects, is critical to ensuring continued reliability. However, these projects, which are proposed and pursued by TOs in New England at their sole discretion, currently operate within a regulatory gap and receive effectively no oversight at a regional level. In Connecticut, the Siting Council provides some oversight over projects within the state, but this process could benefit from further refinement to increase the level of scrutiny afforded to these transmission projects.

As New England's transmission infrastructure ages, the pace and scale of asset condition projects proposed by TOs—and the costs of these projects to ratepayers—is increasing. Based on past and projected expenditures, the region's TOs are investing approximately $9.5 billion in asset condition projects between 2018 and 2030, which is or will be recovered in rates. This significantly outpaces spending on reliability projects. Reliability project needs are identified by ISO-NE in a relatively transparent regional planning process where ISO-NE plays a critical oversight role in identifying reliability need and reviewing solutions to ensure projects solve the needs and are properly scoped. When it comes to asset condition projects, however, ISO-NE has informed the states that it does not believe it has authority to provide *any* oversight based on provisions contained in the Transmission Operating Agreement between ISO-NE and the TOs. This means decisions around the underlying need for proposed asset condition projects, the scope of such projects (*e.g.*, whether a full rebuild or only a partial rebuild of a line is required), their timing (*e.g.*, whether a rebuild must be done all at once or could be segmented with the costs accruing to ratepayers more gradually over an extended period of time), and their costs (*e.g.*, whether included costs are reasonably limited and related to resolving the specific project need) are left solely to the TO.

Large asset condition projects, such as where a TO is completely rebuilding a transmission line, regularly cost hundreds of millions of dollars, with even higher amounts possible. States are preempted under federal law from regulating these costs, which end up in FERC-approved transmission rates. It is critical that FERC, which does have jurisdiction here, scrutinize these projects to ensure that captive state ratepayers are only paying for necessary projects (*i.e.*, "prudently incurred" costs). Unfortunately, FERC is failing to provide effectively any scrutiny of asset condition projects. Instead, FERC's current policy is to presume TOs' expenditures on transmission development, including asset condition projects, are prudent unless a challenger can demonstrate "serious doubt" as to the expenditures. This is an almost impossible burden to meet, especially when doing so would mean that FERC would be disallowing costs for a project that is already operational, which is typically the case.

Under the current process, states and stakeholders can provide input on asset condition projects before the costs of such projects are approved by FERC through a publicly accessible process at ISO-NE's Planning Advisory Committee (PAC); however, TOs are under no obligation to account for, or make changes to their project proposals in response to, the input they receive at the PAC. Historically, for each asset condition proposal, the proposing TO has provided the PAC with only a simple PowerPoint presentation containing a few pictures showing damaged or deteriorating transmission infrastructure that ostensibly shows the need for the project, and then a scope of work describing the proposed replacement project and the estimated cost, with +/- estimate range as high as +200%/-50%. Attendees at the PAC can ask questions and provide feedback, but the TOs themselves ultimately determined how much information to include in their presentations and whether to respond to the states' or other stakeholders' questions or requests for additional information.

Through the efforts of Connecticut, our sister New England states, and the New England States Committee on Electricity (NESCOE), which helps represent our states' perspectives at ISO-NE and FERC, we have made some progress in improving asset condition project transparency at the PAC over the past 18 months. Last year, the TOs collectively agreed, as a result of our state pressure, to provide more detail in their PAC presentations and to adopt a more uniform approach to describing the condition of the transmission infrastructure that they seek to replace. Historically, each TO had adopted its own approach to classifying the condition of its transmission assets, which complicated efforts to compare proposals between TOs. Enhanced project transparency and a more uniform approach in presentations are important steps to enable states and stakeholders to more easily review the purported needs for specific asset condition projects. However, these reforms are only informational in nature and are not substitutes for oversight that can effectuate changes to asset condition proposals when appropriate. TOs still have no obligation to revise a proposed asset condition project or otherwise implement any feedback they receive at the PAC. In other words, this input opportunity is largely a "check the box" exercise and does not provide a meaningful mechanism for project oversight, though it is a directional improvement for transparency.

States can exercise some authority over transmission projects through the regulation of siting, permitting, and construction. In Connecticut, the Siting Council regulates the siting of energy facilities, including transmission lines. A transmission project can come before the Siting Council through a couple of different procedural mechanisms, but under each, the Siting Council evaluates and balances the public need for and the environmental impact of the project in any decision impacting the project. For purposes of a transmission line, public need is defined by statute as existing "when a facility is necessary for the reliability of the electric power supply of the state."[12] State jurisdictional reforms could help supplement the record in Siting Council proceedings related to asset condition projects or other

[12] C.G.S. § 16-50p(c)(3).

transmission projects that have not been through an ISO-NE transmission planning process. PURA also retains authority over construction of transmission infrastructure within the state.[13]

If Connecticut were to lead in pursuing legislative change to enhance state oversight over, and planning processes related to, asset condition projects, including at the Siting Council, this could encourage other New England states to also pursue such reforms or to more fully utilize existing legislative authority they may already have. Action by other states in addition to Connecticut is important because Connecticut ratepayers pay for approximately 25% (our state's proportional load share) of all cost associated with asset condition projects on the regional grid, including projects located in other states which are outside of Connecticut's direct jurisdiction.

Ultimately, DEEP believes an effective solution must include independent review of proposed asset condition projects by an entity with transmission planning and engineering expertise. This type of independent review would significantly address the shortcomings of the existing FERC process by providing an independent expert assessment, which could be used—where supported—to more effectively challenge problematic asset condition projects through existing FERC processes and state siting processes, as necessary.

The same oversight concerns for asset condition projects also plague local transmission service projects. These projects solve a local reliability need, and do not provide broader regional reliability benefits. As such, the costs of these projects are not regionalized but fall exclusively on the ratepayers of the service territory where the project is located. Between 2023 and 2028, Eversource anticipates spending at least $586 million on local transmission projects in its Connecticut service territory.[14] This number excludes several other planned local transmission service projects that Eversource has identified but has not yet provided cost estimates for. Just like asset condition projects, these local transmission service projects are not subject to ISO-NE transmission planning processes or review, and they enjoy the same presumption of prudency and lack of scrutiny at FERC as asset condition projects. The same types of reforms discussed above for asset condition projects are needed for local transmission service projects. Subjecting a TO's self-identified need, scope, and timing for a local transmission service project to independent review would provide greater comfort that ratepayer funds are being allocated to projects that are truly necessary and that viable alternatives are given due consideration.[15]

Absent more robust oversight over asset condition and local transmission service project proposals at the state and/or federal level, DEEP is concerned that, alongside legitimate proposals, the region's ratepayers could be saddled with hundreds of millions or potentially billions of dollars in unnecessary or untimely spending. Such wasteful spending would harm ratepayers and make it difficult to afford other transmission investments needed to improve reliability and affordability, diversify our energy mix, and meet growing energy demands. A group of nationwide large industrial energy users recently filed a complaint at FERC related to FERC's lack of oversight over asset condition and local transmission service

[13] Specifically, C.G.S. § 16-243 provides PURA with the "exclusive jurisdiction and direction over the method of construction or reconstruction in whole or in part of each system used for the transmission or distribution of electricity, with the kind, quality and finish of all materials, wires, poles, conductors and fixtures to be used in the construction and operation thereof, and the method of their use . . . ." *Id.*

[14] As of November 2024, UI has not identified any planned local transmission service projects in its service territory. Information on Eversource's local transmission service projects can be found at: https://www.eversource.com/content/docs/default-source/tranmission/eversource-local-system-plan-listing.xlsx.

[15] A recent report by RMI provides a much more extensive overview of concerns around local transmission service projects. That report is available for download at: https://rmi.org/insight/mind-the-regulatory-gap. The discussion in that report uses the phrase "local transmission" more broadly and includes asset condition projects as well.

projects. The complaint, among other things, seeks to implement an independent planning entity to provide increased oversight over these projects at a regional level. DEEP has intervened in this proceeding and will participate as appropriate. DEEP will also continue to engage with the other New England states to pursue a joint federal solution to these issues, but as noted above, Connecticut taking action on its own could prompt other states to act in their jurisdictions before a federal solution is possible.

A robust oversight approach for asset condition projects is further critical to move forward with "right sizing" transmission projects (*i.e.*, the projects where an existing transmission line could get rebuilt at a larger size to transmit more electricity than the prior design). As discussed above, right sizing projects are expected to start out as asset condition projects. While right sizing has the potential to provide net cost savings and other grid benefits to ratepayers, for DEEP to support a right sizing framework, it is essential as a precondition that there be appropriate oversight over the underlying asset condition projects. Without such scrutiny, the underlying basis for right sizing and its potential benefits to ratepayers cannot be established, and DEEP cannot support a process that continues to subject ratepayers to unchecked expenditures. Once an appropriate process for scrutinizing asset condition projects has been established, DEEP will be more than willing to explore right sizing proposals with the TOs that have the potential to reduce ratepayer costs over the long run. Potential Connecticut legislative reform that could be helpful in incentivizing and enabling beneficial right sizing proposals are also discussed further below.

B. Supply Chains: Collaborate to find state jurisdictional solutions to alleviate bottlenecks and costs in transmission supply chains, while advocating for federal support and solutions to more fully address these concerns.

The transmission industry was not spared by COVID-induced supply chain issues and inflation that affected companies across the economy. Combined with growing electric demand in the U.S. and globally, which is simultaneously increasing demand—and wait times—for new transmission equipment, bottlenecks in transmission supply chains are increasingly problematic. This is exacerbated because the transmission grid includes highly specialized equipment, some of which is produced by only a limited number of manufacturers worldwide.

There are significant bottlenecks for high-voltage direct current (HVDC) transmission equipment needed to transmit electricity efficiently over longer distances. HVDC technology has not been widely used in New England to date but is likely to become more important to access new sources of power generation that are further from load centers and in other regions. These demands are similarly growing in other parts of the U.S. and world. Compared to conventional high-voltage alternating current (HVAC) transmission lines, HVDC lines have significantly lower power line losses over long distances and thus are able to transmit power more efficiently, helping to lower costs over the long run. Due to high global demand for HVDC transmission equipment and bottlenecks in the current supply chain, orders for some types of new HVDC equipment must be made as many as 10 years in advance of delivery—that is, an order today might not be fulfilled until 2035.

Supply chain challenges are also affecting conventional transmission equipment like power transformers that are required for the grid to function and expand. Transformers are used to "step up" voltage levels to allow for more efficient transmission of electricity over long distances and to "step down" voltage back to levels that can be used safely by homes and businesses at the distribution system level. Order lead times for new transformers have increased from approximately one year in 2021 to over two years in 2024, with larger transformers having lead times of up to four years.[16] The costs of new transformers have further risen by 60% to 80% since the pandemic.[17] ISO-NE has identified transformers as a key bottleneck in the buildout of the transmission New England needs to meet demand growth between now and 2050. ISO-NE's analysis suggests that up to 81 existing transformers on the region's transmission system could become overloaded—*i.e.*, no longer be able to reliably meet electricity demand—by 2050 due to expected demand growth. To solve this issue, the region may need to add around 40 additional transformers to the transmission system by 2050. ISO-NE estimates that these transformer investments on the transmission system could cost an estimated $400 million through 2050, though these estimates are likely low based on when ISO-NE made the estimates. While the ISO-NE study did not investigate distribution system impacts, it is reasonable to assume that there will be a need for many new transformers at the distribution system level as well.

Addressing supply chain challenges is critical to ensuring New England has access to the transmission equipment needed to keep up with growing electric demand and aging equipment. DEEP, through its participation in the Northeast States Collaborative on Interregional Transmission, is exploring potential actions states, either individually or collectively, could take to address supply chain concerns. Some early options under consideration include (1) creating frameworks for states to collectively and proactively purchase—ahead of specific projects—key transmission equipment that we know will be needed in the coming years, to ensure this equipment is available, given lengthy order lead times, and (2) purchasing this equipment in bulk to help reduce per unit costs. These discussions are in the earliest possible stages of exploration but could be an area for consideration by the General Assembly in the future.

Given the magnitude of supply chain constraints, which extend well beyond New England and the Northeast, and the costs involved with transmission equipment in general, the federal government will likely also need to play a critical role in developing solutions. Ensuring the reliability of the nation's transmission system is an issue that should have bipartisan support, and DEEP is hopeful that the new federal administration and Congress will support continued federal investments and problem-solving in the transmission sphere. DEEP will continue to coordinate with other states in the region to pursue any such opportunities that might arise.

C. Permitting and Siting of Transmission: Explore opportunities to streamline or reform state permitting and siting processes for transmission in Connecticut to improve outcomes while providing appropriate oversight.

Lengthy permitting and siting processes add to a transmission project's overall timeline, adding expense as developers must account for longer periods of uncertainty around things like financing costs and labor and material cost inflation. One way to help address cost concerns with building transmission is to explore ways to streamline the permitting and siting requirements that projects go through. A balance must be struck to ensure that streamlining efforts do not lead to oversight gaps that may themselves lead to higher costs (*e.g.*, through potential overspending on unnecessary asset condition projects as discussed above) or adverse environmental outcomes.

One option to streamline permitting and siting is to incentivize transmission developers to first maximize use of the existing transmission system, including existing transmission corridors. A more streamlined permitting or siting process could be offered, for example, to transmission projects that utilize certain

[16] *See* https://www.woodmac.com/news/opinion/supply-shortages-and-an-inflexible-market-give-rise-to-high-power-transformer-lead-times/.
[17] *Id.*

advanced technologies within existing corridors to more efficiently use these spaces. The use of advanced conductors could allow more power to flow through existing transmission corridors or to potentially flow the same level power but utilizing reduced transmission tower heights, thereby reducing visual and land use impacts. Other grid enhancing technologies, described in the next section, could enhance the efficiency of existing transmission lines and equipment, avoiding or limiting the need to construct new transmission—and the land use impacts of doing so—while reducing total ratepayer costs. In cases that offer such win-wins, more streamlined siting and permitting approaches could be appropriate without creating oversight gaps.

State permitting and siting processes should also incentivize project designs that minimize disruptions and costs from transmission construction to the greatest extent possible. Ensuring that new transmission projects and asset condition projects are sized correctly when planned and developed is one way to accomplish this goal. For example, it may make sense for ratepayers to pay for proactive, right sized upgrades of transmission equipment before current demand levels require them. Rather than having a TO replace aging transmission equipment with similar equipment today only to have to return in ten years to replace that equipment once again with higher capacity equipment, ratepayers—and adjacent communities—may be better off by upgrading such equipment now, in the first instance. Providing regulatory and siting processes that allow for, and encourage where warranted, right sizing could reduce and simplify these processes by avoiding the need to pursue multiple, sequential projects instead.[18]

Some prior Connecticut Siting Council decisions could be interpreted as expressing concern with the buildout of proactive electricity infrastructure. These concerns seem fact-specific to particular proceedings, but there may nonetheless be ambiguity over whether the Siting Council would approve right sizing projects as discussed in this paper. For example, does a project meet the statutory definition of "public need" if it solves demand growth expected to occur ten years after the in-service date of a project?[19] The Siting Council may well determine that based on ISO-NE analyses and other available information that such a project meets the public need definition. However, additional clarity in the state's siting processes on how an appropriately right sized project can move forward may be valuable. It is imperative that any project that utilizes any newly proposed flexibility be subject to appropriate oversight around both the underlying asset condition issue and the right sizing issue that the proposed project is trying to address (*e.g.*, an appropriate regional oversight process that confirms the need for an asset condition project, combined with a rigorous ISO-NE planning process that has identified the same corridor as in need of upgrades by a certain timeline to meet expected power demand).

[18] Again, right sizing is only appropriate if there is first a reliable oversight structure in place to ensure that the asset condition project underlying a right sizing proposal is necessary; otherwise, a "right sizing" proposal might instead result in excessive ratepayer costs and land and environmental disturbances that are unjustified. ISO-NE must also play a central role, with appropriate state and stakeholder participation, in determining whether there is a win-win opportunity to right size a particular asset condition project, based on the ISO's assessment of future load growth and transmission system needs.

[19] Connecticut statute defines "public need" in this context as "necessary for the reliability of the electric power supply of the state." C.G.S. § 16-50p(c)(3).

D. Advanced Transmission Technologies: Require that transmission owners study and deploy advanced transmission technologies where doing so would provide ratepayer and other benefits.

Advanced transmission technologies, such as advanced conductors[20] and grid enhancing technologies (GETs),[21] refer to technologies that can be deployed on the transmission system to potentially save ratepayers money by reducing or offsetting the need for more expensive near- and longer-term transmission investments. Conductors, which is the technical term for the transmission wires themselves, have historically utilized a steel core for support with a separate conductor metal—the material that transmits the electricity—wrapped around that steel core. Advanced conductors use lighter weight composite materials or carbon cores instead of steel. This lighter weight means that, in general, these conductors can carry the same amount of power over a smaller, less heavy conductor or can double the amount of power that can be moved over a similarly sized traditional conductor with lower line losses.

GETs are another category of advanced, non-traditional transmission technologies that can help get more electricity out of the existing transmission system—*i.e.*, to be able to use existing transmission lines and other infrastructure more efficiently—without having to resort to more costly and land intensive investments in new transmission infrastructure. One example of GETs includes the implementation of technologies and procedures to allow transmission lines to safely operate at higher capacities when weather or other variables allow (*e.g.*, it can be safe to transmit at a higher capacity during colder temperatures without overheating a transmission line). To date, TOs across the country have been slow to adopt both advanced conductors and GETs.

As electric demand grows and our region's energy transition continues, New England's transmission system will need to expand and become more robust. Under the status quo regulatory framework, TOs may not be properly incentivized to pursue newer, advanced transmission technologies as aggressively as states may want. Investments in GETs, for example, might mean that a TO foregoes a higher capital cost investment alternative in new transmission infrastructure. Because TOs are compensated through a return on their total capital investments, reducing capital expenditures through more cost-effective (to ratepayers) GETs could lead to lower profits for a TO in absolute dollars. When it comes to advanced conductors, these technologies may involve higher upfront capital costs compared to deploying conventional conductors; however, TOs may be dissuaded from pursuing these technologies due to a higher perceived regulatory risk of cost recovery (*i.e.*, a risk that these higher expenditures for newer technologies might be considered imprudent) or a general lack of familiarity with the technology. A clear regulatory policy framework that ensures that TOs are taking a long-term view on cost effectiveness and helps better align TOs' profit motives and perceptions of risk with ratepayer interests will likely be needed to overcome these barriers and deploy advanced transmission technologies at scale.

Advanced conductors and GETs are not a panacea and not every project will be the right fit for these technologies. Each project faces its own unique set of circumstances and complications. Reforms that help to increase transparency in TOs' transmission planning processes will help the state and

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[20] A much more detailed explanation about advanced conductors and the role this advanced transmission technology can play in saving ratepayers money while also accelerating the clean energy transition is available in the following report: https://acore.org/wp-content/uploads/2022/03/Advanced_Conductors_to_Accelerate_Grid_Decarbonization.pdf.

[21] Further information on GETs, including more detailed explanations of the various types of GETs available, is available at https://watt-transmission.org/what-are-grid-enhancing-technologies/.

stakeholders better understand where cost-effective use cases for these technologies exist and how TOs are weighing the various costs, benefits, and other variables that go into designing a transmission project. Such reforms could also help to highlight scenarios where these technologies are or are not useful solutions. The state could encourage or require increased transparency around the consideration of advanced transmission technologies in the TOs' transmission planning processes, such as early involvement of relevant state entities in transmission planning processes and/or through the consideration of alternatives specifically focused on these technologies in siting processes or other regulatory approval processes.[22]

There are federal efforts currently underway to help deploy advanced transmission technologies, including requirements recently adopted by FERC in its recent Order Nos. 1920 and 1920-A that transmission providers consider GETs and advanced conductors in their planning processes. In addition and partly in response to these FERC orders, ISO-NE has committed to exploring how advanced transmission technologies can be further included in its regional transmission planning as part of ISO-NE's 2025 work plan. This proposed focus on advanced transmission technologies may be a logical place for the region to explore potential economic incentives that ISO-NE could create to help persuade TOs to pursue advanced transmission technologies where appropriate, subject to FERC approval.

V. Conclusion

This White Paper provides a high-level overview of the complex transmission issues facing Connecticut and New England. In the coming months, DEEP will further analyze and solicit public comments on these issues as part of its Integrated Resources Plan (IRP). Building out the transmission grid in New England over the next decade and beyond will be an important step in ensuring an affordable, reliable, and clean electricity grid for Connecticut's ratepayers.

When efficiently deployed and subjected to appropriate regulatory scrutiny at both the state and federal levels, continued transmission investment is critical to ensuring cost-effective and reliable grid outcomes for our state's ratepayers. Toward this end, DEEP will continue to pursue both in-state and regional opportunities and collaborations to increase oversight over asset condition projects and local transmission projects, identify potential ratepayer benefits and cost savings in areas such as right sizing and deployment of advanced transmission technologies, and take full advantage of opportunities for federal funding to support our transmission system. To the extent there is an interest in exploring reforms at the General Assembly or other venues to address the issues discussed in this paper, DEEP stands ready to discuss.

[22] For example, an applicant for a certificate of environmental compatibility and public need before the Connecticut Siting Council is currently required to provide "a detailed analysis of any nontransmission alternatives to the proposed facility or proposed modification . . . ." C.G.S. § 16-50l(a)(3)(D). PURA also maintains some oversight over the construction of transmission projects through the requirements of C.G.S § 16-243.