UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection	**Docket No. RM21-17**

INITIAL COMMENTS OF
MASSACHUSETTS ATTORNEY GENERAL MAURA HEALEY

Pursuant to the Federal Energy Regulatory Commission's ("Commission" or "FERC") Advance Notice of Proposed Rulemaking entitled *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (2021) ("ANOPR"), published in the Federal Register at 86 Fed. Reg. 40,266 (July 27, 2021), the Office of Massachusetts Attorney General Maura Healey ("Massachusetts AGO") submits these initial comments on potential reforms to improve regional transmission planning, cost allocation, and generator interconnection processes.[1] The Massachusetts AGO is expressly authorized by statute to intervene on behalf of public utility ratepayers and has appeared frequently before the Commission.[2] In addition to representing ratepayer interests, as the chief law enforcement officer of the Commonwealth, the Massachusetts AGO upholds and supports Massachusetts' climate change and clean energy laws and policies.

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[1] The Massachusetts AGO separately joined the Comments of the State Agencies submitted to this docket on October 12, 2021. Those comments are fully incorporated and reiterated herein unless otherwise indicated.

[2] *See* Mass. Gen. Laws ch. 12, § 11E.

The Massachusetts AGO applauds the Commission for seeking public input on potential reforms or revisions to existing regulations, which are urgently needed. A more forward-looking, comprehensive approach to transmission planning is called for in New England. We are confident that properly tailored reforms, as discussed below, would be beneficial to both ratepayers and the operation of the power system, while facilitating achievement of clean energy and climate change requirements in Massachusetts and across the region. Specifically, the Massachusetts AGO recommends that the Commission should consider:

- updating the current near-term transmission planning process and creating a long-term planning process, with: (a) nearer-term transmission planning that considers multi-value solutions to reliability, economic efficiency, and public policy needs in a unified process, and (b) a new, proactive, multi-decade, long-term regional transmission planning process that accounts for anticipated future generation, future load-growth, and other system needs;
- ensuring that regional planners evaluate a more comprehensive range of project benefits according to clear, real, and objective criteria;
- ensuring that all transmission planning reforms address existing environmental and energy inequities and deliver environmental justice;
- protecting consumers from undue costs by: (1) mandating extensive opportunities for meaningful competition in solicitations for transmission solutions, (2) retaining the participant funding model as the default cost allocation method for interconnection network upgrades, and (3) strictly limiting or eliminating return on equity ("ROE") incentives for construction of new transmission facilities; and

- establishing Independent Transmission Monitors for each region that would have authority to, among other things: (1) review planning procedures and rules, (2) review any competitive solicitations, (3) monitor and report on transmission projects and cost overruns, (4) provide independent cost estimates for projects, and (5) review transmission owner spending and transmission rates.

II. COMMENTS

A. A More Forward-Looking, Integrated Approach to Transmission Planning Is Urgently Needed in New England.

Over the past decade, renewable energy generation has increased from 10% to 17% of system generation in the New England region (with zero-carbon energy reaching nearly 50% if nuclear and hydroelectricity imports are included).[3] New England's current penetration of zero-carbon generation is an important accomplishment, but it represents merely the first hurdle in a multi-decade effort. The challenges of achieving economywide net-zero greenhouse gas emissions, as required by Massachusetts statute,[4] are much greater.

In order to successfully integrate additional clean energy resources and decarbonize the power sector—as state and federal policies, evolving economics and technologies, utility commitments, and consumer preferences demand—we must build new transmission resources at a historically unprecedented scale and speed, while simultaneously optimizing the efficiency and bolstering the resiliency of the existing system, safeguarding consumers' access to affordable energy, and ensuring equity and justice for all impacted communities. Our transmission and

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[3] Data is available in ISO-NE's 2011 and 2020 Daily Generation by Fuel Type Reports, https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type.

[4] *See* Mass. Gen. Laws ch. 21N, § 3.

interconnection planning and cost allocation policies, as currently designed and implemented, are not up to the task.

This is evident in New England where many of the transmission planning, development, and cost allocation challenges identified by the Commission in the ANOPR are already manifest and causing very real difficulties.

1. *The Challenges of Interconnecting Offshore Wind Highlight the Shortcomings of Existing Policies.*

The current ISO New England ("ISO-NE") interconnection queue is comprised almost entirely of clean generation or battery storage resources.[5] In particular, the imminent construction and interconnection of gigawatts ("GW") of offshore wind to southern New England is highlighting shortcomings of the current interconnection queue process and Cluster Study approach to interconnection in ISO-NE's Open Access Transmission Tariff ("OATT").[6] The current federal lease blocks off the southern coast of New England can accommodate over 12 GW of generation, and there are currently as many as 8,598 megawatts ("MW") of offshore wind seeking to interconnect to Cape Cod or adjacent locations.[7] From the first MW of interconnected offshore wind to the most recent, per-MW interconnection costs are forecasted by

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[5] Al McBride, ISO-NE, *Offshore Wind Development in New England: May 2021 Update*, Presentation to ISO-NE Joint ISO/RTO Planning Comm., at 6 (June 4, 2021), https://www.iso-ne.com/static-assets/documents/2021/06/a04_2_2021-06-04_ipsac_iso-ne_osw_development_update_final.pdf [*May 2021 Offshore Wind Update*].

[6] *See* ISO-NE, ISO New England Open Access Transmission Tariff § II.19.6 & scheds. 22 & 23 [OATT]. ISO-NE's OATT is Section II of the *ISO New England Inc. Transmission, Markets, and Services Tariff*, https://www.iso-ne.com/participate/rules-procedures/tariff.

[7] *May 2021 Offshore Wind Update*, *supra*, at 6.

ISO-NE to increase 86-fold.[8] In addition, interconnection costs for specific projects may vary by tens of millions of dollars depending on a project's specific queue position.

In the future, offshore wind developers may need to construct billion-dollar high-voltage undersea cables on new rights-of-way simply to interconnect to the grid. Such projects will test the limits of current transmission planning, interconnection, and cost allocation processes. Current processes are designed to ensure safe and reliable interconnection on a project-by-project basis, and generally assume that interconnecting generators are the sole beneficiaries of the new lines. Although there is evidence that an integrated offshore wind transmission system with strategically interconnected generation could save customers many millions of dollars,[9] these and other sensible regional solutions are unlikely to materialize without modifications to existing policies. Building transmission independently for each new offshore wind development is likely to lead to transmission overbuild, system inefficiency, and duplicative costs for ratepayers.

The current difficulties of interconnecting offshore wind to southern New England typify the transmission-related challenges New England and other regions will increasingly face as renewable generation continues to be installed.

2. The Goals of Order No. 1000, and Enhanced Transmission Competition, Have Not Been Realized in New England.

Like other regional transmission organizations and independent system operators ("RTOs/ISOs") across the country, New England's grid operator, ISO-NE, employs a siloed, incremental, and largely reactive approach to transmission planning that is posing increasing problems as the power system undergoes massive transformation. Unnecessary siloes between

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[8] *See infra* notes 38–41 and accompanying text.

[9] *See infra* notes 42–43 and accompanying text.

power markets and transmission planning, and between various kinds of transmission upgrades, are hindering effective planning and harming customers.[10] ISO-NE's current approach is, in part, the product of federal rules that the Commission is now well-poised to reform.[11]

The siloed approach to planning implemented by ISO-NE in response to Order Nos. 2003 and 1000[12] was intended to rationalize system needs and increase transmission competition. But, in practice, the region's inflexible and largely reactive rather than proactive transmission planning processes mean that Order No. 1000's promise of competition has not been realized in New England. Since ISO-NE implemented changes to its OATT to comply with the directives of Order No. 1000 in May 2015, ISO-NE has conducted only one competitive solicitation.[13] Even though ISO-NE planning processes include a requirement to solicit proposals for competitive solutions to transmission reliability, that provision only applies to needs that can be addressed more than three years from the completion of the needs assessment.[14] Thus, for

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[10] *Accord* Americans for a Clean Energy Grid, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* 29 (2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf/.

[11] *See* ANOPR at PP 6–29.

[12] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014); *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

[13] The project was awarded to the incumbent utility. *See* ISO-NE, *Boston 2028 Request for Proposal (RFP) - Review of Phase One Proposals* 31–32 (2020), https://www.iso-ne.com/static-assets/documents/2020/07/final_boston_2028_rfp_review_of_phase_one_proposals.pdf [*Boston 2028 RFP – Phase One Review*]; Memorandum from Brent Oberlin, Dir., Transmission Planning, ISO-NE, to Barry Ahern, Dir., Transmission Asset Mgmt. & Planning, National Grid & Jacob Lucas, Dir., Transmission System Planning, Eversource (Sept. 29, 2020), https://www.iso-ne.com/static-assets/documents/2020/09/boston_2028_mystic_retirement_preferred_solution_notification.pdf.

[14] ISO-NE OATT att. K, §§ 4.1(i) & (j).

project needs that are "time sensitive" (three years or less), ISO-NE can avoid the competitive solicitation requirement. Instead, those projects are developed and built by the incumbent transmission owner alone.[15] As the Commission itself observed:

> Since ISO-NE does not conduct an annual transmission planning process, and instead relies upon Needs Assessment Studies to identify reliability needs, coupled with ISO-NE's typical approach to wait for a market solution to address a reliability need, it appears that all reliability needs in ISO-NE may be classified as immediate need reliability projects.[16]

As discussed below, an improved ISO-NE regional transmission planning process should broadly incorporate the opportunity for meaningful competition in solicitations for transmission solutions in order to ensure that resulting transmission rates are just and reasonable.[17]

3. Transmission Planning in New England Must Be Reimagined to Meet New Regional Challenges.

The history of transmission planning in New England demonstrates that ISO-NE's current approach is not the only pathway to transmission planning—and, indeed, is not the optimal approach for a power system in transition. Between 1960 and 2000, electricity generation in New England increased from 27 terawatt-hours ("TWh") to 117 TWh—a compound annual growth rate of nearly 4% per year.[18] When load was rapidly increasing, the region rightly pursued largescale development of generation and transmission assets. For instance, in the 1960s and 1970s, New England utilities created the New England Power Pool

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[15] *Id.* att. K, §§ 4.1(j)(ii), 4.2.

[16] *ISO New England Inc.*, 169 FERC ¶ 61,054, at P 15 (2019).

[17] *See* 16 U.S.C. § 824d(a).

[18] This computation is based on the U.S. Energy Information Administration's State Energy Data System (SEDS) dataset for the New England States (Variable "ESTCP", Electricity Sales – Total Consumption – Physical Units (kWh)), https://catalog.data.gov/dataset/state-energy-data-system-seds.

("NEPOOL") and the "Big 11 Powerloop"—a set of 11 power plants with more than 6 GW of capacity, and 700 miles of 345-kilovolt ("kV") transmission lines connecting the NEPOOL members' systems.[19] Those lines constitute much of the region's current 345-kV transmission backbone today.

Over the most recent two decades, however, New England's consumption has leveled out, and even fallen slightly due to aggressive energy efficiency efforts.[20] The same trend has played out nationally, with a rapid increase in consumption in the second half of the 20th century followed by low or no growth over the past two decades.[21] During this period, New England's transmission concerns have been largely associated with basic congestion and reliability problems as well as age-related structure replacement programs.[22] Congestion upgrades, in particular, have been so successful that congestion has been all but wiped out in the region—resulting in significant cost savings for ratepayers.[23] In the context of a relatively mature system, siloed planning that considers transmission upgrades separately depending on whether they are intended to promote reliability, market efficiency, or public policy goals may well yield efficient,

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[19] *See, e.g.*, *Public Works Appropriations for 1968: Hearing Before a Subcomm. of the H. Comm. on Appropriations*, 90th Cong. 423–25 (1967) (introducing into the record pages of the Committee Staff's investigation report); *The Interconnected New England Generation Expansion Study: Second Progress Report* (Apr. 14, 1967); *The Interconnected New England Generation Expansion Study: Third Progress Report* (July 16, 1968); *Interconnected New England Generation Study: Generation Task Force Report No. 4* (May 1971).

[20] *See* ISO-NE, *Net Energy and Peak Load* (2020), https://www.iso-ne.com/static-assets/documents/2019/02/enepk_report.xlsx (reporting ISO-NE's annual net energy and peak load data for 2000–2021).

[21] *See* U.S. Energy Info. Admin., *September 2021 Monthly Energy Review* 130, tbl.7.2(b) (2021), https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf.

[22] ISO-NE, *2021 Regional System Plan* 1.1.3.2, 1.1.3.3, 5.10.1 (Draft Sept. 3, 2021), https://www.iso-ne.com/static-assets/documents/2021/09/draft_rsp21_report.docx.

[23] Congestion peaked in 2005 with total costs of $266 million, but by 2020, costs had fallen to just $29 million. *Id.* at tbl.5-3. Net Commitment Period Compensation followed the same trend: costs peaked in 2007 at $215 million then fell to $4.6 million in 2020. *Id.* at tbl.5-4.

and cost-effective, outcomes. Likewise, when the region is addressing latent reliability problems or facilitating one-for-one generator replacement in the Forward Capacity Market, reactive planning on a project-by-project basis may prove to be a sensible approach.

It is increasingly clear, however, that such approaches will not consistently provide just and reasonable outcomes going forward. Over the next thirty years, New England must radically remake its power system in order to meet new system needs, including: achieving state and federal greenhouse gas emission reduction requirements; accommodating market demand for new types of generation resources that have different characteristics than traditional fossil-fuel-fired power plants and are sited in new locations, often far from load centers; facilitating significant load growth due to electrification; satisfying growing consumer preferences for clean generation and electrification of transportation and other end uses; and ensuring the resilience of the system to increasing extreme weather events, cybersecurity attacks, and other novel stresses. These needs are very different from traditional congestion and reliability problems, and they demand new approaches.

The transition to broad electrification and a grid powered predominantly by clean and renewable energy resources poses a considerable challenge to existing planning processes. Recent studies indicate that broad decarbonization of the U.S. economy, as spurred by federal and state policies intended to forestall the most devastating risks of the climate crisis, will require a dramatic increase in the size and scope of the electric system.[24] While these studies vary in

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[24] *See, e.g.*, U.S. Dept. of Energy, *Solar Futures Study* fig. ES-1 (2021), https://www.energy.gov/sites/default/files/2021-09/Solar%20Futures%20Study.pdf; Ryan Jones et al., Evolved Energy Research, *Energy Pathways to Deep Decarbonization A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study* 2–4, 53–55 (2020), https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download [*MA Pathways Report*]; Eric Larson et al., Princeton University, *Net-Zero*

their details and assumptions, all are consistent in indicating that decarbonization necessitates significant increases in new clean generation and new transmission to connect that generation to load reliability and efficiently. For instance, *Energy Pathways to Deep Decarbonization* ("*MA Pathways Report*"), a technical report commissioned by Massachusetts as part of its *2050 Decarbonization Roadmap* study,[25] indicates that, across a wide range of policy-compliant scenarios, New England load will approximately double and the region must install roughly 1 GW of offshore wind and 1 GW of solar each year from now through 2050 to meet the Commonwealth's legal mandate to achieve net-zero greenhouse gas emissions by 2050.[26] To state it another way, the region to date has only built 1-in-9 MW of the clean energy needed to meet 2050 climate targets. To integrate those new clean resources, many miles of transmission must be built, both within the New England footprint and connecting to neighboring control areas. The *MA Pathways Report* also indicates that under least-cost, carbon-compliant pathways, intraregional and interregional transmission would need to be dramatically expanded in order to connect renewable-rich zones with load centers and to ensure system reliability.[27]

America: Potential Pathways, Infrastructure, and Impacts 76–88 (2020), https://netzeroamerica.princeton.edu/img/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf; E3 & Energy Futures Initiative**,** *Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future* 40–43 (2020), https://energyfuturesinitiative.org/efi-reports; Jürgen Weiss, J. Michael Hagerty, & María Castañer, The Brattle Group, *The Coming Electrification of the North American Economy* 17 (2019), https://wiresgroup.com/the-coming-electrification-of-the-north-american-economy/; Eversource Energy, *Eversource's Grid of the Future Study Methodology & Preliminary Results*, Presentation to Joint Meeting of NEPOOL Market Comm. & Reliability Comm. (July 1, 2020), https://www.iso-ne.com/static-assets/documents/2020/06/a2_c_eversource_presentation_grid_of_the_future_study.pdf.

[25] Mass. Exec. Off. of Energy & Envtl. Affairs & Cadmus Group, *Massachusetts 2050 Decarbonization Roadmap* (2020), https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download.

[26] *MA Pathways Report, supra*, at figs. 22 & 53; *see also* Mass. Gen. Laws ch. 21N, § 3.

[27] *MA Pathways Report*, *supra*, at 78–79.

Thus, in many ways, the system needs our region faces in the 2020–2050 period are more analogous to the *status quo ante,* when the New England power system was rapidly expanding. The region must not only conduct asset conditioning and reliability projects but also focus on transmission development to enable efficient bulk transfer of clean energy around the region (and between regions). Given the scope and scale of present needs, increased coordination between generator development, transmission development, and system operation is essential to ensure just and reasonable outcomes for consumers, just as it was a half century ago.

B. The Commission Should Require a Shift to Forward-Looking and More Integrated Regional Transmission Planning While Protecting Consumers from Undue Risks.

The Commission seeks comment on whether regional transmission planning processes should be amended to better account for anticipated future generation needs.[28] The answer is yes. The Massachusetts AGO urges the Commission to reform its policies to require proactive regional transmission planning processes that better account for anticipated future generation and other system needs while appropriately protecting customers from bearing the costs of unnecessary or inefficient transmission development.

Forward-looking planning is essential. Current transmission planning processes, which largely rely on project proponents to propose *ad hoc* upgrades on a piecemeal basis, are an impediment to modernizing the grid and interconnecting the clean energy resources that the market and state policies demand. Moreover, current processes needlessly increase costs for consumers. While a more proactive and holistic planning process, if well-designed and implemented, has the potential to result in significant consumer savings over the long term,

[28] ANOPR at P 44.

consumer protection, stakeholder engagement, and transparency measures must be incorporated into every facet of the process. Without appropriate protections, there is a risk that customers will be saddled with high costs today for speculative assets that may never be needed—veritable "bridges to nowhere"—or for projects pursued for private profits rather than benefits to consumers.

As discussed below, the Massachusetts AGO offers the following recommendations to better coordinate transmission planning with anticipated future generation needs while protecting consumers from undue risks:

1. regional planners should integrate projections of future system generation and demand needs, including relevant federal and state policy targets, into the transmission planning process on both long-term and near-term timescales;

2. regional transmission planning processes should be transparent, adaptive, include meaningful participation of key stakeholders and decisionmakers, and define formal roles for the States and the regional grid operator;

3. regional planners should evaluate, to the extent feasible, a more comprehensive range of a proposed transmission project's benefits according to preestablished criteria that are clear, real, and objective; and

4. a cost allocation framework that recognizes regional costs and benefits should be established for solutions identified through the regional transmission planning process.

These reforms are necessary to ensure that transmission infrastructure will meet long-term system needs in a cost-effective manner, thereby resulting in just and reasonable rates. Thus, they are well within the Commission's statutory authority.[29]

[29] *See* 16 U.S.C. § 824e(a) (authorizing the Commission to act "upon its own motion" to ensure that rates and any "any rule, regulation, practice, or contract affecting such rate, charge, or classification," are not "unjust, unreasonable, unduly discriminatory or preferential"); *id*. § 824q(b)(4) ("The Commission shall . . . facilitate[] the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities . . . ."); *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 89–90 (D.C. Cir. 2014) ("[R]ecogniz[ing] that state and federal policies might affect the transmission market and direct[ing] transmission providers to consider that impact in their planning decisions. . . . fits comfortably within the Commission's authority under Section 206" of the Federal Power Act.).

1. *Future System Needs and Demands Should Be Integrated into Long-Term and Near-Term Transmission Planning.*

The Commission seeks comment on whether it should reform how regional transmission planning processes "model future scenarios to ensure that those scenarios incorporate sufficiently long-term and comprehensive forecasts of future transmission needs."[30] The answer is plainly yes. Regional planning can, and should, more thoughtfully incorporate future generation needs, as well as demand projections and other anticipated system needs such as increased resilience to extreme weather. Planning should consider both system-transforming and incremental upgrades on a variety of timescales. And regional planners should look holistically at maximizing the overall efficiency of the power system rather than segregating projects into artificial silos.

i. **RTOs/ISOs and the States Should Engage in Multi-Decade, Comprehensive, Long-Term Regional Transmission Planning.**

States, local governments, federal agencies, utility companies, investors, research universities, and other public and private actors have conducted sophisticated multi-decade, cross-sectoral, scenario-based analyses to inform long-range planning and decision-making about the energy system.[31] Federal, state, and local policymakers are also continuing to develop policies and programs that have important implications for the energy system and transmission planning, such as strategies to promote widescale electrification of building heating and transportation, and mandates or incentives for utilities to procure more electricity from renewable energy resources. At the same time, technologies and market conditions are rapidly evolving, with major implications for long-term system demands and costs. However, there are

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[30] ANOPR at P 46.

[31] *See supra* note 24.

few mechanisms to integrate such considerations into existing regional transmission planning processes. To meet the challenge of transforming the grid for the future, the Commission should establish a process whereby RTOs/ISOs and other regional transmission planners, States, and other key stakeholders engage in comprehensive, multi-decade planning efforts that consider system needs across various scenarios.

The failure to align state and regional planning processes, and the resulting costs for consumers, is starkly evident in New England. Massachusetts, like various other States, has developed a multi-decade, scenario-based energy "pathways" analysis, the *MA Pathways Report*, to better understand how the energy system and other sectors of the economy must change to achieve the state's greenhouse gas emissions reduction requirements. The *MA Pathways Report* is cross-sectoral in scope (including, *e.g.*, building heating, transportation, and end-use consumption sectors) and considers various kinds of energy sources such as electricity, motor vehicle fuels, and building-heating fuels. Notably, the *MA Pathways Report* includes a representation of the power sector, including estimates of load growth, capacity expansion, and hourly production profiles.[32] The goal of this analysis is to provide state policymakers with directional insights into key needs, common trends, and least-regret decarbonization solutions across the Commonwealth's economy. The analysis allows policymakers, amidst uncertainty, to make policy choices today that are necessary, given the time horizon of investments and the lifespan of infrastructure, to achieve long-range policy targets.

Regarding transmission, the *MA Pathways Report* indicates that, over the next 30 years, intraregional transmission throughput would need to increase by as much as 9.2 GW compared

[32] *MA Pathways Report*, *supra*, at 116, fig. 53.

to reference levels, while interregional transmission (*i.e.*, New England to New York, Quebec, and New Brunswick) would need to increase by 5 to 14.3 GW.[33] It also found that some transmission routes were always needed and that others were frequently needed, including increased interconnection between Quebec, New Hampshire, and Massachusetts.[34] The *MA Pathways Report*'s long timescale enables identification of broad transmission needs with significant forenotice and can help decisionmakers distinguish between likely needs, plausible needs, and scenario-specific needs as well as possible timelines for those needs.

By contrast, ISO-NE rarely plans more than 10 years into the future, and even those plans are predominantly focused on reliability needs.[35] Consequently, the current planning process unduly focuses on projects that address narrow needs and fails to identify solutions that could provide broader regional benefits over a longer-term at lower overall cost to customers. In the void created by the lack of forward-looking regional planning, the interconnection process has become the region's primary mechanism for planning new transmission facilities. But that process, which was designed to ensure that generators can safely and reliability tie into the existing transmission network, is a poor fit for the challenges now confronting the region as the States seek to add massive amounts of clean generation, some of which is located far from load centers or in federal offshore waters.

It is unlikely that developers alone, without coordinated planning, will cost-effectively resolve New England's transmission needs. Offshore wind provides a case in point. State-

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[33] *MA Pathways Report*, *supra*, at tbl.8 & fig. 57.

[34] *Id*.

[35] *See* ISO-NE OATT att. K, § 3 (limiting regional system planning to a 10-year timeframe).

mandated procurements in Massachusetts, Connecticut, and Rhode Island have already resulted in signed contracts or utilities seeking power purchase agreements for about 5 GW of offshore wind.[36] And ISO-NE estimates that its interconnection queue has nearly 15 GW of offshore wind seeking to interconnect along New England's southern coast.[37] Today, all of these projects are planning on developing project-specific radial lines from offshore collection points to on-shore points of interconnection.

Project-specific transmission might be lowest cost (and lowest risk) for individual projects, but this form of *ad hoc* or accretive transmission development is likely neither least-cost for consumers overall nor least-impact for the public generally. The current approach has also led to some prospective wind farms being subject to radically higher interconnection costs than others, due to vagaries of queue positions and ISO-NE impact study determinations, despite the fact that all of these resources are situated in the same offshore lease area and all acquired contracts with the same set of States around the same time. In most regards, these resources are similarly situated, but for purposes of interconnection they most certainly are not. This can be observed most clearly in estimated interconnection costs identified in offshore wind system impact studies. The first 800 MW of offshore wind will require interconnection upgrades estimated to cost about $7.7 million ($9,625/MW installed).[38] The next 800 MW of offshore

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[36] *May 2021 Offshore Wind Update*, *supra*, at 5.

[37] *Id.* at 6.

[38] RLC Engineering, *QP624 – Offshore Wind Interconnection System Impact Study*, at v (ISO-NE Interconnection Request Study, 2019), https://www.iso-ne.com/system-planning/interconnection-service/interconnection-request-studies/ (contains critical energy infrastructure information; ISO-NE approval required to access document).

wind will require upgrades estimated to cost $196 million ($245,000/MW installed).[39] The next 1,200 MW of offshore wind will require upgrades estimated to cost $335 million (or about $279,000/MW installed).[40] And the next 2,000 MW of offshore wind interconnection could require developing new submarine high-voltage direct current ("HVDC") cables from Cape Cod to Boston, on a separate right-of-way, which may cost more than $1 billion ($833,000/MW installed).[41] From the first MW of interconnected offshore wind, per MW offshore wind interconnection costs have been forecasted to increase from $9,626/MW to $833,000/MW; an 86-fold increase.

By contrast, an ISO-NE Economic Study found that 5,800 MW of offshore wind can be interconnected along the southern coast of New England without significant onshore upgrades if the wind resources are distributed across a range of interconnection points.[42] Separately, a study sponsored by merchant transmission developer Anbaric preliminarily suggests that a "planned" offshore wind transmission solution accommodating 3,600 MW of offshore wind in New England could have direct transmission costs $500 million lower than an *ad hoc* approach.[43]

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[39] Mitsubishi Electric, *System Impact Study (SIS): QP 700*, at vii (ISO-NE Interconnection Request Study, 2020), https://www.iso-ne.com/system-planning/interconnection-service/interconnection-request-studies/ (contains critical energy infrastructure information; ISO-NE approval required to access document).

[40] ISO-NE, *First Cape Cod Resource Integration Study: Redacted Non-CEII Version* 13, tbl.6-2 (2021), https://www.iso-ne.com/static-assets/documents/2021/07/cape-cod-resource-integration-study-report-non-ceii-final.pdf.

[41] *See* Al McBride, ISO-NE, *Notice of Initiation of the Second Cape Cod Resource Integration Study*, Presentation to ISO-NE Planning Advisory Comm., at 7 (May 19, 2021), https://www.iso-ne.com/static-assets/documents/2021/05/a4_initiation_of_second_cape_cod_resource_integration_study_presentation.pdf (describing potential needed upgrades); ISO-NE, *2019 Economic Study: Offshore Wind Integration* 33–36 (2020), https://www.iso-ne.com/static-assets/documents/2020/06/2019_nescoe_economic_study_final.docx (discussing potential cost of needed upgrades).

[42] ISO-NE, *2019 Economic Study: Offshore Wind Integration*, *supra*, at 1.

[43] Johannes Pfeifenberger et al., The Brattle Group, *Offshore Transmission in New England; the Benefits of a Better-Planned Grid* 17 (2020),

Planned approaches may also result in lower impact to fisheries, fewer or more constrained landing points, and fewer impacts to environmental justice communities and other communities impacted by transmission siting. Conceptually, this should not be surprising: rarely does a region have the opportunity to develop large swaths of the transmission system from scratch and obtain the benefits of proactive, rational design and development. Despite the intuitive and modeled value of planned approaches, however, ISO-NE is not pursuing such an approach.[44]

The New England States have rightly identified the inadequacy of ISO-NE's 10-year planning horizon in light of the energy system transformation that is already underway. The *New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid* recommends that ISO-NE start conducting a comprehensive, long-term regional transmission planning process that: considers system needs across various resource scenarios, and selects future timeframes that would provide insight into transmission upgrade cost estimates; considers the possible need for system upgrades to accommodate increased terrestrial wind, offshore wind, and solar resources; and provides methods to maximize the use of existing transmission assets.[45]

At the recent request of the New England States, ISO-NE has initiated a high-level 2050 Transmission Study that will "inform[] the region of the amount and type of transmission infrastructure needed to cost-effectively incorporate clean-energy and distributed-energy

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https://brattlefiles.blob.core.windows.net/files/18939_offshore_transmission_in_new_england_-the_benefits_of_a_better-planned_grid_brattle.pdf.

[44] *Cf.* ANOPR at PP 54–60 (discussing examples of planned transmission to facilitate integration of renewable resources in identified geographic zones).

[45] New England States Comm. on Electricity, *New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid* 4–5 (2020), https://nescoe.com/resource-center/vision-stmt-oct2020/.

resources and to meet energy policy goals, including economywide decarbonization" in 2050.[46] It is possible that this study, though primarily intended to disseminate information, could begin to lay the groundwork for longer-range planning that identifies the necessary transmission upgrades that will enable a significant influx of clean generation. But this small step is not nearly enough. The Commission should adopt reforms that require regional transmission planners to engage in routine multi-decade planning processes (*e.g.*, looking 10, 20, and 30 years ahead) that incorporate insights from scenario-based analysis and other relevant considerations, including the state and federal policy landscape, utility commitments, and up-to-date projections of load and costs.

Importantly, regional planning that accounts for long-term, anticipatory system needs must include robust mechanisms to ensure transparency and must include meaningful participation of key stakeholders and decisionmakers, including States. One potential model for a regional planning process in New England could involve establishment of a formal State-led regional planning committee charged with broadly identifying scenarios for analysis. This committee would seek input from other key stakeholders, provide opportunities for public input, and consult with ISO-NE. Achievement of state clean energy and climate change policies would form the backbone of planning scenarios, and studies like the *MA Pathways Report* and the 2050 Transmission Study would offer a valuable foundation for further regional analysis. ISO-NE would then utilize its technical and analytical expertise to identify various portfolios of transmission solutions that could achieve identified regional objectives under the planning

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[46] Vamsi Chadalavada, ISO-NE, *Updated 2021 Annual Workplan*, Presentation to ISO-NE NEPOOL Participants Comm., at 5 (May 6, 2021), https://www.iso-ne.com/static-assets/documents/2021/04/2021_awp_update_05_06_21_pc.pdf.

assumptions and in light of uncertainty, while also maintaining reliability. ISO-NE would also provide other decision-relevant information such as initial projections of costs to consumers and other impacts. The planning committee would evaluate those solutions portfolios and discuss the various trade-offs and costs. And the committee would ultimately determine, based on clear, real, and objective predetermined criteria that are developed with consideration of public input, which regionally beneficial solutions to pursue through competitive solicitations conducted by ISO-NE. This process would reoccur at regular intervals going forward, enabling planners to incorporate updated information into planning.

In order for such a model to succeed, the planning committee's makeup and role in regional planning processes and the corresponding responsibilities of the grid operator must be formalized. Transparency and public participation measures are also essential to foster public confidence in the analysis and decision-making process. In addition, the regional long-term planning processes should be designed and implemented in accordance with adaptive management principles, ensuring that assumptions and other inputs are continually updated to reflect the latest information.[47] An unreasonably regimented process could produce a power system based on yesterday's needs, resulting in unreasonable consumer costs.

[47] Notably, ISO-NE is currently planning tariff revisions that would take a step down this road by codifying the 2050 Transmission Study planning process into its tariff. These planned changes are directionally correct, though short of the comprehensive planning process recommended by the Massachusetts AGO. The current tariff proposal would support ISO-NE's performance of State-requested transmission analysis, including development of high-level transmission concepts, along with cost estimates if requested, to meet State-identified requirements. ISO-NE is also contemplating a second phase of this effort that would enable a State or States to consider potential options for addressing the identified issues and cost allocation for associated transmission improvements. *See generally* Brent Oberlin, ISO-NE, *Attachment K Revisions: Extended-Term Planning*, Presentation to NEPOOL Transmission Comm. (Sept. 28, 2021), https://www.iso-ne.com/static-assets/documents/2021/09/a07_tc_2021_09_28_attk_ext_trans_presentation.pdf.

Notably, a long-term planning process should helpfully inform near-term (sub-10-year) reliability assessments, like those conducted by ISO-NE today. It may also help regional planners proactively identify reliability upgrades with sufficient lead time to avoid constructing new projects using the Order No. 1000 immediate needs exemption. In this way, long-term planning might also enhance the frequency and efficiency of Order No. 1000 competitive solicitations for transmission.

ii. **Near-Term Transmission Planning Should Holistically Consider Multi-Value Solutions to Reliability, Economic Efficiency, and Long-Term System Needs.**

The Commission's prior orders on transmission planning, including Order Nos. 2003 and 1000, have resulted in beneficial reforms. But they have also encouraged the development of siloed regional planning processes that separately evaluate transmission projects for reliability, economic efficiency, and public policy objectives, and thereby are unable consider the full range of potential project benefits and costs.[48] Instead, the Commission should promote near-term planning that seeks to optimize the efficiency of both the power markets and the transmission system simultaneously, and holistically considers upgrades that may simultaneously facilitate reliability, economic efficiency, achievement of state public policy and other long-term system needs.[49]

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[48] *See* ANOPR at P 85; *id.* (Glick, Comm'r & Clements, Comm'r concurring) at PP 8–9.

[49] It is already the goal of the region's power markets to maximize the social surplus (or, roughly, minimize cost). *See Third Restated Certificate of Incorporation of ISO New England Inc.* § 3(a)(ii) (filed Sept. 28, 2021), https://www.iso-ne.com/static-assets/documents/aboutiso/corp_gov/cert_inc/Second_Restated_Certificate_of_Incorporation.pdf. And process improvements in Order Nos. 890 and 1000 were largely designed to "meet transmission needs more efficiently and cost-effectively," Order No. 1000, 136 FERC ¶ 61,051, at P 4, and to "enhance the ability of the transmission grid to support wholesale power markets," *id.* at P 12.

In general, maximizing value for consumers means that it will sometimes be prudent and preferable to select a near-term higher-cost transmission project that not only meets today's needs but also enables proven, substantive cost savings down the road. However, New England's siloed approach to transmission planning inhibits identification of multi-value solutions. ISO-NE's Boston 2028 Request for Proposal ("RFP") illustrates the limitations of current New England planning processes. The Boston 2028 RFP, which is the only competitive solicitation ISO-NE has conducted under Order No. 1000, sought transmission solutions to address reliability concerns in the Boston metropolitan area that are anticipated upon the retirement of the Mystic Generating Station. In focusing on cost-effectively solving reliability needs alone, ISO-NE rejected all but one of thirty-six proposals.[50] While ISO-NE rejected some of these proposals for technical reasons, it eliminated several due to cost considerations alone.[51]

Notably, however, several of the rejected projects potentially could have solved the identified near-term reliability needs *and also* facilitated clean energy integration needs anticipated over a longer term. For example, incumbent utilities offered eight projects presenting a spectrum of costs and benefits,[52] including proposals for increased south-to-north interface throughput, which could have enabled more energy to be transferred from the offshore-wind-rich southern coast to metropolitan Boston.[53] Further, one developer proposed a higher-cost project that appears to be designed to address many of the same needs subsequently identified by ISO-

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[50] *See Boston 2028 RFP – Phase One Review*, *supra*, at 33.

[51] *Id.* at 31–32.

[52] *See* ISO-NE, *Boston 2028 RFP – Review of Phase One Proposals: Appendix A – Redacted Executive Summaries from Phase One Proposals* 6, tbl.1-1 (2020), https://www.iso-ne.com/static-assets/documents/2020/07/final_boston_2028_rfp_review_of_phase_one_proposals_appendix_a.pdf.

[53] *Id.* at 8–11, 22–25, 47–50 (summarizing proposals for Projects BOS-001, BOS-007, and BOS-021).

NE in its *Second Cape Cod Resource Integration Study*—a cluster study of upgrades needed to interconnect additional offshore wind in the Cape Cod, MA area.[54] These proposals suggest it is possible that, had ISO-NE holistically evaluated proposals considering regional needs beyond reliability alone, it might have identified a project that cost-effectively solved multiple system needs.[55]

The Commission should promote planning processes and policies that enable regional planners to better identify and opportunistically develop such multi-value solutions through near-term reliability planning processes. The New England States Committee on Electricity's ("NESCOE") Overlay Network Expansion ("ONE") Transmission concept offers an example of one possible mechanism to integrate some public policy goals into ISO-NE's system reliability planning process.[56] Under the ONE Transmission concept, regional planners would explore whether a reliability transmission upgrade need aligns with any State-identified public policy needs, and, if so, they would advance a multi-use transmission project. Concepts like this have the potential to provide greater visibility into cost-effective multi-value investments, save ratepayers money by reducing overlapping needs, and enhance siting efficiency.

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[54] *Id.* at 17–21, 26–29 (summarizing proposals for Projects BOS-005 and BOS-009).

[55] *Cf.* Letter from U.S. Sens. Edward Markey & Elizabeth Warren to Gordon van Welie, President & Chief Exec. Offr., ISO-NE, at 2 (June 5, 2020), https://www.iso-ne.com/static-assets/documents/2020/06/2020_06_12_sens_markey_warren_response_from_gvw_combined.pdf (arguing that state public health and climate change policy "priorities should be reflected appropriately among the evaluation criteria for the Boston 2028 RFP").

[56] NESCOE, *Overlay Network Expansion (ONE) Transmission: Concept for Discussion*, Presentation to ISO-NE Planning Advisory Comm. (Apr. 14, 2021), https://www.iso-ne.com/static-assets/documents/2021/04/a5_nescoe_overlay_network_expansion_transmission_concept_for_discussion.pdf.

2. *The Commission Should Ensure That Regional Planners Evaluate a More Comprehensive Range of Project Benefits According to Clear, Real, and Objective Criteria.*

The Commission is seeking comment on whether criteria in addition to those related to traditional reliability, economic, and public policy needs should be planned for and considered in the evaluation of benefits in the transmission planning process.[57] The Massachusetts AGO urges the Commission to adopt reforms that ensure regional planners evaluate, to the extent feasible, a more comprehensive range of a project's benefits according to preestablished, uniform criteria that are clear, real, and objective, and that better capture the many diverse values a transmission project is anticipated to provide to the system. This broad range of benefits could include, for example:

- reduced energy production cost (*i.e.*, congestion),[58]
- enhanced access to lower cost generation capacity (*e.g.*, resources in geographically distant wind/solar rich regions),
- avoided reliability-must-run contracts,
- reduced energy transmission losses,

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[57] ANOPR at PP 72, 86–89.

[58] In particular, regional planners should consider the combined impact of new transmission paired with new generation when assessing production cost improvements. Today, when economic efficiency transmission projects are assessed, planners consider the generation system as it is and then assess whether a new line (or other upgrades) could reduce congestion. *See* ISO-NE, *Types of Transmission Upgrades* 1 (2020), https://www.iso-ne.com/static-assets/documents/2020/09/types-of-transmission-upgrades-from-old-section-2.1.1-of-rsp.docx. In practice, however, when new transmission and generation are considered in concert, it is the portfolio impact of both that matters. Economic assessments of building new generation, without enabling transmission, in a constrained zone would typically show significant curtailment and foregone benefits, while transmission without generation could show only modest congestion benefits. Considering both elements in concert would demonstrate the benefit of avoided congestion and reduced production costs associated with new transmission and generation. This would enable regional planners to better align transmission expansion with generator expansion and lower overall rates for consumers.

It also may be prudent to evaluate cost savings in the forward capacity market (*i.e.*, the change in inframarginal capacity offers). This is because capacity market costs are directly related to energy market offers and both, together, drive the deployment of capital investment for generation.

- avoided or deferred costs of other prospective transmission projects, and
- system resiliency benefits considering anticipated climate change impacts over the project's lifespan.

In considering revisions to project evaluation criteria, the Commission should be mindful that expanding the suite of benefits considered by regional planners could shift the cost-benefit ratio for some projects. If not appropriately constrained and defined, overly broad criteria could encourage speculative project development and result in unreasonably high transmission costs for regional ratepayers. Moreover, overbroad or abstract benefit criteria could potentially result in the selection of projects that have general societal benefits but not net benefits for the power system, improperly shifting the cost burden for such benefits from taxpayers to electric ratepayers. To ensure customers are appropriately protected, the criteria for evaluating benefits must be clear, real, and objective. Regional planners should establish criteria through a transparent public process that incorporates input from a broad range of stakeholders, including States and consumer advocates.

3. The States Should Establish a Bulk Transmission Cost Allocation Framework for Solutions Identified Through the Regional Transmission Planning Process.

The Commission seeks feedback on potential reforms to ensure that the costs of bulk transmission facilities developed through the regional transmission planning process discussed above "are allocated in a manner that is roughly commensurate with those benefits."[59] The Massachusetts AGO agrees with the Commission's suggestion that "a more integrated and holistic process" is appropriate for projects identified through that regional transmission planning

[59] ANOPR at P 75.

process.[60] The regional allocation of costs for such projects should be rooted in evaluation of regional costs and benefits and should be designed to guide cost allocation determinations for regionally planned solutions portfolios. This framework should be robust enough that it provides certainty to developers and ratepayers.

C. Cost Allocation for Network Upgrades Should Better Facilitate Solutions That Address Future Needs While Protecting Consumers from Undue Costs and Risks.

The Commission seeks input on potential changes to processes for allocating interconnection costs—in particular, the participant funding approach to cost allocation that is broadly used by RTOs/ISOs, including ISO-NE, for interconnection-related network upgrades.[61] Under the participant funding approach, the costs of an interconnection-related network upgrade are assigned directly to a voluntary interconnecting customer. As described below, the participant funding approach is protecting ratepayers in New England by encouraging developers to minimize costs and discouraging inefficient and speculative projects. But, as noted by the Commission, participant funding can inhibit, in some instances, the development of regionally beneficial renewable generation projects where developers are unable to finance upgrade costs or where state procurements are driving development.[62] We urge the Commission in any reforms to allow ISO-NE to retain its participant funding model as the default cost allocation method for interconnection network upgrades and consider alternative cost allocation methods only in instances where participant funding may inhibit realization of regional benefits.

[60] *Id.* at P 86.

[61] *See id.* at PP 98, 100, 111–49.

[62] *See id.* at PP 111–30.

As an initial matter, it is important to note that if the Commission establishes an appropriate forward-looking regional process, the Commission may also address concerns about the participant funding model resulting in unreasonably high interconnection costs. For example, concern over the participant funding model exists, in part, because some projects are being assigned very large upgrades that almost assuredly provide regional benefits and benefits to future customers. If an improved regional planning process, as discussed above, can identify and implement portfolios of projects that deliver significant regional benefits (such as an integrated offshore wind interconnection plan) then the residual interconnection costs to connect a specific new facility to the expanded "backbone" of the grid would be reduced. Or put a different way, if regional planning can prospectively address true regional needs, then participant funding may still be the optimal approach for paying for interconnection costs in most instances.

The use of participant funding in New England aligns with the longstanding efforts of electric restructuring to shift economic risk from the consumers of electricity to its developers and producers. ISO-NE's tariff codifies that principle in its participant funding model for interconnection-related network upgrades, which assigns 100% of the costs of an interconnection-related network upgrade directly to the interconnecting customer.[63] By requiring interconnecting resources to pay for their own network upgrades, the current tariff encourages developers to find low-cost points of interconnection and minimize their costs. If the expected costs of interconnection at a specific point of interconnection are too high, a developer might seek to pause its project or pursue an alternative interconnection location. Moreover, participant funding provides interconnecting resources strong incentives to carefully consider the

[63] ISO-NE OATT sched. 12.

cost and necessity of upgrades identified by ISO-NE or the transmission provider as necessary for interconnection and to seek modification as warranted. In this way, the participant funding approach aligns the interests of the developer with system interests in cost-containment and efficiency. And, as noted in Order No. 2003, "under the right circumstances, a well-designed and independently administered participant funding policy for [interconnection-related] Network Upgrades offers the potential to provide more efficient price signals and a more equitable allocation of costs than [a] crediting approach."[64]

Nevertheless, the Commission notes that, in some instances,

> there are circumstances where this allocation of interconnection-related network upgrade costs may not be roughly commensurate with the distribution of benefits. . . . Allowing transmission customers to receive the benefits of interconnection-related network upgrades without paying for a proportionate share of their costs is an example of the "free rider" problem that the Commission's "beneficiary pays" cost causation principle is supposed to avoid.[65]

There are plainly instances where interconnection of additional clean generation can provide regional benefits and reduce existing costs, such as vulnerabilities to extreme weather or congestion. Certain billion-dollar network upgrades that have been tentatively identified in New England may fall into this category. For example, under the participant funding approach, certain offshore wind resources seeking to interconnect on Cape Cod must fund the cost of expensive new undersea high-voltage cables developed on a separate right-of-way.[66] These cables will not only facilitate interconnection but also increase local system reliability, reduce

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[64] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 695 (2003).

[65] ANOPR at P 112.

[66] *See supra* note 41 and accompanying text.

congestion between the nearby load zones, and facilitate the integration of clean energy resources, which will generate system benefits for all customers in the region.[67]

Instances like these suggest that it may be prudent for the Commission and ISO-NE to consider alternative approaches in certain circumstances. For instance, a version of participant funding under which costs are allocated among a group of interconnection customers could help address cost and uncertainty issues for certain similarly situated developers, as well as the "free rider" problem identified by the Commission, without shifting costs to ratepayers. Such an approach might make sense for new offshore wind in New England, where most or all planned MW are sited in the same lease area and under contract with the same set of States. There are a variety of potential participant-funded cost-splitting models that could be workable, such as permitting interconnection customers to divide the combined cost among themselves according to their share of delivered generation or permitting a subset of interconnection customers to pay the entire cost of needed upgrades upfront and seek reimbursement from other customers in accordance with an agreed-upon fee schedule.

The Massachusetts AGO has serious concerns about the Commission's suggestion to move to a broad cost-sharing model, under which developers and ratepayers would split the bill for interconnection upgrades, or to a model where ratepayers would pay for all interconnection upgrades.[68] Such approaches would shift significant costs and risks onto ratepayers, regardless of whether upgrades generate regional benefits. These approaches also eliminate the incentives

[67] Moreover, because these cables and related equipment are characterized as interconnection-related network upgrades, the infrastructure will be developed by the incumbent utility rather than through a competitive solicitation, which could reduce costs for consumers.

[68] *See* ANOPR at PP 123–34.

for efficiency and cost minimization that the participant funding model provides. To the extent the Commission considers such approaches, determining which projects will be eligible for cost-sharing, how much risk ratepayers should bear, and the costs that ratepayers will pay are important questions with significant implications for ratepayers.

The Massachusetts AGO recommends that, if implemented, any cost-sharing or cost-socialization approach should be limited to large interconnection upgrades that have made a regional benefit showing and that exceed a certain defined threshold of dollars per MW of delivered generation or when upgrades exceed a certain interconnection voltage. RTOs/ISOs would continue to rely on participant funding for upgrades that fall below the threshold. Additional protections and oversight measures would be essential to ensure appropriate checks on costs, and to ensure projects that have access to cost-sharing or cost-socialization will truly benefit the region and its ratepayers. Establishment of Independent Transmission Monitors with authority to review spending on transmission infrastructure and identify instances of potentially excessive facility costs could be useful to that end, as discussed further below.[69]

D. Any Incentives for New Transmission Facilities Should Be Appropriately Limited.

The Commission seeks comment on "whether and, if so, how to expand or improve any incentives to incent the development of regional transmission facilities that demonstrably may offer a more efficient or cost-effective solution to an identified need than local alternatives."[70] Specifically, the Commission seeks comment on whether to limit any existing ROE adder incentives to regional rather than local transmission projects when the

[69] *See* discussion *infra* at section II.F; ANOPR at PP 163–75.

[70] ANOPR at P 61.

regional project is selected as more efficient or cost-effective.[71] The Massachusetts AGO is on record as favoring the elimination or strict limitation of transmission company ROE incentives.[72] We share the view of Chairman Glick that "it is 'not clear that [transmission companies] are superior to other public utilities that can and do invest in transmission facilities— including competitively developed transmission facilities—or that awarding [transmission companies] a higher ROE actually leads to greater transmission investment.'"[73] Existing transmission incentives are effectively a handout from ratepayers to transmission companies already receiving extremely generous returns. Therefore, if incentives are utilized at all, they should be sparingly and strategically employed to incentivize specific regional goals and benefits.

Should the Commission decide to adopt an approach that incents regional transmission facilities that are found to be more efficient or cost-effective than local solutions, the Commission must also implement process reforms, as discussed above, to ensure that regional planners consistently evaluate a more comprehensive range of alternative projects' benefits according to clear, real, and objective criteria.[74] Such reforms are necessary to ensure that any incentivized regional project will in fact provide superior outcomes for ratepayers.

Ultimately, any transmission incentive approved by the Commission for regional transmission projects should be carefully evaluated and sparingly granted.

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[71] *Id.*

[72] State Entities, Comments, Docket No. RM20-10-000, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, at 12 (filed July 1, 2020); State Entities, Comments, Docket No. RM20-10-000, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act, Supplemental Notice of Proposed Rulemaking*, at 2, 11 (filed June 25, 2021).

[73] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act,* 170 FERC ¶ 61,204 (2020) (Glick, Comm'r, dissenting) at P 2.

[74] *See* discussion *supra* at section II.B.2; State Entities (July 1, 2020), *supra*, at 17.

E. The Commission's Reforms Must Address Existing Inequities and Deliver Environmental Justice at Every Stage of the Transmission Planning, Development, and Cost Allocation Process.

Although the ANOPR does not mention environmental justice or equity, the Massachusetts AGO urges that any transmission planning and cost allocation process reforms must be designed and implemented to address historic inequities and deliver environmental justice and energy justice, consistent with the Commission's goal of better incorporating such concerns into energy decision-making processes. It is particularly important that regional planners and the Commission consider not only distribution of the benefits and costs of new transmission solutions but also the ongoing costs of the existing system if no reforms are implemented. Those costs are not equitably shared.

The nation's energy system has been planned, sited, and operated in ways that disproportionally burden low-income communities and communities of color and reinforce structural racism and oppression.[75] The existing grids were designed primarily to facilitate transportation of energy from polluting fossil-fuel power plants, which are disproportionately located in low-income communities and communities of color where they cause health, environmental, and economic harms.[76] Black Americans, in particular, are the most likely to live

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[75] *See, e.g.*, Shalanda Baker, *Anti-Resilience: A Roadmap for Transformational Justice within the Energy System*, 54 Harv. C.R.-C.L. L. Rev. 1, 12 (2019) (describing the "racist politics that led to the formation of the nation's energy system [and] persist today" with the system's reliance on "energy production concentrated in areas dense with black and brown bodies"); Leslie Fleischman & Marcus Franklin, NAACP & Clean Air Task Force, *Fumes Across the Fence-Line: The Health Impacts of Air Pollution from Oil & Gas Facilities on African American Communities* 3 (2017), http://www.catf.us/wp-content/uploads/2017/11/CATF_Pub_FumesAcrossTheFenceLine.pdf ("The life-threatening burdens placed on communities of color near oil and gas facilities are the result of systemic oppression perpetuated by the traditional energy industry, which exposes communities to health, economic, and social hazards.").

[76] *See, e.g.*, Maninder P.S. Thind et al., *Fine Particulate Air Pollution from Electricity Generation in the US: Health Impacts by Race, Income, and Geography*, 53 Envtl. Sci. Tech. 14,010, 14,013 (2019) (finding that Black Americans have the highest average exposure to, and risk of death from, fine particulate matter pollution from

near a power plant and suffer the greatest risks from unhealthy power-plant pollution.[77] In addition, when energy system failures occur, already vulnerable communities suffer unequal harms.[78] During the 2021 Texas power crisis, for example, communities of color were more likely to experience outages.[79] And historically, those communities that bear the greatest harms from the energy system have often had the least access to and least input into the planning and decision-making processes that affect them.[80]

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electricity generation, and that low-income households are more exposed the higher-income households); Anna Rosofsky & Jonathan I. Levy et al., *Temporal Trends in Air Pollution Exposure Inequality in Massachusetts*, 161 Envtl. Res. 76 (2018) (finding that concentrations of fine particulate-matter and nitrogen oxide pollution in Massachusetts were highest in Black and Latinx communities); NAACP et al., *Coal Blooded: Putting Profits Before People* 15 (2012), https://naacp.org/resources/coal-blooded-putting-profits-people (people who live within 3 miles of a coal power plant have a lower than average income and 39% are people of color); Adrianna Quintero, et al., *U.S. Latinos and Air Pollution: A Call to Action* 6, 15 (2011), https://www.nrdc.org/sites/default/files/LatinoAirReport.pdf (stating that 39% of Latinx Americans and 68% of Black Americans live within 30 miles of a power plant, and that a majority of Latinx Americans live in areas with unhealthy air quality, putting them at greater risk for respiratory disease and illness).

[77] *See* Thind et al., *supra*; Quintero et al., *supra*, at 15.

[78] *See, e.g.*, Constantine E. Kontokosta et al., *Energy Cost Burdens for Low-Income and Minority Households*, 86 J. Am. Planning Assoc. 89, 97 (2020) (finding that communities of color generally experience greater energy cost burdens than white communities of comparable income); Shalanda Baker et al., *The Energy Justice Workbook* 20 (2019), https://iejusa.org/wp-content/uploads/2019/12/The-Energy-Justice-Workbook-2019-web.pdf (power outages uniquely burden low-income communities of color "given that they are unable to 'bounce back' as quickly from events that damage food and medicine supplies"); Vincent Reina & Constantine Kontokosta, *Low hanging fruit? Energy Efficiency and the Split Incentive in Subsidized Multifamily Housing* 13 (NYU Furman Ctr. Working Paper, 2016), https://furmancenter.org/files/NYUFurmanCenter_EnergyEfficiency_WorkingPaper_July2016.pdf (finding that subsidized public housing units, which are often older and less energy-efficient, consume more energy than comparable market-rate properties).

[79] *See* Press Release, Rockefeller Found., *Frozen Out: Minorities Suffered Four Times More Power Outages in Texas Blackouts* (Apr. 14, 2021), https://www.rockefellerfoundation.org/news/frozen-out-minorities-suffered-four-times-more-power-outages-in-texas-blackouts/ (satellite imagery analysis shows that communities with high populations of people of color were more than four times more likely to suffer a power outage during the 2021 Texas power crisis); James Dobbins & Hiroko Tabuchi, *Texas Blackouts Hit Minority Neighborhoods Especially Hard*, N.Y. Times, Feb. 16, 2021, at A14 (reporting that many Black and Lantinx communities were among the first to experience outages during the 2021 Texas power crisis).

[80] *See, e.g.*, Sanya Carley & David M. Konisky, *The Justice and Equity Implications of the Clean Energy Transition*, 5 Nature Energy 569, 572 (2020) (discussing how energy decision-making procedures are not inclusive, particularly of communities most impacted by energy infrastructure); Baker, *supra*, at 7, 9 (arguing that dismantling structural inequality in current energy policy will require, among other things, "policy approaches that aim for greater inclusion of people of color and low-income communities in the renewable energy transition").

The Commission must seek, through its transmission planning and cost allocation reforms, to undertake not just "a series of necessary technical changes required to facilitate the transition away from fossil fuels" but rather "structural changes that disrupt the ways that the [energy] system itself operates to harm people of color and low-income communities."[81] New transmission proposals should be evaluated with equity impacts and mitigation opportunities as a central consideration. The Commission should engage affected communities much earlier in the planning process than is status quo and ensure there are more opportunities for diverse stakeholder engagement at every stage of the planning process. The Commission should specifically consider the role its new Office of Public Participation will play in transmission planning. In addition, regional planners should utilize better mechanisms for sharing information with state siting authorities.

F. The Commission Should Consider Establishing Independent Transmission Monitors.

The Commission seeks comment "on whether, to improve oversight of transmission facility costs, it would be appropriate for the Commission to require that transmission providers . . . establish an independent entity to monitor the planning and cost of transmission facilities in the region."[82] The Massachusetts AGO preliminarily supports the idea of Independent Transmission Monitors ("ITMs") introduced in the ANOPR and encourages the Commission to seek further public input on this promising concept. There are a variety of conceivable models for the ITMs' range of authorities and how they might engage with RTOs/ISOs, States, transmission companies, and the Commission. If thoughtfully designed and implemented, we

[81] Baker, *supra*, at 24.

[82] ANOPR at P 163.

believe a requirement for ITMs has the potential to provide significant benefits to consumers. And as noted above, additional independent checks on transmission spending may be particularly appropriate if the Commission adopts planning or cost allocation process reforms that introduce greater risk to ratepayers.

If the Commission were to establish regional ITMs, the Massachusetts AGO recommends that ITMs should have authority to, among other things, review planning procedures and rules, review any competitive solicitations, monitor and report on transmission projects and cost overruns, provide independent cost estimates for projects, and review transmission owner spending.[83] In addition, any reports, studies, and findings prepared by the ITMs should be made publicly available.

III. CONCLUSION

The Massachusetts AGO appreciates the Commission's solicitation of public input on the important issues raised in the ANOPR. We respectfully urge the Commission to consider the above comments and recommendations as it considers potential reforms to improve electric regional transmission planning, cost allocation, and generator interconnection processes.

[83] For additional detailed recommendations regarding ITMs, *see* the Comments of the State Agencies submitted separately in this docket on October 12, 2021.

Respectfully submitted,

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October 12, 2021

CERTIFICATE OF SERVICE

In accordance with 18 C.F.R. § 385.2010, I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated this 12th day of October, 2021.

/s/ Megan M. Herzog
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