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. RM21-17-000**

COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION

Pursuant to the April 21, 2022 Notice of Proposed Rulemaking ("NOPR"),[1] the Solar Energy Industries Association ("SEIA") submits these comments on the Commission's proposed reforms to improve electric regional transmission planning and cost allocation.

Since 2010, regionally planned transmission has decreased significantly.[2] This decline of regionally planned transmission is inconsistent with the fast-evolving transmission resource mix. Customers are unable to maximize the benefits of this new generation. They are left paying for high-cost energy on a system that where reliability and resiliency are under increasing threats from climate change. The reforms proposed in this NOPR are a first step in remedying the unjust and unreasonable rates that consumers face today. By instituting the robust regional transmission planning reforms proposed in this NOPR, the Commission will ensure that customers can maximize a broad range of benefits, that states can achieve their public policy goals, and that the grid of today can keep pace with the needs of the future.

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[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (2022).

[2] Jay Caspary, et al., Disconnected: The Need for a New Generator Interconnection Policy at 21 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf.) ("The total regionally planned transmission investment in [regional transmission organizations] decreased by 50 percent.").

I. The Need for Reform

A. Current regional transmission planning and cost allocation policies have resulted in in Commission-jurisdictional rates that are unjust and unreasonable and unduly discriminatory and preferential.

SEIA supports the Commission's general findings on the need for reform. As the Commission found in the NOPR, there has been an absence of long-term, comprehensive transmission planning.[3] Instead the grid is being built incrementally, using the generator interconnection process to build large-scale transmission network upgrades. The interconnection process is a poor stand-in for transmission planning. Transmission upgrades that have potentially significant benefits for a broad range of entities are planned through a process that focuses on a small number of interconnection customers.[4] This process is unlikely to identify the more efficient or cost-effective solutions to transmission needs driven by changes in the resource mix and demand. This has resulted in inefficient transmission investment that cannot meet the needs of the changing resource mix.[5] The costs of these inadequate investments are recovered through Commission-jurisdictional rates.[6] Continuing with the status quo "may result in transmission customers paying more than necessary to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof—either or both of which could potentially render Commission-jurisdictional rates unjust and unreasonable or unduly discriminatory or preferential."[7]

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[3] NOPR P 25.

[4] NOPR P 27; *see also* Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 176 FERC ¶ 61,024, Glick Concurrence, P 10 (2021) ("ANOPR").

[5] NOPR PP 42, P 39.

[6] NOPR P 25.

[7] NOPR P 25.

For the transmission planning conducted outside of the interconnection process, a recent report by the Lawrence Berkeley National Laboratory shows that current transmission planning approaches run the risk of understating the economic value of new transmission infrastructure.[8] The process also results in significant congestion charges that could be alleviated with increased transmission capacity.[9]

The Commission has an obligation under the Federal Power Act (FPA) to correct the deficient transmission planning process and ensure Commission-jurisdictional rates are just, reasonable, and not unduly discriminatory.

B. The Commission has the authority to remedy these unjust and unreasonable rates.

Section 206 of the FPA provides the authority for the Commission to fix the unjust and unreasonable transmission planning process. This provision allows the Commission to initiate a proceeding to revise any "rate, charge or classification" related to the transmission or sale of electricity that it determines is "unjust, unreasonable, unduly discriminatory or preferential."[10] Section 206 also allows the Commission to set aside wholesale rates and practices that are "unjust, unreasonable, unduly discriminatory or preferential."[11] It is through this Section 206 authority that the Commission issued Order No. 1000 to remedy practices that prevented the "efficient and cost-effective development of transmission facilities used to provide Commission-

[8] Dev Millstein et al., Empirical Estimates of Transmission Value using a Locational Marginal Prices, Lawrence Berkeley National Laboratory, at 3 (2022), https://emp.lbl.gov/publications/empirical-estimates-transmission.
[9] *Id*. at 33.
[10] 16 U.S.C. § 824e (2020).
[11] *E.g.*, *S. Carolina Public Service Authority v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) ("To regulate a practice affecting rates pursuant to Section 206, the Commission must find that the existing practice is 'unjust, unreasonable, unduly discriminatory or preferential,' and the remedial practice it imposes is 'just and reasonable.'") (citing 16 U.S.C. 824e(a)).

jurisdictional services."[12] It is through this Section 206 authority that the Commission can again fix the deficient transmission planning process that are resulting in unjust and unreasonable rates. The reforms the Commission set forth in the NOPR, with some modification, will help ensure that Commission jurisdictional rates are just, reasonable, and not unduly discriminatory.

II. Long-Term Regional Transmission Planning

A. Development of Long-Term Scenarios

The Commission proposes to require that public utility transmission providers participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning conducted on a forward-looking basis.[13] This planning would identify transmission needs driven by changes in the resource mix and demand identified through the development of Long-Term Scenarios and evaluate transmission facilities to meet those needs.[14] To develop the Long-Term Scenarios, the Commission proposes to require transmission providers to: (1) use a transmission planning horizon no less than 20 years into the future in and reassess and revise those scenarios at least once every three years; (2) incorporate a set of Commission-identified categories of factors that may affect transmission needs driven by changes in the resource mix and demand; (3) develop a plausible and diverse set of at least four Long-Term Scenarios; (4) use "best available data" (as defined in the Specificity of Data Inputs section below) in

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[12] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, P 59 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, o*rder 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).

[13] NOPR P 68.

[14] NOPR P 68.

developing their Long-Term Scenarios; and (5) consider whether to identify geographic zones with the potential for development of large amounts of new generation.[15]

SEIA generally supports this proposal. If executed correctly, using Long-Term Scenarios to identify transmission needs will ensure that regions identify and build out transmission that will be necessary for resources coming online. The requirements proposed in the NOPR could help do that, but to do that successfully, the Commission must provide clear and mandatory minimum requirements for transmission providers, discussed below.

1. Transmission Planning Horizon and Frequency

The Commission proposes to require transmission providers to using a minimum horizon of 20 years in their Long-Term Scenarios, reassessing the scenarios at least once every three years.[16]

SEIA supports the 20-year planning horizon. During the November 2021 Technical Conference in this proceeding, multiple panelists argued that a 20-year planning horizon would be a significant improvement over the current planning process. Transmission planning needs to be anticipatory.[17] The current transmission process is not anticipatory. Further, the process does not appear to be able to keep up with the changing needs of the system, resulting in a piecemeal approach of building transmission as needs arise.[18] It does not get large scale transmission built.[19]

[15] NOPR P 91.

[16] NOPR P 97.

[17] November 2021 Technical Conference Tr. at 161.

[18] November 2021 Technical Conference Tr. at 133.

[19] November 2021 Technical Conference Tr. at 133.

Transmission development activities, such as planning, permitting, and construction, can take a long time.[20] A 20-year planning approach better informs the investment decisions that developers must make in the near-term when building transmission, even if the transmission solutions identified will not be needed for another 12 to 15 years.[21] And with the three-year reevaluation process, transmission planners and developers can adjust their plans, and account for changes in technologies before they are too far along in the transmission building process.[22]

While SEIA supports the 20-year planning horizon, we urge the Commission to consider a 40-year planning horizon, which will more accurately capture the lifetime benefits of transmission. As the Commission notes in the NOPR, "transmission facilities provide significant benefits over their entire useful life."[23] This useful life "generally exceeds 20 years by a substantial margin."[24] A standard benefit-cost analysis for durable assets generally uses the lifetime of the asset as a planning horizon.[25] A 40-year horizon will better capture and evaluate the full amount of benefits transmission lines provide.

[20] November 2021 Technical Conference Tr. at 136.

[21] November 2021 Technical Conference Tr. at 131-132.

[22] November 2021 Technical Conference Tr. at 131-132.

[23] NOPR P 239.

[24] NOPR P 229; *see also* Ari Peskoe, Is the Utility Transmission Syndicate Forever?, 42 Energy L.J. 1, 30 (2021); *see e.g.* California Independent System Operator, Inc., 2021-2022 Transmission Plan, Sec. 4.3.2, Benefit analysis (March 17, 2022), http://www.caiso.com/InitiativeDocuments/ISOBoardApproved-2021-2022TransmissionPlan.pdf.

[25] *See e.g.* U.S. Dept. of Transportation, Benefit-Cost Analysis Guidance for Discretionary Grant Programs, at 10 (March 2022), https://www.transportation.gov/sites/dot.gov/files/2022-03/Benefit%20Cost%20Analysis%20Guidance%202022%20%28Revised%29.pdf.

2. Transmission Planning Factors, Number of Scenarios, and Best Available Data

The Commission proposes to require that transmission providers incorporate, at a minimum, the following categories of factors in the development of the Long-Term Scenarios:

> (1) federal, state, and local laws and regulations that affect the future resource mix and demand;
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> (2) federal, state, and local laws and regulations on decarbonization and electrification;
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> (3) state-approved utility integrated resource plans and expected supply obligations for load serving entities;
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> (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation;
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> (5) resource retirements;
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> (6) generator interconnection requests and withdrawals; and
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> (7) utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand.[26]

SEIA supports the Commission's proposed list of factors to be included in the development of Long-Term Scenarios. SEIA urges the Commission to ensure that these factors are the *minimum* requirements for each Long-Term Scenario.

SEIA supports the Commission's proposal to require transmission providers to incorporate factors relating to the federal, state, and local legally binding obligations (factors (1), (2), and (3)).[27] Laws and regulations can drive significant investment in new resources, which will require transmission to connect those new resources to load. As part of this, the Commission should require transmission providers to include the effects of federal tax policies, like the

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[26] NOPR P 104.

[27] NOPR P 106.

Inflation Reduction Act of 2022, which will encourage investment in utility scale renewable energy in the Long-Term Scenarios.

With respect to the remaining categories of factors, the Commission proposes to allow transmission providers "flexibility in how they incorporate each factor into Long-Term Scenarios," including allowing transmission providers to discount certain factors to account for uncertainty.[28] In order for transmission providers to capture the full range of inputs that will impact both the supply and demand of energy, and therefore the transmission needed to allow the supply to serve demand, SEIA urges the Commission to limit the flexibility it will provide transmission providers in incorporating the non-legally binding impacts on supply and demand (factors (4), (5), (6), and (7)). As the Commission states, Long-Term Scenarios are "a tool to identify transmission needs driven by changes in the resource mix and demand."[29] All of these factors will impact the generation mix and developing a transmission system that accounts for these factors is critical.[30] Transmission providers *must* incorporate factors that drive supply and demand into transmission planning. If transmission providers are given the flexibility to effectively ignore these factors, then transmission planning will be incapable of identifying the "transmission needs driven by changes in the resource mix and demand."

Factors (4) and (7) will result in increased demand for energy. Transportation electrification, which is rapidly increasing,[31] will put more load on the grid.[32] State and local

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[28] NOPR PP 107-108.

[29] NOPR P 84.

[30] November 2021 Technical Conference Tr. at 36.

[31] Fiona Wissell, Brittany Speetles, Matt Townley, Deb Harris, and Stacy Noblet, The Impact of Electric Vehicles on Climate Change, at 4-5, https://www.icf.com/insights/energy/impact-electric-vehicles-climate-change (showing that electric vehicle sales doubled between 2020 and 2021).

[32] *Id.* at 19.

renewable energy goals often become mandates that are later incorporated into integrated resource plans.[33] Utility and corporate goals that are promises to shareholders should not be discounted.[34] Corporate goals, and corporate emissions are likely to come under increased scrutiny if the U.S. Securities and Exchange Commission ultimately issues its final rule that would require companies to make "Climate-Related Disclosures," which would include climate-related governance, risk, business impacts, targets and goals.[35]

While factors (4) and (7) impact demand, factors (5) and (6) impact supply. Retirements will happen, especially as many thermal generators reach the end of their useful lives. In its 2021 Long-Term Reliability Assessment, NERC reported that approximately 48.8 GW of thermal generation plan to retire by 2026, with many more potential retirements that have yet to be announced.[36] New generation will come online to replace those retiring generators, but not always in the same location as the retiring generation, creating new transmission needs.

To ensure some level of certainty in how to reflect the transmission planning factors into the Long-Term Planning Scenarios, the Commission can set forth guidelines in the Final Rule on the information used to determine these factors. SEIA proposes the following guidelines:

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[33] November 2021 Technical Conference Tr. at 61.

[34] November 2021 Technical Conference Tr. at 62.

[35] *The Enhancement and Standardization of Climate-Related Disclosure for Investors*, 87 Fed. Reg. 21,334 (April 11, 2022).

[36] NERC, *2021 Long-Term Reliability Assessment*, at 30, 35 (Dec. 2021).

Transmission Planning Factor	**Guidelines**
(4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation	Transmission providers should use the data and models used in NREL's Electrification Futures Study,[37] Solar Futures Study,[38] Storage Futures Study,[39] and Transportation Futures Study.[40]
(5) resource retirements	Transmission providers should only include the retirement of resources that have provided notice under the applicable tariff provisions.
(6) generator interconnection requests and withdrawals	Transmission providers should only include interconnection customers that have signed a facilities study agreement, or other applicable study agreement. At this stage of the interconnection process, interconnection customers generally have reasonable certainty in the costs of network upgrades to determine whether to proceed through the interconnection process.
(7) utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand	For utility commitments, transmission providers should include data from state resource plans and regulatory filings. For corporate commitments, transmission providers should include data from the Clean Energy Buyers Association Deal Tracker.[41] For state and local goals, transmission providers should include information from the Sierra Club's Ready for 100 database.[42]

As part of the requirement to include each of these supply and demand factors in scenario planning, the Commission should establish minimum baseline assumptions across all scenarios.

[37] Available at https://www.nrel.gov/analysis/electrification-futures-approach.html.

[38] Available at https://www.nrel.gov/analysis/solar-futures.html.

[39] Available at https://www.nrel.gov/analysis/storage-futures.html.

[40] Available at https://www.nrel.gov/analysis/transportation-futures/index.html.

[41] Available at https://cebuyers.org/deal-tracker/.

[42] Available at https://www.sierraclub.org/climate-and-energy/map.

These assumptions should reflect extreme conditions that impact demand, such as cold snaps, heat waves, and supply, such as correlated outages.

SEIA also discourages the Commission from allowing transmission providers to discount any of the Long-Term Scenarios. Discounting any factor in scenario planning would effectively allow transmission providers to discount away market forces that will have significant effects on supply and demand. Scenario planning inherently includes uncertainty. However, the requirement for transmission providers to use at least four distinct Long-Term Scenarios in Long-Term Regional Transmission Planning will allow transmission providers to reflect that uncertainty.

Finally, to ensure consistency and accuracy in transmission planning results, SEIA supports the Commission's requirement for transmission providers to use "best available data inputs" when developing Long-Term Scenarios.[43] SEIA urges the Commission to issue standards and guidelines as to what constitutes "best available data inputs" for each of the seven planning factors.[44] The Commission should hold regular technical conferences to discuss potential data sources. Standardized data inputs are critical for ensuring that the factors in scenario planning result in accurate transmission plans across the country.

3. Identification of Geographic Zones

The Commission proposes to require transmission providers to "consider" identifying geographic zones within the region that have the potential for development of large amounts of new generation for incorporation into the Long-Term Scenarios.[45] SEIA urges the Commission

[43] NOPR P 131.

[44] NOPR P 134.

[45] NOPR P 145.

to "require" transmission providers, with the input of stakeholders, to identify these zones and incorporate them into the Long-Term Scenarios. Identifying these geographic zones will allow transmission providers to take advantage of economies of scale from high capacity lines.[46] Planning for transmission that will serve where generation is likely to be sited will ensure that fewer lines are needed to provide transmission to and from more resources. Transmission providers could use the tools created by the National Renewable Energy Laboratory to help identify these zones, including:

- U.S. Solar Siting Regulation and Zoning Ordinances database, a collection of documented solar siting ordinances at the state and local (e.g., county, township) level throughout the United States;[47]
- U.S. Wind Siting Regulation and Zoning Ordinances, a collection of documented wind siting ordinances at the state and local (e.g., county, township) level throughout the United States;[48] and
- reV: The Renewable Energy Potential Model, a spatial and temporal model that allows users to assess renewable resource potential, technical potential, and supply curves at varying levels of detail.[49]

The Commission notes that states in multi-state transmission planning regions may have differing energy policies that may be impacted by the identification of such zones.[50] However, the Commission's proposed three-step process for identifying the zones already includes safeguards for the states to voice their concerns. Proposed step one of the geographic zone identification process would require a transmission planning region to solicit stakeholder input,

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[46] November 2021 Technical Conference Tr. at 161.

[47] Available at https://data.openei.org/submissions/5734.

[48] Available at https://data.openei.org/submissions/5733.

[49] Available at https://www.nrel.gov/gis/renewable-energy-potential.html.

[50] NOPR P 152.

including state siting authorities.[51] The transmission planning region must then use these discussions to modify the draft geographic zones as appropriate to produce a final list of designated geographic zones within the transmission planning region.[52] It is in that step that states with differing energy policies can voice concerns about resource siting and the financial impacts associated with that siting. Further, incorporating state and local siting ordinances into the zone identification process allows the transmission providers to reflect the differing policies of the states in their planning regions.

B. Coordination with the Interconnection Process

The Commission proposes to require that transmission providers consider in their Long-Term Regional Transmission Planning regional facilities that address interconnection-related needs that a transmission provider has identified multiple times in the generator interconnection process but have not been constructed due to the withdrawal of the upgrade-triggering interconnection requests.[53] Such upgrades must be identified in two interconnection queue cycles during the preceding five years, be at least 200 kV or higher and/or cost at least $30 million. The upgrades are limited to interconnection needs not already addressed in an executed generator interconnection agreement.[54]

SEIA generally supports the Commission's proposal. Including these facilities in Long-Term Regional Transmission Planning could help alleviate the increasing number of queue withdrawals by ensuring that costly transmission is built via the transmission planning process,

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[51] NOPR P 148.

[52] NOPR P 149.

[53] NOPR PP 166-173.

[54] NOPR P 173.

as opposed to shifting costs to the interconnection customer. As ACEG noted in its paper, *Disconnected*, the lack of cost certainty in the interconnection process sets into motion a "vicious reinforcing cycle" of queue withdrawals and restudies which shift sometimes significant costs further down in the interconnection queue.[55]

For this proposal to succeed though, SEIA requests that the Commission make the following modifications and clarifications. First, SEIA requests that the Commission clarify that the phrase "interconnection related transmission needs" would allow transmission providers to include in this determination either individual *or* aggregated transmission solutions that address specific needs.[56]

Second, transmission facilities identified pursuant to this directive should be included in Long-Term Regional Transmission Planning. In the NOPR, the Commission proposed to require transmission providers to "consider regional transmission facilities to address interconnection-related needs pursuant to this reform" in Long-Term Regional Transmission Planning which would be a factor in the Long-Term Scenarios.[57] SEIA urges the Commission to require transmission providers to assume that these network upgrades will be built and include the upgrades in their Long-Term Regional Transmission Planning. As Enel notes in its whitepaper, it

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[55] Jay Caspary, et al., Disconnected: The Need for a New Generator Interconnection Policy at 17 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf.)

[56] *See e.g.* Southwest Power Pool, Inc., 2020 Integrated Transmission Planning Assessment Report, at 87, https://www.spp.org/documents/63434/2020%20integrated%20transmission%20plan%20report%20v1.0.pdf (showing that the final consolidated portfolio of transmission planning projects included projects approved projects where some are individually identified and others are multiple "projects" aggregated into one solution.)

[57] NOPR P 167.

is reasonable to assume that even if the projects supporting these lines withdraw, others will take their place.[58]

Third, once a transmission provider identifies the same network upgrade in two different interconnection cycles, that line should be included in the next Long-Term Regional Transmission Planning update cycle, even if five years have not passed since the network upgrade was initially identified.

Fourth, SEIA requests that the Commission remove the requirement that a network upgrade must be "at least 200 kV." Instead, each transmission planning region should be required to use their own definition of transmission facilities, which may include transmission lines of lower voltages and substations.

Fifth, SEIA requests that the Commission remove its $30 million threshold for network upgrade costs and replace it with a $100,000 per megawatt of installed capacity threshold. The "Implied Cost Threshold" beyond which new generators are often no longer financially viable is about $100,000 per megawatt of installed capacity.[59] The Implied Cost Threshold is a ratio, not a set number, recognizing that the cost of network upgrades should be proportionate to the size of the project.

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[58] Enel, Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning at 12, https://www.enelgreenpower.com/content/dam/enel-egp/documenti/share/working-paper.pdf.

[59] *See* American Wind Energy Association, Clean Grid Alliance, and SEIA, *Generator Contributions to Transmission Expansion*, at 2 (Aug. 2020), http://cleangridalliance.org/_uploads/_media_uploads/_source/Generator_Contrib_Xmission-V3a-FINAL.pdf; *see also* NOPR P 172, FN 303.

C. Evaluation of the Benefits of Regional Transmission Facilities

1. The proposed "benefits"

In the NOPR, the Commission declines to prescribe a definition of "benefits" or "beneficiaries," nor require use of any specific benefits.[60] Instead, the Commission outlined a set of 12 Long-Term Regional Transmission Benefits that "may be useful in evaluating transmission facilities for selection in the regional transmission plan."[61]

SEIA urges the Commission to require transmission providers to include all of the Long-Term Regional Transmission Benefits as a minimum set of benefits for their Long-Term Regional Transmission Planning processes. The final rule should account for the full range of transmission benefits and use multi-value planning to comprehensively identify investments that address all categories of needs and benefits. The benefits listed in the NOPR "recognize the full value of new transmission deployment."[62]

In addition to the 12 Long-Term Regional Transmission Benefit, the Commission should also set emissions reductions as a benefit.[63] The electric sector is the largest source of carbon dioxide and other greenhouse gas emissions, which themselves are the largest contributors to climate change.[64] As the Commission recently noted, extreme weather events driven by climate change threaten reliability.[65] Transmission providers should seek out transmission solutions that

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[60] NOPR P 183.

[61] NOPR P 185.

[62] Derek Stenclik, Ryan Deyoe, Multi-Value Transmission Planning for a Clean Energy Future, at 9 (June 2022), https://www.esig.energy/wp-content/uploads/2022/07/ESIG-Multi-Value-Transmission-Planning-report-2022a.pdf.

[63] *See e.g.* Southwest Power Pool (SPP), Benefits for the 2013 Regional Cost Allocation Review, September 13, 2012, Section 3.4.

[64] *See* U.S. Environmental Protection Agency, Sources of Greenhouse Gas Emissions, https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions#electricity; NASA, The Causes of Climate Change, https://climate.nasa.gov/causes/.

[65] NERC, *2021 Long-term Reliability Assessment* at 6 (Dec. 2021), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

reduce carbon emissions, not just because we are in a climate crisis, but because the effects of this climate crisis threatens the reliability of the grid.

2. Application of benefits in non-RTO regions

The proposed list of the Long-Term Regional Transmission Benefits should apply the same in both RTO and non-RTO regions.[66] As a preliminary matter, the Commission has the authority to regulate transmission planning, regardless of whether a transmission provider is in an RTO or not. Under the Energy Policy Act of 2005, the Commission may exercise its authority "in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities."[67] The Commission relied on this authority, in part, when it issued Order No. 890.[68] There is no basis to apply different benefits to a non-RTO area, especially since many of the proposed Long-Term Regional Transmission Benefits have already been calculated in non-RTO regions.[69]

Further, without a directive from the Commission to non-RTO transmission providers to use Long-Term Regional Transmission Planning, and the requirement to evaluate Long-Term Regional Transmission Benefits, there is a risk that the regions would not engage in such planning, and instead would rely on state integrated resource planning ("IRP") process to build

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[66] NOPR P 187.

[67] 18 U.S.C. § 824q(b)(4).

[68] *See Preventing Undue Discrimination & Preference in Transmission Serv.*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), 118 FERC ¶ 61,119, P 79, *order on reh'g*, Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[69] *See generally* NOPR Sec. IV.C.iii.a.3 (describing the proposed list of the Long-Term Regional Transmission Benefits, with citations to examples of where the benefits had been used in non-RTO areas); *see also* Johannes Pfeifenberger et al., The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, at 48-49 (Oct. 2021), https://gridprogress.files.wordpress.com/2021/10/transmission-planning-for-the-21st-century-proven-practices-that-increase-value-and-reduce-costs-7.pdf (Brattle-Grid Strategies Oct. 2021 Report).

transmission. Transmission planning in non-RTO regions is performed from the bottom up and is informed by the IRP process.[70] However, those processes are not integrated, often being dealt with in two different state proceedings. The IRP process assumes certain transmission topologies and does not incorporate lower cost transmission alternatives to generation procurement. When the IRP process is then incorporated into the transmission planning process, the transmission plans are then focused around the already-selected higher-cost generation. A holistic long-term transmission planning process, conducted via an Independent Transmission Monitor, that actively considers network benefits, including deferred generation investment, would allow for more cost-effective solutions.

3. Calculation of benefits

There is plenty of literature that transmission providers could use in calculating these benefits. The October 2021 report from the Brattle Group and Grid Strategies outline many of these benefits and include quantification methods, as well as where these benefits have been applied.[71] There is also experience among transmission providers in evaluating these benefits, and the Commission itself outlines several instances where such benefits were evaluated by regional planning organizations.[72] The Midcontinent Independent System Operator, Inc.'s Long

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[70] Transcript of the 11/10/2021 First Meeting of Joint Federal-State Task Force on Electric Transmission, at 88-89, Docket No. AD21-15.

[71] The Brattle Group and Grid Strategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (Oct. 2021), https://gridprogress.files.wordpress.com/2021/10/transmission-planning-for-the-21st-century-proven-practices-that-increase-value-and-reduce-costs-7.pdf.

[72] NOPR P 189-225.

Range Transmission Plan Tranche 1 portfolio is another, recent, example of how to quantify five of the twelve benefits proposed by the Commission.[73]

As with the proposal to review "best available inputs," SEIA recommends that the Commission host regular technical conferences to evaluate the calculation of these benefits to determine best practices for all regions to follow.

D. Selection of Regional Transmission Facilities

The Commission proposes to provide public utility transmission providers the flexibility to propose the selection criteria and does not mandate any specific criteria.[74] The only firm requirement for transmission providers with respect to selection criteria is that the criteria must be (1) "transparent and not unduly discriminatory criteria, which seek to maximize benefits to consumers over time without over-building transmission facilities"; and (2) provide a process to coordinate with the relevant state entities in developing the criteria.[75]

Similar to the recommendation above to set a minimum set of Long-Term Regional Transmission Benefits for transmission providers to include in their Long-Term Regional Transmission Planning processes, SEIA urges the Commission to establish a set of minimum requirements for each transmission provider to use in selecting regional transmission facilities. Without a minimum set of selection criteria, regions may fail to select lines that provide significant regional benefit. Along with these minimum benefits, the Commission should require

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[73] *See* Rob Gramlich, Enabling Low-Cost Clean Energy And Reliable Service Through Better Transmission Benefits Analysis, at 17, https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf.

[74] NOPR P 243.

[75] NOPR P 241.

transmission providers to use a portfolio approach in selecting regional transmission facilities in the regional transmission plan.

E. Implementation of Long-Term Regional Transmission Planning

The Commission recognizes that the Long-Term Regional Transmission Planning process may overlap with public utility transmission providers' near-term assessment of transmission needs captured by existing regional transmission planning processes.[76] The Commission seeks comment on whether there is a need to coordinate the initial timing sequences between Long-Term Regional Transmission Planning and the existing near-term regional transmission planning processes.[77]

The Long-Term Regional Transmission Planning process should not just overlap with the current reliability, economic and public policy planning processes—they should all be part of the same planning process. The Commission should no longer silo the planning processes. Siloed transmission planning processes will not build the grid of the future.[78] A holistic process that builds transmission to meet reliability, economic, public policy, *and* long-term needs allows transmission providers to find the optimal transmission solutions.[79] To facilitate this process, the Commission should require transmission providers to engage in portfolio-based planning that

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[76] NOPR P 253.

[77] NOPR P 253.

[78] May 6 Taskforce Transcript at 83; Feb. 16 Transcript at 24-25.

[79] May 6 Taskforce Transcript at 84; *see also* SPP Script ("The SCRIPT recommends developing a comprehensive assessment capable of addressing reliability, regulatory compliance, economic, and public policy needs while facilitating and ensuring regional and local planning coordination and meeting the needs of service customers. The annual assessment will holistically address overlapping and associated transmission needs with optimal solutions beneficial to the collective participants. The consolidated assessment provides a proactive and manageable position for SPP and its stakeholders to successfully facilitate potential changes introduced in the future regulatory rulemaking due to comments and determinations from FERC Docket No: RM21-17-000.")

integrates all relevant factors, reliability, economic, and public policy, into Long-Term Regional Transmission planning.

F. Considerations of Dynamic Line Rates and Advanced Power Flow Controls

The Commission proposes to require each transmission planning region to consider whether selecting transmission facilities that incorporate dynamic line ratings or advanced power flow control devices would be more cost-effective than facilities that do not include these technologies.[80] SEIA generally supports the NOPR proposal to incorporate dynamic line ratings and advanced power flow control devices in the transmission planning process. The failure to adequately consider these cost-saving technologies may result in unjust and unreasonable rates. When applied to existing transmission lines, Grid Enhancing Technologies are and ideal medium-term solution that bridges the gap in timing between building generation (around five years) and building transmission (around 10 years) by expanding capacity on existing transmission lines enough to allow new generation to come online without significant network upgrades. To ensure the effectiveness of this requirement, we request that the Commission make a few adjustments to the proposal.

First, the Commission should use the broader term "Grid Enhancing Technologies" instead of specifying the use of "dynamic line ratings or advanced power flow control devices." In the NOPR, the Commission explicitly declined to use the broader term, stating that the "operational experience with dynamic line ratings and power flow control devices" provides the ability for transmission providers to consider their operations.[81] While it may be the case *today*

[80] NOPR P 274.

[81] NOPR P 276.

that there is little experience with other technologies, that experience may grow in the future. Without the requirement to include those technologies, transmission providers may be hesitant to do so,[82] and innovation that will increase grid capacity and save consumers money may be stunted. The Commission would be forced to conduct another time-consuming rulemaking to require transmission providers to incorporate future technologies, delaying the speedy deployment of these technologies. To provide guidance to transmission providers and owners, the Commission should host regular technical conferences to discuss improvements and innovations in these technologies.

Second, the Commission should *require* transmission planning regions to incorporate Grid Enhancing Technologies into the transmission planning process, where such technologies are capable of providing the functions required by the Long-Term Regional Transmission Planning process and can be relied upon on a long-term basis. Given the increased need for transmission capacity, failing to include technologies that optimize existing transmission corridors and provide cost-effective solutions for consumers could result in unjust and unreasonable rates. To determine whether such technologies are feasible, transmission providers should provide the following information to market participants: modeling assumptions, contingency analysis results, asset age, and environmental and footprint constraints.

Finally, the Commission should require transmission providers to include in their Long-Term Scenarios Grid Enhancing Technologies on existing lines as part of the long-term transmission plans.

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[82] *See* NOPR P 258 (outlining the opposition to GETs by transmission owners).

III. Regional Transmission Cost Allocation

SEIA supports the Commission's finding that reforms to public utility transmission providers' regional cost allocation methods are necessary to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.[83] Transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs.[84] Cost allocation is critical to developing new transmission, and without clear guidance on how to pay for the selected transmission lines, this NOPR will be ineffective.[85]

The Commission proposes to require each transmission planning region include in its tariff either "(1) a Long-Term Regional Transmission Cost Allocation Method to allocate the costs of Long-Term Regional Transmission Facilities, or (2) a State Agreement Process by which one or more relevant state entities may voluntarily agree to a cost allocation method, or (3) a combination thereof."[86] As part of this requirement, transmission providers in each transmission planning region would be required to seek the agreement of relevant state entities within the transmission planning region.[87] The transmission providers must then explain how the proposed Cost Allocation methodology either reflects the agreement of the relevant state entities or, if an agreement cannot be reached, explain the good faith efforts by the relevant public utility transmission provider to seek agreement.[88]

[83] NOPR P 278.

[84] Order No. 1000, 136 FERC ¶ 61,051 at P 496.

[85] NOPR P 297.

[86] NOPR P 302.

[87] NOPR P 303.

[88] NOPR P 303.

SEIA supports a combination of a Long-Term Regional Transmission Cost Allocation Method and a State Agreement Process. States that want to take on the costs of new transmission facilities to serve their needs should be allowed to. However, better planning helps the entire transmission system, so ensuring a method to allocate costs in a way that recognizes the regional benefits of better planning will help that transmission get built. We encourage the Commission to require that transmission providers use the same set of benefits used to select the Regional Transmission Facilities in determining how to allocate costs.[89]

State support is key to the development of regional transmission facilities and the key to obtaining that support is for transmission providers to institute processes that allow for robust input of the relevant state agencies early in the transmission planning process. SEIA recommends that as part of the requirement to obtain state support for transmission lines, that the Commission require transmission providers to consult with the relevant state agencies in developing the long-term transmission plans. This process would allow the state agencies to give input on siting concern and cost allocation issues.

Despite having a robust planning process that incorporates state feedback along the way, there will be instances in which the relevant parties are unable to come to an agreement.[90] SEIA supports the proposal to allow a 90-day time period to memorialize a state-negotiated cost allocation methodology in writing.[91] If agreement cannot be reached, then the region's Long-Term Regional Transmission Cost Allocation Method should apply as a default cost allocation methodology.[92]

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[89] NOPR P 302.

[90] NOPR P 310.

[91] NOPR P 319.

[92] NOPR P 320.

SEIA urges the Commission and transmission planners to limit the opportunity for a single state to effectively veto a transmission line because of cost allocation concerns. If the parties are unable to agree on transmission facility allocation, and a relevant state authority withholds or denies the siting permit for the transmission facility, the Commission should use its authority under the newly revised backstop authority under section 216 of the Federal Power Act.[93] Ensuring a default cost-allocation mechanism in the face of disagreement, and providing for backstop siting authority in the face of that disagreement, will ensure that transmission that will promote public policy will be built.

While the state agreement approach will allow states to proactively pay for transmission that bolsters individual policy goals, having a backup cost allocation methodology in place recognizes a fundamental truth about wholesale markets: States in an interstate market cannot be wholly insulated from legally valid policy choices of other states. Further, states *with* renewable portfolio standards subsidize states *without* such standards.[94] State policies encouraging renewable energy decrease capacity market prices in a region, benefiting customers regardless of whether they are in a state with a renewable portfolio standard.[95]

IV. Enhanced Transparency of Local Transmission Planning Inputs In the Regional Transmission Planning Process and Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities

In the NOPR, the Commission found that there is no requirement that transmission providers provide information about potential in-kind replacements of existing transmission

[93] 16 U.S.C. § 824p(b).

[94] Galen Barbose, U.S. Renewable Portfolio Standards, at 39 (July 2019), https://eta-publications.lbl.gov/sites/default/files/rps_annual_status_update-2019_edition.pdf.

[95] Grid Strategies, A Moving Target at 14 (May 2020), https://gridprogress.files.wordpress.com/2020/05/a-moving-target-paper.pdf.

facilities in either their local or regional transmission planning processes.[96] The lack of coordination could result in a missed-opportunity to "right-size" the planned transmission replacement with a more cost-effective and efficient facility.[97] The Commission proposes to address this by requiring transmission providers to enhance transparency of: (1) the criteria, models, and assumptions that they use in their local transmission planning process, (2) the local transmission needs that they identify through that process, and (3) the potential local or regional transmission facilities that they will evaluate to address those local transmission needs.[98] As part of this reform, the Commission proposes to require transmission providers to review and evaluate transmission facilities at or above 230 kV that the public utility transmission provider owns and that it estimates may need to be replaced with a new in-kind transmission facility over the next 10 years that may need to be "right-sized."[99]

SEIA supports the Commission's proposal to require transmission providers to consider "right-sizing" transmission facilities. Much of the nation's transmission facilities are over 50 years old and nearing the end of their lives.[100] Ensuring that the lines that replace them be evaluated not just for reliability, but also for public policy needs, allows these lines to be designed in a way that maximizes the benefits provided by these lines.

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[96] NOPR P 399.

[97] NOPR P 399.

[98] NOPR P 400.

[99] NOPR P 405.

[100] ACEG Jan. 2021 Planning Report at 18-24.

V. CONCLUSIONS

SEIA respectfully request that the Commission accept its comments and recommendations regarding the Commission's proposed reforms to improve the electric regional transmission planning and cost allocation and generator interconnection processes.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned certifies that a copy of this pleading has been served this day upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 17th day of August 2022.

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