UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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| Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection | ) ) ) ) ) ) | Docket No. RM21-17-000 |

**COMMENTS OF THE AMERICAN CLEAN POWER ASSOCIATION, ALLIANCE FOR CLEAN ENERGY-NEW YORK, CLEAN GRID ALLIANCE, MID-ATLANTIC RENEWABLE ENERGY COUNCIL, AND NEW YORK OFFSHORE WIND ALLIANCE ON NOTICE OF PROPOSED RULEMAKING**

The American Clean Power Association ("ACP"),[1] Alliance for Clean Energy-New York ("ACE-NY"),[2] Clean Grid Alliance ("CGA"),[3] the Mid-Atlantic Renewable Energy Council Action ("MAREC Action"),[4] and the New York Offshore Wind Alliance

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[1] ACP is a national trade association representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind, solar, energy storage, and electric transmission in the United States. The views and opinions expressed in this filing do not necessarily reflect the official position of each individual member of ACP.

[2] The Alliance for Clean Energy New York (ACE NY) is a 501(c)3 member-based organization. Our mission is to promote the use of clean, renewable electricity technologies and energy efficiency in New York State, in order to increase energy diversity and security, boost economic development, improve public health, and reduce air pollution. We aim to be the voice of the clean energy industry in New York, and we support New York State's achievement of its ambitious climate action goals.

[3] Clean Grid Alliance (CGA) is a 501(c)(3) nonprofit organization based in St. Paul, Minn., whose mission is to advance renewable energy in the Midwest. Launched in 2001, CGA has been an active stakeholder in the MISO process at the state and regional levels and a leading organization working on transforming state energy policy. CGA's membership includes industry representatives working in wind, solar and storage as well as environmental nonprofit organizations, public interest groups, clean energy advocates, farm groups, and businesses providing goods and services to the renewable energy industry who come together to reduce carbon and deliver a renewable energy future.

[4] MAREC Action is a nonprofit organization formed to advance utility-scale renewable energy development within the Mid-Atlantic region and adjacent areas. MAREC Action's footprint includes ten

("NYOWA"),[5] (collectively "Clean Energy Associations") appreciate the opportunity to provide comments on the Federal Energy Regulatory Commission's ("Commission") Notice of Proposed Rulemaking ("NOPR")[6] in the above-captioned proceeding. In the NOPR, the Commission has identified numerous aspects of current rules regarding regional transmission planning and cost allocation that are not just and reasonable. The Clean Energy Associations submit these comments to assist the Commission in developing a final rule that adopts many of the reforms in the NOPR for Long-Term Regional Transmission Plans ("LTRTPs"), with certain improvements identified herein.

## I. INTRODUCTION

As detailed below, the Clean Energy Associations support significant reforms to many aspects of regional transmission planning. At a high level, the Clean Energy Associations recommend that the Commission make broadly applicable findings under Section 206 of the Federal Power Act, and implement *pro forma* transmission planning requirements as a replacement rate.[7] Though not universally true, many regions have failed to proactively develop transmission that meets the needs of the changing resource

jurisdictions within PJM (nine states and Washington, D.C.). MAREC Action members include utility scale wind, offshore wind, solar and battery storage developers, wind turbine manufacturers and non-profit organizations dedicated to the growth of renewable energy technologies.

[5] The mission of the New York Offshore Wind Alliance is to ensure the timely and responsible development of offshore wind in the Atlantic Ocean off the coast of New York State, at a level necessary to contribute to New York's mandate for a 100% emissions-free grid by 2040. NYOWA strategically advocates for cutting-edge policies that achieve this offshore wind power development and protect coastal and marine ecosystems, and strive to create in-State, quality, family-sustaining jobs, and reinvestment in New York's disadvantaged communities. NYOWA is an initiative of the Alliance for Clean Energy New York.

[6] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022) ("NOPR").

[7] The Commission should allow transmission providers to the opportunity demonstrate on compliance that nonconforming transmission planning practices are consistent with, or superior to, the *pro forma* requirements. The Commission should evaluate compliance filings from transmission providers – as well as their track record of regional transmission development – to ascertain whether current practices may, in some cases, be just and reasonable in terms of fully accounting for transmission benefits, evaluating long-term needs, and successfully planning transmission to meet those needs.

mix over the past decade, and have made progress only in fits and starts – rather than in a consistent, predictable fashion. For example, the Midcontinent Independent System Operator ("MISO") recently approved a portfolio over $10 billion in new regional projects that provided a range of quantifiable benefits. [8] However, while this tranche represents a vital step forward for the region, MISO had gone a full 11 years since approving a comparable group of projects, and it will, of course, be several years before any Tranche 1 projects are placed in service.

Similarly, the Clean Energy Associations recommend the *pro forma* use of a wide range of quantifiable benefits in conducting long-term transmission planning.[9] The Clean Energy Associations submit that it is essential to adopt a shared baseline, with Commission oversight over any regional variations based upon compliance filings. A final rule that holistically evaluates needs, incorporates the full range of quantifiable benefits, and assigns costs consistent with those benefits would be legally durable and a massive improvement upon the status quo.

## II. THE COMMISSION SHOULD ACT TO REFORM REGIONAL TRANSMISSION PLANNING

### A. The Commission Appropriately Identifies Many Aspects Rendering Current Transmission Planning Practices Unjust and Unreasonable

In the NOPR, the Commission appropriately proposes to utilize Section 206 of the Federal Power Act[10] to determine that several aspects of regional transmission planning – at least on a *pro forma* basis – are unjust and unreasonable, requiring replacement under

[8] *See* Multi-Value Projects, https://www.misoenergy.org/planning/planning/multi-value-projects-mvps/ (updated 2022).

[9] Again, the Clean Energy Associations submit that transmission providers and state agencies should have the opportunity to identify (for example) any benefits that may be currently accounted for in Integrated Resource Plans subject to state jurisdiction. This would help to ensure that long-term transmission planning does not double-count benefits.

[10] 16 U.S.C. § 824e.

the statute. Regional transmission planning processes (writ large) are insufficiently long-term, and fail to comprehensively address system needs or the benefits of expanded transmission.[11] As the Commission states, many transmission planning processes "fail to perform a sufficiently long-term assessment of transmission needs; adequately account on a forward-looking basis for known determinants of transmission needs driven by changes in the resource mix and demand; and consider the broader set of benefits and beneficiaries of transmission facilities planned to meet those transmission needs."[12]

The Clean Energy Associations agree with the Commission's findings in the NOPR that current regional transmission planning process will not adequately meet the needs of the electricity sector as customer and reliability needs continue to evolve.[13] As the Commission and others (including ACP)[14] have pointed out, current transmission planning processes are not sufficiently long-term nor comprehensive enough to meet these needs. Current planning processes are often reactive to current or foreseeable operational needs or requests for interconnection and works to meet these categories of needs – but to ensure that consumer costs are just and reasonable, transmission planning should be proactive in addressing foreseeable future needs at a regional scale. Otherwise, the transmission solutions will be piecemeal, addressing numerous short-term, local needs as they emerge – at a much greater net cost to consumers than proactive planning.

Clean energy generation and storage resources are rapidly being planned and built out – which necessarily affects where transmission will be needed years from now as the grid evolves to accommodate these shifts.[15] This is of course problematic when "years

[11] NOPR at PP28-33.
[12] NOPR at P35.
[13] NOPR at P28
[14] Comments of ACP and the Energy Storage Association, Docket No. RM21-17 at 21-30 (Oct. 12, 2021) ("ACP ANOPR Comments").
[15] The Brattle Group, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electrical Grid* (2015), https://www.brattle.com/insights-events/publications/toward-more-effective-transmission-planning-addressing-the-costs-and-risks-of-an-insufficiently-flexible-electricity-grid/.

from now" arrives, but transmission capacity may not be available. Failure to proactively plan will almost certainly result in higher costs on customers in the future,[16] in comparison to a forward-looking planning process that can identify lower-cost or higher-value projects that will meet more customers' long-term needs.[17] Costs can be half as much in proactively planned systems compared to the current incremental, reactive approach.[18] Additionally, a recent study from the Lawrence Berkeley National Laboratory found that real-time power prices show significant geographic differences, both within and between regions – but, in many cases, *average* power prices are stable over time.[19] These value differences are heightened in extreme and high-value periods, and more transmission would help to equalize these price differences and unlock value for customers. Put simply, the *lack* of transmission capacity imposes real and demonstrable costs *today*; in the absence of robust and proactive transmission planning rules, the Commission cannot reasonably determine that rates remain just and reasonable (and, in fact, should find that the opposite is the case).

This *status quo* cannot continue, given the scope of transmission that needs to be built out in the next few decades. Studies have shown that transmission will need to

[16] The Brattle Group, *Transmission Planning and Benefit-Cost Analyses* at 21 (Apr. 2021), https://www.brattle.com/wp-content/uploads/2021/07/Transmission-Planning-and-Benefit-Cost-Analyses.pdf. The problem is highlighted in the offshore wind context, where states like New York and New Jersey have been left to address offshore wind integration issues via public policy transmission projects and ad hoc solutions; rarely are the transmission needs for offshore wind holistically evaluated alongside other grid solutions to maximize net benefits and minimize customer costs.
[17] *Id.* at 7.
[18] Brattle-Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs* (2021) at 10, (citing PJM analysis of proactive transmission approaches as compared to reacting to individual interconnection requests), 12 (noting transmission costs in MISO as little as 1/5 of the cost for interconnection-based transmission upgrades), https://www.brattle.com/insights-events/publications/brattle-economists-identify-transmission-needs-and-discuss-solutions-to-improve-transmission-planning-in-a-new-report-coauthored-with-grid-strategies/ ("Transmission Planning for the 21st Century").
[19] Millstein et al, *Empirical Estimates of Transmission Value Using Locational Marginal Prices,* Berkeley Lab at 3 (Aug. 2022), https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf ("LBNL Transmission Value Study").

increase by 60% by 2030 and may need to triple by 2050 to reach full decarbonization.[20] This expansion could cost anywhere from $230 to $690 billion.[21] In light of the price tag associated with needed expansion, it is prudent to ensure that these costs are not unjust or unreasonable in relation to the benefits provided – which demands longer-term, more holistic planning than current *pro forma* practices require.

At present, transmission planning and cost allocation requirements in many regions fail to provide assurance that the most beneficial and cost-effective solutions are actually being evaluated, let alone ultimately selected, for several reasons:

- Transmission providers do not have to perform a sufficiently long-term assessment of transmission needs;
- Transmission planning fails to adequately account, on a forward-looking basis, for known determinants of transmission needs driven by changes in the resource mix and demand;
- Transmission planning often fails to consider the broad set of benefits and beneficiaries of transmission facilities planned to meet those needs; and
- An excessive amount of transmission planning occurs today through interconnection-driven network upgrades (which are developed when generators or energy storage seek to connect to the transmission system).[22] This is particularly problematic in RTO regions utilizing participant funding, where generators are *solely* responsible for the cost of network upgrades to the transmission system. This increases costs, and results in deployment of transmission solutions that are not tailored to foreseeable future needs.

[20] Molly Seltzer, *Big but Affordable Effort Needed for America to Reach Net-Zero Emissions by 2050*, (Dec. 15, 2020), https://www.princeton.edu/news/2020/12/15/big-affordable-effort-needed-america-reach-net-zero-emissions-2050-princeton-study.
[21] The Brattle Group, *The Coming Electrification of the North American Economy* at 17 (2019), https://wiresgroup.com/wp-content/uploads/2020/05/2019-03-06-Brattle-Group-The-Coming-Electrification-of-the-NA-Economy.pdf.
[22] NOPR at PP36-38.

Failing to take these into account results in ineffective transmission planning that does not identify the most cost-effective and efficient facilities. Indeed, evidence shows that this approach to transmission planning is inefficient,[23] and that it often results in generators funding high-voltage upgrades that provide system-wide benefits.[24]

### B. The Commission's Findings Support the Use of § 206 of the Federal Power Act to Improve *Pro Forma* Transmission Planning

The Clean Energy Associations therefore generally support FERC's preliminary findings in the NOPR, and encourages a formal finding in a Final Rule that current *pro forma* transmission planning and cost allocation practices are not just and reasonable. Under § 206 of the Federal Power Act, such a finding would require FERC to replace these rates with just and reasonable ones.[25] Any final rule should be evaluated based upon its efficacy in resolving these issues.

## III. THE COMMISSION MUST ESTABLISH A JUST AND REASONABLE REPLACEMENT RATE FOR TRANSMISSION PLANNING

As noted above, the Clean Energy Associations recommend that the Commission adopt *pro forma* changes to regional transmission planning. In doing so, the Commission should utilize a "do no harm" approach. A robust general finding is appropriate under § 206, and the Commission can then evaluate compliance filings to determine whether

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[23] *See Transmission Planning for the 21st Century* at 28 (Citing to a PJM study which found the current generation interconnection study process - evaluating one interconnection cluster at a time- approximately doubles the onshore transmission costs of integrating offshore wind generation compared to a proactive planning process).
[24] Sankaran, V., Parmer, H., & Collison, K., *Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits*, ICF Resources, LLC (Sept. 9, 2021), https://acore.org/wp-content/uploads/2021/09/Just-Reasonable-Transmission-Upgrades-Charged-to-Interconnecting-Generators-Are-Delivering-System-Wide-Benefits.pdf.
[25] 16 USC § 824e(a).

transmission providers currently utilize processes that are consistent with, or superior to, the improvements outlined here.

The Clean Energy Associations submit that a consolidated regional transmission planning process is necessary to achieving just and reasonable rates as noted above. The NOPR proposes to retain separate siloes for different types of transmission. The Clean Energy Associations reiterate that a truly holistic planning process would further improve upon the proposal, because the continued separation of needs assessment will ensure that some transmission solutions that could be designed to meet multiple needs will not be constructed, while solutions designed for a smaller subset of needs will be designed in a less cost-effective manner (in the aggregate).[26] Maintaining the silos (distinguishing reliability, from market efficiency, from public policy needs) ignores the demonstrable fact that transmission benefits overlap across these categories, as recognized by existing RTO analysis.[27] A new or expanded transmission line placed in service to serve a reliability need will change power flows and create upstream and downstream price impacts, and a portfolio of lines providing congestion relief will support reliability. The Clean Energy Associations again submit that retaining siloed processes leads to unjust and unreasonable rates, and that the Commission should use its authority to consolidate these processes.[28]

If the Commission is unwilling to require the elimination of siloes in the final rule, it should send a strong signal that such an approach would be an *option* that planning authorities could adopt and that because of the significant benefits brought to consumers,

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[26] ACP ANOPR Comments at PP43-47.

[27] *See* PJM. *2021 Regional Transmission Expansion Plan analysis* at p. 86, https://www.pjm.com/-/media/library/reports-notices/2021-rtep/2021-rtep-report.ashx. PJM's report shows congestion relief benefits of previously identified reliability projects. PJM's 2021 cycle of analysis included near-term simulations for study years 2022 and 2026. They identified collective and constraint-specific transmission system congestion due to the impacts of previously approved RTEP projects not yet in service.

[28] ACP ANOPR Comments at 22 ("ACP/ESA recommend that the Commission specifically find that siloed transmission planning is unjust and unreasonable, and co-optimized transmission planning must replace it.").

a holistic approach would be viewed favorably. However, even with the proposal to retain distinct categories of transmission projects, the Commission has put forward several proposals that render rates more just and reasonable than current *pro forma* transmission planning requires. The Clean Energy Associations identify provisions that are worth retaining in a final rule, as well as certain provisions that should be strengthened further or changed altogether prior to finalization. The Clean Energy Associations also submit that three critical elements of transmission reform, against which any replacement rate should be judged, are:

- Transmission providers, or applicable transmission planning bodies, must have the obligation to assess long-term system needs in a proactive and robust fashion.
- Evaluation of long-term, multiple-value needs must be sequenced appropriately, and with awareness of all other categories of transmission projects. Today, the first needs evaluated often relate to local or reliability projects for transmission owners and the upgrades associated with interconnection requests. The reverse should be the default, where inter-regional and regional investments providing multiple reliability and economic benefits are considered first, with anticipated and unanticipated local reliability needs filling in the gaps in between regional planning cycles. Conducting regional (or interregional) planning without identifying areas of complementarity between these processes makes it difficult to proactively address transmission needs efficiently. The Clean Energy Associations propose that LTRTP benefits include avoiding future standalone local reliability and economic projects, described further below.
- Transmission providers, or applicable transmission planning bodies, must have the obligation to evaluate projects that meet all system needs in a proactive and robust manner that maximizes net benefits. In non-RTO regions

there are no clear forums for Long-Term Regional Transmission Planning. If existing forums like SERTP and WestConnect will ultimately be able to address these responsibilities, the Commission should require that they establish more collaborative and comprehensive stakeholder engagement to develop effective, holistic long-term plans.

### A. The Clean Energy Associations Support Significant Reform of Regional Planning, and Urges the Adoption of *Pro Forma* Long-Term Scenario-Based Planning

First, the Clean Energy Associations are highly supportive of long-term planning that uses a range of scenarios and identifies transmission needs on a portfolio basis, and submits that such long-term scenario planning *must* include state and local policies. For long-term scenario planning, the Clean Energy Associations support the Commission's proposal for a LTRTP process with a 20-year planning horizon, to be repeated at least every 3 years.[29] This plan should be actionable rather than merely informational. Transmission providers should be required to establish holistic criteria for approval of portfolios and individual projects. Any projects which are approved at the end of a planning cycle should be included in updated models in the next transmission planning cycle, as well as the next applicable generation interconnection planning iteration.

The Clean Energy Associations ask that in this process, federal, state, and local policies, along with utility integrated resource plans, generator retirements, interconnection requestions, corporate commitments, and technology fuel costs and trends be fully considered. Each of these factors can be quantified and as such should be fully reflected in scenarios evaluated by transmission planners. All of these goals should be fully incorporated, without "discounting" of targets not enshrined in law or regulation;

[29] NOPR at P56.

if necessary, changes in non-binding obligations could be treated as a sensitivity or probabilistic change in one or more scenarios to determine how they might affect optimal transmission development.[30]

Failing to consider these factors would result in increased unjust and unreasonable rates. However, considering these factors, particularly state policies and their intersection with likely interconnection requests and the future of the resource mix, will allow for a more proactive and cost-effective approach to regional transmission planning, allowing for cost savings[31] and rates that are just and reasonable. In forecasting the future resource mix for these purposes, planners should incorporate the best available information on specific needs associated with federal, state, and local policies, corporate procurement targets, and utility decarbonization goals. Additionally, because the newly-signed Inflation Reduction Act[32] provides significant funding for electrification (for example, of vehicles and heavy industry) that could result in load growth,[33] at least some scenarios should evaluate transmission needs under higher-than-anticipated load growth to ensure long-term reliability.

Next, regarding the number of scenarios, the NOPR would require four scenarios;[34] ACP's initial comments recommended three to four, to provide appropriate "bookends" for various sensitivities.[35] The Clean Energy Associations submit that three to four

[30] *See* NOPR at P108 (preliminarily finding that some level of discounting is appropriate for utility, corporate, and federal, state, and local goals affecting the future resource mix).
[31] *See Transmission Planning for the 21st Century* at 30.
[32] H.R. 5376, 117th Congress. The Inflation Reduction Act was signed into law on August 16, 2022.
[33] *See* Resources for the Future, *Retail Electricity Rates under the Inflation Reduction Act of 2022* (2022) ("Lower electricity prices under the IRA also can be expected to accelerate electrification of transportation and buildings, which would likely complement the nation's climate policy goals and provide additional savings to households. The IRA provides substantial incentives for energy efficiency and electrification that are expected to provide substantial additional savings to consumers."), https://www.rff.org/publications/issue-briefs/retail-electricity-rates-under-the-inflation-reduction-act-of-2022/.
[34] NOPR at P121.
[35] ACP ANOPR Comments at 48.

scenarios is likely appropriate in many circumstances, but urges the Commission to ensure sufficient flexibility in terms of the "correct" number.

Ensuring detailed, transparent, and relevant data and future scenarios that realistically assess probable future is critically important. Some regions have a history of underestimating the development of new generation in such scenarios, which has shifted the burdens to interconnection customers for large-scale transmission better evaluated in a holistic planning process. High-impact, low-probability events should be assessed wherever jurisdictionally appropriate. Which events are included in each planning process should be open to regional determination subject to Commission approval (for example, the types of events and seasons most appropriate to incorporate may vary by geography, with summer wildfires and heatwaves posing greater risks in one area, and severe cold snaps elsewhere) – but given the widespread impact of climate change to the entire U.S. transmission system, such events should be included in each planning process. The degree of these types of events may be analyzed as probabilistic sensitivities *within* scenarios as a baseline, rather than distinct scenarios in and of themselves, and should appropriately cover potential *increases* in clean energy demand as well as *decreases* (in comparison with a discounting approach, which would only account for potential decreases).[36] However, no scenario or sensitivity should assume historic operating conditions will persist given the unpredictable and increasing impact of climate change.

In addition to including high-impact, low-probability events, scenarios should incorporate aging infrastructure and planned replacements, along with load and generation trends informed by both historical data and applicable policy drivers.

[36] This is important, because evaluating further increases in policy-driven clean energy resources in transmission planning scenarios could help to provide "optionality" – for instance, if particular facilities could assist in integrating significant new energy resources in the future, this would be valuable information in selection of the most beneficial transmission options. Offshore wind is one such example; given the time and expense of procuring cable-laying vessels for any future expansion of transmission, ensuring future flexibility is essential.

Considering these factors will ensure that LTRTPs keep pace with changes in supply and demand. For all relevant inputs that transmission providers choose to include, they should be required to explain the number and basis for including them.

The Clean Energy Associations are also supportive of the concept of identifying geographic zones based upon resource potential and commercial interest.[37] The Clean Energy Associations submit that ensuring the proactive identification of future generation needs in transmission planning must accompany any specific zone designations. Where resources are available for zone identification (based upon specific policy requirements, power purchase agreements, interconnection requests, advance indications of interest, or other drivers), such identification should be voluntary, driven by utilities, states, or interconnection customers.

Zones should take into account federal, state, and local policies, and any differing resource procurement goals for affected jurisdictions should be addressed through cost allocation (discussed further *infra*). Whether or not zones are designated in a particular LTRTP, the Commission should direct jurisdictional transmission planning entities to balance the tradeoff between generation that may cost less, but could have higher transmission costs, with more load-proximate but higher-cost generation. While rates associated with transmission and energy should both be taken into consideration,[38] when considering whether rates are overall just and reasonable, such determination should be a function of the lowest *delivered cost of energy* rather than merely the lowest *transmission* cost. Finally, where states (through IRPs or other means) or federal agencies (through the designation of onshore or offshore resource lease areas) designate particular zones for resource development, jurisdictional transmission planners should incorporate these determinations. Overall, the concept of geographic zones could be a useful tool in

[37] *See* ACP ANOPR Comments at 46.
[38] 16 USC § 824d.

identifying least-cost delivered energy, and should allow for indications of interest and willingness to pay from interconnection customers and states (as detailed *infra*).

The Clean Energy Associations also support the use of a portfolio approach, including multi-value project portfolios, and submits that such an approach should be included in any *pro forma* transmission planning requirements. As the Commission itself has pointed out, MISO has greatly benefited from its Multi-Value Project (MVP) process.[39] Projects planned through the MVP process have resulted in much lower interconnection costs for generators, as compared to transmission upgrades planned in response to interconnection requests; analysis conducted to date predicts that further savings can be achieved as more projects are planned through this process.[40]

Finally, the Clean Energy Associations are supportive of uniform *pro forma* long-term regional transmission planning requirements across both RTO and non-RTO regions. This should include clear direction that non-jurisdictional transmission providers adopt comparable planning requirements in their reciprocity tariffs.

### B. Treatment of Network Upgrades in LTRTP Should be Improved Upon Via Proactive Identification

As ACP noted in its ANOPR comments, network upgrades are fundamentally part of the overall transmission system, and should be planned accordingly.[41] However, in the NOPR, the Commission proposes a "third time's the charm" approach, in which high-voltage or high-cost upgrades must have been identified (and not selected or constructed) twice in the past five years to be incorporated in the LTRTP.[42] This approach has the merit of acknowledging the fundamental fact that network upgrades are ultimately part of

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[39] *See e.g.* NOPR at P135.
[40] *See Transmission Planning for the 21st Century* at 7.
[41] ACP ANOPR Comments at 10.
[42] NOPR at P169.

integrated transmission systems, and provide at least some benefit to all system users.[43] However, this proposal ultimately falls short of the need for, and benefits of, proactive planning of transmission, because it is intrinsically *reactive* and treats regional cost allocation only as a method of last resort – when it can and should be addressed earlier. Requiring multiple failures to move forward with network upgrades before addressing them in a regional plan risks delaying necessary transmission facilities, relative to what could be achieved via more proactive planning.

While the Commission's proposed test acknowledges the need for enhanced coordination between interconnection and LTRTP, the specific problem the Commission seeks to address – addressing network upgrade costs with broader social benefits that are in excess of what a single project can commercially bear - can be more efficiently addressed with better regional planning. However, absent certainty around the extent to which the Commission will ultimately endorse transmission planning reforms, interconnection process reforms are also necessary. As such, the Clean Energy Associations reiterate their support for a suite of reforms to regional transmission planning and interconnection processes to ensure network upgrade costs are efficient and their allocation is just and reasonable.[44] In the context of the regional transmission planning reforms identified in this proceeding, FERC should first and foremost establish more robust *proactive* measures to solve the problems identified in the NOPR.

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[43] See ACP ANOPR comments at 15 (citing ACORE-ICF study).

[44] Specifically, the Commission should direct transmission providers to evaluate interconnection customers in a reasonable fashion based on transparent, reasonable, comparable, and verifiable study assumptions; allocate costs to a cluster of projects causing the thermal or stability limit violation as opposed to a serial, 'first-to-cause' approach; reform participant funding and allocating cost responsibility based on approaches previously outlined, i.e., based on a voltage split or transfer distribution factor; provide projects the flexibility to request the level of service that is most economical, ranging from 100% ERIS to 100% NRIS; and finally, as the Commission has recognized in this docket, reforms to more holistically incorporate grid enhancing technologies and market mechanisms to more efficiently integrate interconnecting customer generation.

The Clean Energy Associations also support two measures that would better ensure that necessary transmission is built without requiring multi-year delays as interconnection customers balk at excessive upgrade costs. First, and most importantly, the Commission should require each LTRTP to incorporate likely future generation. In fact, *all* LTRTP scenarios should equally reflect projects in the queue that have received Facilities Studies (or another applicable third-phase study) from a transmission provider. Additionally, at least one scenario should reflect projects in the queue that have received System Impact Studies to ensure that sensitivities related to greater-than-expected generation deployment are accounted for, as well as any other commercial or policy-driven indicators of likely future generation and where it is likely to be built. Similarly, all scenarios should incorporate any likely merchant High-Voltage Direct Current ("HVDC") transmission facilities, and each scenario should incorporate the effects that these projects will likely have based upon comparable late-stage studies. The Clean Energy Associations recommend that the Commission require "advanced-stage merchant HVDC transmission" be evaluated in all planning scenarios. While having received a Facilities Study from the local transmission provider should be one way to demonstrate that a merchant line under development is advanced-stage, there should be alternate ways for merchant transmission projects to demonstrate readiness and ensure evaluation. These could include having obtained a construction permit from at least one state, having acquired a substantial portion of the project's right of way, or, for interregional transmission projects, having an executed interconnection agreement with a second transmission provider.

Second, rather than requiring two failures in the past five years to develop network upgrades as transmission, the Clean Energy Associations propose that each regional planning entity allow interconnection customers to *request* evaluation of assigned network upgrades for regional benefits in the LTRTP if they meet a materiality threshold. Upon receipt of a study from a transmission provider that indicates that upgrades would exceed a given threshold – such as the proposed thresholds of 200kV and/or $30 million, a relative standard of $200/kW for total upgrade costs, or a Transfer Distribution Factor above 20% on the local transmission system (a metric used by SPP), interconnection customers could request that the facilities be evaluated for inclusion in the next iteration of the LTRTP. The Clean Energy Associations recommend using the System Impact Study, at which point projects would have demonstrated a commitment to moving forward and would face consequences for withdrawal, but would not be on the verge of signing a Generator Interconnection Agreement (which would be the case at the Facilities Study stage). If the next LTRTP would be conducted out-of-sync with the applicable interconnection timetable, interconnection customers should be able to receive a one-time waiver to remain in the queue (potentially falling into the next cluster or class year) while the requested facilities are evaluated.[45] As a condition of this request, interconnection customers would be evaluated as beneficiaries of the proposed facility to allow accurate cost allocation. This means that costs would *not* be presumptively passed solely to load; instead, the applicable planning body would instead evaluate benefits for all system users, and would appropriately allocate costs to customers where benefits exceed costs under the applicable regional standard. The subsequent iteration of the LTRTP should identify whether a regional transmission facility would fully or partially address the need that a network upgrade was initially planned for.

This approach would have several advantages. First, it would allow for identification of synergies between the LTRTP and high-voltage, high-cost network upgrades. Because network upgrades are part of the integrated transmission system, the process of evaluation should be as integrated as possible. Second, this approach would support better alignment of the costs and benefits; rather than relying upon

[45] Conversely, the ability for interconnection customer to request that upgrades be evaluated during the next planning cycle should allow interconnection customers to withdraw from the queue without being subjected to a withdrawal penalty, if a requested upgrade is not selected through the planning cycle.

interconnection customers to finance (in regions with participant funding, to finance without reimbursement) transmission facilities, the costs of regionally beneficial facilities would be allocated consistent with judicial precedent. Interconnection customers would still be responsible for their share of costs for the additional benefits to future generation that would be evaluated. The Clean Energy Associations' proposed approach would serve as a "safety valve" in case high dollar, high-voltage upgrades are not initially identified in the LTRTP – by far the preferred option – there would be an opportunity to appropriately scrutinize these facilities for their consistency with regional needs. Finally, the Clean Energy Associations emphasize the need for finalization of interconnection reforms (proposed by the Commission in Docket No. RM22-14) which will be complementary to the reforms in this proceeding.

### C. The Commission Should Adopt a Minimum Benefits Standard on a *Pro Forma* Basis, Utilizing the Quantifiable Benefits Identified in the NOPR

ACP has previously noted that transmission planning fails to account for all of the quantifiable benefits of transmission.[46] The NOPR identifies twelve potentially quantifiable benefits of long-term regional transmission planning:

(1) avoided or deferred reliability transmission projects and aging infrastructure replacement;
(2) either reduced loss of load probability or reduced planning reserve margin;
(3) production cost savings;
(4) reduced transmission energy losses;
(5) reduced congestion due to transmission outages;
(6) mitigation of extreme events and system contingencies;
(7) mitigation of weather and load uncertainty;
(8) capacity cost benefits from reduced peak energy losses;
(9) deferred generation capacity investments;
(10) access to lower-cost generation;
(11) increased competition; and

[46] *See* ACP NOPR Comments at 24-26.

(12) increased market liquidity.[47]

In addition to these benefits, the Clean Energy Associations submit that the Commission could also recognize the economic and climate benefits of transmission that enables new generation, much of which will be renewables, to interconnect. In particular, where *states* require consideration of these benefits of specific types of generation (for instance, in New York's public policy-driven transmission planning), the Commission should ensure that regional planning incorporates these state-driven benefit assessments.

However, the NOPR does *not* require that *any* of these benefits specifically be used.[48] If finalized in its present form, this would potentially lead to several problems. First, the failure to incorporate identifiable benefits risks skewing benefit-to-cost ratios *against* developing necessary transmission – because all costs would be included, but not all benefits would be. Second, significant disparities in regional identification of long-term transmission projects could have harmful spillover effects on coordinated activities such as interregional transmission and conducting affected systems studies; if adjacent regions do not have a shared starting point in evaluating benefits, coordination will continue to be more challenging than necessary.

These concerns are not speculative. Many regions that notionally have multi-driver planning options available already fail to use them. They instead continue to plan principally based on reliability needs and generation interconnection requests.[49] While the Clean Energy Associations recognize that requiring the use of *all* benefits in planning might not be possible in *all* circumstances, a minimum benefits standard would be just and reasonable. Each region should presumptively use the same benefits evaluated in reliability and economic projects to identify efficiencies, and should further quantify the

[47] NOPR at P185
[48] NOPR at P186 ("We clarify that these are just examples, and we are not proposing to require that public utility transmission providers use any specific benefits or calculate those benefits in a particular manner when conducting Long-Term Regional Transmission Planning.")
[49] *Transmission Planning for the 21st Century* at 13.

benefits associated with the criteria the Commission notes in the NOPR. Consistent with the rest of these comments, the minimum benefits standard should be *pro forma*, and the Commission should (of course) consider regional variations when justified.

*Not* requiring benefits to be evaluated could lead to higher costs in the long-term, and, thus, unjust and unreasonable rates. Without considering a larger number of benefits, transmission projects that would have large net benefits would not be chosen if known benefits (or even only a small number of potential benefits) were not compared against the upfront costs.[50] The costs would frequently outweigh the limited benefits assessed, when those costs were actually less than the full slate of benefits. This would prevent customers from experiencing the benefits and potential future cost savings resulting from them – and past analysis shows that typical benefit-cost analysis (often focused on production cost savings) systematically undervalues the benefits of transmission. As ACP's ANOPR comments noted, an expanded analysis of transmission benefits by the Southwest Power Pool in 2016 found that only evaluating production cost savings (but not other benefits, such as reliability, reserve margin, losses, wheeling, and wind integration) failed to identify more than one-third of the quantifiable benefits of a group of transmission projects.[51]

Thus, the Clean Energy Associations submit that all twelve benefits listed in the NOPR should therefore be presumptively adopted on a *pro forma* basis. Benefit analyses should presumptively incorporate the benefits that can be demonstrably quantified across each region, including: Production costs (MWh), avoided generation costs (MW) and improved supply diversity, avoided reliability and local economic projects, and reduced transmission line losses, as identified in the NOPR. This would ensure that all regions have a common starting point, and transmission providers could then propose just and

[50] The Brattle Group, *Transmission Planning and Benefit-Cost Analyses* at 26, (Apr. 2021).
[51] ACP ANOPR Comments at 27 (citing, Southwest Power Pool, *The Value of Transmission Report* (Jan. 2016) available at https://spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf.)

reasonable variations as necessary. A common starting point would also aid in ensuring better interregional coordination, since all regions would then have similar ways of measuring benefits. Benefits should also not be calculated solely based upon "normal" or average system conditions, as a large portion of transmission benefits can occur during abnormal or extreme conditions or events.

There is also a sound legal basis for FERC to require these benefits on a *pro forma* basis. Each of these benefits clearly occurs within the power system, which FERC has clear authority and responsibility to address.[52] The benefits that each region uses in selecting long-term regional transmission projects should also be directly linked to eventual cost allocation, as discussed below, and should be evaluated based upon the asset life, which is often 40 years or more. At a bare minimum, benefits assessments should mirror the proposed 20-year period for transmission planning in the Proposed Rule.

Additionally, the Clean Energy Associations encourage the Commission to require transmission providers to link near-term and long-term planning processes, so that local reliability and economic benefits are accounted for in LTRTP processes. This minimum requirement is necessary because long-term planning processes may identify valuable future multi-value upgrades that are not yet economic (e.g., only economic 15 years out). Local reliability needs –anticipated and not – are often left open to be subsequently addressed via shorter-term local processes. If and when local lines are subsequently constructed, the value of future LTRTP projects could be reduced. This dynamic risks perpetuating the prioritization of near-term reliability needs above proactive regional planning that also considers the full range of longer-term needs—which would be at odds with the intent of the NOPR. Therefore, the Commission should

[52] 16 U.S.C. § 824k. Other benefits – such as pollution reductions and public health benefits – are still calculable, but would not pertain directly to rates, terms, and practices within the Commission's jurisdiction.

require on a pro forma basis that LTRTP expressly allow for anticipated and *unanticipated* local needs as part of the benefit calculation. Additional near-term planning reforms should also include evaluation of Grid Enhancing Technologies (discussed further below) as a potential means of addressing unanticipated local needs arising before the LTRTP identifies a future economic need.

### D. The Commission Should Ensure Transparent and Consistent Selection of Regional Transmission Projects

In the NOPR, the Commission proposes to require transmission providers to use transparent, non-discriminatory criteria for selecting regional projects, with the aim of maximizing benefits to customers without overbuilding facilities; the Commission also proposes that transmission providers should evaluate projects to ensure that they address transmission needs spurred by changes in resources and demand.[53] The Clean Energy Associations strongly support these aims, and submits that the Commission can best ensure that selection criteria are sufficiently transparent by using a standardized set of benefits, at least on a *pro forma* basis (*see supra*); should the Commission continue to utilize a benefit-to-cost ratio, the Clean Energy Associations recommend that that ratio not be allowed to exceed Order No. 1000's maximum B:C ratio of 1.25:1.

The Clean Energy Associations also support a *pro forma* LTRTP that would select facilities that maximize net benefits across multiple scenarios, and weighting the benefits based upon the probabilities or sensitivities of those scenarios.[54] While regional flexibility and a clear role for state consultation in selection of projects are essential elements as well, the Commission should seek to establish a clear and consistent *pro forma* baseline that applies uniform project evaluation criteria consistent with those

[53] NOPR at P241-42.
[54] *See* NOPR at P251.

established in planning studies for project selection, with appropriate opportunities for regions to adopt variations that are consistent with or superior to that baseline. This will help to minimize differences across seams, and enable state regulators, consumers, and other market participants to evaluate LTRTPs on an apples-to-apples basis as much as feasible.

Additionally, the Clean Energy Associations continue to support the ability of state entities and interconnection customers to voluntarily fund all or part of a facility identified in an LTRTP.[55] ACP's ANOPR Comments proposed two potential options that would provide just and reasonable opportunities for states and interconnection customers to ensure that necessary transmission infrastructure is developed:[56]

- The Transmission Alternative Right would allow for selection of a project evaluated in the LTRTP, but that was not selected (either due to not meeting the applicable benefits assessment, or another project that would resolve the same or similar needs being selected). Under this option, states or interconnection customers could "buy down" the gap between the evaluated benefits and applicable benefits threshold, so that a project that would not otherwise be selected could become part of the LTRTP. This right would *not* confer the right to prioritize transmission capacity on the facilities.
- The Transmission Expansion Right would allow states or interconnection customers to fund expanded transmission *beyond* what is identified in the LTRTP. For example, if an applicable regional process identified a 345kV facility that was needed, voluntary funding could be used to increase the capacity to 500kV - perhaps in anticipation of a longer-term public policy need, or future interconnection request, that was not incorporated in the LTRTP. Because this would involve developing transmission facilities with

[55] *See* NOPR at P252.
[56] *See* ACP ANOPR Comments at 76.

additional capacity, the funding parties would be able to obtain time-limited priority usage of a commensurate portion of the expanded capacity, and would retain the incremental capacity attributes associated with the expanded transfer capability. As noted in ACP's earlier comments, this would be consistent with precedent such as the Commission's Order No. 807.[57] The incremental portion of the transmission could be voluntarily funded, and the base portion would use the applicable *ex ante* regional cost allocation approach (unless an *ex post* allocation is agreed to).

For both rights, there should be a fixed window – potentially 90 days – following each iteration of the LTRTP during which states or interconnection customers can seek to fund alternative or expanded transmission. The sponsoring party should sign a letter of intent to fund the applicable alternative, and a deposit could be required shortly after submittal of the letter as a firm indication of interest.

Finally, the Clean Energy Associations also submit that a similar approach can be used in identification of geographic zones, an issue upon which the Commission requests comment.[58] Here, states and interconnection customers should have the option to identify particular areas of interest *prior to or in parallel with* each iteration of the LTRTP. This would be accompanied by an indication of willingness to pay from the states or interconnection customers. Such an approach would help to ensure that necessary transmission is built where it is needed, and would be analogous to Texas' approach with Competitive Renewable Energy Zones. For CREZ, transmission was developed proactively based in part upon the willingness of generators to fund necessary facilities.

[57] ACP ANOPR Comments at 76-78; *see also Open Access and Priority Rights on Interconnection Customer's Interconnection Facilities*, Order No. 807, 150 FERC ¶ 61,211, at P 109 ("Order No. 807"), *order on reh'g*, Order No. 807-A, 153 FERC ¶ 61,047 (2015).
[58] NOPR at PP146-153.

Under the CREZ approach, transmission was developed proactively based in part upon the willingness of generators to fund necessary facilities ahead of existing line expansion and new line construction. The Public Utilities Commission of Texas adopted a test to assess sufficient financial commitment to warrant approval of CCNs for CREZ facilities, including the amount of generation currently under development, and renewable capacity represented by signed interconnection agreements demonstrating sufficient financial commitments for identified zones. For new lines without sufficient development or signed interconnection agreements, generators also had the opportunity to demonstrate financial commitment by posting collateral.[59] Such a commitment both represents a clear method for transmission planners to confirm areas of interest, and also to share in the risk of new line construction. The Clean Energy Associations submit that the CREZ model should be available and permissible in all regions, and request that FERC establish a clear process for applying this model.

### E. Although a Holistic Transmission Planning Process Would Be Superior, if the Commission Retains Separate Economic and Reliability Siloes it Should Include the Ability to "Right-Size" Those Projects

The Clean Energy Associations reiterate their support for a truly holistic transmission planning process that fully integrates all drivers, without separate siloes for distinct categories of transmission.[60] This is appropriate because any given transmission facility can help to address multiple regional needs, and ultimately the transmission

[59] Project No. 34577, PUCT, Proceeding to Establish Policy Relating to Excess Development in Competitive Renewable Energy Zones, Order Adopting Amendments to S25.174 as Approved at the October 8, 2009 Open Meeting, P. 3, ("If the sum of the capacity represented by completed projects, projects under construction, signed interconnection agreements and collateral is at least 50% of the designated capacity for a CREZ, the financial commitment requirement will be deemed to be met for that CREZ." ), https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.174/34577adt.pdf
[60] ACP NOPR Comments at 22.

system is an *integrated* system – where facilities identified and built through economic, reliability, local, interconnection, regional, and interregional processes are jointly operated. A transmission planning process that identifies and co-optimizes benefits *across* these siloes can provide the most value to customers.

This has been compellingly demonstrated by MISO's analyses of both its MVPs and its more recent Long Range Transmission Planning (LRTP) Tranche 1 Portfolio. The LRTP analysis found that production cost savings accounted for 19-53% of the total benefits of the lines, with reliability, decarbonization, and lower generation capital costs each accounting for roughly an equally large share of benefits.[61] The MVP analysis also found production cost savings were complemented by large reliability benefits.[62]

However, in the NOPR the Commission proposes to leave the current approach intact, for nearer term transmission planning in the siloes of reliability and economic projects. Within that context, the Clean Energy Associations offer two specific recommendations. First, even if a final rule does not require that economic and reliability transmission projects be integrated with the LTRTP, the rule should make clear that regions *may* still submit plans that do so.

Second, once LTRTPs begin to be produced for a given region, they should be evaluated for consistency with economic and reliability projects when the latter are selected; this would serve to identify potential compatibilities and opportunities to "right-size" similar to the Commission's proposal for treatment of local transmission needs.[63] As discussed below, the NOPR proposes to allow incremental expansion of transmission projects initially identified as local needs, with an incremental cost allocation framework,

[61] *MISO Reliability Imperative: Long Range Transmission Planning*, at 8 (July 25, 2022), https://cdn.misoenergy.org/20220725%20Board%20of%20Directors%20Item%2002a%20Reliability%20Imperative%20LRTP625714.pdf.
[62] *2011 Multi-Value Project Portfolio, Results and Analyses* at 49 (Jan. 10, 2012), https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf.
[63] *See* NOPR at PP405-06.

to accommodate needs identified in the LTRTP. The Clean Energy Associations submit that it would be appropriate to adopt comparable treatment for reliability and economic projects. Where synergies exist between these categories of transmission and needs identified through the LTRTP, it should be presumptively permissible to use a similar "right-sizing" approach.

### F. The Commission Should Require Evaluation of Grid-Enhancing Technologies, Including Energy Storage, in Regional Planning

In the NOPR, the Commission recognizes the value of two specific Grid-Enhancing Technologies ("GETs") – Dynamic Line Rating ("DLR") and advanced Power Flow Control ("PFC") devices. [64] The Commission proposes to require their inclusion as they meet two defined criteria: (1) the technologies have sufficient operational experience, and (2) the nature of the technologies allows for their consideration in regional transmission planning.[65] The Clean Energy Associations fully support the proposed requirement to evaluate dynamic line rating and power flow controls as solutions in regional plans, and to subsequently deploy these technologies where they are appropriate and cost-effective. The Clean Energy Associations also note that GETs provide value beyond least-cost – such as speed to deployment, modularity over time, reduced environmental and geographic footprint, and lower development risk – and supports the WATT Coalition's proposal that GETs be considered for near-term regional projects as well as LTRTPs. Additionally, the Clean Energy Associations specifically support consideration of storage-as-transmission in LTRTPs.[66]

[64] *Id.* at PP274-276.
[65] *Id.* at P276.
[66] *Id.* at P279.

### 1. DLR and PFCs

The Clean Energy Associations agree with the Commission's proposal to require evaluation of DLR and PFC technologies in regional transmission planning. GETs, including DLR and PFCs, can provide substantial benefits at lower total costs in many circumstances. Their operational use is well-demonstrated at this point, and inclusion in LTRTP will help to ensure that customers are deriving maximal benefits from both the existing transmission system and future infrastructure. The Commission also seeks comment on whether non-RTO/ISO regions should be required to update their systems if DLRs are identified as more efficient or cost-effective solution than other types of transmission facilities;[67] ACP supports implementation of such a requirement in any final rule.

### 2. Energy Storage

Energy storage as a transmission asset fully satisfies the Commission's criteria of operational experience and relevance in regional planning; storage-as-transmission has the potential to provide immense value to the grid. The Clean Energy Associations recommend that the Commission should similarly require consideration of energy storage in regional transmission planning, along with the other identified GETs. Regarding the first criteria – operational experience –energy storage is a widely deployed technology in the U.S. with over 4,600 MW operational at the close of 2021.[68] More specifically, storage assets have been providing value to the transmission and distribution system for years including the Presidio Battery in Texas,[69] the APS Punkin Battery in Arizona,[70] and

[67] *Id.* at P277.
[68] Energy Information Administration, *Electricity Monthly Update,* (July 5, 2022) https://www.eia.gov/electricity/monthly/update/archive/june2022/.
[69] *Presidio NaS Battery Project*, Electric Transmission Texas (2019), http://www.ettexas.com/Projects/Presidio ("In the event of a transmission outage, the battery system is capable of automatically deploying to provide backup transmission power.").
[70] Gavin Bade, *APS to Deploy 8 MWh of Battery Storage to Defer Transmission Investment,* Utility Dive (Aug. 2017), https://www.utilitydive.com/news/aps-to-deploy-8-mwh-of-battery-storage-to-defer-transmission-investment/448965/.

the Nantucket Battery in Massachusetts (among others).[71] Beyond the U.S., large-scale Storage as a Transmission Asset ("SATA") systems are operating or under construction in countries such as Australia, Colombia, and Lithuania. Operational know-how is well established for energy storage broadly, and transmission and distribution applications more specifically. Additionally, the creation of an Investment Tax Credit for energy storage in the Inflation Reduction Act will reduce the cost of storage deployment in a range of applications, including SATA.

Regarding the Commission's second criterion (whether technologies can be incorporated in regional planning), the Clean Energy Associations note that several regions have selected SATAs based on system needs, most notably CAISO, or adopted tariff language allowing for the Storage as a Transmission-Only Asset ("SATOA"), in MISO.[72] When focusing on SATA, FERC has acknowledged the eligibility of SATA to be considered in transmission planning processes and cost allocation.[73] However, this precedent has failed to manifest in broad adoption. Only MISO and CAISO have adopted rules and regulations in their transmission tariffs, with SPP's proposal pending at this time.[74] ISO-NE is proceeding with a stakeholder process to develop rules for storage-as-transmission.[75]

[71] *New Nantucket Energy Storage Project Highlights Value of Transmission Deferral*, Guidehouse Insights (Nov. 2019), https://guidehouseinsights.com/news-and-views/new-nantucket-energy-storage-project-highlights-value-of-transmission-deferral.
[72] *See* MISO Tariff, Att. FF, Transmission Expansion Planning Protocol, § (G)(1)(c)(i).
[73] *See e.g. Western Grid Dev., LLC,* 130 FERC ¶ 61,056 (Western Grid), *reh'g denied*, 133 FERC ¶ 61,029 (2010); *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,051 (2017); *Midcontinent Independent System Operator, Inc*., 172 FERC ¶ 61,132 (2020) ("MISO SATOA Order").
[74] *See generally* Docket No. ER22-2344.
[75] Sam Mintz, *ISO-NE Weighs Allowing Storage as Transmission*, RTO Insider (Apr. 26, 2022), https://www.rtoinsider.com/articles/30019-iso-ne-weighs-allowing-storage-transmission.

As described in a recent report from the Pacific Northwest National Laboratory,[76] storage can interact with transmission planning processes in two ways: storage *as* transmission and storage *in place* of transmission. When storage acts as transmission, it provides *specific services* to the transmission system, and when it serves in place of transmission, it provides market services that reduce or eliminate the need for transmission infrastructure.[77] The Clean Energy Associations submit this portion of these comments focused on the first concept (SATA).

Storage is fully capable of providing transmission capabilities, separating it from other generation assets and system reserve products. For example, the rapid automated response time (less than 200 milliseconds) mimics breakers on the transmission system following faults. Additionally, storage's ability to inject and withdraw energy in precise amounts gives transmission providers versatility to meet multiple contingency conditions. Storage also has grid-forming and blackstart capabilities in circumstances where the grid is unstable following a contingency. In these circumstances, storage is not providing market services that replace transmission; instead, storage is serving as an integrated component *in* the transmission system that enhances the overall grid.

Accordingly, the Clean Energy Associations recommend the Commission require evaluation of Storage as a Transmission Asset alongside other GETs in any final rule. A *pro forma* tariff for LTRTPs should make clear that SATAs are an asset class capable of providing transmission services and receiving cost recovery. SATA should be evaluated in all transmission planning processes on an even footing with conventional solutions, and entities should be allocated using the applicable regional cost allocation method as

[76] Twitchell et al, *Enabling Principles for Dual Participation by Energy Storage as a Transmission and Market Asset,* Pacific Northwest National Laboratory (2022), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-32196.pdf ("PNNL Dual Participation Report").
[77] *Id* at 1.5.

FERC proposes in the NOPR for other GETs.[78] Any revenues from the market due to state-of-charge management or operation during a contingency would be attributed against the SATA's revenue requirement, which would ensure that there is no opportunity or incentive to affect market outcomes; any rules that allow market revenue to be gained from SATA deployment should ensure that such deployment does not compete with or disadvantage market storage resources. Consistent with ACP's past positions on MISO and SPP's proposals for storage-as-transmission,[79] the Clean Energy Associations urge the Commission to determine that ownership and operation of SATAs should not be limited to transmission owners.

ACP's initial comments identified a range of circumstances under which energy storage be appropriately incorporated into transmission planning.[80] In response to the NOPR, the Clean Energy Associations submit that the following two use cases would be specifically consistent with the Commission' s GETs criteria, and clear circumstances where storage would be serving a transmission function:

1. Applications where the grid operator or transmission provider requires functional control of a resource to resolve non-routine reliability transmission issues that cannot be addressed by a market solution.[81] Transmission planners must ensure loads can be restored if any single component on the transmission system fails (N-1). If meeting non-routine issues beyond N-1 conditions

[78] NOPR at P274.
[79] *See* Comments of the American Clean Power Assoc., Docket Now. ER22-2344 at 2 (Aug. 2, 2022)(noting that limitation of storage-as-transmission to transmission owners in most circumstances requires heightened scrutiny of any market impacts); Comments and Protest of Joint Stakeholders, Docket No. ER20-588 (Jan. 21, 2020)(raising concerns that MISO's proposal was "unlawful because it "creates an unduly discriminatory preference for storage projects proposed by Transmission Owners (TO Projects) over identical storage projects proposed by non-TOs (Non-TO Projects))." ACP's predecessor organization, the American Wind Energy Association, joined the Joint Stakeholder filing.
[80] ACP ANOPR Comments at 61.
[81] MISO SATOA Order at P58 ("[A] storage facility will not be evaluated as a potential SATOA unless MISO requires functional control of the resource in order to resolve a non-routine (i.e., not an N-0 or N-1) reliability Transmission Issue that could not be addressed by a market solution.").

require transmission expansion, the construction of new local generation, or the derating of existing infrastructure, planners should be required to evaluate energy storage as one of the solutions they consider. SATA can be valuable in the Contingency Relief use case (including but not limited to N-1-1 contingencies). Using battery storage in lieu of constantly maintaining headroom on a transmission line (derating) can accommodate higher power flows in the case of a failure. One option to meet this requirement is to maintain headroom on a transmission line. For example, a transmission line that could operate at 350 MW of transfer capacity might be limited to lower threshold (e.g. 300 MW) under normal operations to ensure power flow can be stepped up in abnormal operations to accommodate power that would normally flow on a parallel line. On a high-demand line, limiting power flow comes at a cost for ratepayers. An alternative solution is to allow the transmission line to operate closer to its full transfer capacity rating and use abattery to accommodate sudden failure. The battery would be required to perform for a defined period of time (e.g. 1 hour) to allow grid operators time to reconfigure power flows. As noted above, and condition with Commission precedent, SATA deployment should not supplant market solutions where the latter are viable.

2. Applications where solutions are being considered to solve the reliability of the transmission system, such as inertia, blackstart, voltage stability, or other stability related challenges,[82] and where market-based solutions are not appropriate or effective. As has been demonstrated in Europe, a higher percentage of inverter-based generation will change the inertia of the

[82] ACP ANOPR Comments at 64

transmission system. Energy storage has been found to be a cost-effective solution to add either synchronous inertia—or in the case of battery storage, synthetic inertia--to the transmission system, particularly when the storage asset is used for multiple purposes (e.g., inertia, system strength, and blackstart).

Finally, the Clean Energy Associations note that U.S. and international experience demonstrate the value of SATA projects:

- Waupaca Area SATA (MISO): A battery energy storage system proposed as SATOA was and selected by MISO under MISO's FERC-approved SATOA tariff. The traditional solution (adding a circuit) was found to have a capital cost of $13.07 million compared to $12.24 million for the SATOA option.[83]
- Dinuba Substation (CAISO): CAISO identified a SATA alternative to a line rebuild at a higher thermal limit to be a cost-effective solution in their 2018 transmission plan. The SATA solution was found to be $14M compared to $16M for the line rebuild.[84]
- Gridboosters (Germany): The German Gridbooster concept calls for energy storage to be deployed as part of the German National Grid Development plan to increase transfer capacity across existing lines by providing contingency support, thus lower redispatch (i.e., out of market) cost. A consulting report by third-party Consentec found that the 1.3 GW pilot phase of assets would save the German grid 200M euros in redispatch costs by increasing transfer capacities as SATA

[83] PNNL Dual Participation Report at 19.
[84] *Id.* at 22, § 1.5.1.

assets. They also identified 400M € in annual savings from a total portfolio of 13.3 GW.

- Victorian Big Battery (Australia): The Victorian Big Battery (VBB) was selected to provide contingency support for the Victoria to New South Wales Interconnector (VNI), increasing the transfer capacity by up to 250 MW during peak times. This SATA asset would be procured via a third-party service. The service was estimated to cost 82M AUD compared to an estimated benefit of 220M AUD for a benefit-cost ratio near 2.6x.[85]

### G. The Commission Should Presumptively Require Cost Allocation to Track Identified Benefits, But Should Allow for Regional Variations on Compliance

The Clean Energy Associations strongly recommend that any final rule make clear that cost allocation should be in line with and closely related to the multiple benefits used in project selection, as discussed *supra* and in previous comments.[86] The alignment of benefits and costs does not require "exacting precision," and FERC may use presumptions where necessary – but, in general, legal precedent requires that cost allocation closely track benefits. [87] This represents a just and reasonable starting point for cost allocation, but does not preclude bespoke regional variations on either an *ex ante* or

[85] *See* https://victorianbigbattery.com.au/.
[86] ACP ANOPR Comments at 75.
[87] *See Illinois Comm. Comm'n v. FERC*, 756 F.3d 556, 558 (7th Cir. 2014) (discussing that where western PJM utilities stand to benefit from transmission projects in the eastern portion of PJM, they can be required to contribute in proportion to those benefits, but such costs have to be "roughly commensurate" with benefits); *Long Island Power Authority v. FERC*, 27 F.4th 705, 713–14 (D.C. Cir. 2022) (holding significant weight should be given to both regional and local benefits in cost allocation); *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1261 (D.C. Cir. 2018) (holding that a decision to not allow cost-sharing was arbitrary where a proposed transmission line conferred regional benefits).

*ex post* basis. For example, MISO's cost allocation for Multi-Value Projects, and SPP's for Highway/Byway projects (based upon voltage level) would represent viable options for regions to use at their own election. Additionally, where voluntary contributions are involved, allocations may be changed in ways that might not be directly proportional to benefits.

In determining appropriate allocation of costs, the Clean Energy Associations agree that states have a vital role to play and is supportive of efforts to involve states in *ex ante* cost allocation approaches. Where states are involved proactively and benefits are demonstrated, it may facilitate projects moving forward more readily. In contrast, while *ex post* frameworks that rely on voluntary contributions from states or interconnection customers may be useful in some circumstances, the Clean Energy Associations note that they may not appropriately acknowledge system-wide benefits of high-voltage elements. In these scenarios, long-haul, high-voltage lines could be treated as benefitting only a single state – which courts have found improper,[88] and which is unlikely to yield agreement in practice. Accordingly, the Clean Energy Associations agree with the Commission's proposal that a State Agreement Process must not be mandatory. Overall, states should certainly be involved in the process for determining cost allocation (as well as in informing the scenarios and study assumptions that would determine such allocations). These *ex ante* frameworks should also be on file for LTRTPs. *Ex post* frameworks should not be excluded, but should be careful to ensure they are still acknowledging the wide-spread benefits of transmission projects.

While the Clean Energy Associations acknowledge that states have a key role to play in transmission advancement, it is concerning that the NOPR does not provide clarity around how disagreements among states or transmission providers will be handled in multi-state regions both within and out of RTOs.[89] The Clean Energy Associations

[88] *See Old Dominion*, 898 F.3d at 1261.
[89] NOPR at P310.

recommend that in the absence of state concurrence on either an *ex ante* or *ex post* approach, FERC presumptively require cost allocation to track the identified and quantifiable benefits reflected in the long-term regional transmission planning project selection.  This division would then be reflected in rates, which would provide clarity on the *default* cost allocation methodology. The Clean Energy Associations recommend that the Commission establish a method upfront for these situations to improve transparency in the process and provide more certainty to affected parties. Where it is necessary for the Commission to determine an alternative cost allocation approach that will need to be agreed to, the Clean Energy Associations believe that setting a timeframe is necessary and that a 90-day period would be reasonable.

Finally, as elsewhere, a *pro forma* approach would allow for regional variation where cost allocation practices are consistent with or superior to the requirements adopted in a Final Rule.  For example, if vertically integrated utilities subject to state-jurisdictional integrated resource planning can demonstrate that the state planning process appropriately identifies needs and assigns costs based upon future planned generation consistent with state policies, certain requirements may not be applicable.

### H. The Clean Energy Associations Support Improved Transparency in Local Transmission Planning, Including Many Aspects of the NOPR's "Right-Sizing" Proposal

The Clean Energy Associations support FERC's proposal to require transparency in how local transmission projects are identified and selected, and to allow "right-sizing" by linking LTRTP projects to local replacements and upgrades to improve efficiencies. This proposal is consistent with ACP's ANOPR comments, which support improved transparency and coordination of local and regional transmission planning to better realize efficiencies.[90]

[90] ACP NOPR Comments at 30.

The Commission proposes to allow "right-sizing" to allow for cost-effective expansion of circuits or increased voltage for projects above 230kV while planned replacements or upgrades are occurring.[91] The Clean Energy Associations generally support this proposal, including adoption of an updated incremental cost allocation framework for the "right-sized" components of such projects; however, the 230kV threshold should be adjusted regionally as appropriate, as the "high-voltage" facilities in (for example) ISO-NE are typically far lower voltage than such facilities in MISO. As noted above, the Clean Energy Associations also recommend that the Commission provide similar opportunities for right-sizing of reliability and economic projects to take advantage of comparable efficiencies between these siloes and the LTRTP. Finally, each region should have the regular opportunity to review local planning criteria for consistency with regional planning, as PJM's manuals require.[92]

However, the Clean Energy Associations do not take a position on the ownership of incremental transmission facilities identified through the LTRTP that are added to local projects through "right-sizing," and whether these incremental facilities must be owned by the incumbent transmission provider. The Clean Energy Associations will evaluate other proposals in the record, and may provide reply comments on this issue as appropriate.

[91] NOPR at PP405-412

[92] *See* PJM's Manual 14B, 1.1 Planning Process Work Flow ("As part of the review of Supplemental Projects PJM will also apprise the relevant Transmission Owner if a baseline upgrade might alleviate or partially mitigate the need for a Supplemental Project. In addition, PJM will determine if a Supplemental Project might impact a baseline need identified through the RTEP process, which might be in progress.").

## I. In Addition to Regional Transmission, The Commission Should Consider Requiring Joint Interregional Planning and Cost Allocation

Although the focus of the NOPR is on regional transmission, adoption of transmission planning reforms would necessarily have implications for interregional transmission. The Clean Energy Associations therefore submit that interregional transmission planning coordination should reflect any regional transmission reforms adopted in this proceeding, which would help to ensure consistency between processes and appropriate evaluation of benefits.[93] The Clean Energy Associations also support allowing transmission providers to propose interregional facilities in LTRTPs.[94] Further, as noted above, adoption of a *pro forma* minimum benefits standard would aid the ability to plan and allocate costs of interregional facilities.

Experience has shown that, for all practical purposes, the interregional coordination process required by Order No. 1000 does not produce effective results. For most planning regions, this coordination process has essentially become a box-checking exercise, has failed to identify (much less implement) needed projects, and consequently has failed to alleviate rates and practices identified by the Commission as unjust and unreasonable more than a decade ago. The need for interregional transmission has only grown more pressing since then. the Clean Energy Associations submit that FERC should consider – in this proceeding, or a subsequent one - requiring joint interregional planning as an integral part of a comprehensive and holistic transmission planning rule.

Interregional transmission planning will facilitate the achievement of state and federal public policy goals at least total cost and greatest net benefits. As an example, several states along the Eastern Seaboard have adopted ambitious targets for the deployment of offshore wind (OSW) to meet state climate and economic development objectives. New York's landmark Climate Leadership and Community Protection Act

[93] *See* NOPR at P428.
[94] *Id* at P430.

codifies a state requirement of at least 9,000 MW of offshore wind generation by 2035. New Jersey lawmakers have set an equally ambitious goal of 7,500 MW of offshore wind development by 2030. Both New York and New Jersey have taken significant steps to achieve these goals by soliciting and awarding thousands of MW of OSW projects already.

The Biden Administration is supporting these state objectives by committing to accelerating the identification and leasing of additional wind energy areas to support at least 30 GW of OSW by 2030. In January, the Bureau of Ocean Energy Management leased nearly half a million acres in the New York Bight - a large triangular swath of the Outer Continental Shelf off the coasts of New York and New Jersey – capable of supporting between 6-11 GW of new OSW generation. Coupled with existing offshore wind lease areas, it is estimated that there is now sufficient acreage to meet New York and New Jersey's combined goal of roughly 16 GW by 2035.

The New York Bight lease areas are proximate to, and capable of serving, both the New York (NYISO) and New Jersey (PJM) markets. Both states, however, have recognized that onshore and offshore transmission constraints could be an impediment to the integration of new OSW development and, in cooperation with their RTOs, have taken steps to unbottle these resources. In March 2021, the New York Public Service Commission found that New York public policies on climate reduction and renewable development were driving the need for additional transmission, and requested the NYISO conduct a competitive solicitation to develop additional transmission transfer capability between Long Island and New York.[95]. Similarly, In November 2020 the New Jersey Board of Public Utilities (BPU) formally requested that PJM Interconnection incorporate

[95] Order, Case 20-E-0497 et.seq., *In the Matter of New York Independent System Operator, Inc.'s Proposed Public Policy Transmission Needs for 2020* (issued and effective March 19, 2021).

New Jersey's offshore wind goals into the PJM transmission planning process through the PJM State Agreement Approach (SAA).[96]

These efforts could be significantly bolstered, enhancing resiliency and reliability throughout the region. An effective interregional planning process should identify transmission constraints, explore whether joint and common investments can offer more viable and cost-effective solutions than individual regional solutions, and appropriately allocate costs in a consistent fashion.

The Commission's findings in the NOPR echo these concerns, pointing out that in establishing Order No. 1000, it determined that "the transmission planning requirements of Order No. 890 were too narrowly focused geographically and failed to provide for adequate analysis of the benefits associated with interregional transmission facilities in neighboring transmission planning regions."[97] In Order No. 1000, the Commission concluded that interregional transmission coordination reforms were necessary, which included "[c]lear and transparent procedures that result in the sharing of information regarding common needs and potential solutions across the seams of neighboring transmission planning regions will facilitate the identification of interregional transmission facilities that more efficiently or cost-effectively could meet the needs identified in individual regional transmission plans."[98] Perhaps admitting that these reforms have not led to increased interregional coordination, the Commission finds in the NOPR that "there is significant need for interregional transmission coordination" and that "it is necessary to revise the existing Order No. 1000 interregional transmission coordination requirements to apply them to the proposed Long-Term Regional Transmission Planning reforms in this NOPR to ensure that interregional transmission coordination is just and reasonable."[99]

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[96] Order, *In the Matter of Offshore Wind Transmission*, Docket No. QO20100630 (Nov. 18, 2020).
[97] NOPR at P424.
[98] *Id.* at P424 (Citing Order No. 1000 at P368).
[99] *Id.* at P425.

To remedy these issues, the NOPR proposes that transmission providers in neighboring transmission planning regions be required to revise their existing interregional coordination procedures (and regional transmission planning processes as needed) to require the sharing of information regarding the respective transmission needs identified in the LTRTP, as well as potential transmission facilities to meet those needs; and identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address transmission needs identified through LTRTP. In addition, the NOPR proposes to require that transmission providers in neighboring transmission planning regions revise their interregional transmission coordination procedures (and regional transmission planning processes as needed) to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution to transmission needs identified through LTRTP. However, despite industry changes since Order No. 1000, including changes in the resource mix, operational challenges, and increasing regional integration, the NOPR does not propose changes to the existing interregional transmission coordination and cost allocation requirements of Order No. 1000.

With respect to coordinated interregional transmission planning and cost allocation, the reforms proposed in the NOPR would require that transmission providers revise their existing interregional transmission coordination procedures to reflect the LTRTP reforms. the Clean Energy Associations submit that requiring identification of beneficial interregional projects through the regional transmission planning process is a good start. However, this requirement should be a bare minimum. Separate Commission action will be needed on interregional transmission planning and cost allocation. The Clean Energy Associations urge the Commission to start such a proceeding as soon as possible to ensure that the grid evolves in an integrated, beneficial, and flexible manner across seams, rather than as a patchwork of regional facilities. Failure to do so increases costs to customers by millions – or even billions – of dollars throughout the country.[100]

### J. Transmission Incentives and Federal Right of First Refusal

The Clean Energy Associations do not take a position on the Commission's proposal to allow federal Rights of First Refusal for regional transmission projects that utilize a joint ownership structure, or on whether a ROFR should be applied to facilities identified through "right-sizing." However, consistent with ACP's past positions on MISO and SPP's proposals for storage-as-transmission,[101] the Clean Energy Associations urge the Commission to determine that ownership and operation of these resources be open to any qualified entity.

Similarly, the Clean Energy Associations do not take a position on the proposed utilization of an Allowance for Funds Used During Construction incentive (rather than a Construction Work in Progress incentive) for projects identified in the LTRTP.

The Clean Energy Associations look forward to reviewing other initial comments on these issues, urges the Commission to provide greater clarity on the types of ownership structures and competitive models it envisions under its proposal, and will file reply comments if appropriate.

[100] LBNL Transmission Value Study at 15.
[101] *See* note 78 and accompanying text, *supra*.

## IV. CONCLUSION

With the NOPR, the Commission has provided a potential framework to meaningfully reform regional transmission planning and cost allocation for the first time in a decade. The Clean Energy Associations urge the Commission to move forward with a final rule in this proceeding, and to adopt the refinements to the NOPR identified in these comments.

Respectfully submitted,


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August 17, 2022