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 AMERICAN CLEAN POWER ASSOCIATION AND THE U.S. ENERGY STORAGE ASSOCIATION ON ADVANCE NOTICE OF PROPOSED RULEMAKING

The American Clean Power Association ("ACP")[1] and the U.S. Energy Storage Association[2] ("ESA", jointly "ACP/ESA") appreciate the opportunity to provide comments on the Federal Energy Regulatory Commission's ("Commission") Advance Notice of Proposed Rulemaking ("ANOPR")[3] in the above-captioned proceeding. In the ANOPR, the Commission has rightly identified numerous aspects of current rules regarding transmission planning, cost allocation, and generator interconnection that require substantial and immediate reform. ACP/ESA offer two overarching recommendations:

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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] ESA is the national trade association dedicated to energy storage, working toward a more resilient, efficient, sustainable and affordable electricity grid – as is uniquely enabled by energy storage. With more than 230 members, ESA represents a diverse group of companies, including independent power producers, electric utilities, energy service companies, financiers, manufacturers, component suppliers, and integrators involved in deploying energy storage systems around the globe. Further, our members work with all types of energy storage technologies and chemistries, including, but not limited to, lithium-ion, advanced lead-acid, flow batteries, zinc-air, compressed air, liquid air, and pumped hydro. The views and opinions expressed in this filing do not necessarily reflect the official position of each individual member of ESA.

[3] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Advance Notice of Proposed Rulemaking, 176 FERC ¶ 61,024 (2021) ("ANOPR").

First, the Commission should act rapidly to reform certain aspects of generator interconnection procedures that are demonstrably unjust and unreasonable. These near-term action items – which include the elimination of participant funding for network upgrades in Regional Transmission Organizations and Independent System Operators (collectively, "RTOs/ISOs") – rest upon a clear record, and in some cases can be remedied through the use of rates or practices that the Commission has already approved.

Second, the Commission should act to shift transmission planning and cost allocation to a holistic and proactive process that *simultaneously* addresses key drivers, including – but not limited to – economic, reliability, public policy, and future generation needs. These actions are complementary over the long term, as a holistic transmission planning process will also help to address transmission-related interconnection issues.

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I. EXECUTIVE SUMMARY

The Commission should act quickly on two tracks to address the longstanding deficiencies that currently plague transmission planning, cost allocation, and generator interconnection processes across the country, and that are stifling America's ability to transform and transition into a more modern, efficient, affordable, and clean electricity future. First, the Commission should take immediate steps to initiate a rulemaking addressing generation interconnection issues that have become demonstrably unjust and unreasonable. Second, the Commission should move forward with another rulemaking to fully shift transmission planning and cost allocation to a holistic framework that accounts for the full range of transmission benefits over an appropriate time horizon, and assigns costs commensurate with those benefits. While these suggested actions are complementary, adopting the generation interconnection-related reforms proposed herein on a separate, fast-track basis is critically important precisely *because* the enhanced transmission planning reforms proposed herein will take longer to implement and pay dividends.

A. Interconnection Reforms

The Commission should immediately move toward reforming certain aspects of its generation interconnection rules that are patently unjust and unreasonable today, and for which replacement rates or practices that would provide positive relief are readily identifiable. ACP/ESA specifically identify several reforms that would complement the broader transmission planning reforms detailed *infra* in Section II.B.2, but can and should be addressed in the near term via a stand-alone rulemaking. These reforms would have an immediate and positive impact on making generator interconnection just and reasonable. These unjust and unreasonable practices can and should be addressed in a near-term proceeding in a near-term proceeding:

1. Eliminate participant funding in RTO/ISO regions.[4]

The record clearly shows that, at present, generators are funding significant portions of the transmission system that benefit other users, and which provide net benefits under traditional benefit-cost analysis. Because the Commission has already approved a just and reasonable default rate, from which participant funding was a permissible variation under Order No. 2003,[5] elimination of participant funding would provide immediate relief from a demonstrably unjust and unreasonable practice while broader transmission reforms, detailed below, are ongoing. As the American Council on Renewable Energy's recent report[6] shows, conservative analysis of required generator interconnection upgrades indicate that economic benefits frequently accrue to load from these lines. In some cases, adjusted production costs analysis alone shows a benefit-to-cost ratio in excess of 1.25:1, the Commission's *maximum* threshold for regional cost allocation under Order No. 1000. [7] In practice, many parties benefit today from

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[4] *See* ANOPR at P 119 ("We seek comment on whether it is appropriate to eliminate or reduce participant funding for interconnection-related network upgrades in RTOs/ISOs…").

[5] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 (2003) ("Order No. 2003"), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004) ("Order No. 2003-B"), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

[6] 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), available at: https://acore.org/wp-content/uploads/2021/09/Just-Reasonable-Transmission-Upgrades-Charged-to-Interconnecting-Generators-Are-Delivering-System-Wide-Benefits.pdf ("ACORE Study").

[7] Importantly, Order No. 1000 set a benefit-cost ratio of 1.25:1 as a *ceiling*, not a *floor*. *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 646 (2011) ("Order No. 1000"), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (Under "Cost Allocation Principle 3" "[i]f a benefit to cost threshold is used to determine which transmission facilities have sufficient net benefits to be selected in a regional transmission plan for the purpose of cost allocation, it must not be so high that transmission facilities with significant positive net benefits are excluded from cost allocation. A public utility transmission provider in a transmission planning region may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. *If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a higher ratio*.")(emphasis added).

transmission investments that are paid for solely (or grossly disproportionately) by generators. This is unjust, unreasonable, unduly discriminatory, and.is inconsistent with applicable precedent regarding costs and benefits to be "roughly commensurate."[8]

2. Generically reform Order No. 2003's crediting policy.

ACP/ESA propose that the Commission adopt, as part of the generation interconnection-specific rulemaking proposed above, a new national crediting policy delineating Transmission Providers' refund obligation under Order No. 2003 to only those network upgrades "downstream" from the interconnection substation. Thus, under ACP/ESA's proposed approach, the generator (or cluster of generators) would have the sole responsibility for the costs of interconnection-related network upgrades up to and including the interconnection substation; upgrades electrically downstream from the interconnection substation would be the responsibility of the applicable transmission provider. The Commission should also implement guidelines to limit network upgrades to the most direct, local impacts that a project has on the electric grid. This will reduce interdependence among interconnection customers, avoid the need for constant restudies, and shorten the interconnection process.[9] This proposed bright-line test is consistent with the Commission's 'beneficiary pays' principle and is administratively simple to implement; it is also based on evidence, as well as physical laws of networked transmission systems. This approach would be administratively simple to implement and would provide essential schedule and cost certainty – which is sorely lacking today under

[8] *See Ill. Com. Comm'n v. FERC,* 576 F.3d 470, 477 (7th Cir. 2009).
[9] For example, Enel North America, a member of ACP and ESA, proposes the use of a 20% transfer distribution factor ("TDF") as a threshold to determine whether an upgrade is built as a result of the interconnection study. While ACP/ESA do not specifically endorse this proposal, the Commission should consider whether comments in the record would allow for a regionally consistent and predictable set of rules for upgrade cost responsibility. For further details, please refer to Enel North America Inc's comments in this proceeding

the current construct - as the Commission moves to a new transmission planning paradigm (as described further below).

3. **Require binding cost caps, potentially including the use of a variance band or envelope, no later than the signing of the Generator Interconnection Agreement.**

At present, generators have little cost certainty throughout the interconnection process, and are at risk of being assigned substantial upgrade costs even *after* a generator interconnection agreement ("GIA") is signed. Generators should be able to receive increasing certainty with respect to their upgrade cost responsibilities as the interconnection process progresses, potentially through a shrinking variance band as the applicable studies are completed. The Commission has approved cost caps in interconnection contexts in some regions such as CAISO,[10] but they are not a standard practice. "Cost envelopes" that limit maximum upgrade cost exposure are used in other contexts, including for interconnection of distributed energy resources in some states, and a similar construct should be applied to the generator interconnection process.[11] A reasonable cost envelope or variance band would account for potential cost increases due to changes such as commodity prices, but would ensure that interconnection customers are fully aware of their maximum cost exposure as they move forward with a GIA.

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[10] *See, e.g. California Indep. Sys. Operator Corp*., 176 FERC ¶ 61,207 (2021) (approving Cluster 14 interconnection procedures, including a cost cap between studies allowing for up to a 25% increase in costs); *see also California Indep. Sys. Operator Corp*., Docket No. ER19-2679 (Oct. 18, 2019) (letter order approving CAISO interconnection enhancements, including "revis[ing] the cost allocation rules for the interconnecting and neighboring Participating Transmission Owners (PTOs) to include PTO-specific cost estimates in interconnection studies that sum to a single, combined maximum cost responsibility for the interconnection customer's entire project and to clarify how reimbursements for reliability network upgrades will be paid to each PTO at various stages…").

[11] Bird, et. al., Nat'l. Renewable Energy Lab, *Review of Interconnection Practices and Costs in the Western States,* at Table 19 (2018), NREL/TP-6A20-71232 available at https://www.nrel.gov/docs/fy18osti/71232.pdf.

4. Require harmonization and synchronization of affected system studies.

Affected system rules – intended to assure reliability on adjacent transmission systems when a generator interconnects in one area - are badly broken. The Commission should act to harmonize the key inputs that adjacent transmission providers' systems must use (including non-jurisdictional transmission providers, where possible) so that a common set of study assumptions are utilized to the greatest extent possible. The Commission should also require better synchronization of affected system studies; at present, affected system studies may be completed after Generator Interconnection Agreements are signed or even after projects are operational, resulting in dramatically escalating and unpredictable associated network upgrade costs that in many instances are nearly impossible for interconnection customers to anticipate. Reform of this system would render the interconnection process more predictable, and just and reasonable. Other proposals in this proceeding may provide the basis for using harmonized assumptions.[12]

5. Require modeling of energy storage based upon anticipated use.

Current modeling methodologies for energy storage are often inconsistent with real-world operation – for instance, assuming that storage will charge at nameplate capacity during peak demand, and discharge at nameplate during low load periods. This type of operation is inconsistent with market signals and can be prevented through proper controls, but its modeling can lead to unreasonable interconnection upgrade costs for storage. The Commission should require the use of realistic dispatch assumptions, which will accurately reflect energy storage usage and prevent excessive upgrade costs.

[12] *See* Comments of Enel North America, as discussed at n.9, *supra*.

Finally, as part of the implementation of all of the interconnection reforms described above, ACP also recommends that the Commission adopt and apply a uniform standard that any requested variations from the revised *pro forma* LGIP and LGIA must be "consistent with or superior to" the *pro forma* tariff. Thus, these reforms should presumptively apply to transmission providers both in and out of RTOs/ISOs.

B. Enhanced Transmission Planning and Cost Allocation

Second, and of equal or greater importance, the Commission should replace the current unjust and unreasonable approach to transmission planning and cost allocation. The Commission should establish a transmission planning paradigm that incorporates all planning inputs on a consolidated, co-optimized basis. This approach would incorporate anticipated future generation into transmission needs, which would ultimately result in the coordinated development of many transmission facilities that are presently planned and constructed as generator-driven network upgrades. The Commission should adopt a functional approach and find that facilities that will be *operated* as parts of the integrated transmission system should be *principally planned as transmission*, through a single, integrated process that considers multiple drivers and the multiple benefits of new transmission simultaneously. The transmission system – which is operated jointly, but incorporates projects identified through different processes today – provides broadly shared benefits, and transmission planning and cost allocation should expressly acknowledge this.[13]

An integrated transmission planning approach would increase total system efficiency and result in just and reasonable rates. Most notably, it would provide greater reliability at lower total costs to customers. Among the range of potential grid options, larger-scale transmission is often lower-cost (on a per-delivered megawatt-hour basis)

[13] For an example of an integrated planning process, please see Enel North America Inc.'s comments in this proceeding and accompanying white paper entitled "Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning."

because of significant economies of scale. However, current planning and cost allocation approaches frequently fail to account for both the scope of the benefits, and the duration for which they are provided. Networked transmission inherently has multiple benefits, only some of which are identified today – and largely through separate processes, including identification of economic, reliability, local transmission repair or replacement, public policy, or generator interconnection/network upgrade needs. The Commission should consolidate these various transmission drivers and require transmission providers to co-optimize their processes to produce the maximum expected net benefits. Additionally, transmission facilities typically last for several decades. The Commission should therefore incorporate anticipated benefits based upon a realistic asset life – which will accurately reflect the projects' usage, and increase the identified benefits. The ANOPR also rightly identifies practices such as a portfolio approach of transmission projects[14], and a "transmission-first"[15] approach that would enable development of infrastructure in high-quality resource areas to support generation development in the future. ACP/ESA support both of these practices, as described in greater detail in Section II.B.2.

Additionally, ACP urges the Commission to utilize evidence-based presumptions in cost allocation wherever possible – as is permitted under legal precedent[16]–because

[14] ANOPR at P 89, 91 (requesting comments on a potential portfolio approach with a minimum set of transmission benefits).
[15] ANOPR at P 57 (inquiring "Whether the Commission should require transmission providers in each transmission planning region to establish, as part of their regional transmission planning and cost allocation processes, a process to identify geographic zones that have the potential for the development of large amounts of renewable generation and plan transmission to facilitate the integration of renewable resources in those zones…").
[16] *See e.g. Ill. Com. Comm'n v. FERC,* 576 F.3d at 477 ("We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars. … If it cannot quantify the benefits to the midwestern utilities from new 500 kV lines in the East, even though it does so for 345 kV lines, but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region, then fine; the Commission can approve PJM's proposed pricing scheme on that basis. For that matter it can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages.")(internal citations omitted).

individualized benefit-cost analyses for each system upgrade would generate excessive delays.

II. COMMENTS

A. Section 206 of the Federal Power Act Requires the Commission to Replace Unjust and Unreasonable Rates

The Commission has initiated this proceeding under Section 206 of the FPA.[17] Under the first prong of Section 206, the Commission must first determine whether an existing rate is unjust, unreasonable, unduly discriminatory, or preferential.[18] Under the second prong of Section 206, if the Commission indeed determines that the existing rate is unjust, unreasonable, unduly discriminatory, or preferential, then the Commission must determine a just and reasonable replacement rate.[19]

Pursuant to this standard, ACP/ESA submits that substantial aspects of currently effective generator interconnection and transmission planning and cost allocation rules are no longer just and reasonable and must therefore be replaced with a new paradigm, as proposed herein.

1. Current Rates and Practices Regarding Generator Interconnection are Unjust and Unreasonable

Interconnection queues have become increasingly dysfunctional, and place unjust and unreasonable cost burdens on generators. Historically, these costs used to be less than 10% of the total project costs in many most cases. However, in recent years, due to a variety of conditions, that proportion has now risen to levels up to 100% of the generation

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[17] ANOPR P1 (FERC is inquiring into whether certain existing regulations are no longer just and reasonable).
[18] *See* 16 U.S.C. § 824e (2018); *Emera Maine v. FERC*, 854 F.3d 9, at 23, 25-26 (D.C. Cir. 2017)(describing the Commission's "dual burden" under Section 206).
[19] *Id.*

project costs.[20] From 2013 to 2017, the costs of interconnection upgrades rose 43%.[21] Due to these exorbitant costs and the fact that required network upgrades are providing benefits well beyond the interconnection of new generators, participant funding for network upgrades is inconsistent with Commission and judicial precedent on cost causation. The current participant funding model in RTOs/ISOs, wherein individual generators (or clusters of generators) are required to fully pay network upgrades to the transmission system is no longer just and reasonable.

The policies currently in place are a vestige that no longer works. In the early 2000s, a generator-by-generator planning process, coupled with individual assignments of network upgrade costs, proved workable. In part, this is because gas generation resources, which were the main type of interconnecting generator in the early 2000s, could often interconnect with transmission systems with some flexibility on the precise location. As noted in the ANOPR, the transformation of the electric sector toward renewables is a basis for revisiting these regulations.[22] The location-specific and scalable nature of renewable energy make the old interconnection paradigm impractical today, and even more so moving forward. Because renewable energy – which is now the leading category of resources in interconnection queues – is often built at a large scale, in high-quality resource areas far from customers, these projects often require larger transmission upgrades to serve load.

By the early 2010s, as wind development in particular grew, interconnection queues quickly became overloaded. As the queues reached capacity, large network upgrade costs would be assigned to whichever generator was the next project in the queue. This is the "serial" practice of interconnection, wherein each generator was reviewed independently for its own impacts on the grid in the order it entered the

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[20] AMERICANS FOR A CLEAN ENERGY GRID, Caspary, J., Goggin, M., Gramlich, R., Schneider, J., *Disconnected : The Need for a New Generator Interconnection Policy,* Americans for a Clean Energy Grid, 6 (Jan. 2021) available at https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.pdf.
[21] *See id.* at 15.
[22] ANOPR at PP 3 (noting the transforming electricity sector), 34 (noting the changing resource mix).

interconnection queue. In one commonly used metaphor, this effectively charged the next car trying to merge onto a congested highway the entire cost of building a whole new lane. Understandably, the unlucky generation owner who had the burden to pay for an applicable network upgrade solely due to its place in line, would often drop out of the queue. This would often in turn shift the responsibility of paying for the network upgrade to another developer, potentially causing a domino effect of cancellations.

In many regions a cluster study process – in which groups of interconnection customers are studied together – has offered some improvements, especially with regard to the time that it takes for interconnection customers to receive their study results, and the Commission has noted the improved efficiencies that cluster studies can provide.[23] For example, prior to moving to a cluster study approach some regions had interconnection queues that could have taken decades to move through on a serial basis. But although the cluster study approach has improved the timeline for the interconnection study process to some degree, clusters of projects can be – and are- still assigned unreasonable interconnection costs. The current dynamic of these participant-funded approaches, and the high-voltage, broadly beneficial system elements funded through them is no longer just and reasonable.[24]

Unfortunately, under the participant funding model that prevails in RTOs/ISOs, individual generation interconnection customers often unjustly pay for network upgrades. Although these upgrades are identified through the interconnection study process, in practice they provide broader benefits that should be borne by a broader set of beneficiaries. Participant funding also results in higher power purchase agreement ("PPA") prices and increases the cost of delivered power for consumers, particularly when study results are delayed and there is uncertainty over the developer's network upgrade cost responsibility at the time the PPA is executed. Importantly, congestion

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[23] *See* Order No. 2003 at P155("Clustering is strongly encouraged in queue management and the Interconnection Study process for all Transmission Providers.").

[24] ANOPR at PP 41, 111 (seeking comment on whether the Order No. 2003 assumptions allowing RTOs to use participant funding remain valid, and whether participant funding is just and reasonable).

revenue rights and similar long-term financial transmission rights have generally proven to be vastly inadequate in value to compensate generators for the investment in network upgrades, and should not be viewed as a viable substitute for eliminating participant funding.

Accordingly, the current paradigm produces unjust, unreasonable and unduly discriminatory outcomes because generation interconnection customers often "foot the bill" for projects that others benefit from but do not fund. This violates both sound economic principles – because it creates a significant "free rider" problem - and applicable legal precedent. In addition, if other transmission needs were planned in a co-optimized way with generator interconnection needs, the resulting transmission solutions would in many cases result in lower costs to *both* retail consumers and generators, as detailed below.

Notably, a recent study[25] commissioned by the American Council on Renewable Energy ("ACORE") and ACP closely examined how generation interconnection customers in both SPP and MISO often fund network upgrades that provide broader benefits to the system that are well beyond those received solely by the interconnection customer. As noted therein, "[u]sing very conservative assumptions, [the ACORE Study] evaluated the economic benefits of a representative sample of network upgrade projects assigned through the MISO and SPP [generator interconnection] process over the last seven years."[26] Twelve representative network upgrades, six in each RTO, were eventually selected for cost-benefits analysis, with benefits calculated using *only* analysis of the Adjusted Production Cost ("APC") savings to the shared system.[27] Despite the study's very conservative assumptions, the ACORE Study found that "of the 12 network upgrades reviewed, ten provided positive benefits to consumers, with eight having

[25] *See* ACORE Study, *supra* n. 6.
[26] *See id.* at 3.
[27] *See id.* at 4. (Importantly, APC is one of the key metrics used to calculate economic benefits in both MISO and SPP, as well as in other major electricity markets.).

benefits that exceeded 10% of the costs."[28] In some cases, network upgrades had benefits exceeding 125% of the costs, which would have made them eligible as economic transmission projects (using the Order No. 1000 1.25:1 benefit-cost ratio). This finding led the ACORE Study to correctly conclude that "network upgrades often provide benefits to consumers that can exceed their allocated costs, resulting in an inconsistency between the payments and the benefits received."[29]

The ACORE Study strongly supports ACP/ESA's position that allocating the entire cost of network upgrades (*i.e.*, those upgrades identified as a result of an individual generator's interconnection request) to individual generation interconnection customers is unjust and unreasonable. These upgrades are operationally indistinguishable from the rest of the transmission system and provide broad benefits to consumers. This incongruity is inconsistent with applicable precedent.

As the Commission has explained, "discrimination is 'undue' when there is a difference of rates, terms or conditions among similarly situated customers."[30] The Commission has also clarified, "[t]o say that entities are similarly situated does not mean that there are no differences between them; rather, it means that there are no differences that are material *to the inquiry at hand*."[31] Both the Commission and federal appellate courts have opined on the issue of what constitutes undue discrimination in the context of transmission planning and cost allocation. For example, in *Northern Indiana Public Service Company v. Midcontinent Independent System Operator, Inc.*, the Commission found that "certain provisions of the [PJM-MISO Joint Operating Agreement ("JOA")] and MISO tariff [were] unjust, unreasonable, or unduly discriminatory or preferential

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[28] *See id.* at 38.
[29] *See id.*
[30] *See Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,076, at P 369 (2007) ("In general, discrimination is 'undue' when there is a difference of rates, terms or conditions among similarly situated customers."); *see also ISO New England Inc.*, 174 FERC ¶ 61,252, at P 27 (2021) (emphasis added) ("The determination as to whether a Commission-regulated rate or practice that provides different treatment to different classes of entities is unduly discriminatory is fact-based, and turns on whether those classes of entities are similarly situated.").
[31] *N.Y. Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,124, at P 10 (2018) (emphasis added).

pursuant to section 206 of the FPA because [MISO's] . . . cost and voltage thresholds [for classifying interregional projects] prohibit[ed] from consideration [for interregional cost allocation] certain transmission projects . . . benefit[ing] both [MISO & PJM] regions."[32] Accordingly, the Commission required "MISO to reduce its minimum voltage threshold for a [sic] interregional economic transmission project from 345 kV to 100 kV" to allow *all projects* providing interregional benefits to be considered for interregional cost allocation.[33] Although this finding was in the context of interregional transmission, its logic applies equally to regional transmission and facilities identified in the interconnection context.

Moreover, federal appellate courts and the Commission have long held that beneficiaries of transmission projects must pay a rate for transmission that is "roughly commensurate" with the benefit that they receive from such transmission projects.[34] For example, in the U.S. Court of Appeals for the Seventh Circuit's 2009 decision in *Illinois Commerce Commission v. FERC*, that Court rejected a Commission order that initially approved PJM's proposal to allocate costs of transmission lines greater than 500kV to all utilities in PJM on a *pro rata* basis, because the Commission had failed to show how certain utilities in the western portion of PJM would benefit from these 500kV lines. Notably, the Court stated that while it "[did] not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars," the Commission nonetheless had to articulate and justify why "the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region," which the Court held the Commission failed to do.[35] After remanding the Commission order at issue for further proceedings, in 2014, the Seventh Circuit once again rejected and remanded a second Commission order that

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[32] 155 FERC ¶ 61,058, at P 129 (2016).
[33] *See id.*
[34] *See Ill. Commerce Comm'n v. FERC,* 576 F.3d at 476-77; *Alcoa Inc. v. FERC,* 564 F.3d 1342, 1346-47 (D.C. Cir. 2009); *Midwest ISO Transmission Owners v. FERC,* 373 F.3d 1361, 1368-69 (D.C. Cir. 2004); *Sithe/Independence Power Partners, L.P. v. FERC,* 285 F.3d 1, 4-5 (D.C. Cir. 2002).
[35] *See Ill. Commerce Comm'n v. FERC,* 576 F.3d at 477.

approved PJM's proposal related to allocating costs of transmission lines greater than 500 kV because it held that the Commission had once again failed to quantify benefits to the point where it could meet the "the modest goal of [demonstrating] rough commensurability."[36]

Further, in a recent case that touched on Commission precedent related to cost causation and transmission cost sharing,[37] the U.S. Court of Appeals for the District of Columbia Circuit "remanded a Commission decision accepting a PJM tariff amendment that would have prohibited regional cost allocation for high-voltage transmission projects that have 'significant regional benefits' if such transmission projects were included in a regional transmission plan only to satisfy an individual utility's planning criteria."[38] The D.C. Circuit did so because it found the Commission's "'categorical *refusal to permit any regional cost sharing* for an important category of projects *conceded to produce significant regional benefits*' to be irreconcilable with the cost causation principle."[39] The Court stated that, "[g]iven the significant regional benefits of high-voltage transmission lines, FERC's decision to approve the amendment was arbitrary" because it "denie[d] cost sharing for *all* projects included in the Regional Plan only to satisfy the planning criteria of individual utilities— *including* for high-voltage lines."[40] The D.C. Circuit went on to explain that the cost causation principle "prevents regionally beneficial projects from being arbitrarily excluded from cost sharing—a necessary corollary to ensuring that the costs of such projects are allocated commensurate with their benefits."[41]

These cases collectively stand for the proposition that it is unjust, unreasonable, and unduly discriminatory for Commission-jurisdictional rates and practices to prevent broadly beneficial network upgrades from being allocated across a wider group of

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[36] *See Ill. Commerce Comm'n v. FERC,* 756 F.3d 556, 562 (7th Cir. 2014).
[37] *Old Dominion Electric Cooperative v. FERC*, 898 F.3d 1254 (D.C. Cir. 2018) ("ODEC").
[38] *See Midcontinent Indep. Sys. Operator, Inc*., 172 FERC ¶ 61,095, at P 47 (2020) (emphasis added) (describing D.C. Circuit's decision in *ODEC*) (citations omitted).
[39] *See ODEC* at 1263 (emphasis added).
[40] *See id.* at 1261 (emphasis in original).
[41] *Id.* at 1263.

beneficiaries, *simply because such upgrades were identified to satisfy an individual interconnection customer's interconnection request*, while other electrically and operationally similar upgrades (*i.e.*, those identified through the traditional transmission planning process) are allocated on a broader basis (rather than directly to a specific interconnection customer or specific load). Moreover, the *Illinois Commerce Commission* and *ODEC* cases make clear that beneficiaries of transmission projects may be allocated costs of such projects so long as the Commission can show that the costs allocated to such beneficiaries are "roughly commensurate" with the benefits received. Unfortunately, today's prevailing cost allocation approaches to generation interconnection customers do not comport with this well-established legal precedent, and accordingly must be rectified by the Commission.

Finally, ACP/ESA note that despite the Commission's post-Order 2003 goal of improving certainty for interconnection customers,[42] several major barriers remain in place. First, the series of interconnection studies preceding a Generator Interconnection Agreement often fail to provide increasing levels of certainty on final network upgrade costs. Second, affected system studies are frequently untethered from the timing or assumptions of studies used by the local transmission provider, which can result in significant upgrade costs issued even after projects have commenced operation. And third, energy storage resources are studied using counterintuitive assumptions that do not reflect actual intended usage.

[42] *See, e.g.*, *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845-B, 168 FERC ¶ 61,092, at P 1 (2019) ("("On April 19, 2018, the Commission issued Order No. 845, which revised the Commission's *pro forma* Large Generator Interconnection Procedures (LGIP) and *pro forma* Large Generator Interconnection Agreement (LGIA) *to improve certainty for interconnection customers, promote more informed interconnection decisions, and enhance the interconnection process*.") (emphasis added).

2. Transmission Planning and Cost Allocation Rates and Practices are Unjust and Unreasonable

In 2011, the Commission issued Order No. 1000, which sought to "support the development of those transmission facilities identified by each transmission planning region as necessary to satisfy reliability standards, reduce congestion, and allow for consideration of transmission needs driven by public policy requirements."[43] However, a decade on, Order No. 1000 has fallen far short of the Commission's intent. Instead, current regional planning rules and processes lead to unreasonably high costs that are passed on to customers, contrary to the letter and spirit of Order 1000.[44] All too often, such processes fail to facilitate the consideration or evaluation of more efficient or cost-effective alternative ways of meeting multiple needs – specifically, the larger, higher-voltage, longer-term, and more regionally beneficial solutions, versus multiple smaller solutions that might result from the current uncoordinated interconnection and local reliability planning efforts.

Transmission is fundamentally a "public good" – much like roads, water, and broadband networks – that provides benefits to all users. Like other public goods, it must be planned centrally for future needs - but current rules fall short for several reasons.[45] Here, ACP/ESA highlight some of the most significant failures of current transmission planning rules. ACP/ESA further note that cost allocation should appropriately operate *downstream* of the transmission planning and benefit reforms discussed herein. As summarized next, the current approach fails to account for the full range of transmission benefits, as well as the beneficiaries, and also runs afoul of the precedent that the Commission should ensure that customers are allocated costs that are "roughly

[43] Order No. 1000 at P 3.
[44] *See e.g. Planning for the Future*, Americans for a Clean Energy Grid at 10 (2021) ("Planning for the Future").
[45] *See e.g.*, Planning for the Future, p.45, citing Paul Joskow, *Transmission Capacity Expansion is Needed to Decarbonize the Electricity Sector Efficiently*, Joule 4, at 1-3, January 15, 2020, available at https://economics.mit.edu/files/18711.

commensurate" with the benefits that such customers receive. Thus, the failure to account for transmission benefits results in corresponding failures to allocate costs commensurate with those benefits; conversely, accurately reflecting those benefits can lead to just and reasonable cost allocation, as detailed in Section II.B.2, *infra*.

ACP/ESA urge the Commission to account for, and act to correct, several specific failures of the current transmission planning framework.

i. Failure to Holistically Plan for Large-Scale Transmission

First, current transmission planning, which has come to focus on incremental expansion and retaining near-term reliability, ultimately leads to unreasonably high costs in the long run compared to proactive long range transmission planning. Studies have shown the large economies of scale in transmission, with reduced costs for each megawatt-hour delivered.[46] Multiple independent studies have found that coordinated transmission planning will deliver enormous customer benefits.[47] However, regionally planned large-scale transmission projects are rare today. In part, this is because regional planning is not meeting the Order 1000 requirement of consolidated planning. These efforts were expected to look for opportunities to more cost-effectively meet *multiple* needs with larger solutions, [48] versus the multiple smaller solutions that may result from interconnection and local reliability planning efforts – but which are not coordinated. As a result, in some regions local projects have been funded orders of magnitude beyond regional projects. Analysis of five years of MISO transmission planning, provided by Clean Grid Alliance, makes this clear:

[46] Planning for the Future, pp. 93-94.
[47] *See also* Planning for the Future pg. 89, Appendix A, (providing full overview of literature).
[48] *See*, *e.g*., Order No. 1000 at P 11 ("At its core, the set of reforms adopted in this Final Rule require the public utility transmission providers in a transmission planning region, in consultation with their stakeholders, to create a regional transmission plan. This plan will identify transmission facilities that more efficiently or cost-effectively meet the region's reliability, economic and Public Policy Requirements.")

Regional Grid Investment Missing in MISO

Projects approved in MISO Transmission Expansion Plans (2016-2020)

	# Local Projects ($)	# Regional Benefit Projects ($)
2016	382 ($2.6 B)	1 ($108 M)
2017	348 ($2.6 B)	6 ($134.5 M)
2018	440 ($3.3 B)	2 ($4.5 M)
2019	480 ($3.9 B)	0
2020	515 ($4.2 B)	0
Total	**2,165 ($16.6 B)**	**9 ($247 M)**

Data Source: MISO MTEP Reports, https://www.misoenergy.org/planning/planning/

A key problem in the current transmission planning and cost allocation approach is the distinct "silos" of economic, reliability, and public policy transmission projects.[49] In truth, projects identified to satisfy one of these categories can realistically meet all of these needs, as well as others (as detailed below). ACP/ESA also note that a distinct "public policy" category has been a notable failure, as only single-state RTO/ISOs (CAISO and NYISO) have been able to meaningfully plan public policy transmission projects, and state energy storage mandates have typically not been specifically accounted for. Accordingly, ACP/ESA recommend that the Commission specifically find that siloed transmission planning is unjust and unreasonable, and co-optimized transmission planning must replace it.

[49] *See* ANOPR at P 85 (noting that reliability, economic, and public policy needs "are generally considered in a silo from one another").

If siloed processes identify the same or similar solutions to meet different needs, the process that finishes first will affect the cost allocation. An example of this was the Helena to Hampton Corners upgrade that was identified in MISO's Market Congestion Planning Study ("MCPS"). The line showed significant economic benefits, until the realization that a similar upgrade, Helena to Scott, had been identified three months *earlier* in the interconnection process. When a sensitivity study was completed evaluating Helena to Hampton Corners with the addition of the generator interconnection upgrade for Helena to Scott included in the model, the economic benefits from Helena to Hampton Corners dropped below the required 1.25 benefit to cost ratio for approval.[50] This project was thus not built - but the Helena to Scott line, with costs charged *only* to generators, and with no consideration of *any* economic benefits to load, was still required in the interconnection study. Had the MCPS study been completed three months prior to the interconnection study, it is likely that Helena to Hampton Corners would have been approved with costs assigned to load. Planning processes that result in costs assigned to different parties simply depending on which siloed process finished first cannot be just and reasonable. The transmission solution ultimately selected in the interconnection process is another example of projects that clearly had economic benefits to load but were assigned instead to generators.

Similarly, the sequence of upgrade determination can result in sub-optimal transmission buildout. In CAISO, upgrades required to address reliability needs are identified first, and then policy and economic upgrades are identified. This can result in a set of "band-aid" solutions that address only the reliability needs when a policy and economic upgrade could bring benefits across all three aspects. When smaller reliability upgrades are approved first and then included in economic models, the economic benefits of regional lines evaluated in the *second* process are often reduced because of the earlier,

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[50] MISO MTEP19 Report, Executive Summary, pages 41-43 (2019) available at https://www.misoenergy.org/stakeholder-engagement/stakeholder-feedback/mtep19-report-draft/.

smaller upgrades, thus making it impossible for the larger economic upgrades to meet required benefit-to-cost ratios.

ii. Failure to Account for All Transmission Benefits

Next, a full range of transmission benefits are not being considered, leading to under- investment and higher consumer costs in the long run. Where regionally planned projects are identified, they are typically "economic" projects that utilize Order No. 1000's 1.25:1 benefit to cost ratio based upon production cost savings. However, this approach undeniably ignores numerous benefits of transmission entirely. A 2013 report from the Brattle Group and a 2021 Brattle Group-Grid Strategies report have identified multiple other categories of benefits.[51]

[51] *See* Chang, J., Pfeifenberger, J., & Hagerty, J.M., *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments* at v,(July 2013) available at https://wiresgroup.com/the-benefits-of-electric-transmission-identifying-and-analyzing-the-value-of-investments/ ("Brattle 2013"); Brattle-Grid Strategies (October 2021) *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs,* https://gridprogress.files.wordpress.com/2021/10/transmission-planning-for-the-21st-century-proven-practices-that-increase-value-and-reduce-costs-7.pdf ("Brattle 2021").

The 2013 report noted numerous categories of transmission benefits not accounted for in typical planning processes:

Table ES-1
Potential Benefits of Transmission Investments

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Production cost savings as traditionally estimated
1a-1i. Additional Production Cost Savings	a. Reduced transmission energy losses
	b. Reduced congestion due to transmission outages
	c. Mitigation of extreme events and system contingencies
	d. Mitigation of weather and load uncertainty
	e. Reduced cost due to imperfect foresight of real-time system conditions
	f. Reduced cost of cycling power plants
	g. Reduced amounts and costs of operating reserves and other ancillary services
	h. Mitigation of reliability-must-run (RMR) conditions
	i. More realistic representation of system utilization in "Day-1" markets
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects
	b. Reduced loss of load probability or c. Reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses
	b. Deferred generation capacity investments
	c. Access to lower-cost generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Development Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits

The 2013 report was recently updated, and the 2021 Brattle report similarly identifies numerous categories of benefits from transmission that current planning approaches fail to account for:[52]

TABLE 5. ELECTRICITY SYSTEM BENEFITS OF TRANSMISSION INVESTMENTS

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Adjusted Production Cost (APC) savings as currently estimated in most planning processes
2. Additional Production Cost Savings	i. Impact of generation outages and A/S unit designations
	ii. Reduced transmission energy losses
	iii. Reduced congestion due to transmission outages
	iv. Reduced production cost during extreme events and system contingencies
	v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
	vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
	vii. Reduced cost of cycling power plants
	viii. Reduced amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run (RMR) conditions
	x. More realistic "Day 1" market representation
3. Reliability and Resource Adequacy Benefits	i. Avoided/deferred cost of reliability projects (including aging infrastructure replacements) otherwise necessary
	ii. (a) Reduced loss of load probability or (b) reduced planning reserve margin
4. Generation Capacity Cost Savings	i. Capacity cost benefits from reduced peak energy losses
	ii. Deferred generation capacity investments
	iii. Access to lower-cost generation resources
5. Market Facilitation Benefits	i. Increased competition
	ii. Increased market liquidity
6. Environmental Benefits	i. Reduced expected cost of potential future emissions regulations
	ii. Improved utilization of transmission corridors
7. Public Policy Benefits	Reduced cost of meeting public policy goals
8. Other Project-Specific Benefits	Examples: increased storm hardening and wild-fire resilience, increased fuel diversity and system flexibility, reduced cost of future transmission needs, increased wheeling revenues, HVDC operational benefits
9. Employment and Economic Stimulus Benefits	Increased employment and economic activity; Increased tax revenues
10. Increased Health Benefits	Lower fossil-fuel burn can result in better air quality

[52] *See* Brattle 2021 at p.34, Table 5 (2021).

The Brattle 2013 analysis was partially applied by the Southwest Power Pool in its 2016 *Value of Transmission* report.[53] There, SPP found that while production cost savings for a group of transmission projects resulted in just under $10.5 billion in benefits, inclusion of even *some* of the benefits identified by the Brattle 2013 report (specifically reliability, reserve margin, losses, wheeling, and wind integration) resulted in $16.6 billion in benefits.[54] In short, the "traditional" approach failed to account for roughly a third of the quantified benefits – which were *still only assessed on a partial basis* relative to the multiple acknowledged benefits of transmission. Additionally, most transmission benefits are calculated over time periods with unrealistic caps,[55] despite the fact that transmission facilities will typically be in service for decades.

Although the precise benefits that are un- or under-accounted for in current planning paradigms may vary regionally, ACP/ESA submit that SPP's case is likely typical – since there is rarely even an effort to *quantify* transmission benefits beyond Adjusted Production Cost savings, let alone incorporate them in planning. The Brattle 2021 analysis shows that the "traditional" B:C analysis of a range of transmission projects in NYISO, CAISO, MISO, SPP, and ATC consistently understate the full range of quantifiable benefits.[56] ACP/ESA urge the Commission to find that that narrow benefit metrics, applied against an unrealistically brief timeframe, are unjust and unreasonable. As discussed below, the Commission should require the use of a wider range of benefit metrics.

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[53] *See,* Southwest Power Pool, *The Value of Transmission Report* (Jan. 2016) available at https://spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf.

[54] *Id.* at 7.

[55] *See How Transmission Planning & Cost Allocation Processes Are Inhibiting Wind & Solar Development in SPP, MISO, & PJM,* Julie Lieberman, ACORE, B-5 (Mar. 2021) available at https://acore.org/how-transmission-planning-and-cost-allocation-processes-are-inhibiting-wind-and-solar-development/ (noting that MISO economic planning is conducted over 20 years, and capped at 25 years from the approval date, the latter cap can result in benefits calculated over fewer than 20 years if the in-service date of a project is more than 5 years past the approval date).

[56] Brattle 2021 at 33, Fig. 5.

iii. Failure to Incorporate Future Generation and Storage into Transmission Planning

One specific area that is excluded from transmission planning and is of specific concern to ACP/ESA and their members, is the failure to account for either *planned* or *necessary* future generation and energy storage in transmission planning. *Planned* future generation should include all future generation additions and retirements included in utility resource plans and public announcements. Indeed, in many cases state-approved Integrated Resource Plans are also *not* expressly incorporated in transmission planning. And regional planning processes have undercounted the future mix of wind, solar, and storage, principally because of reliance on known generator interconnection agreements (for example, PJM's market efficiency planning process includes generators that have executed or expect to execute Interconnection Service Agreements).[57] Basing transmission planning processes on these types of binding features or criteria therefore neglects to plan infrastructure around the future resource mix, and does not take into account generators further down the queue that may not have signed an agreement.[58] When planning for transmission needs over a 20-year planning horizon, it is necessary to include utility-planned and state policy-driven generation that does not yet have executed interconnection agreements. *Necessary* future generation would include transmission necessary to meet state and federal policy goals (for example, state Renewable Portfolio Standard programs or energy storage mandates, or the federal statutory goal of 25 GW of renewable generation on public lands by 2025). This should also include public policies regarding energy storage; to date, few transmission planning processes directly incorporate state goals for energy storage. California was the first state to implement a requirement that utilities purchase 1.3 GW of energy storage. Many states have followed

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[57] *Planning for the Future* at pg. 31.
[58] *Id.*

since, with Maine providing the most recent example of a procurement target.[59] ACP/ESA ask the Commission to ensure state goals for energy storage are included in public policy planning, and storage solutions are appropriately identified where states have put in place such requirements.

As detailed above, current interconnection practices – including the use of participant funding – also result in unjust and unreasonable failures of planning that lead to unjust and unreasonable cost allocation. This can be understood as *both* an interconnection and a transmission planning issue. The failure to meaningfully proactively plan transmission that accounts for future generation needs, coupled with generator-funded network upgrades in many regions, creates a "free-rider" problem. Some system users receive significant benefits that they bear no cost responsibility for, while others are funding those broader benefits.[60] The current incremental approach (funding transmission upgrades piecemeal through the generation interconnection process) is ultimately more costly, because it encourages participants to delay investment in hopes that someone else will value a transmission project highly enough to enter the queue and fund that project. This delays overall investment in the transmission system, and creates piecemeal investment when upgrades are funded, rather than encouraging proactive investment which could lead to more efficient outcomes.[61]

ACP/ESA again submit that failure to incorporate these foreseeable future system needs is also unjust and unreasonable. Existing utility resource plans and attainment of state and local requirements should – at a minimum - be the "business as usual" case for transmission planning. As noted above, attainment of these policies should be incorporated into the overall transmission benefits, which the Commission should require transmission providers to attain on a co-optimized basis at least total cost.

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[59] Maine passed legislation in 2021 and set a 300 MW energy storage target to be achieved by 2025, and 400 MW by 2030. *See* State of Maine, Governor's Energy Office, https://www.maine.gov/energy/initiatives/renewable-energy/energy-storage (last accessed Oct. 11, 2021).
[60] *Id.* at 28.
[61] *Id.* at 65.

iv. Interregional Transmission Has Not Been Developed

Interregional transmission planning has also fallen far short of Order No. 1000's goals.[62] The current process has resulted in almost no new transmission - yet in severe weather events, interregional ties are fully utilized. The scope of interregional planning has been limited to addressing economic congestion on market-to-market flowgates, and local reliability issues near the seams. While the ANOPR is focused on *regional* transmission, the Commission also rightly seeks comment on whether associated reforms to interregional planning and coordination are necessary to render regional transmission planning reforms effective.[63] ACP/ESA submit that the Commission should expand the scope of a transmission rulemaking to include planning for interregional transmission that facilitates interregional support 1) during extreme events (quantifiable as reliability and resilience benefits) and 2) under higher-renewable futures, based upon the planned and necessary future generation and storage, as detailed *supra*.

v. Transparency Failures of Local Transmission

Regional transmission, both inside and outside of RTOs, has been under-planned, while local upgrades may not account for potential synergies of responding to multiple drivers. In non-RTO regions in particular, the local planning processes are not subject to the transparency requirement of the regional planning process, and the opportunity to leverage and consolidate project upgrades may not be assessed from the perspective of larger regional needs.[64]

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[62] *See generally* Order No. 1000 at PP 345-481.
[63] ANOPR at P 57.
[64] Planning for the Future at 98-99.

B. Proposed Replacement Rates and Practices

Consistent with Section 206 of the FPA, which requires the Commission to establish the replacement rate when it identifies unjust or unreasonable practices, ACP/ESA proposes that the Commission move forward with one or more Notices of Proposed Rulemaking to implement the following reforms. As noted above, ACP/ESA recommends that the Commission require rapid action on the high-priority interconnection reforms, while continuing to move towards a holistic transmission planning process that incorporates future generation needs and associated upgrades.

To establish greater consistency, predictability, and stability with the respect to the application of all of the the interconnection, transmission planning, and cost allocation reforms discussed in this section, ACP proposes that the Commission allow transmission providers to request a variance from the *pro forma* provisions, but that the Commission only grant such variances if the the requesting entity demonstrate that the proposed variance is "consistent with or superior to" the *pro forma* provisions. A uniform standard applicable to transmission providers both inside and outside of RTOs/ISOs will ensure that the reforms adopted by the Commission to address and improve the current challenges described above will be consistently applied and that any deviation from the standards adopted by the Commission after a deliberative rulemaking process will be, at a minimum, consistent with those standards.

1. Near-Term Interconnection Reforms

i. The Commission Should Immediately Eliminate Participant Funding, Modify its Order No. 2003 Crediting Policy to Establish a Bright Line Between Interconnection Customer and Transmission Provider Responsibilities at the Interconnection Substation, and Provide Clear Guidance on Which Facilities Are Considered Network Upgrades

Ending Participant Funding

The Commission should reform the practice of participant funding, which requires interconnecting generators to pay for all or most of the cost of network upgrades identified in the interconnection study process without reimbursement.[65] Under participant funding, interconnection customers have become responsible for funding all or most of the cost for substantial parts of the transmission system, as detailed above. Accordingly, the Commission should determine that participant funding is no longer just and reasonable.[66] This reform should be fast-tracked for the earliest feasible implementation date, in part because the Commission has already determined a just and reasonable rate that can replace participant funding. In Order No. 2003, the Commission adopted its current "crediting" approach – in which interconnection customers fund network upgrades and are paid back over up to twenty years by the transmission provider

[65] The ANOPR defines participant funding for interconnection-related network upgrades as "the direct assignment to a particular interconnection customer of the costs of interconnection-related network upgrades that would not be needed but for the interconnection." ANOPR at P 29. In some cases, RTOs have used hybrid models. MISO currently applies participant funding to 90% of the costs of upgrades that are 345 kV and above, while assigning the remaining costs to transmission customers. Until 2009, MISO had used a 50-50 cost allocation model. *Midwest Independent Transmission System Operator, Inc*, 129 FERC ¶ 61,060 (2009). Today, where participant funding is used, it is at or near 100% cost allocation to interconnection customers. CAISO requires participating transmission owners to reimburse generators for reliability network upgrades (though reimbursement is limited to $60,000 per installed MW of generation capacity) and also requires the reimbursement for all costs of local delivery network upgrades.

[66] ANOPR at PP P41, 111.

– as the national default.[67] RTOs/ISOs were permitted to seek independent entity variations for participant funding,[68] and they did so. However, with over a decade and a half of evidence, the Commission now can and should reverse its findings from Order No. 2003 through an interconnection-specific proceeding, which can be advanced separately and more rapidly than the transmission planning reforms that the Commission should *also* adopt from this proceeding.

Immediate reform is required because, in many of the most promising areas for renewable development, participant funding has created a formidable (and in some cases insurmountable cost barrier) to competitive entry by new market participants, because planned transmission capacity expansions fail to keep pace with the demand for renewables. Even in areas where upgrade costs may not stifle all development, there remain lengthy queues and study delays as generators submit multiple interconnection requests to probe the transmission system - only to withdraw when network upgrade cost assignments are higher than expected. The Commission has historically taken up the mantle of removing barriers to entry. Participant funding reform is necessary to ensure that the transmission grid remains accessible and does not become an impediment to the timely and efficient interconnection of renewable generation projects.

Participant funding reform is also necessary to align costs with benefits and eliminate free ridership. Under the practice of participant funding, some transmission

[67] Order No. 2003-B at P 36 ("We further clarify that the Interconnection Customer is entitled to full reimbursement for its upfront payment and the period for reimbursement may not be longer than the period that would be required if the Interconnection Customer paid for transmission service directly and received credits on a dollar-for-dollar basis, or 20 years, whichever is less.").

[68] Order No. 2003 at PP 695 ("[T]he Commission believes that, under the right circumstances, a well-designed and independently administered participant funding policy for Network Upgrades offers the potential to provide more efficient price signals and a more equitable allocation of costs than the crediting approach . . . ."), 698 ("For a Transmission Provider, such as an RTO or ISO, that is an independent entity, the Commission continues to allow flexibility regarding the interconnection pricing policy that each independent entity chooses to adopt, subject to Commission approval."), P 700 ("[T]he Commission wishes to emphasize that, by allowing an independent Transmission Provider to adopt a pricing policy, such as the 'but for' approach, that differs from the crediting approach that the Commission is requiring for non-independent entities, the Commission is not abandoning the goals that the Commission has established for interconnection pricing, as described above.").

customers benefit from interconnection-related network upgrades that are fully funded by others. More than 15 years after the Commission expressed its expectation that participant funding would provide value to interconnecting customers funding network upgrades, interconnecting generators are increasingly being asked to fund -*without* reimbursement - the cost of significant network upgrades that are electrically and geographically remote from the generator's point of interconnection, and which often reflect *existing* weaknesses in the grid. Upgrading these facilities provides transmission customers with a broad range of significant economic and reliability benefits, yet the cost of these upgrades is not allocated in a manner that is roughly commensurate with the distribution of benefits. The solution is to end participant funding, and replace it with the already-approved crediting approach, with the improvements detailed *infra*.

Crediting Reforms

To reform participant funding and remedy the unjust and unreasonable status quo, ACP/ESA recommend the nationwide implementation of a modified version of the *pro forma* Open Access Transmission Tariff's crediting policy, wherein generators are reimbursed for the cost of network upgrades over a period not to exceed 20 years.[69] As part of a fast-tracked interconnection rulemaking, ACP/ESA propose that the Commission adopt a new nationwide crediting policy with clear divisions of responsibility. Interconnection-related network upgrades up to and including the interconnection substation should be the sole responsibility of the generator (or cluster of generators), while upgrades downstream from the substation would be the responsibility of the applicable transmission provider.[70] This approach should be standardized among RTO/ISO and non-RTO/ISO regions to ensure consistency and predictability.

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[69] *See* Order No. 2003-B at P 36. To the extent generators in RTO or ISO regions are not taking transmission service against which credits could be applied because, for example, the generator's output is sold at the generation busbar, then a lump sum repayment would be due within 20 years under the crediting policy.

[70] NextEra Energy Resources, a member of both ACP and ESA, has included a detailed explanation of this proposed division of responsibility at the interconnection substation in their comments in this proceeding.

Adopting this proposed bright-line division would ensure that generators pay for those network upgrades that clearly and directly benefit them. Cost allocation is inherently an inexact science. However, a sensible point of delineation would be the boundaries of the interconnection substation, which often must be constructed (or in the case of an existing substation, expanded) to accommodate a new generator interconnection. These network upgrades – which ACP/ESA terms interconnection-substation network upgrades ("ISNUs") – are foreseeable to interconnecting generators, generally not cost-prohibitive, and typically provide limited benefits to other transmission customers. Direct assignment of these network upgrade costs to interconnecting generators is appropriate and consistent with 'beneficiary pays' cost allocation principles. By contrast, network upgrades that are electrically further downstream (such as the reconductoring of a 35-mile, 230 kV transmission line that is three substations away from the point of interconnection) are challenging for interconnection customers to foresee when they enter the queue, are frequently cost-prohibitive, and provide significant, demonstrable benefits to transmission customers. For these network upgrades, it is appropriate to require interconnection customers to provide up front funding, as this will continue to discipline siting decisions, but to also require full reimbursement through credits or a lump sum within 20 years, consistent with Order No. 2003-B.

Such a paradigm fully aligns with the Commission's "beneficiary pays" principles. Importantly, the costs of the downstream upgrades that would benefit transmission users more broadly would be allocated accordingly. As explained in *Illinois Commerce Commission v. FERC*, the courts "have never required a ratemaking agency to allocate costs with exacting precision."[71] Rather, the Commission can apply of reasonable presumptions regarding which upgrades provide broader benefits, so long as it has "an articulable and plausible reason to believe that benefits are at least roughly

[71] *Ill. Commerce Comm'n v. FERC,* 576 F.3d at 477 (citing *Midwest ISO Transmission Owners v. FERC,* 373 F.3d at 1368-69; *Sithe/Independence Power Partners, L.P. v. FERC,* 285 F.3d at 5; *Western Mass. Elec. Co. v. FERC,* 165 F.3d 922, 927 (D.C. Cir. 1999)).

commensurate" with costs assigned.[72] The proposed division of responsibility under this modified crediting approach satisfies that standard.

Clarity on Network Upgrade Facilities

Furthermore, the Commission should also implement clear requirements to limit network upgrades to the most direct, local impacts that a project has on the electric grid. The key to a successful interconnection process is to reduce interdependency between queued generation interconnection projects. If new generators were fully independent from one another, there would be no restudy risk, queue churn, or shifting upgrade costs. To reduce interdependency in interconnection queues, study processes must be reformed to create results for interconnection requests that are local, individual and binding. This could include limiting network upgrades to only what is "local" to a generation project.

One reasonable metric for electrical distance from a generation facility might be the Transfer Distribution Factor (TDF), which measures the percentage of the electricity produced by a generator which travels on a given transmission facility. The TDF concept is commonly used in interconnection processes today, but low TDF thresholds and thresholds based on group impacts trigger regional upgrades and create a large degree of interdependency between projects. The Commission should give appropriate consideration to comments in this proceeding that would enable a standard framework for all Transmission Providers to assign network upgrades to Energy Resource Interconnection Service ("ERIS") customers, and should consider similar voltage impact thresholds on an individual project basis as well.[73] This framework could be applied to all scenarios, including both system intact and post-contingency grid conditions. Further, these thresholds could also be applied to Contingent Facilities. Constraints on the

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[72] *Ill. Commerce Comm'n v. FERC,* 576 F.3d at 477.

[73] The TDF or other metric should be high enough to limit interdependency among projects. In their comments submitted to this proceeding, Enel North America Inc. suggests using a TDF threshold of 20% or greater. ACP/ESA do not specifically endorse this approach, but encourage the Commission to provide careful consideration of it and any other proposals that would provide clarity regarding which facilities might be considered network upgrades.

transmission system, including neighboring systems (known as "Affected Systems", discussed in further detail at Section II.B.1.iii, *infra*), where an Interconnection Customer's usage would be below the threshold would then not be assigned for mitigation in order to obtain ERIS service. If a constraint were identified in the regional planning process, that process would produce a more efficient design through more comprehensive studies, and the constraint would only be mitigated if it is shown to be beneficial to load.

Utilizing a reasonable and consistent threshold to assign network upgrades is consistent with current Commission rules and NERC standards. Using such a threshold would limit new network upgrades to only those local to a generation project. This fits within the Commission's standard of ERIS being "as available," while not guaranteeing protection from curtailment in all circumstances. However, it could still create an efficient way for local constraints to be mitigated - which likely provides a means to cost-effectively reduce congestion and/or curtailment for an individual generator. A reasonable threshold for cost allocation to limit the scope of upgrades for a generator is also consistent with NERC reliability standard TPL-001-4, which allows for curtailment of non-firm (i.e. ERIS) generation to mitigate transmission constraints *prior* to requiring a system upgrade to be built.[74]

Limiting generator-paid network upgrades to transmission facilities that are local to the project reduces the interdependency between similarly queued projects and reduces the volume of upgrades assigned on neighboring affected systems. By establishing a firm threshold for identifying interconnection upgrades, generators can better model interconnection costs before they enter the interconnection process. This also increases the certainty that projects requesting interconnection will be built.

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[74] *See* Transmission System Planning Performance Requirements, https://www.nerc.com/files/TPL-001-4.pdf.

Relationship of Participant Funding and Transmission Planning Reforms

ACP/ESA fully acknowledge that, in the longer run, the transmission planning reforms identified below would change the default approach for network upgrades – including the crediting mechanism. However, the situation has become so acute and inequitable that even as an interim measure, removal of participant funding and nationwide use of the crediting approach would render interconnection procedures far more just and reasonable than they are today. Longer-term transmission reforms could result in a potential successor mechanism that might mitigate the problems created by participant funding, result in cost allocations between system users that are consistent with the Commission's "beneficiary pays" principles, and preserve signals for generators to site their resources efficiently – but in the near term the Commission should adopt the framework that it has already determined to be just and reasonable, with the identified reforms to its Order No. 2003 crediting policy.

Participant funding reform would immediately address some of the most acute challenges facing renewable developers, but long-term efforts are also required to shape the grid of the future efficiently and cost-effectively. The planning reforms recommended herein will, over time, lead to optimal, forward-looking transmission investments and reduce the cost of upgrades identified through the interconnection study process. These planning reforms are important, but they will take time. Regions will likely need to reshape their existing planning processes through a series of compliance filings following the issuance of a Final Rule in this proceeding, and even once those compliance filings are approved, the first projects resulting from the revised planning process will not be energized for many years. That is why it is critically important that the Commission prioritize participant funding reform for much-needed near-term relief, while allowing time for the planning regions to implement equally important long-term solutions to transmission planning.

Finally, the costs reimbursed to interconnecting generators should be allocated as broadly as possible within RTO/ISO regions, consistent with beneficiary pays cost allocation principles. To the extent participant funding reform raises difficult network upgrade cost allocation questions in multi-state RTO regions where load and new generation may be distributed unevenly, the Commission should leverage the recently formed FERC-State Transmission Task Force to help broker new cost allocation solutions in these regions, in partnership with utilities, customers, and other impacted stakeholders.

ii. The Commission Should Require Binding Cost Caps No Later than the Signing of a Generator Interconnection Agreement

Another contributor to interconnection queue dysfunction is the unpredictable nature of network upgrade costs. One might reasonably expect that interconnection customers and transmission providers would have increasingly accurate and precise information on the types of upgrades and costs needed as projects move closer to construction. In practice, as noted above, upgrade costs can vary wildly, and in many regions have little value until the final facilities study.

ACP/ESA propose that the Commission require that network upgrade costs be capped no later than when a Generator Interconnection Agreement is signed (or filed unexecuted with the Commission). This approach could reasonably include a variance band (as used today in CAISO), which would allow for some level of increase or decrease based upon changing system conditions or construction costs; however, it would provide cost certainty for interconnection customers which is absent today. A variance band approach would ideally cap *maximum* upgrade responsibility early in the process, and become more precise as projects approach the GIA stage. *Pro forma* GIPs and GIAs should require planning level cost estimates from the Transmission Planner early on in the interconnection study process (e.g., Phase I of a two-phase cluster process, or a System Impact Study phase where a Facilities Study is the next phase). These cost estimates, utilizing a variance band to allow for potential reasonable changes such as shifts in commodity prices, should limit maximum exposure for interconnection customers and provide greater certainty throughout the process.

iii. The Commission Should Require Adjacent Transmission Providers to Harmonize and Synchronize Affected System Studies

Affected Systems issues remain highly salient and problematic. In some cases, these studies can lag years behind the studies for the native system and can assign generators orders of magnitude more in upgrade costs than the native system.[75] While the adoption of crediting would remove some of the problem (as generators would ultimately be reimbursed), the prospect of late-breaking upgrades that can – in some cases – require hundreds of millions in additional costs remains problematic. Generators must still finance those expenditures.

The Commission took some steps toward addressing affected system issues in 2018, but these actions remain incomplete. ACP/ESA recommends a rulemaking focused on two key changes: first, that regions *harmonize* their interconnection study assumptions, and second that they *synchronize* their study schedules. Adjacent regions make widely varying assumptions on a range of inputs, including the applicable distribution factor on a given transmission system, and the treatment of capacity on those systems. This proceeding will likely present the Commission with a range of possible approaches to ensure consistency among transmission providers, and these assumptions must be better aligned.[76] Second, study schedules are far out of sync – in some cases, literally by years. This can result in substantial upgrade costs on the affected system after a project is already operational. ACP/ESA recommend that all applicable affected system studies be completed no later than the issuance of the facilities study (or local equivalent) from the host transmission system. Importantly, this treatment would be reciprocal – that is, projects on one transmission provider's system would receive certainty from the adjacent system *at the time when this information is decisionally valuable*, and vice versa.

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[75] *See e.g.,* MISO DPP 2017 February West Area Phase 3 Study, at x. https://cdn.misoenergy.org/GI-DPP-2017-FEB-West-Phase3_System_Impact_Report_PUBLIC391580.pdf (showing $261 million in SPP affected system upgrade costs for two projects requiring only $14 million in MISO network upgrade costs).

[76] For example, see comments of Enel North America Inc., as discussed *supra* n.9 and accompanying text.

iv. The Commission should require the use of realistic assumptions when modeling energy storage for interconnection studies

In Order No. 845, the Commission considered whether existing interconnection modeling and study practices appropriately account for the unique operational characteristics of energy storage.[77] Although the Commission declined to set prescriptive requirements for energy storage modeling, the Commission did encourage implementation of approaches that would "save costs and improve the efficiency of the interconnection process."[78]

Despite the Commission's direction in Order No. 845, current modeling methodologies used in multiple regions do not meet the aforementioned stated criteria of saving costs and improving efficiency. Storage is often modeled under worst-case conditions that do not reflect real-world operation.[79] For example, steady-state studies may assume that storage charges at nameplate rating during peak demand and discharges at nameplate rating during low load shoulder periods. This operating profile does not match the expected dispatch of storage in response to wholesale market pricing signals, nor the ability of storage to install software and hardware controls to prevent dispatch in response to predefined line loading criteria and/or predetermined time periods.

The effect of these study assumptions is to incent storage companies to site projects in locations with the lowest possible shift factor contributions to all limiting N-1 and N-1-1 binding elements, *regardless* of whether the shift factor contribution indicates that a storage project might in fact help *relieve* a transmission constraint. When storage is modeled as both 100% charging and 100% discharging in an interconnection study

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[77] *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043 (2018) ("Order No. 845"), *order on reh'g*, Order No. 845-A, *order on reh'g*, Order No. 845-B, 168 FERC ¶ 61,092 (2019).

[78] Order No. 845 at P 544. Reform of Generator Interconnection Procedures and Agreements, 83 Fed. Reg. 21342, p. 21410 (July 23, 2018) (to be codified at 18 C.F.R. 37).

[79] *See e.g.* E-mail from Danny Musher, Director, Market Design of Key Capture Energy, LLC (Aug. 25, 2021)https://cdn.misoenergy.org/20211012%20PSC%20Stakeholder%20Comment%20on%20Dispatch%20of%20Storage%20in%20MTEP%20and%20DPP%20Studies_Key%20Capture%20Energy595054.pdf .

case, even if the project helps resolve congestion when injecting, it will appear to exacerbate the congestion when withdrawing (or vice versa). Storage developers are therefore incentivized to avoid any and all significant contributions to binding transmission elements, as this increases the likelihood that an interconnecting project could be assigned cost-prohibitive network upgrades under existing participant funding rules.

This siting approach — although rational under the current paradigm — has significant drawbacks. Importantly, it inhibits the ability of storage to provide key benefits to the bulk system, including increased utilization of the existing transmission infrastructure. Standalone storage in particular has great flexibility in siting because it is not subject to the same resource availability or land constraint limitations of other types of interconnection projects. A standalone storage project could locate close to transmission congestion (e.g., close to a load center with an import constraint) and operate in a manner such that it relieves congestion (e.g., assist in importing incremental generation from outside the load center). Such beneficial use cases may not be viable under current study assumptions, which erroneously assume that the project will exacerbate, rather than relieve congestion.

ACP/ESA therefore recommend that the Commission require more accurate interconnection modeling of energy storage based on actual realistic dispatch assumptions. This will unlock the ability for storage to locate close to transmission constraints and provide significant congestion relief and system benefit, without incurring expensive network upgrade costs.

2. Holistic Transmission Planning and Cost Allocation Reforms

The Commission should move forward with minimum *pro forma* planning and cost allocation standards that all Transmission Providers must adopt. Consistent with ACP's recommendation above in the context of near-term interconnection reforms, at the time at when transmission planning and cost allocation compliance filings are due, transmission providers should be able to file alternatives as long as they are "consistent with or superior to" the *pro forma* tariff. This standard for exceptions should apply equally, both inside and out of RTOs/ISOs. ACP/ESA recommend that a Proposed Rule incorporate the following elements.

i. First Step – Enhanced Transmission Planning

There are multiple aspects of good transmission planning practice that the Commission could require of all transmission providers to improve regional and interregional transmission planning across the country.[80] ACP/ESA offer several suggestions and some examples of where these are successfully used today. ACP/ESA urge the Commission to include each of these proposals in a final rule. Some are more easily required in the near term, as they would necessitate less change in existing transmission planning processes. Others may take more time to develop and define through a lengthier stakeholder process.

a. Proactive Planning for anticipated future generation and load

The most basic flaw across all planning and interconnection processes is that so-called "planning" is generally not actually focused on the future need. Planning a

[80] *See e.g.* Brattle 2021 at 70.

transmission system means connecting future generation with future load. The first and most important step is to include anticipated generation and load in the planning process.

Transmission planning must consider future changes in the generation fleet, otherwise the resulting transmission grid will not identify real transmission needs far enough in advance to address them. Just as planners today include reasonable estimates of changes in load, future generation (the type, quantity, and location) must be *fully incorporated* into transmission planning - not merely considered as required by Order No. 1000. Future generation modeled in these scenarios must include utility resource plans and renewable or decarbonization commitments, as well as any state or local policy commitments.

Location of all future generation may not be known, but transmission planners can do a good job of estimating the locations. First, any known new generation with utility contracts, as well as additional generators with signed GIAs should be modeled at their exact locations. The interconnection queue can provide information on additional potential sites as can wind and solar resource maps, and planners can also eliminate inappropriate locations.

Transmission is a costly and long-lead time resource. Thus, the planning process should consider transmission needs over a longer planning horizon. Proper economic policy is to evaluate benefits and costs *over the life of the asset*, with discounting of future benefits and costs to today's dollars. ACP/ESA therefore urge planning based on future generation needs over a 20-25 year period, with evaluation of interim periods as well, such as 5, 10, and 15 years out for informational purposes. This allows the process to identify solutions that are "right sized" for those future needs. It is much more efficient - in terms both of cost, and the optimal use of transmission corridors - to build a single larger transmission line that can meet multiple needs over a longer period of time, than to build several smaller solutions to meet the needs of each increment of new generation (or reliability need, or other driver). This is exactly why transmission planning and interconnection planning must be more aligned and preferably integrated.

Economic analysis of transmission investments should properly evaluate benefits over a longer period as well. ACP/ESA recommend at least 40 years for transmission lines, as such assets typically have an expected life of 40-60 years or more[81].

Generation interconnection planning and transmission planning should, at a bare minimum be well coordinated and full integration of the two would provide for the greatest efficiency in expanding the grid. Not only is there the potential to speed up the process to interconnect new generation, but also to ensure that the most cost-effective solutions are identified. Planning for interconnection and transmission separately, with each planning process considering only a limited set of transmission needs, can result in two solutions being identified when one may meet multiple needs for a lower cost. Order 1000 includes a requirement that Transmission Owners look to find alternative solutions or opportunities to consolidate multiple transmission projects when fewer solutions can address the needs more cost effectively.[82] But to ACP/ESA's knowledge, this kind of coordination and consolidation is not happening. In fact, individual Transmission Owners may have the incentive to avoid alternative projects or project consolidation, as it can reduce their investments and thus their rate of return on upgrades they may build. Consolidation may also open more projects up to competition with independent transmission developers. It is incumbent on the Commission to institute requirements that transmission planning processes with separate drivers are well coordinated at a minimum, otherwise development will not happen - and consumers are at risk of paying high costs for inferior and potentially duplicative solutions. But the ideal outcome is for *all* transmission planning to be fully integrated. This ultimate solution also reflects the fact that transmission, while it may be *identified* to meet a single need, does not *provide* only one benefit once it is built.

The Commission also asks in the ANOPR whether it "should require transmission providers in each transmission planning region to establish, as part of their regional

[81] ANOPR at P48.
[82] *See* Order No. 1000 at PP 148, 368, 374.

transmission planning and cost allocation processes, a process to identify geographic zones that have the potential for the development of large amounts of renewable generation and plan transmission to facilitate the integration of renewable resources in those zones.[83]" ACP/ESA agree that forward-looking planning should identify zones or locations where significant generation is likely to be developed. With respect to renewable resources, these are zones with high levels of wind and/or solar. Identifying resource zones in advance and planning transmission that provides an outlet ensures that those resources can be built when needed, and that the transmission solutions are not implemented in a piecemeal manner that would lead to higher costs to consumers. The Commission already has examples of successful transmission planning efforts that have identified key resource zones and built transmission to allow development of resources in those zones. ERCOT Competitive Renewable Energy Zones ("CREZ"), the MISO Regional Generator Outlet Study resulting in the first portfolio of Multi-Value Projects, and the CAISO Location Constrained Resource process are examples that the Commission should consider and are discussed in further detail below. These types of "transmission first" approaches – or, framed differently, transmission planned *with* generation – can and should be applied broadly to areas with high energy resource potential that are experiencing (or are likely to experience) significant interconnection requests, such as coastal transmission adjacent to offshore wind lease areas.

Proactive transmission planning done correctly will consider a range of transmission drivers or needs, as well as a range of benefits and beneficiaries. It should also compare cost and benefits of individual upgrades to consolidated transmission solutions that can meet multiple needs including reliability and economic benefits, as well as integration of new resources and load.

Finally, ACP/ESA acknowledge that planning inherently involves uncertainty – and there are well-established means of incorporating uncertainty while still planning for

[83] ANOPR at P 57.

future needs and maximizing customer benefits. Given that the details of future transmission needs cannot be known to the precise megawatt or cent, the use of scenario planning (or multiple sets of future assumptions) is very helpful in both determining future transmission needs and solutions. In planning for future transmission, planners must include assumptions about load growth, fuel prices, as well as the future generation resource additions and retirements and their locations on the grid. Given future uncertainty, the best way to assess what those assumptions should be is to create multiple futures, with different sets of plausible assumptions. Ideally, one of those futures would be a "business as usual" case representing the existing future resource plans of the utilities in the planning area and any local, state or federal policy requirements. Then other futures can be created with changed adjusted assumptions based on possible changes (e.g. increased commitments to decarbonization, increased electrification of transportation and other uses such as home heating, and increased fuel prices) . Having three to four different future scenarios allows the planning process to create bookends for the possible futures considered, as well as consideration of a middle ground. Evaluating the benefits of transmission solutions under multiple future scenarios allows the identification of solutions that are "least regrets" given future uncertainty.

b. Portfolio Planning

One of the key challenges in approving transmission upgrades is the fact that the siloed planning processes typically only consider a single benefit to justify a project. But while a transmission project may be driven by only one initial transmission need, most transmission upgrades will ultimately bring many benefits to a variety of beneficiaries across the system.[84] Economic planning processes often only contemplate adjusted production cost savings benefits. Interconnection planning studies rarely consider any

[84] *See* ANOPR at PP89, 91.

benefits beyond those to the interconnecting generators. But once an upgrade is put into service, it can and will serve multiple needs and multiple beneficiaries. A transmission project justified based on its potential to reduce economic congestion today will later be relied on to ensure reliability – which emphasizes the need to accurately assess the full range of benefits before a project is developed, to avoid a mismatch between benefits and the allocation of costs. A perfect example of this occurred recently in the MISO footprint during the polar vortex event in the southern states in the US in February of 2021. During that time power was sent from PJM and MISO North to MISO South and SPP. MISO has stated that its portfolio of Multi-Value Projects, which were initially approved based on economic benefits and their ability to support utilities in meeting state renewable portfolio standard requirements, were critical during this event to meet reliability needs and serve load in southern states.[85] The MVP lines were designed to send energy from west to east, and planners never contemplated that they might be essential to send energy from the east to the west and south. A more holistic transmission planning approach would appropriately account for these reliability benefits at the time that projects are planned, which would further support those projects' consumer benefits and inform appropriate cost allocation.

ACP/ESA urge the Commission to consider requiring all transmission planning to consider all the benefits of potential transmission upgrades as suggested by the Brattle 2021 report on analyzing the value of transmission investments[86]. Without a more complete accounting of the benefits of new transmission, two unjust outcomes often occur. First, if the full range of future benefits are not considered, often upgrades cannot meet the required benefit-to-cost ratio. But this is is hardly surprising, if only one or two benefits are included in that calculation. If projects are not approved because the benefits evaluation is limited, consumers will not receive the true benefits of these upgrades -

[85] *See* ACORE, *Transmission Makes the Power System Resilient to Extreme Weather* at 13 (July 2021), https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.
[86] Brattle 2021 at 70.

because they simply won't be built. Second, if the full range of benefits are not considered, then the full range of beneficiaries will not be charged, thus resulting in unjust rates.[87] Adjusted Production Cost benefits should be the starting place, but not the end of economic benefits evaluation. Additionally, reliability and resource adequacy benefits should be evaluated, as well as capacity cost savings, market benefits, and environmental and public policy benefits. While NERC has no resilience requirement, the resilience benefits of new networked transmission are increasingly being recognized; should an accepted, formal method for quantifying this benefit be developed, it should be required in evaluation of new upgrades as well.

In all transmission planning studies, including interconnection studies, all technologies should be considered. Advanced conductors may cost slightly more, but could (for example) deliver substantially more energy and/or provide more resilience by sagging less and creating less risk of contact with vegetation. Grid-Enhancing Technologies ("GETs") and energy storage can often accomplish network objectives at much lower cost. These options should be fully considered on a routine basis in transmission planning.

ACP/ESA understand that this would be a paradigm shift in transmission planning, and that it may take longer for RTOs/ISOs to work with their transmission owners and other stakeholders (and for transmission providers in non-RTO/ISO regions to coordinate) to redesign transmission planning in this way. But the potential benefits are far reaching because optimized solutions, like the potential to consolidate smaller transmission projects in a single evaluation, will ultimately save consumers money.

What would a comprehensive transmission planning process look like? It would co-optimize transmission solutions for the greatest net benefits wherever possible, focus

[87] ACP/ESA believe this has become a serious concern in the interconnection process, as described in further detail at Section II.A.1, *supra.* Large interconnection upgrade costs are being assigned only to interconnecting generators, yet these network upgrades would realistically be expected to bring a much wider set of benefits to a broader region.

on the multiple long-term benefits over the life of the asset[88], and break down the Order No. 1000 siloes of economic, reliability, public policy (as well as interconnection) to require all transmission planning incorporate these multiple drivers and benefits jointly as much as possible.[89] As detailed above,[90] As detailed above, siloed processes can result in suboptimal transmission investment, near-term "band-aid" solutions, and excessive reliance upon generators to fund broadly beneficial infrastructure. At a minimum, there should be a "regional first" directive, where RTOs/ISOs and Transmission Owners are required to look for opportunities to consolidate smaller projects into fewer/larger and more cost-effective projects that are evaluated simultaneously for the full range of benefits. This could include *a* requirement that Transmission Planners demonstrate a process to evaluate larger regional alternatives to smaller local upgrades comparing the benefits of each to their respective costs, and this comparison must include a wider range of benefits analysis.

c. Interregional Joint Planning

Order No. 1000 required RTOs/ISOs to coordinate on interregional planning, and to have a method of cost allocation for interregional lines.[91] However, very few interregional lines have been approved across the country, and along some seams, such as along the MISO-SPP seam, *no* interregional transmission upgrades have been approved since Order No. 1000 – despite significant congestion and geographic price divergence in

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[88] ANOPR at P48.
[89] ANOPR at P39.
[90] *Id.*
[91] *See* Order No. 1000 at Summary Para. ("[T]his Final Rule requires that each public utility transmission provider must participate in a regional transmission planning process that has: (1) a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation; and (2) an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions in the interregional transmission coordination procedures required by this Final Rule."), PP 345-481, 578-84.

some areas. As the generation mix continues to shift, increasing the importance and value of locational diversity of both load and generation, and as extreme weather events are increasingly disrupting the reliable delivery of electricity to consumers, interregional planning is becoming even more critical. Regions have not been planning together for transmission that will allow their markets to operate in a more optimized way, or that will allow them to support each other during events like the Texas Freeze of 2021.

To better serve consumers they must improve interregional planning, and it is incumbent on the Commission to put requirements in place that have teeth.[92] The country's power sector and broader economy need true interregional joint planning, not merely communication and coordination that allows each region to rely on a different set of planning assumptions. Interregional planning should include joint planning, meaning the use of a single joint model to analyze alternative ways to meet multiple regions' goals together rather than independently. In turn, this requires harmonization of assumptions and methodologies, as well as synchronization of timetables. Allowing each region to analyze potential interregional upgrades using their own regional models may be more time efficient, but it does not accomplish real interregional planning. Allowing each region the option of rejecting a beneficial interregional upgrade due to Order 1000's requirement that all interregional upgrades must be approved within each region's planning process, means that one region, using its preferred assumptions, can claim that it does not benefit from the upgrade - when under other assumptions benefits would be shown.

Key aspects of interregional joint planning also have some overlap with affected system studies. As noted, affected systems studies are increasingly resulting in delays in the interconnection process. ACP/ESA urge the Commission to consider how Affected

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[92] *See* ANOPR at P62 ("We recognize that potential reforms discussed for comment above may require greater interregional or state-regional coordination to be fully realized in a just, reasonable and not unduly discriminatory or preferential manner. As a result, we seek comment on whether reforms to the current interregional transmission coordination process, including potentially requiring interregional transmission planning, are needed or appropriate for making the potential approaches discussed above effective, and whether such reforms are consistent with the Commission's authority under section 206 of the FPA.").

Systems studies could be incorporated into interregional planning rules, so that solutions can be better optimized to serve needs in both regions and serve multiple needs at a lower net cost to consumers. As noted previously, ACP/ESA identified a number of improvements to regional and interregional transmission planning that the Commission can require in the near term, including proactive planning, portfolio planning and required interregional planning that cannot be simply rejected by a single region. Included in these recommendations is a move away from siloed planning to more coordinated planning, and a mandatory process to consolidate multiple transmission projects where one larger project could meet the needs of the region and deliver greater net benefits more cost-effectively.

d. Efficient Transmission Planning Practices are Proven and Workable

There are several examples of proactive, holistic transmission planning accounting for future generation that the Commission should consider. Elements of each of these approaches have been shown to be just and reasonable, and therefore should inform the Commission's efforts to develop a rule requiring holistic and forward-looking transmission planning.

MISO has been on the forefront of innovation in regional transmission planning for some time. The Commission should take note of MISO's Long Range Transmission Planning ("LRTP") effort which officially kicked off in the summer of 2020, though some might say it started even earlier with MISO's update to its planning "futures". The futures themselves are the most forward looking in the industry with Future 1, (characterized as "business as usual" with a model that assumes generation changes in the region representing 85% of utility resource plans and decarbonization goals as well as all state renewable portfolio standards and climate goals). Future 1 represents a 63% carbon reduction from 2005 levels.[93] Future 2 and Future 3 go beyond Future 1 and represent the potential of more aggressive decarbonization goals and increase electrification in both the transportation sector and home uses such as heating.[94] But the most important example from MISO's LRTP planning effort is that it moves beyond typical transmission planning siloes to consider both economic planning, and reliability planning, while also considering additional regional reliability challenges that arise under the higher renewable penetrations that are expected under these utility plans. By doing more comprehensive planning like this MISO can better optimize the transmission solutions it identifies such that they can address multiple drivers (NERC reliability requirements, regional reliability needs related to energy delivery, resource adequacy, and resilience, and reduction of economic congestion).

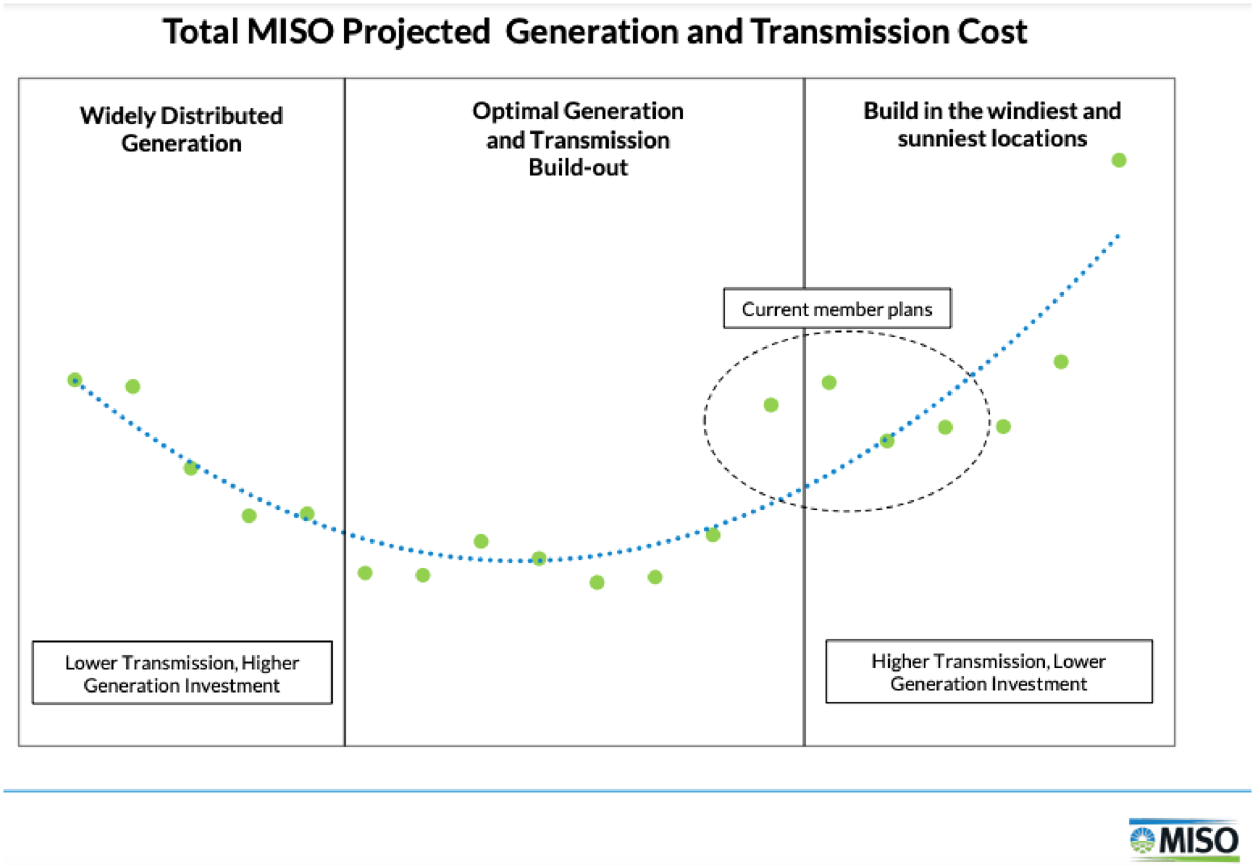
ACP/ESA strongly supports this kind of planning, which gets beyond the silos that the Commission discussed in its ANOPR,[95] and takes a long-term look at transmission needs (MISO's LRTP has a 20-year planning horizon). While it may not be necessary to do a regional planning effort with this level of rigor annually, it should be done on a regular basis and no less than every three years. ACP/ESA do note, however, that the LRTP effort, though superior to the kind of regional planning most other regions engage in, still does not achieve *fully* consolidated planning or full optimization of transmission solutions to address multiple needs. To improve its process further, MISO should seek to both integrate interconnection planning into a consolidated planning process, and also to incorporate a process by which MISO as the independent entity works to optimize transmission solutions by seeking to find opportunities where one larger transmission

[93] *See MISO Futures Report,* (April 2021) available at https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf
[94] *Id.*
[95]*See* ANOPR at P39 (seeking comment on whether to end the separation of transmission into the Order No. 1000 categories of reliability, economic, and public policy projects). In its framing questions, the ANOPR also asks "whether the regional transmission planning and cost allocation processes' consideration of transmission needs driven by reliability, economic considerations, and Public Policy Requirements [are] inappropriately siloed from one another . . . ." *Id*. at P 5 (internal citation omitted).

solution can more cost-effectively solve the transmission issues than multiple smaller projects, many of which are identified in Transmission Owner's local planning processes.

MISO's earlier comprehensive planning effort, which is often referred to by the cost allocation category that the projects were approved under - Multi-Value Projects ("MVPs") - was another planning effort that sought transmission solutions that would address multiple drivers and bring multiple benefits. The planning effort that led to the MVPs was called the Regional Generator Outlet Study ("RGOS") and was largely driven by the need to identify transmission that would support MISO's utility members' compliance with state RPS requirements, while at the same time reducing the potential for future economic congestion. One key aspect of this effort, which has similarly been discussed in the LRTP effort today, is a focus on optimizing the combination of transmission and generation additions for overall least cost to consumers. Specifically, if all renewable generation were sited locally to limit the need for transmission additions, the energy output of this generation would be lower and thus more costly. Similarly, if all generation were sited remotely, so as to gain the greatest output from the generation, the transmission costs tend to be higher. Thus, MISO's planning effort seeks to get close to the "sweet spot" where transmission additions are lower, and there is both a mix of local and remote generation such that the combination is least cost. This concept is often referred to as the "smile curve" or "bathtub curve", as the example below shows. [96]

[96] MISO Planning Advisory Committee, *Long Range Transmission Planning - Preparing for the Evolving Future Grid* (August 12, 2020), Slide 7, available at: https://cdn.misoenergy.org/20200812%20PAC%20Item%2003c%20Long%20Range%20Transmission%20Planning%20Presentation465531.pdf.



As with the LRTP effort described above, the RGOS effort considered multiple benefits in justifying the need for the transmission upgrades, as well as justifying the broad cost sharing approach of the MVP cost allocation methodology. Unfortunately, there was never another RGOS effort, and it took 10 years before MISO started another comprehensive planning process with the LRTP effort. It is critical that this kind of planning be done on a more regular basis, because MISO utilities are experiencing a need now for more regional transmission solutions to support the generation shift they are planning, and the time it will take to both complete the planning process and then site, permit, and construct these lines means that they will not be in service for 5 or more years.

Lastly, the RGOS effort and subsequent MVP cost allocation also provide an example of portfolio evaluation of the benefits of the regional plan for transmission build out. Evaluating the benefits of individual transmission projects often does not give a complete estimate of the expected benefits of a set of regionally planned and optimized lines, as the benefits of the whole are often greater than the sum of the benefits of each project analyzed on its own. MISO's MVP portfolio has consistently shown benefits well in excess of the costs, as analyzed multiple times in MISO's triennial review of this portfolio of projects.[97] The RGOS planning process and the MVP cost allocation methodology have also been challenged at both thethe Commission and the circuit court and have continued to be shown to a just and reasonable approach.

The last "best practice" ACP/ESA highlight from MISO is its recent effort to adjust the interconnection process timeline to allow for greater opportunity for better coordination between the generator interconnection study processes and the larger MISO Transmission Expansion Planning ("MTEP") process. This is also a necessary step to move towards potential consolidation of interconnection and regional transmission planning. MISO's Generator Interconnection Process ("GIP") as described in MISO's tariff is over 500 days long, (that is, when no study delays are experienced). MISO is now proposing to reduce that timeline to a little over a year. Of course, a shorter interconnection timeline is a benefit to generation developers, but this proposed change should *also* allow the GIP to be aligned with the annual MTEP process. Alignment of the two processes can allow GIP upgrades to be evaluated in the MTEP process, which could include analysis of the economic benefits these upgrades would provide to load, and allow for consideration of how these upgrades might be consolidated with other local or regional transmission upgrades to reduce the cost to both developers and load. As this effort at MISO is still underway and not yet approved by the Commission, the advantages

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[97] Midcontinent Independent System Operator, *MTEP14 MVP Triennial Review*, (Sep. 2014) available at https://cdn.misoenergy.org/MTEP14%20MVP%20Triennial%20Review%20Report117061.pdf , and *MTEP17MVP Triennial Review*, (Sep. 2017), available at https://cdn.misoenergy.org/MTEP14%20MVP%20Triennial%20Review%20Report117061.pdf.

of aligning the GIP with MTEP have not been pursued yet. But ACP/ESA view this as a positive step towards greater coordination and ultimately to a consolidated planning process.

Next, with respect to best practices, the Commission should consider (1) NYISO's "Public Policy Transmission Planning Process"[98] and (2) CAISO's reliance on public policy driven needs[99] as examples where public policy considerations form the basis and need for new transmission projects. Although imperfect, NYISO and CAISO have successfully planned and cost allocated at least some public policy transmission projects. However, as noted above, the Commission should require that public policy drivers be fully integrated with overall transmission planning for all transmission providers, not just single-state RTOs/ISOs.

Finally, the Commission should consider past initiatives that utilized a forward looking, proactive approach to construct high-quality transmission resources in *advance of the construction of specific generation projects utilizing such transmission resources.*[100] Past examples include (1) ERCOT's CREZ approach,[101] (2) the Tehachapi Renewable Transmission Project,[102] (3) SPP's Highway-Byway/Priority Projects,[103] and (4) MISO's MVP projects, discussed *supra*.

ERCOT's CREZ approach is widely seen as solving several of the problems seen under Order No. 1000. Although the CREZ was enabled by unique state legal

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[98] *See* New York Independent System Operator, *Public Policy Transmission Planning Manual* (June 2020), available at https://www.nyiso.com/documents/20142/2924447/M-36_Public%20Policy%20Manual_v1_0_Final.pdf.
[99] *See, e.g.*, California Independent System Operator Corp., (last visited Sept. 28, 2021) available at: https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2021-2022-Transmission-planning-process (stating "[t]ransmission mitigation solutions may meet reliability, economic or public policy-driven needs that support state, federal, municipal and county policy requirements and directives.").
[100] ANOPR at PP 36, 44.
[101] *Transmission & CREZ Fact Sheet*, Powering Texas (last visited Sept. 28, 2021), *available at*: https://poweringtexas.com/wp-content/uploads/2018/12/Transmission-and-CREZ-Fact-Sheet.pdf.
[102] *See* Southern California Edison, *Tehachapi Renewable Transmission Project* (last visited Sept. 28, 2021), available at: https://www.sce.com/about-us/reliability/upgrading-transmission/TRTP-4-11.
[103] *See* T. Wilner, *FERC Approves SPP's 'Highway/Byway' Cost Allocation*, Windpower Monthly (June 28, 2010), available at: https://www.windpowermonthly.com/article/1012826/ferc-approves-spps-highway-byway-cost-allocation.

requirements (and ERCOT is not within the Commission's jurisdiction), its success demonstrates the benefits of taking a proactive approach. By building large-scale transmission outside the normal interconnection planning process, and assessing generation potential and transmission needs at once, CREZ unlocked 18,000 MW of additional generation capacity.[104] The Public Utility Commission of Texas proceeded with the planning for CREZ in two phases.[105] The first phase both designated areas as a competitive renewable-energy zone and provided initial estimates of the maximum generating capacity that was expected of transmission to accommodate the zone, through a CREZ Transmission Optimization Study.[106] Generation was therefore planned at the same time that transmission was assessed. As the Public Utility Commission of Texas' Order on Rehearing stated, the purpose of the study was to identify transmission proposals that would be the most beneficial for delivering the estimated capacity from the designated CREZ. The second phase focused on the major transmission improvements necessary to deliver the energy generated by the CREZ lines.[107] This model of addressing transmission and generation together, has been cited as a method to work around the typical "chicken or the egg" approach – where transmission lines are only built after there is a GIA, or generators only being built after transmission lines are available.

The Tehachapi Renewable Transmission Project in CAISO took a similarly proactive approach. The project was borne out of the Tehachapi Collaborative Study Group which consisted of full collaboration between energy and transmission stakeholders, including impacted participating Transmission Owners, technical representatives from project sponsors, technical representatives from the California

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[104] *See How Transmission Planning & Cost Allocation Processes Are Inhibiting Wind & Solar Development in SPP, MISO, & PJM,* Julie Lieberman, ACORE, P.14 (Mar. 2021) available at https://acore.org/how-transmission-planning-and-cost-allocation-processes-are-inhibiting-wind-and-solar-development/
[105] *Commission Staff's Petition for Designation of Competitive Renewable-Energy Zones Docket No. 33672 Order on Rehearing*, PUBLIC UTILITY COMMISSION OF TEXAS, http://www.ettexas.com/Content/documents/PUCTFinalOrderonCREZPlan100708.pdf
[106] *Id.*
[107] *Id.*

Energy Commission, and the California Electricity Oversight Board.[108] This collaborative study group process produced study reports one and two years after formation.[109] CAISO collectively studied the system impacts of a group of interconnection customers, rather than each potential generator one-at-a-time. Studying the interconnection of multiple projects in a proximate geographic location together resulted in greater efficiency in the design of network upgrades.[110]

In certain instances (such as in the examples of NYISO, CAISO, and ERCOT), the proactive planning approaches to construct transmission resources pursuant to state public policies and/or in advance of generation were implemented in single state RTOs/ISOs. Although multi-state regions where various states may have divergent policy objectives based on respective beneficiaries in their states pose different challenges, the forward-looking approaches utilized in these single-state regions should not be wholly left out or ignored with respect to multi-state regions Projects that maximize net benefits can address public policies of one or more states simultaneously with other regional needs, and a cost allocation approach described below could provide an avenue for states to fully or partially fund transmission projects supporting their policy goals.

e. Role of Energy Storage in Transmission Planning

ACP/ESA also urge the Commission to include energy storage in transmission planning reform. To that end, the Commission should act to ensure inclusion of storage in the planning process, allow for the use of GETs in the interconnection and

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[108] *Cal. Indep. Sys. Operator* (CAISO), *Memorandum re: Decision on Tehachapi Project,* at 3, fn. 1 January 18, 2007
[109] *Id.*
[110] *Id.*

transmission planning processes,[111] require reforms to cost-benefit criteria, modeling requirements, transparency and grid utilization data, and ensure the the co-optimization of generation and transmission development .

In the Energy Policy Act of 2005, Congress recognized that energy storage, including battery storage, is a technology that can provide transmission services.[112] The Commission further clarified that finding in the *Western Grid Development, LLC* declaratory order[113] and more recently in the MISO Storage as a Transmission Only Asset (SATOA) proceeding.[114] The Commission continues to explore incentive structures for Grid Enhancing Technologies.[115] While ACP/ESA support this incentives initiative, our comments in this section are not contingent upon the Commission issuing an order on incentives for GETs. While creative ownership models or incentives can improve the economic viability of storage, there are numerous applications today where storage can be competitive under a standard cost-of-service model where storage is treated like any other equipment connected to the transmission system such as a substation, STATCOM, or transmission tower. ACP/ESA urge the Commission to adopt non-discriminatory criteria for inclusion of energy storage in transmission planning that allow for a range of project sponsors.

Energy storage is a proven technology that has been deployed around the world to enhance grid performance. Since the use of energy storage as a transmission asset may be unfamiliar for some stakeholders participating in this ANOPR process, ACP/ESA have

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[111] Grid Enhancing Technologies can "increase the capacity, efficiency, or reliability of transmission facilities" and " include, but are not limited to: (1) power flow control and transmission switching equipment; (2) storage technologies, and (3) advanced line rating management technologies." *See* Grid Enhancing Technologies, Notice of Workshop, Docket No. AD19-19-000 (Sept. 9, 2019).
[112] Pub. L. No. 109-58, § 1223, 119 Stat. 953 (2005) (1223"DEFINITION OF ADVANCED TRANSMISSION TECHNOLOGY. — In this section, the term 'advanced transmission technology' means a technology that increases the capacity, efficiency, or reliability of an existing or new transmission facility, including . . ."… (11) energy storage devices (including pumped hydro, compressed air, superconducting magnetic energy storage, flywheels, and batteries).").
[113] 130 FERC ¶ 61,056, at P 43 (2010).
[114]*Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,186 (2020).
[115] *See, e.g.*, Docket No. AD19-19-000 proceeding.

outlined four exemplary Use Cases at the end of this section[116] (see Section II.B.2.i.e(7)) along with concrete sample projects that have been approved by planners and regulators or already placed in service.

1) The Commission should require ISO/RTOs and transmission owners in all balancing authorities to evaluate energy storage in selective applications.

While the adoption of energy storage as a generation asset has exploded in the U.S., with battery storage found in every RTO/ISO interconnection queue, energy storage as a transmission asset is frequently overlooked in the U.S., with more use cases found internationally. Additionally, as deployment of energy storage technologies other than lithium-ion batteries increases in the coming years, it is critical to assess not only battery applications, but those technologies that may be able to provide stability services. In the ANOPR, the Commission sought comment on whether and how grid-enhancing technologies, which include energy storage, should be included in transmission planning.[117] ACP/ESA submit that energy storage and GETs can improve the performance of the transmission system and their evaluation should be selectively required in transmission planning processes.

Although the Commission should require planners to include energy storage in selective applications, the objective is not to slow the transmission planning process by forcing energy storage into every single transmission upgrade. ACP/ESA suggest the Commission ask transmission planners to determine their own criteria and thresholds for including energy storage. The criteria should encompass applications where energy storage is likely to be cost effective and the thresholds should ensure analysis is bundled in a manner that allows transmission planners to execute efficiently. ACP/ESA offers the

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[116] These use cases are included for discussion purposes and are not intended as an exhaustive list of transmission and reliability use cases for energy storage today and in the future.
[117] See ANOPR at P 48.

following criteria and thresholds for consideration by the Commission, transmission planners and other stakeholders.

Applications with significant load or generation growth uncertainty. Decades of steady, predictable load growth have been replaced in the past years with challenges predicting load growth with any certainty.[118] Additionally, decades of sparse new generation interconnection requests have been replaced in many regions with a flood of clean energy projects seeking interconnection to the transmission system.[119] The Commission should consider requiring any scenario in which there is uncertainty estimating load growth (and its impact on cost/benefit calculations) to consider a modular solution such as energy storage. While new transmission lines, or even reconductoring of a transmission line, are high-cost/high-value solutions which are hard to scale up or down, energy storage is easy to deploy in incrementally. Storage can accommodate immediate needs, and is comparatively easy to scale up if load growth persists. ACP/ESA suggest that transmission planners be required to consider energy storage where the difference between low and high load growth scenarios is > 25%.

Applications where new transmission is atypically costly. It is more expensive to build and maintain new transmission in urban areas, areas that requires undergrounding (underground, underwater, or over water) or mountainous terrain. ACP/ESA suggest that transmission planners be required to identify such high-cost applications and, ensure energy storage is evaluated as part of the alternatives or complements. ACP/ESA suggest transmission planners use the total projected lifetime cost to ensure construction and higher maintenance costs are included, and any single upgrade > $50M total lifetime cost be required to include storage in the mix of solutions considered.

[118] Taylor Sloane, *Why big bets on transmission and distribution infrastructure are no longer necessary*, FLUENCE (May 25, 2018), https://blog.fluenceenergy.com/energy-storage-for-transmission-and-distribution-planning.

[119] For example, CAISO received 373 in 2020 application window, versus annual average of 113. PJM has seen even more dramatic growth in recent years.

Applications where new transmission lines are difficult to site due to land-use constraints. Siting new transmission lines across areas with a land-use constraint, such as environmentally or culturally sensitive areas, is increasingly difficult. The risk that the project will proceed through the planning process, only to be halted during the siting approval process under the jurisdiction of state commissions, is significant.[120] With a low profile and small footprint, energy storage can both limit the incursion on environmentally sensitive land or be sited in a manner to limit objections from local population. For battery energy storage specifically, approximately 200 – 300 MW of energy storage can fit onto the space required to run 2,000 ft of 220 kV transmission line. ACP/ESA suggest that transmission planners be required to include a energy storage solution in the evaluation process if it is likely the transmission line will be sited on land that has been designation as environmentally or culturally sensitive.

Applications where near-term, modular solutions will reduce cost for ratepayers. Historically, system planners have only been able to solve high LMP or congestion costs with large solutions (e.g., a new natural gas plant or a new or reconductored transmission line). Therefore, the cost of high LMP and congestion had to be high enough to justify the cost of the solution. Planners have not typically had access to smaller, modular solutions that could be deployed quickly and at a fraction of the cost of a new transmission line, such as storage. Transmission providers should be required to look at local transmission constraints to determine if energy storage can be deployed effectively to reduce costs for ratepayers.

Application where N-1 planning requires either transmission expansion or local generation. Transmission planners are required to ensure loads can be restored if any single component on the transmission system fails (N-1). If meeting N-1 requires either transmission expansion, the construction of new local generation, or the deration of

[120] *See*, Suedeen G. Kelly & J. Porter Wiseman, *No Easy Transmission Fixes*, North American Wind Power, (Dec. 2016) https://www.akingump.com/images/content/5/3/v2/53869/NAW1612-Akingump.pdf (list of projects cancelled or still awaiting siting approval).

existing infrastructure, planners should be required to evaluate energy storage as one of the solutions they consider. Energy storage has been found to be cost effective multiple times in similar applications in Europe.

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. As has been demonstrated in Europe, a higher percentage of inverter-based generation will change the inertia of the 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).

While ACP/ESA ask the Commission to encourage transmission planners to consider energy storage in all applications, the scenarios listed outline scenarios where it should be required.

2) Interconnection customers should be allowed to request the evaluation of GETs, including storage, to reduce interconnection costs and minimize delays

Outside of the role that energy storage can play to meet reliability, economic or policy driven transmission needs, energy storage may prove to be a cost-effective solution for network upgrades driven by the interconnection of new generation. While energy storage is not a substitute for transmission lines where none exist, most projects awaiting interconnection analysis in the queue now are trying to connect as closely as possible to where transmission infrastructure already exists.

The Commission sought comments on the requirement to include GETs, which include energy storage, in interconnection studies.[121] While it is not clear that storage will be more cost-effective than reconductoring a transmission line in all circumstances, energy storage can certainly be built more quickly than most transmission upgrades and should be included in the toolbox of solutions considered.

Additionally, energy storage can be built independently and interconnected to the transmission system on a set schedule in many applications. Therefore, ACP/ESA submit that energy storage (and potentially other GETs) should qualify as a standalone network upgrade,[122] and be included under the Option to Build. Order 845 removed the limitation that interconnection customers could only exercise the option to build a transmission provider's interconnection facilities and stand-alone network upgrades in instances when the transmission provider cannot meet the dates proposed by the interconnection customer. Order 845-A further defined a stand-alone network upgrade as, "network upgrades that an interconnection customer may construct without affecting day-to-day operations of the transmission system during their construction."

After the Option to Build facilities are constructed by the interconnection customer, they are transferred to the transmission owner to own and operate.

3) The Commission should require transmission planners to reevaluate benefits of energy storage included in cost/benefit analysis.

The Commission sought comments on how the benefits and costs of transmission infrastructure should be accounted for in planning models.[123] ACP/ESA submit that

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[121] ANOPR at P 158.
[122] *See* FERC Order 845-A, at P 2 n.5 ("Stand alone network upgrades: shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.")
[123] ANOPR at P 48.

energy storage provides valuable benefits that are not reflected in cost/benefit analysis today.[124] These benefits largely mirror the scenarios outlined *supra*, where ACP/ESA requested that energy storage be included in the evaluation process, and noted several aspects of transmission benefits that are un- or under-accounted for in current processes.

Optionality value: In 2017, Arizona Public Service built a 2 MW, 4-hour duration battery energy storage system for less than the cost of its next best alternative, a 20-mile transmission upgrade. While this is a distribution-connected example, it demonstrates the value of quickly deploying a solution that meets a near-term need and leaves options open to build or upgrade a transmission line in the future. Where there is uncertainly in load growth, transmission planners should be allowed to place a quantifiable benefit on the ability to meet a small need now and defer a larger investment until growth becomes clearer. For example, consider a simple scenario where planners are evaluating a $100M solution to meet load growth that may, or may not, materialize three years in the future. If there is a 50% probability of load growth materializing, there is significant risk that planners will have committed $100M and received no benefit. However, if planners have the option to build a $10M solution while they wait for load projections to become clearer, that is the equivalent of a $40M benefit that should be included in cost/benefit analysis.[125]

Risk management/repurposing value. Traditional transmission solutions are usually physically permanent. If system dynamics change and operational challenges move or

[124] *See also* ENERGY STORAGE ASSOCIATION, POLICY POSITION ON STORAGE AS TRANSMISSION (2019) https://energystorage.org/wp/wp-content/uploads/2019/12/2019-Policy-Position-Storage-as-Transmission.pdf.

[125] In this example, planners are considering a $100 transmission upgrade which would be necessary if a high load growth materializes, a scenario that planners assign a 50% probability. If the transmission upgrade is made, planners commit $100M today. If planners have the option to spend $10M on battery storage that can address near-term reliability requirement, there is a chance planners may not need to commit $100M. Taking into account probabilities, in the battery storage scenario, the expected CapEx is $50M (50% probability of $0 future costs + 50% probability of $100M future cost). Accounting for the $10M expense, the benefit of not committing funds now is $40M for ratepayers. For additional detail on analysis approach, see: Sloane, T., Transmission & Distribution: Using Real Option Pricing Models to Value Energy Storage Optionality in T&D Investment Deferral.

become naturally alleviated, there are limited opportunities to repurpose traditional transmission solutions. Storage projects can help manage investment risk since they can be repurposed for other uses, and even potentially relocated, if they are no longer needed for their original purpose.

Time to deployment. Storage can often be built and brought online faster than traditional wires solutions. If the solution is proving a cost saving for ratepayers (e.g., reducing congestion cost), a net present value calculation comparing solutions would highlight the benefit of reducing costs in the near-term versus out years.

Project risk. The likelihood of storage project completion may also be higher than traditional wires solutions, owing to fewer permitting and other challenges, which can support greater certainty in planning. Environmental impact, physical footprint and environmental justice concerns are considerably smaller for storage as transmission compared to a traditional wires solution.

Finally, when comparing the cost/benefit of a assets with two different lifetimes (e.g., 20 year life of battery storage vs 50 year life of a transmission line) ACP/ESA ask the Commission to ensure the two technologies are compared on an equitable basis. A net present value approach, which includes lifetime O&M metrics, appropriately discounts future benefits and costs of both technologies. With regards to areas of collaboration, ACP/ESA suggest any transmission planner that is new to modeling energy storage or including it in simulations be required to work with experienced consultants for the first few years. Finally, ACP/ESA suggest teaming with U.S. National Labs to understand and correctly model projected cost declines for energy storage. The NREL report is recommended as a minimum baseline for planners to use. [126]

[126] WESLEY COLE ET AL., NATIONAL RENEWABLE ENERGY LABORATORY, COST PROJECTIONS FOR UTILITY-SCALE BATTERY STORAGE: 2021 UPDATE (June 2021) https://www.nrel.gov/docs/fy21osti/79236.pdf

4) New energy storage models are required, as transmission planners should no longer use pumped hydro storage models for all energy storage resources.

In the ANOPR, the Commission sought comment on the use of probabilistic transmission planning[127] and updates required to models to better reflect renewable generation resources.[128] ACP/ESA support the Commission's efforts to ensure modeling tools are updated to include both synchronous-based and inverter-based generation and asks the Commission to extend any requirement to upgrade tools to include energy storage providing transmission services as well.

PROMOD and PLEXOS are the primary tools used in transmission planning. PROMOD simulates the hourly commitment and dispatch of generation to meet load while recognizing and maintaining transmission system security limits. PROMOD provides hourly data while PLEXOS is sub-hourly. PROMOD simulations are used to quickly evaluate the economic benefit/cost ratio of potential solutions, the increase or decrease in hourly or monthly congestion cost as well as the impact on reliability metrics. Unfortunately, both models typically use modified pumped hydro storage to simulate the performance of energy storage, which has the net effect of undervaluing it. Pumped hydro is a poor proxy, particularly in scenarios where battery-specific storage is used to relieve congestion on the transmission system, because it is scheduled – rather than automatically dispatched when transmission constraints are reached.

For example, planners may be evaluating solutions to relieve congestion on a transmission line that can occur during hours of high wind generation in the evening, early morning hours in the winter, or late afternoon peak load hours in the summer months. Transmission planners now typically use a pumped hydro asset as a proxy in PROMOD and predetermine a schedule for the battery energy storage system to be

[127] ANOPR at P 49.
[128] *Id.* at P 50.

charged as discharged (e.g., discharge at 8 PM, charge at 10 PM, discharge at 6 AM, charge at 9 AM, etc.). While planners may have guessed correctly, any pre-scheduled solution will almost certainly be suboptimal. Instead, transmission models should be able to automatically tie the dispatch of battery storage to constraints (e.g. battery is discharged when reliability constraints on a transmission line are exceeded and charged when the load on the line drops below reliability thresholds). Tying the dispatch of asset to constraints is already done in PROMOD for other generation assets. For example, PROMOD limits the dispatch of old generation units located in the greater New York metropolitan region to stay below SOx and NOx emission requirements. [129]

ACP/ESA ask the Commission to require transmission planners to update simulation models to better reflect the real value provided by all energy storage solutions.

5) Transmission utilization data should be made available to enable optimal planning of battery storage solutions

The Commission sought comment on transparency measures, specifically whether it should consider new transparency measures, beyond what is currently utilized within ISO/RTO regions.[130] ACP/ESA encourages the Commission to require periodic publication on grid utilization, to show how one of the most expensive assets in the U.S. is currently being used. A study commissioned by Western Electricity Coordinating Council (WECC) provides a strong example that can be standardized across regions.[131] The study included hourly power flow, operating limits, hourly firm and non-firm schedules, and Available Transfer Capability. Additionally, the study determined congestion metrics for each of the 25 WECC rated transmission paths. Similar to a load

[129] In meetings with PJM to review analysis of project submitted in RTEP in 2017, a combination of new transmission mission and battery storage, PJM acknowledged deficiencies in modeling. This remains an open issue.
[130] ANOPR at P 172.
[131] *Western Interconnection Transmission Path Utilization Study: Path Flows, Schedules and OASIS ATC Offerings WECC Transmission System 2008 & 2009, Including 10 Year History*. WECC Transmission Expansion Planning Policy Committee. June, 2010 available at https://www.wecc.org/Reliability/2009_WI_TransPath_UtilizationStudy.pdf.

duration curve, which shows how long (percentage of time or hours per year) load exceeds thresholds, a transmission usage duration curve shows how frequently power flow on a transmission line exceed thresholds. A load duration curve has been a very useful tool for planning organizations to understand the value of flattening load curves, thereby eliminating expensive "peaker" generation. Similarly, a transmission usage duration curve will help planners determine the value of reducing peak power flows on transmission lines that only occur a few hours per year.

A 2016 Commission staff report considered six key metrics to evaluate investment patterns and whether action is required to facilitate more cost-effective investment.[132] While those metrics considered important criteria such as the amount of competitive activity via the percentage of non-incumbent transmission projects, Commission staff did not consider utilization metrics. ACP/ESA ask the Commission to require a similar report to be published regularly for all of the major (>138 kV) transmission lines and aligned with relevant regional planning timetables.

The WECC report provided valuable information in a public document and WECC did not find the need to limit access to ensure data security. Certainly, additional information could be made available by controlled access, but the data already included in the WECC report provides significant insight to companies looking to develop battery storage solutions targeting peak utilization hours, constrained transmission pathways, and other opportunities for GETs.

Additionally, ACP/ESA ask the Commission to require utilization data to be made available in any scenario where energy storage will be considered as a solution consistent with the recommendations above. Annual transmission plans typically identify thermal and voltage constraints for one peak hour per year. Additional data on the duration of the

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[132] *2016 Transmission Metrics: Initial Results - Staff Report*, Docket No. AD15-12-000 (March 17, 2016). FERC staff proposed six key metrics: percentage of nonincumbent transmission project bids or proposals; load-weighted curtailment frequency; RTO/ISO price differential; load-weighted transmission investment (incremental); load-weighted circuit-miles (incremental); circuit miles per million dollars of investment. *Id.* at 4-6.

peak would enable transmission providers to better optimize battery solutions to target transmission peaks, and would generally ensure transparency regarding potential benefits of transmission projects.

6) Full optimization of battery storage requires creative ownership models

As the Commission knows, storage can provide market services (e.g., Energy, Capacity and Ancillary Services) and a look at any ISO/RTO interconnection queue in the U.S. will prove how quickly storage is becoming cost competitive. As has been discussed here, storage can also provide transmission services and qualify as a cost-of-service asset (for more information on transmission Use Cases see Section II.B.2.e(7)).

The Commission sought comment on new approaches that may facilitate the co-optimization of generation siting and transmission development.[133] As an asset that can switch from one dispatch interval to the next from providing generation services to operating as a transmission asset, ACP/ESA ask the Commission to ensure the full consideration of storage in any strategy to co-optimize generation siting and transmission development.

At its simplest, storage is an asset that can be incorporated in transmission plant, similar to any other STATCOM, substation, or transmission tower. At its most complex, a storage asset can be owned by one party to provide transmission services and leased to another to provide market services, or vice versa. As in any other asset connected to the transmission system, increasing an asset's utilization improves the benefit to cost ratio. An asset that sits idle provides less value to ratepayers than one that is used 24/7/365. While storage as transmission does not require the Commission to define the parameters of more creative ownership models, any effort to optimize generation siting and transmission planning may require the Commission to formalize the energy storage multi-service Policy Paper[134] in an Order.

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[133] ANOPR at P49

[134] *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, Policy Statement, 158 FERC ¶ 61,051 (2017).

Finally, ACP/ESA highlight a creative model approved in Australia, where active power is sold into markets by the IPP and reactive power is contracted by the transmission owner.[135] The key in each innovative, complex, or straight forward commercial model is the full control of the asset by the transmission operator while the asset is providing transmission services.

7) Understanding energy storage use cases, and how battery storage can act as a transmission asset.

Since some confusion remains over the role of energy storage in providing transmission services, ACP/ESA outline four primary Use Cases below, along with sample projects. The Use Cases are not intended to be exhaustive, only to highlight the various applications that have already demonstrated their cost-effectiveness.

Use Case 1: N-1 Contingency Relief. Using energy storage in lieu of constantly maintaining headroom on a transmission line accommodate higher power flows in the case of a failure. Transmission planners are required to ensure that all loads can be restored if any single component on the transmission system fails (N-1 Contingency). 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 will 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 at its full transfer capacity rating (e.g. 350 MW) and use energy storage to accommodate sudden failure. The storage solution would be required to perform for a defined period of time

[135] *Ballarat Energy Storage System*, https://arena.gov.au/projects/ballarat-energy-storage-system/.ARENA, https://arena.gov.au/projects/ballarat-energy-storage-system/ (last updated Feb. 10, 2021).

(e.g. 1 hour) to allow grid operators time to reconfigure power flows. This business case is the basis for the 250 MW Australian SIPS[136] project which came online in 2020.

Use Case 2: Congestion Management. Using energy storage to reduce congestion and pockets of high locational marginal prices (LMP), thereby reducing costs for ratepayers. Congestion on transmission lines increases LMP values at various points on the grid. While this can benefit generators, it is a cost shouldered by ratepayers. Higher LMP values are designed as price signals to encourage new generation to be sited in congestion zones or transmission upgrades to be planned. While transmission planners annually target regions with high LMP/congestion costs and work to develop solutions, historically planners have only had large (e.g. a new natural gas plant, or a new transmission line) solutions to deploy. Planners have lacked smaller, modular solutions that can be deployed across the grid to levelize LMP values and reduce congestion. This can be particularly complicated in areas where it is difficult to site new generation or transmission lines, either due to the cost of land, air quality requirements, or zoning restrictions. A prime example is the cost differential of electricity between upstate and downstate New York. With a small, low-profile footprint, and the ability to build small modular solutions, storage can be deployed to benefit ratepayers. In Colombia, the Minister of Energy has issued a tender for a 50 MW/50 MWh battery system to relieve congestion where new transmission has been difficult to permit, and a reliability requirement is requiring out-of-merit generation to be dispatched. In the U.S., CAISO has selected a number of battery projects that are more cost effective than running new transmission, and where fossil-based generation is difficult to site.[137] While these projects are authorized by the CPUC,

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[136] Allan O'Neill, *Victoria's Big battery: What exactly is it for?*, AUSTRALIAN ENERGY COUNCIL, (Nov. 26, 2020) available at https://www.energycouncil.com.au/analysis/victoria-s-big-battery-what-exactly-is-it-for/.

[137] *See Arevon opens 100MW Saticoy battery storage facility in California, US*, NS ENERGY, (June 30, 2021), https://www.nsenergybusiness.com/news/arevon-saticoy-battery-facility-oxnard/ (describing a battery system built in Oxnard, CA where local restrictions forced CAISO to reconsider plans for a natural gas plant located behind a transmission constraint.

instead of being included in the CAISO transmission plan for cost allocation, the need for the projects is driven by transmission constraints.

Use Case #3: Grid Forming Applications. Using energy storage to provide grid services such as voltage support, reactive power, synchronous inertia and virtual inertia, blackstart, or combinations thereof. While transmission planners have several other specialized tools at their disposal to provide grid services, energy storage can be competitive when used to provide multiple services in combination. With high levels of inverter-based renewable generation, European transmission planners are increasingly seeking solutions to provide virtual inertia, such as a fast-responding battery. Additionally, there are alternative forms of energy storage being deployed that can provide the synchronous inertia that the grid is currently accustomed to. An example is the 450 MW Grid Booster project approved by EU regulators in 2021 for construction in 2024.[138]

Use Case #4: Peak load Relief. Energy storage is sited locally to reduce peak load on a transmission line, thereby keeping the transmission system from exceeding reliability thresholds. Many loads follow predictable patterns, for example, a peak during summer afternoon hours when air-conditioning load is at its highest. In scenarios where such load is predictable, and thermal or voltage constraints are exceeded, it may be cost effective to deploy energy storage locally, on the load side of the transmission constraint. While this scenario starts to blur the line between generation and transmission, the key distinctions are how the energy storage asset is operated, and whether the need for the project was driven by a transmission constraint. A sample project is the Oakland Clean Energy Initiative where battery storage is deployed locally within Oakland, dispatched by PG&E to minimize local load on transmission system serving Oakland, and developed in

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[138] Andreas Franke, *Germany approves power grid law to speed up expansion, boost renewables rollout*, S&P GLOBAL (Feb. 1, 2021) https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/germany-approves-power-grid-law-to-speed-up-expansion-boost-renewables-rollout-62408538.

response to the need for a costly transmission upgrade to continue to serve Oakland load.[139]

ii. Second Step – "Layered" Cost Allocation

To address the unjust, unreasonable, and unduly discriminatory treatment discussed above in Section II.A.2, ACP/ESA recommend that the Commission adopt a "layered" approach for allocating costs associated with transmission projects. Under this approach, transmission costs would first be assigned to load in line with identifiable anticipated benefits, but could incorporate cost contributions from states and interconnection customers at later steps. ACP/ESA recommends that the Commission adopt a *pro forma* cost allocation policy that incorporates the following steps.

First, the costs of transmission projects that are identified pursuant to the enhanced transmission planning process discussed previously in Section II.B.2.i should be allocated first and foremost to customers (provided that such projects' benefits exceed their costs under the applicable benefits-to-cost framework, using a holistic assessment of all likely benefits, and seeking to maximize net benefits). Such broad allocation will ensure that the primary beneficiaries of transmission, namely customers, are fairly and equitably allocated transmission costs, which is in line with sound economic principles and Commission precedent.[140] To correctly identify the beneficiaries of transmission upgrades, ACP/ESA recommend that the Commission utilize a benefit-to-cost ratio that considers the broad categories of benefits that transmission confers on customers. For example, Table 1 from the 2013 Brattle Report[141] identified the broad categories of transmission-related benefits, which provides an example of the types of benefits that

[139] Press Release, PG&E, CAISO Approves PG&E Oakland Clean Energy Initiative (Mar. 23 2018) https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20180323_caiso_approves_pge_oakland_clean_energy_initiative.

[140] *Ill. Commerce Comm'n v. FERC,* 576 F.3d 470, 477 (7th Cir. 2009) ("[A]ll approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them. Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.") (internal citations and quotations omitted).

[141] *Supra* note 63.

should be considered by Transmission Owners when identifying beneficiaries of transmission projects and calculating benefits-to-costs ratios for proposed transmission projects; as noted *supra*, this list of benefits was applied in SPP, and identified numerous quantifiable benefits of transmission projects that had not been initially planned for.

Next, states and/or generation interconnection customers should be given the opportunity to provide some of the funding for transmission upgrades. This would allow states and/or generation interconnection customers to build alternative or expanded transmission projects compared to projects identified in the base case. Specifically, ACP/ESA proposes two circumstances in which states or interconnection customers might opt to do so, with different implications. The election to use either right should be closely synchronized with a region's overall transmission planning process, so that the state and generator layers do not delay their use.

- **The "Transmission Alternative Right":** First, states and/or generation interconnection customers should have the opportunity to fund the cost difference between *original* and *alternative* transmission projects, or to ensure that a project can clear the applicable benefit-to-cost ratio. For example, if transmission projects identified as part of the enhanced transmission planning process with the greatest benefit-to-cost ratio diverge from a state or generator's future needs, the state or generator could contribute funding to ensure that an alternative project moves forward in the regional plan. Alternatively, if a project fails to meet the regional benefit-to-cost ratio, a state or generator could "buy down" the costs, enhancing the net benefits.
- **The "Transmission Expansion Right":** Second, states and/or generation interconnection customers would be given the opportunity to fund *expanded* transmission capacity - beyond the capacity of the original transmission project selected under the enhanced transmission planning process. If a regional plan identified a particular upgrade or

new line, states or generators could opt to "future-proof" that transmission by paying for higher-voltage, higher-capacity transmission.

The Transmission Alternative Right would allow a state and/or generation interconnection customer to partially fund a transmission option originally identified via the regional transmission planning process. The state- or generator-selected option could either be the same project that was actually *selected* in the regional transmission planning process, or could be an alternate project with a lower benefit-to-cost ratio for customers than the regionally selected project that would meet the same regional needs. If states or interconnection customers volunteer to pay a higher percentage of the project's costs, such that the resulting benefit-to-cost ratio of the *alternative* project ultimately selected would equal or exceed the benefit-to-cost ratio of the *original* project that would have otherwise been selected via the transmission planning process, it could move forward.

For example, assume that the transmission planning process identified a 345kV line as the best way to address long term planning concerns in a particular area, but identified a primary route that had a greater benefit-to-cost ratio such that it was selected over a similar 345kV line using an alternative route. In the event that a generator desired to have the line be built via the alternative route, it could elect to fund a portion of the line that would result in the costs of the project to customers decreasing, which (all else equal) could increase the benefit-to-cost ratio to a point where the partially generator-funded transmission alternative would be selected and built over the original project's planned route. Importantly, even if a generator or state opted to fund a line using the Transmission Alternative Right, it would be constructed using the same regional process, and its full capacity would be subject to open access requirements.[142]

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[142] *See, e.g.*, Order No. 807 at P 7 ("In Order No. 888, the Commission, relying upon its authority under sections 205 and 206 of the FPA, established non-discriminatory open access to electric transmission service as the foundation necessary to develop competitive bulk power markets in the United States. Order

Similarly, if a planned transmission project met an identified transmission need, but did not quite meet the required B/C ratio, states or interconnection customers could choose to pay a portion of the costs of the upgrade such that the remaining costs to load do meet the B/C ratio. This would ensure that customers do not pay for more benefits than they actually receive.

In contrast, the Transmission Expansion Right would allow a state and/or generation interconnection customer to fund the incremental cost of *expanding* the capacity of a transmission project identified via the transmission planning process in exchange for priority access to the *incremental* capacity for a defined period of time. For example, assume that the transmission planning process identifies a 345kV line as the best way to address long term planning concerns in a particular area, but a generator wishes to potentially build a large offshore wind farm that will require (or would benefit from) a 500kV line. In this case, the generator could pay the additional amount necessary to fund the 500kV line relative to the cost of a 345kV line. In return, the generator could ensure that its offshore wind farm, once built, would have priority access to the incremental capacity enabled by the voluntary upgrade to a 500kV line for a limited period of time; a state Transmission Expansion Right could be used to ensure that resources identified through a state's public policies would have transmission access upon construction. This priority access could be reflected in firm point-to-point transmission rights, higher curtailment priority, or deliverability rights, consistent with the region's approach to determining transmission capacity and rights.

Allowing a Transmission Expansion Right aligns with a similar approach that the Commission utilized in Order No. 807, in which the Commission affirmed that "it is

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No. 888, codified in section 35.28 of the Commission's regulations, requires that any public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must file an OATT and comply with other related requirements.") (citing *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996)).

generally in the public interest . . . to allow an [owner of Interconnection Customer Interconnection Facilities ("ICIF")] . . . to retain priority rights to the use of excess capacity on ICIF that it plans to use to interconnect its own or its affiliates' future generation projects."[143] Allowing states and generation interconnection customers to receive a Transmission Expansion Right serves to balance the interests and needs of individual interconnection customers and the Commission's open access requirements. In essence, this approach would treat the *incremental* capacity enabled by the Transmission Expansion Right as comparable to ICIF, while treating the *base* capacity (of the 345kV line, in the example above) as regionally planned and immediately subject to open access. And as in Order No. 807, a state or generator would have a limited term for priority use of the facility; the Commission should consider whether the five-year period identified in Order No. 807 or a longer period would be appropriate under this concept.

iii. Third Step – Treatment of Residual Interconnection Facilities and Network Upgrades

Given the broad scope of the enhanced transmission planning process, ACP/ESA anticipate that the majority of upgrades needed to facilitate the expected addition of clean generation resources will be identified, and will have their costs allocated, pursuant to the proactive transmission planning and cost allocation process described previously. That said, there will still be a need for network upgrades that are developed in the interconnection process based on generation interconnection customers' need and willingness to pay, rather than being proactively planned via the transmission planning process. Moreover, these network upgrades, even though developed via the interconnection process, will in many instances benefit other interconnection customers and/or have broader system benefits. For the reasons discussed previously in Section B.1.i, the generation interconnection customer should receive credits for funding all

[143] *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).

network upgrades downstream from the interconnection substation, while interconnection-related network upgrade costs up to and within the interconnection substation should remain the sole responsibility of the generation interconnection customer.

3. Additional Issues

i. Timing

As noted above, ACP/ESA believe that certain high-priority interconnection issues can and should be addressed on an accelerated timetable. ACP/ESA also note that certain aspects of transmission planning reform could be accomplished more rapidly than a full reconsideration of planning and cost allocation rules. Specifically, the Commission should consider whether a requirement that transmission plans account for future generation (as indicated by interconnection queues and state public policies) can be integrated with current planning processes relatively quickly; additionally, the Commission should also consider whether smaller, separate projects and upgrades can be evaluated jointly to allow for "future-proofing" when upgrades and replacements are needed. A local reliability upgrade might incorporate transmission line or substation elements that could also provide economic benefits and enable integration of future generation

ii. Transition Mechanism(s)

The Commission should also ensure that the transition from current interconnection and transmission planning rules is as seamless as possible. ACP/ESA recommends a "hold harmless" requirement for planned projects. For network upgrades, ACP/ESA recommends that cluster and serial studies open as of the date of a final rule continue through the existing interconnection process, as revising the rules midstream would be highly disruptive.

iii. Independent Transmission Monitor Concept

In the ANOPR, the Commission sought comment on the concept of an independent transmission monitor, which might be responsible for review of transmission planning processes and transmission provider spending.[144] Although ACP/ESA do not take a position on this concept at this time, we will carefully review comments to the Commission in this proceeding. ACP/ESA remain interested in measures that can ensure transparency, prompt action, and cost-effectiveness in transmission planning, while avoiding potentially duplicative or dilatory procedures.

III. Conclusion

In the ANOPR, the Commission has appropriately identified many of the most pressing issues facing transmission planning, cost allocation, and interconnection. As detailed in these comments, the Commission should act rapidly to remedy several of the most pressing issues regarding generator interconnection regulations, including eliminating participant funding in RTOs/ISOs, updating the Order No. 2003 crediting approach to improve certainty, providing clear criteria for which facilities might be designated as network upgrades, and synchronizing and harmonizing affected system studies. Simultaneously, the Commission should initiate a rulemaking to move transmission planning towards a holistic and co-optimized approach that considers as many benefits as possible – including economic, reliability, public policy, and generator interconnection needs - and maximizes them simultaneously. This enhanced benefits assessment would then directly inform a just and reasonable cost allocation methodology.

[144] ANOPR at P 164, *et seq*.

ACP/ESA appreciate the opportunity to provide input on this vital proceeding and look forward to working with the Commission and other stakeholders to move these concepts into reality.

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October 12, 2021