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
NORTHWEST & INTERMOUNTAIN POWER PRODUCERS COALITION**

The Northwest & Intermountain Power Producers Coalition ("NIPPC") is a membership-based advocacy group representing competitive electricity market participants in the Pacific Northwest and Intermountain region. NIPPC has a diverse membership including independent power producers and developers, electricity service suppliers, transmission companies, marketers, storage providers, and others. NIPPC is committed to fair and open-access transmission service, cost effective power sales, consumer choice in energy supply, and fair, competitive power markets in the Northwest and adjacent markets.

NIPPC supports a competitive electric power supply marketplace in the Pacific Northwest and Intermountain West based on the following principles: adequacy and reliability of electric supply is supported and not compromised; all market and transmission access, pricing, and regulatory structures allow all market participants to operate under fair and equivalent terms and conditions in the regional marketplace; efficient and transparent pricing signals that facilitate investment in electric power supply and transmission infrastructure; and cost effective environmental, safety, and security best practices are put in place and maintained.

NIPPC members have collectively invested billions of dollars in existing generation resources in the United States and have substantial operating assets in the West along with renewable and thermal projects in advanced stages of development, all of which are tied to and rely on the *pro forma* Open Access Transmission Tariff ("OATT") for access to power markets. Therefore, NIPPC appreciates and supports the Federal Energy Regulatory Commission's ("FERC" or "Commission") initiation of this Advanced Notice of Proposed Rulemaking ("ANOPR").

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I. BACKGROUND

The Northwest and Intermountain Power Producers Coalition ("NIPPC") represents a broad spectrum of independent power producers and developers, electricity service suppliers, transmission companies, marketers, storage providers, and others who are actively involved in building electric generation and advocating on energy policy issues.

NIPPC's comments on this ANOPR are narrowly focused on its members' experiences in the Pacific Northwest and the Rocky Mountain regions of the Western Interconnection ("the non-RTO West"). The Commission must consider the unique characteristics of this region. First and most obviously, it does not have a Regional Transmission Organization or an Independent System Operator ("RTO" and "ISO"). While many of the transmission providers in the region have successfully joined the Energy Imbalance Market ("EIM") operated by the California Independent System Operator ("CAISO") and continue to explore ways to implement a day ahead market and other elements of RTOs, past efforts to form an RTO outside of California have failed. While NIPPC remains convinced that an RTO would be the most beneficial market structure for the West, NIPPC supports the Commission's exploration of OATT reforms to regional planning and interconnections laid out in the ANOPR to ensure that wholesale power rates remain just and reasonable. Notably, the lack of an RTO has implications for cost allocation of regional transmission projects. In the absence of an RTO or some other mechanism, costs cannot simply be allocated across the entire region but must be recovered through OATT rates.

Second, western states like California, Oregon, and Washington are taking leading roles in meeting ambitious climate goals by adopting aggressive clean energy policies that will require significant new renewable and other zero carbon generation. The generation resources needed to meet those climate policies will require new transmission lines. For a variety of reasons, the most efficient and cost-effective renewable generation will need to be sited far from load which will likely require new transmission infrastructure across the systems of multiple transmission owners. Since many segments of the transmission grid serving the Pacific Northwest are already fully subscribed and increasingly congested, new transmission infrastructure will need to be planned, permitted, and constructed to ensure that Western states are able to meet their goals. If the Commission cannot find equitable solutions to allocation of costs to regional expansion of the transmission system and addressing interconnection issues, states may fail to achieve their clean energy goals.

Third, the Commission must consider the unique characteristics of the transmission providers in the region and the limits of its jurisdiction. While the largest transmission owner and operator in the Northwest, the Bonneville Power Administration ("BPA"), has an OATT, it is generally not subject to the Commission's jurisdiction. Further, in other parts of the West, consumer owned utilities are not subject to the Commission's jurisdiction, even though they own and operate significant portions of the high-voltage transmission grid. Other transmission systems in the region are operated by investor-owned utilities ("IOUs") that are subject to Commission jurisdiction. These IOUs continue to pursue development, ownership, and operation of their own generation in competition with independent power producers. Given the mix of transmission owners and the different jurisdictional purviews they fall under, the Commission's concerns about non-discriminatory open access to interconnection and transmission service are just as important now as they were when the Commission adopted Order No. 888.

NIPPC and its members agree that additional reforms to the Commission's regional transmission planning, cost allocation, and generator interconnection processes are needed to ensure that Commission jurisdictional rates for transmission service are just and reasonable and that wholesale power rates remain competitive.[1] Non-discriminatory access to interconnection and transmission is and has been the core principle underlying development of a competitive market for generation. As such, any changes resulting from this ANOPR should preserve and build upon the Commission's existing open access and non-discrimination principles.

The regional transmission planning requirements of Order No. 1000 in particular have proven inadequate in meeting the needs of the industry in the non-RTO West. Rapidly changing public policies require changes in transmission planning to ensure a safe, reliable power supply and access to renewable energy resources. Expansion of the transmission grid is critical to meeting federal, state, local, and corporate clean energy targets. The Commission correctly recognizes that the significant challenges to grid expansion to meet public policy requirements driven by state carbon policy goals require changes to its requirements for regional planning, cost allocation, and interconnection.[2] By continuing to develop the reforms described in the ANOPR, the Commission can eliminate many of the obstacles and inefficiencies of the current OATT paradigm.

II. SUMMARY OF RECOMMENDATIONS

A. The regional transmission planning process should provide state policy makers with information to make informed generation resource decisions;

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1 Advance Notice of Proposed Rulemaking, Docket No. RM21-17-000 at P 3 (July 15, 2021).

2 ANOPR at P 3.

B. The regional transmission planning process should consider alternative scenarios and sensitivities;

C. The regional transmission planning process should consider how to aggregate generation in renewable resource zones to optimize transmission expansions;

D. The Commission should require all transmission customers to submit twenty-year forecasts of their loads, resources, and transmission service requirements to transmission providers and these forecasts should form the primary inputs for regional transmission planning;

E. Transmission providers should perform cluster studies for interconnection and transmission service requests on coordinated timelines;

F. Transmission customers should be allowed to link their interconnection service and transmission service requests across multiple transmission providers;

G. The Commission should require independent oversight of the transmission planning process; and

H. The Commission should work with state commissions to develop a mechanism to increase state engagement in transmission planning.

III. COMMENTS

A. LIMITATIONS OF THE ORDER NO. 1000 PROCESSES

The Commission's Order No. 1000 required transmission providers to participate in a regional transmission planning process that produced a single regional transmission plan. Unfortunately, outside of RTOs, the Order 1000 planning process does not produce sufficient information about alternatives to the "primary plan" to allow policy makers to weigh alternatives. Rather, in the non-RTO regions, the Commission's Order No. 1000 regional planning requirements have resulted in a process where the Order No. 1000-compliant regional planning groups simply look at the member utilities' individual transmission plans and determine whether a different regional transmission solution would be more cost-effective than the aggregated individual utility plans.[3] This regional transmission planning process in the non-RTO markets needs to be improved to achieve the following objectives.

1. The Primary Goal of the Regional Transmission Planning Process Should Be to Develop Information to Inform Decisions on Generation Additions

Order No. 1000 does not require the transmission planning process to consider, evaluate, or report on whether alternative generation scenarios[4] would result in more efficient or cost-effective transmission build outs. The result is that state commissions responsible for approving new generation do not have sufficient information about the comparative costs of local versus distant generation. The question that is never asked in the regional planning process – and the key question that needs answering – is whether it is more efficient and cost-effective to invest in transmission upgrades to tap distant generation resources or to invest in potentially more expensive and less efficient generation that does not require new transmission investment.

One of the outputs of transmission planning under the Commission's jurisdiction should be an analysis that provides state commissions with sufficient information to allow them to make informed decisions. The benefits of locating renewable energy generation resources widely apart to capture differences in weather patterns are well known, but these geographic diversity benefits for reliability and production costs are not considered as part of the regional transmission planning process; nor are the benefits of allowing a group of load-serving entities to share a

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3 ANOPR at P 37.

4 In using the phrase "alternative generation scenarios," NIPPC does not intend to suggest that the regional planning process could select a different type of generating unit for study. Instead, NIPPC suggest that the regional planning process would consider relocating that generating unit to a different geographic region for the purpose of concentrating new generation resource development in regions that could be served by efficient expansions of the transmission system.

portfolio of widespread resources. Instead, each load-serving entity's generation choices are simply an input to the regional planning process and no information regarding alternatives is ever developed.[5] The planning process never develops sufficient information to inform state commissions about whether they should encourage utilities under their jurisdiction to add generation close to load – even if that local generation has a higher cost of energy – or to invest in transmission expansion to allow their customers to access more distant generation resources at a potentially lower combined cost. NIPPC recommends the Commission should require the transmission planning process to provide state regulators and policy makers with sufficient information so that they can make informed decisions regarding future generation resource additions, including how to optimize generation resource costs and transmission costs.

2. The Commission Should Require the Regional Transmission Planning Process to Consider Alternative Scenarios

As the Commission notes, local utilities' transmission plans are incorporated into regional transmission planning processes as inputs with little opportunity for stakeholder comment. While Order No. 1000 did require the regional transmission planning process to consider economic planning studies to explore alternative transmission solutions that might meet regional transmission needs more effectively than the individual local transmission plans, the requirement has had little impact. Regional transmission planning organizations continue to rely on the generation resource assumptions embedded in the local transmission plans and simply consider whether an alternative transmission solution can better mesh together the generation assumptions in the local utility plans. Regional transmission planners have consistently rejected

5 ANOPR at P 37.

stakeholder proposals to explore alternative generation or transmission scenarios that would point towards an optimized transmission and generation development for the region as a whole.

For example, in 2016 stakeholders submitted two study requests to ColumbiaGrid.[6] One request would have studied a 600 MW upgrade to the Pacific DC Intertie. The other would have studied the impacts of replacing coal fired generation in Montana (Colstrip Units 1, 2, and 3) with a combination of renewable resources and/or gas-fired generation. These requests were intended to address public policy requirements and potential transmission impacts associated with compliance obligations under the U.S. Environmental Protection Agency's Clean Power Plan and California's 50% Renewable Portfolio Standards. ColumbiaGrid determined that neither request reflected an Order No. 1000 Potential Need because neither request addressed a reliability concern, an economic concern, or a public policy requirement of any of ColumbiaGrid's members.[7] By refusing to perform the requested studies, the transmission planning process failed to develop information that could have informed subsequent state decisions and policies regarding future generation resource additions.

This primary focus on optimizing the member utilities' individual transmission plans also increases the hurdles for merchant developers to be considered even when they bring creative transmission solutions to meet a region's need for future generation. Recently, NorthernGrid received three proposals submitted by independent transmission developers and selected none of

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6 Until recently, responsibility for regional planning in the Pacific Northwest was shared between ColumbiaGrid and Northern Tier Transmission Group. The result was that regional planning was split between two different entities. Fortunately, those two groups recently merged to form NorthernGrid.

7 *2017 Biennial Transmission Expansion Plan*, ColumbiaGrid at 14-15 (October 11, 2021), https://www.northerngrid.net/private-media/documents/2017_Columbia_Grid_Plan.pdf.

them into its Regional Transmission Plan.[8] The consistent response is that Order No. 1000 includes no requirement that the regional planning process include evaluation of alternative generation or transmission. In contrast, WestConnect, as part of the development of its study plan, does allow stakeholders to submit scenarios for study during an open window. Of the four scenario requests submitted for the 2020-21 Study Plan, WestConnect did accept two.[9] The consistent refusal by NorthernGrid to explore alternative generation scenarios in regional transmission planning in the Pacific Northwest makes it more difficult to identify least-cost combinations of generation development and transmission expansion.

3. The Regional Transmission Planning Process Should Include Consideration of Energy Policy Trends

Similarly, the regional transmission planning process in the Northwest considers only those public policy considerations that have been formally enacted. While the policy trend in many states is towards greater future reliance on non-carbon emitting generation resources, NorthernGrid (and its predecessors) refuse to consider these policy trends or study scenarios that assume more aggressive changes in the future mix of generation in the development of the regional plan. The result is a significant lag in consideration of public policy requirements – especially because NorthernGrid has decided to wait for public policy requirements to be reflected in its member utilities' local transmission plans. As a result, public policy requirements may not be reflected in the regional transmission plan for two to four years after a public policy requirement is adopted. The resulting regulatory lag would be mitigated if regional planning

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8 *Draft Regional Transmission Plan for the 2020- 2021 NorthernGrid Planning Cycle*, NorthernGrid at 2-3 (Oct. 11, 2021), https://www.northerngrid.net/private-media/documents/2020-21_Draft_Regional_Transmission_Plan.pdf.

9 *WestConnect Regional Transmission Planning 2020-21 Planning Cycle Final Regional Study Plan*, WestConnect at 24 (Oct. 11, 2021), https://doc.westconnect.com/Documents.aspx?NID=18668&dl=1.

organizations included sensitivity studies that explored the transmission needs in the event of more aggressive decarbonization policies. But because the regional planning process consistently fails to include these types of studies,[10] the result is a transmission planning process that significantly lags behind increasingly rapid developments in public policy choices regarding the future generation resource mix. Another result is that policy makers and state commissions are left with no accurate information regarding the transmission requirements of policies (and associated costs) that are under consideration. This lack of information creates the risk that rates under the Commission's jurisdiction will be unjust and unreasonable.

4. The Commission Should Allow Transmission Customers to Link Interconnection and Transmission Service Requests Across Transmission Providers

The Commission correctly notes the lack of interaction between the interconnection process and the regional transmission planning process.[11] The Commission also notes that transmission planning models generally only consider interconnecting generation projects that are near the end of the interconnection process.[12] The Commission, however, fails to note that there is also a disconnect between the transmission service queue and the regional planning process.

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10 NorthernGrid considers only enacted public policy requirements. Despite clear legislative pressure in Oregon for more aggressive statutes to combat climate change, NorthernGrid did not incorporate any non-enacted policies into its analysis. NorthernGrid 2020-21 Final Study Scope p. 23. Ultimately, Oregon did adopt House Bill 2021 in 2021 which calls for 100% clean electricity by 2040, but this significant impact to regional demand for renewable energy and its associated transmission will not be considered by NorthernGrid until its next planning cycle begins in March of 2022, with results to be published in late 2023.

11 ANOPR at P 23.

12 ANOPR at P 23.

In many parts of the West, new generation resources are located far from their potential loads and require not only interconnection service but also transmission service across the territories of multiple transmission providers (some of which are not under the jurisdiction of the Commission). One of the greatest challenges for developers in the non-RTO West is the need to manage not only the interconnection queue but also the transmission service queues of multiple intervening transmission providers. A generation project that needs transmission service (and transmission upgrades between its location and its ultimate load) will be unlikely to proceed deep into the interconnection process without also knowing the timing and costs of upgrades needed for its transmission service. Therefore, the Commission should explore mechanisms to link, in some manner, interconnection and transmission service requests across transmission providers. NIPPC lists several potential mechanisms below in Section C.2.

5. The Regional Transmission Planning Process Should Not Rely on the Interconnection Queue as the Primary Signal for Transmission Needs

The interconnection queue can inform transmission providers of the locations where there are good opportunities for development of new generation. Nevertheless, NIPPC suggests that a mechanism which relies solely on the interconnection queue to trigger regional transmission expansions will be ineffective in driving transmission expansion of the magnitude needed to support the demand for gigawatts of new renewable generation. By relying primarily on interconnection requests (in addition to transmission service requests) to signal the need for new transmission facilities, the regional planning process will not identify needed transmission upgrades in time for them to be in place when they are needed. Utilities in the non-RTO West typically identify a need for generation resource additions on a two-year planning cycle (their integrated resource plans); those same utilities then proceed with a procurement process that takes roughly six months. A new renewable energy generation project can be constructed in roughly 18 months. In contrast, the design, permitting, and construction of a major regional transmission infrastructure project can take ten years (or longer if federal NEPA and other studies need to be completed). In short, regional transmission projects need to be under construction well before generation projects need to be identified and enter the interconnection or transmission service queues. The result is that a regional transmission planning process that relies primarily on interconnection queues (and transmission service queues) is fundamentally flawed. These queues provide one indication of market demand to transmission planners and policy makers but there are inherent limitations in a regional transmission planning process that relies primarily on these queues. Without a regional planning process that ensures that cost-effective regional transmission projects will be planned and permitted well before they are needed, utilities will be limited to considering only those generation resources that can be interconnected and delivered to load on the existing grid even if those generation resources are more expensive and less efficient in the long term than more distant resources that could have been tapped if transmission had been developed in a timelier manner.

6. The Regional Transmission Planning Process Should Consider an Expanded Set of Reliability and Public Policy

As explained in Section A.1 above, the paradigm of basing transmission expansion primarily on the transmission service requests or interconnection queues is outdated. NIPPC agrees with the Commission that there needs to be an expanded set of reliability and public policy principles that are likely to drive future transmission demand. The factors suggested by the Commission include:

- federal, state, and local climate and clean energy laws and regulations;
- federal, state, and local climate and clean energy laws under debate – in many cases state and local policy priorities and trends are clear even if the details have not yet been formally established;

- utility and corporate energy and climate goals – this factor should include corporate energy goals not just for load-serving entities, but also corporate goals of large retail loads;
- trends in technology costs – including shifts towards electrification of buildings and transportation; and
- resource retirements – all too often regional planning processes do not consider resource retirements until those retirements are reflected in local utility transmission resource plans.[13]

NIPPC agrees that the existing transmission planning processes do not adequately consider future transmission needs. As the Commission notes, the planning processes only trigger transmission expansion plans in response to the generator interconnection process and/or the transmission service request queue.[14] As NIPPC observed above, this trigger is often misaligned; development timelines for generation additions (especially renewable generation) are much shorter than the development timelines for transmission expansion – especially transmission expansion needed to connect new renewable energy resource zones to load.

NIPPC also agrees with the Commission's observation that transmission planning looks at an overly narrow set of transmission needs often located in a single transmission owner's footprint.[15] Utilities often assume in their resource planning processes – erroneously – that transmission across neighboring systems will be available when it is needed.[16] The result is that

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13 ANOPR at P 46.

14 ANOPR at P 44.

15 ANOPR at P 27.

16 *See, for example*, *Portland General Electric Company 2019 Integrated Resource Plan*, Oregon Public Utility Commission Docket No. LC 73 at 148 (July 19, 2019). (Available at https://edocs.puc.state.or.us/efdocs/HAA/lc73haa162516.pdf). PGE's 2019 Integrated Resource Plan section 5.5.4 in which PGE stated: "In this IRP, each portfolio incorporates the costs of transmission to deliver each generating resource to PGE's service territory. For modeling purposes, PGE assigns BPA tariff rates to future generation projects in the Utility's portfolio that require BPA transmission. This assumes that off-system generation resources with the characteristics detailed in this chapter will have access to transmission at BPA rates."

utilities find themselves limited to considering the resources that *can* be delivered to their customers even if those resources are not as efficient and cost-effective as resource choices that *could* have been available if the planning process had resulted in actionable plan that led to an expansion of the transmission grid. NIPPC provides additional comments on expanding regional planning considerations below in Section D.

B. INTERCONNECTION PRICING POLICY AND ALLOCATION OF NETWORK UPGRADE COSTS IN INTERCONNECTION

The Commission suggests that it may be time to reexamine the rationale behind the Commission's pricing policy for interconnection-related Network Upgrades.[17] NIPPC agrees that the current process is not working and requires top-to-bottom reform. NIPPC also supports the Commission in its proposals to consider specific reforms to make those processes more efficient and less costly, as well as to explore and develop criteria to allow generation projects that are more "ready" to proceed so long as any criteria ultimately approved adequately maintains open and non-discriminatory access to interconnection and transmission.

1. Requiring Interconnection Customers to Fund Network Upgrades is Inefficient

Currently, in non-RTO regions, the Commission's policy requires interconnection customers to finance the entire costs of Network Upgrades associated with their interconnection requests. Interconnection customers must pay upfront for Network Upgrades assigned to them. Those funds are then repaid to the transmission customer over time in the form of transmission credits (with a lump sum payment at the end of a given period). As the Commission has recognized, this is a financing mechanism, not a rate mechanism.[18] This mechanism does not work well, largely because it places the initial financial burden for Network Upgrades on

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17 ANOPR at P 41.
18 Order No. 2003-C, 70 Fed. Reg. at 37,662.

interconnection customers that move forward first, even though the facilities will ultimately be shared by multiple transmission customers. Requiring the interconnection customer to fund the interconnection upgrades also obscures and inflates the actual cost of the associated energy and capacity of the new generation.

In many cases, significant upfront Network Upgrade costs are beyond the means of developers to finance. As a result, those projects are unlikely to ever be built despite the advantages they may otherwise create for the broader grid. This problem is especially acute in those situations where a new transmission line could serve a larger number of new generation customers. If the cost and risk associated with Network Upgrades for the projects could be distributed across all the projects, many more projects could be viable. But when the "first-mover" is responsible for all the Network Upgrade costs (even if it receives credits and reimbursements from subsequent interconnecting customers), the financing burden is often too large for any of them to proceed. In these cases where interconnection customers face enormous upfront costs for Network Upgrades, the subsequent interconnection transmission customers receive access to the Network Upgrades funded by the "first-mover."

2. The Commission Should Base Regional Transmission Planning on Twenty Year Forecasts of Load, Generation, and Transmission Service Requirements

NIPPC encourages the Commission to consider an alternative mechanism. The Commission has long recognized that beneficiaries should ultimately bear the costs associated with transmission expansion.[19] The Commission is also considering that benefits of transmission upgrades should include not just reliability and competition benefits generally recognized by the

[19] ANOPR at P 11.

Commission in the past, but also the additional benefits of allowing development of the vast quantity of renewable resources needed to meet the ambitious decarbonization goals of many states and a growing list of major corporations, other private-sector entities, and local governments.

The Commission should consider which would be more likely to yield an efficient and cost-effective transmission system: 1) a system designed through a process based on aggregating interconnection requests (which the Commission already knows is subject to disruption from customers leaving the queue); or 2) a system designed through a comprehensive regional planning process. NIPPC suggests that the interconnection queue information should be considered in regional planning but that interconnection requests must not be the primary driver of transmission expansion.

Accordingly, NIPPC urges the Commission to seek comment on the following proposal. Under the OATT, Network Integration Transmission Service customers are already required to provide transmission providers with ten-year load and resource forecasts. NIPPC asks the Commission to consider extending and strengthening the requirement for ten-year load and resource forecasts. The Commission could encourage or require all OATT transmission customers (including point-to-point customers) to provide twenty-year load and resource forecasts.[20] The Commission should also require the twenty-year load and resource forecast to identify all the transmission service arrangements that will be required to deliver the identified

[20] NIPPC notes the likely need for flexibility in whether all transmission customers or only some transmission customers are encouraged or required to provide these forecasts. There may be little value and significant administrative burden in requiring point-to-point customers with minimal transmission service rights to submit these forecasts. Similarly, by the nature of their business, competitive retail providers in the non-RTO West who serve load that can fluctuate significantly over the course of several years may be poorly positioned to produce meaningful forecasts.

resources to the ultimate load (including Long Term Firm Point to Point Service). Transmission providers would use these twenty-year load, resource, and transmission service forecasts as the primary input to local and regional transmission planning. At the appropriate time, (but well in advance of the need for the service) the transmission provider(s) would conduct an "open season" process similar to what the Commission has approved in the natural gas pipeline context.[21] Those transmission customers who provide their loads, resources, and transmission requirements to their transmission provider(s) could be given priority access to the "open season" for service on the increment of new capacity on the expanded transmission line. Transmission customers who indicate a need for transmission service in their twenty-year forecast could be given the first option to subscribe to service on the expanded lines. Transmission customers who did not commit to a long-term plan for their transmission needs could participate in a secondary mechanism for any capacity remaining after completion of the initial open.

NIPPC suggests that the use of twenty-year forecasts for transmission planning be implemented in conjunction with an additional reform that would encourage customers to submit requests into regional planning processes for transmission service to new generation resource zones – but without initially requiring the designation of any specific generation unit(s). Over time and after coordination with state commissions, the designations would be further refined for future planning cycles. These requests could then be aggregated in the regional planning studies and resulting costs of upgrades to the infrastructure allocated to the transmission customers requesting the service.

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[21] NIPPC suggests the "open season" as a concept. NIPPC encourages the Commission to seek further comment on how transmission providers would conduct an open and transparent open season process and its timing.

NIPPC's support for this concept is cautious. To be successful it must be accompanied by other reforms in the regional transmission planning and cost allocation paradigms. Many of those other reforms appear in the ANOPR and are further discussed below. NIPPC notes that in the non-RTO West, transmission planning is not independent. At both the local and regional levels, transmission planning is primarily controlled – and often staffed – by the incumbent transmission providers. There is a significant concern that this control of the regional planning process could lead to transmission owners favoring their own or affiliate generation resources. Not only would utilities have an opportunity to favor their own generation in the resource forecast, but through the regional planning process utilities could also direct transmission expansion to renewable resource zones where they have projects. Nevertheless, NIPPC urges the Commission to seek input from stakeholders on how using an expanded load, resource, and transmission service forecasts for planning transmission expansions could be implemented, while also taking comment on how to ensure that incumbent transmission providers do not take advantage of the reforms in order to favor their own generation units.

3. The Costs of Transmission Expansions Are Unlikely to Become Stranded

The Commission also broaches the concern that Network Upgrades built in advance of need would be "abandoned" and become a burden on ratepayers.[22] In the current environment of a major shift in generating resources in the West, NIPPC observes that if a particular project fails it is highly likely that another project will step in to take its place in the queue, ensuring that whatever Network Upgrade costs could legitimately be assigned to the first generator will ultimately be paid by another. This is especially the case for renewable generation, where the

[22] ANOPR at P 178.

best renewable resources tend to be concentrated in specific areas, so that transmission capacity is very likely to be used by adjacent projects. The prospect of stranded costs for Network Upgrades associated with transmission expansion for renewable generation appears unlikely.

C. THE EXISTING REGIONAL TRANSMISSION PLANNING AND COST ALLOCATION AND GENERATOR INTERCONNECTION PROCESSES MAY BE INADEQUATE TO ENSURE JUST AND REASONABLE RATES

NIPPC agrees that it is appropriate to examine whether the regional transmission planning, cost allocation, and generator interconnection policies continue to ensure that transmission rates remain just and reasonable and not unduly discriminatory or preferential.[23]

1. A Transmission Provider Should Fund Upgrades for Generation Resources Needed to Serve Its Own Loads

Regarding local transmission needs, where a generator is interconnecting to transmission and will be serving that transmission provider's own load with the total output of the generator, the Commission should not be concerned about cost shifts between generators and load. In this case, requiring the load-serving entity rather than the transmission customer to bear the cost of interconnection costs would not inappropriately shift those costs to the load-serving entity because its load benefits from the energy from the interconnecting generator. In this case, where a generator interconnection customer will serve the load of the transmission provider, it is not clear why the Commission would not simply hold the transmission provider responsible for all the costs of interconnection. Requiring the interconnection customer to fund the interconnection upgrades simply obscures the actual cost of the associated energy and capacity of the generator – which must otherwise be inflated to cover the cost of interconnection upgrades. The simple situation described here is a clear example of what the Commission should identify in seeking a

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23 ANOPR at P 30.

broader shift away from individual generators financing the upfront costs of interconnection upgrades.

2. The Commission Should Allow Transmission Customers to Link Multiple Transmission Service Requests to Their Interconnection Requests

More complicated situations occur when a developer seeks to interconnect its project with one transmission provider, while selling the output to load in another transmission provider's region. The disconnect between the interconnection and transmission service queues under the current OATT structure presents a significant challenge to generation developers. In much of the non-RTO West, the developer must manage not only the interconnection queue, but also the transmission service queue of one or more transmission providers (the host transmission system as well as any intervening transmission systems). In these situations, managing the timelines of the interconnection process as well as the timelines of multiple transmission service request processes poses a significant challenge for generation developers.

One reform the Commission should consider in this ANOPR is a mechanism that would allow developers to link their interconnection service request to their transmission service request(s) so that the interconnection queue timelines and transmission service timelines can be considered together and the development of any upgrades is coordinated across all impacted transmission providers. Specifically, the Commission should consider whether transmission customers should be allowed to "link" their requests for interconnection service and transmission service so that the timelines for development of Network Upgrades are linked across multiple transmission systems. This process could include coordination of studies across multiple transmission providers, development of a single plan of service across multiple systems, and specifically allowing these types of requests to receive consideration in regional planning processes. One way this could be accomplished would be to allow transmission customers to supplement their initial transmission service requests with information identifying their transmission service requests on other systems that should be considered together and require transmission providers to coordinate on their studies of these requests.

D. PLANNING FOR NEEDS OF FUTURE GENERATIONS AND SCENARIO PLANNING

NIPPC agrees the Commission should amend the regional planning process to require planning for the transmission needs of future generations, including electric generation projects that are not yet in the interconnection queue.[24] The current process fails to account for transmission and generation needs of anticipated future generations. The result of the failure to plan for transmission well in advance of actual needs will result in limiting future electric generation options to projects that can be shoehorned into the existing transmission system – and these resources may not be the most efficient or cost-effective in meeting the capacity needs of load-serving entities.

1. The Commission Should Require Planners to Consider a Range of Sensitivities and Alternative Futures in the Regional Planning Process

One solution would be to require regional planning processes to incorporate sensitivity studies and alternative scenarios. States and other stakeholders should be allowed to propose scenarios for analysis in the regional planning process. While the Commission already requires planning for existing public policy requirements, the Commission could also require analysis of likely future scenarios involving, for example, electrification of the transportation system or advancements in energy technology. Information regarding the potential transmission upgrades

24 ANOPR at P 44.

identified by these sensitivity analyses should be available to state regulators and stakeholders to inform their subsequent generation resource decisions.

As noted above, NIPPC also recommends that the Commission require regional planners to consider alternative generation scenarios. The regional planning studies should identify alternative geographic locations for generation choices to optimize the combined cost of generation and transmission investments for future generations. The studies should strive to identify the transmission expansions needed to open new generation resource zones for development as that generation is needed in the region.

The Commission seeks comment on whether the regional planning process should be restructured to require modeling of future scenarios and what specific factors shaping the generation mix are appropriate for transmission planning purposes. The factors suggested by the Commission include:

- federal, state, and local climate and clean energy laws and regulations;
- federal, state, and local climate and clean energy laws under debate – in many cases state and local policy priorities and trends are clear even if the details have not yet been formally established;
- utility and corporate energy and climate goals – this factor should include corporate energy goals not just for load-serving entities, but also corporate goals of large retail loads;
- trends in technology costs – including shifts towards electrification of buildings and transportation; and
- resource retirements – all too often regional planning processes do not consider resource retirements until those retirements are reflected in local utility transmission resource plans.[25]

NIPPC agrees that all the factors listed by the Commission should be a required part of the regional transmission planning process.

[25] ANOPR at P 46.

2. The Commission Should Require Planners to Consider Public Policy Trends and Other Factors Likely to Impact Demand for Energy in the Future

NIPPC also suggests that it is appropriate for the planning process to consider federal, state, and local climate and clean energy goals that have not been enshrined into law. In many cases, state and local policy priorities and trends are clear even when the details of those policy trends have not yet been formally adopted. Considering these trends in the planning process – even only as part of a sensitivity study – would reduce the regulatory lag in incorporating aggressive public policy efforts into regional planning processes. Likewise, utility and corporate energy and climate goals should be included. This factor should include corporate energy goals not just for load-serving entities, but also corporate goals of large retail load customers in the region. Corporate demand for energy, especially renewable energy, is significant. In 2020 (during the pandemic), U.S. companies announced 11.9 GW of corporate power purchase agreements, down somewhat from 14.1 GW in 2019.[26] NIPPC also supports including trends in technology costs, including shifts in electrification of buildings and transportation. Finally, NIPPC fully supports including resource retirements as a factor.[27] Too often, regional planning processes do not reflect resource retirements until those retirements are reflected in local utility transmission resource plans despite often clear public policy trends away from certain types of generation resources.

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26 *Global Corporate Clean Energy Purchasing Up 18% in 2020*, Renewable Energy World (Jan. 27, 2021), https://www.renewableenergyworld.com/solar/global-corporate-clean-energy-purchasing-up-18-in-2020/#gref.

27 ANOPR at P 51.

Regarding the Commission's concerns about changing the factors that must be considered in the regional planning process, NIPPC notes the optimal output of a reformed planning process is not a single set of transmission expansions for the region subject to mandatory cost allocation, but rather a report that identifies a range of transmission upgrades that would be required to cost-effectively and efficiently meet different future scenarios. It will remain up to state commissions to determine the most efficient and cost-effective generation solution that meets their ratepayers' needs. Once a generation portfolio is selected, the best solutions for transmission expansion will be clearer. But if the Commission continues to rely on existing processes for the approval of specific transmission expansion proposals, then the risk of unjust and unreasonable cost allocation remains.

3. The Commission Should Ensure That Expanding the Scope of Regional Transmission Planning Does Not Lead to Delays

The Commission should require regional planning processes to include plausible long-term scenarios designed to identify more efficient and cost-effective transmission solutions for the long-term generation resource needs of the planning regions.[28] NIPPC also agrees that the Commission should require the regional planning process to consider additional stakeholder input in the development of scenarios to explore transmission needs of future generations.[29] NIPPC, however, cautions that a scenario development process must not delay the actual study timelines. Our experience with the WECC interconnection-wide planning process for the Western Interconnection funded by DOE is that without strict timelines, stakeholders can take months or even years to agree on the plausible scenarios that should be studied as sensitivities. Any stakeholder scenario development process must not seek to develop "perfect" future

[28] ANOPR at P 52.
[29] ANOPR at P 52.

scenarios at the expense of delays in the study process. Any additional requirement that includes stakeholder input on the development of scenarios must be structured in such a way that input is meaningful but does not delay the transmission planning process timelines.

4. The Commission Should Expand the Types of Benefits Considered for Allocation of the Costs of Regional Transmission Expansion

In response to the Commission's question as to whether and how long-term scenarios should be used in identifying and soliciting solutions to meet future transmission needs, NIPPC suggests that transmission providers should focus on a broader set of benefits of transmission facilities and identify a portfolio of transmission facilities in identifying a more efficient or cost-effective solution.[30] NIPPC recommends that the Commission require the regional planning process to identify the least cost transmission solution given the load growth and resource retirement assumptions from local utility plans without being bound by the generation resource zones selected in those plans.[31] In performing this study, the regional planning process should not be limited to future resource development signaled in local transmission plans but should be allowed to aggregate demand across the region and relocate generation sources to different geographic zones in order to determine the most efficient transmission expansion plan needed to meet a region's needs. The result of this study should not automatically be included in any mandatory cost allocation process. Rather, the study results should be designed to inform state regulators and policy makers of the costs associated with different policy choices related to generation resource additions. Load-serving entities, state regulators, and transmission providers

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30 ANOPR at P 53.

31 Again, NIPPC's intention here is to allow regional planners to consider relocating generation resources to a different geographic region for the purpose of optimizing transmission expansion. NIPPC is not suggesting that regional planners would be allowed to substitute different fuels or types of renewable generation for those set forth in the utility plans.

can use existing state processes to inform future generation resource additions, which would be reflected in future cycles of the transmission providers' local transmission planning processes.

E. THE COMMISSON SHOULD ENCOURAGE STAKEHOLDERS TO IDENTIFY RENEWABLE ENERGY RESOURCE ZONES

NIPPC agrees that the Commission should require transmission providers, state commissions, and other interested parties in each transmission planning region to identify geographic zones with the potential for the development of large amounts of renewable generation.[32] Many regions have already undertaken these types of studies, even if they are not yet required to be incorporated into regional transmission planning processes.[33] The process to identify new resource zones should also provide estimates of the likely construction timeline and costs associated with expanding the transmission grid to tap generation resource potential in the most likely zones for development within the planning horizon. One challenge for the Commission with this reform will be to ensure that the interconnection process associated with transmission expansion to new generation resource zones remains open and non-discriminatory. The process to identify and select renewable energy resource zones must not bias or favor IOU or affiliate development of new generation. Furthermore, the existing OATT process should remain in place to allow continued interconnection of generation assets to the existing grid.

Regarding the criteria used to identify renewable energy zones, the Commission should consider the criteria used in the Western Renewable Energy Zones – Phase 1 report ("WREZ")

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32 ANOPR at P 54.

33 *See, for example, Western Renewable Energy Zones - Phase 1 Report*, Department of Energy (Oct. 11, 2021), https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/WREZ_Report.pdf.

from June 2009.[34] This joint initiative of the Western Governors' Association and the U.S. Department of Energy established criteria for determining the highest quality and most cost-effective renewable energy resource zones in the Western Interconnection. The WREZ identified onshore wind resources of Class 3 and above under the power density classification of the National Renewable Energy Laboratory and solar resources with a direct normal irradiance of 6.5 kWh/square meter per day. WREZ determined that geographic regions identified as resource zones (Qualified Resource Areas in its terminology) should be capable of supporting 1,500 MW of generation with moderate capacity factors. Additionally, the process excluded lands where renewable energy development was precluded by state and federal statutes or regulations. Regarding how states and local entities could provide input into a process to identify renewable energy zones, the Commission should base any requirements on the successful WREZ process in the Western Interconnection.

The Commission should be less concerned about whether there is commercial interest in developing generation in any particular renewable resource zone.[35] The reality is that once there is transmission available and loads are seeking to procure new generation, there is a high likelihood that commercial interest will rise to meet the demand especially if state commissions have acted to approve the transmission expansion. Regarding the Commission's concern that safeguards are needed to ensure that transmission infrastructure is built only to satisfy expected needs and not speculative commercial interests,[36] the Commission should consider mandating a process for regional transmission planning organizations to report their findings to the state

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34 *Western Renewable Energy Zones - Phase 1 Report*, Department of Energy at 6-8 (Oct. 11, 2021) https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/WREZ_Report.pdf.

35 ANOPR at P 57.

36 ANOPR at P 57.

commissions and policy makers and other regulatory bodies with jurisdiction over generation resource procurement. These organizations would have responsibility for approving any transmission expansion needed to reach new generation resources – and presumably would do so only if transmission expansion to new generation resources proved to be the most efficient and cost-effective solution.

F. THE COMMISSION SHOULD CONSIDER HOW COSTS ALLOCATED THROUGH A REGIONAL MANDATORY COST ALLOCATION PROCESS ARE ACTUALLY RECOVERED IN TRANSMISSION RATES OUTSIDE OF AN RTO

The reforms NIPPC recommends above will also require the Commission to reconsider mandatory cost allocation in the regional planning process. NIPPC recognizes that changing the regional planning process to explore a range of possible futures and portfolios of transmission expansion projects requires changes to the Commission's mandatory cost allocation requirements. By recommending expanded scenario planning, NIPPC intends that these studies would provide policy makers and state commissions with valuable information to make informed decisions about how to phase transmission investments to reach the most cost-effective generation options for the region's needs on a realistic timeline. Such a mechanism would allow states to continue to choose the generation resources that best meet their policy priorities while identifying the transmission needed to connect those generation resources to load efficiently and cost-effectively.

1. Outside of RTOs, Cost Allocation Should Be Independent From the Regional Transmission Planning Process and Should Incorporate State Input

NIPPC believes the planning process should identify the most efficient future transmission build out that results in the lowest cost of energy for future generations. These plans could then be referred to a separate cost allocation process which includes the input of state regulators and other stakeholders in selecting the specific transmission build out that will be subject to mandatory cost-allocation. NIPPC suggests that a planning process that fails to provide state commissions and policy makers with information to make informed decisions about the costs of different combinations of generation and transmission is more likely to lead to unjust and unreasonable rates than one that provides this information to them.

NIPPC understands how the Commission intended mandatory cost allocation of regional transmission needs to function in an RTO. It is not clear, however, that mandatory cost allocation is relevant in the non-RTO West (especially when significant portions of the transmission grid are owned by entities not subject to the Commission's jurisdiction). In the absence of an RTO, there is no Transmission Access Charge or similar mechanism to allocate transmission project costs to all customers in a region. The Commission likely intended the costs of regional transmission projects to be allocated to all the transmission providers participating in the regional planning process and that these transmission providers in turn would incorporate those costs into their transmission rates. But the significant role of non-jurisdictional transmission providers in the non-RTO West who participate "voluntarily" in the regional planning processes interferes with the Commission's requirement for mandatory cost allocation. Any cost allocation mechanism must consider how it would apply to non-jurisdictional transmission providers who participate in regional planning processes on a voluntary basis.

2. The Commission Should Seek Comment on How Transmission Providers and States Could Develop a Cost Allocation Mechanism Outside of RTOs

NIPPC urges the Commission to solicit input from transmission owners and state commissions to explore how allocation of the costs of regional transmission expansion could work in the non-RTO West. Future generations will need a cost allocation mechanism that ensures their transmission needs will be met. NIPPC suggests that the responsibility for that cost allocation should not reside solely within the regional planning group(s). Rather NIPPC suggests that responsibility should be shared with state commissions and other stakeholders responsible for generation resource decisions. The Commission should also consider that if it were to adopt NIPPC's suggestion above to base long-term regional planning on an expanded load/resource/transmission service forecast, then the loads committing to those transmission expansions would pay for service on those lines and a separate mandatory cost allocation mechanism might be superfluous.

G. INCENTIVES FOR REGIONAL TRANSMISSION FACILITIES

The Commission seeks comment on incentives for regional transmission facilities.[37] Above, NIPPC suggested that regional planning should be based on twenty-year forecasts for load, resource, and transmission requirements. The most valuable mechanism that would incentivize regional transmission would be one based on transmission customers who make commitments to take service on the proposed transmission (either through the load, resource, and transmission service forecasts mentioned above or through a mechanism similar to the "precedent agreement" approach used to support gas pipeline expansions). NIPPC suggests the greater certainty of cost recovery from getting upfront commitments from transmission customers to take service on expanded transmission facilities is sufficient. NIPPC is concerned an equity adder incentive for transmission development will simply increase the costs of transmission without actually incenting transmission developers to take on the risk of building in advance of need without commitments from customers to take service. If customer commitments are in place, there is no risk to justify a greater return on equity.

[37] ANOPR at P 61.

H. INTERREGIONAL AND STATE COORDINATION

NIPPC agrees with the Commission's suggestion that the recommendations endorsed in these comments would require additional interregional and state-to-state coordination.[38] The interregional coordination requirement in Order No. 1000 has proven ineffective in identifying and developing cost-effective interregional transmission projects. In the long run, the Commission should require joint interregional planning between neighboring regions. In the short term, however, the Commission should focus on reforming the regional planning process to mitigate the regional planning problems identified in the ANOPR. The Commission should also begin the process of defining a mechanism that requires regional transmission planning processes to solicit the input and approval of states more proactively in all elements of the regional transmission planning process from developing the assumptions to be used in the studies to formally approving transmission projects and cost allocation.[39]

I. COORDINATION BETWEEN REGIONAL PLANNING AND INTERCONNECTION PROCESSES

NIPPC agrees that the Commission should consider mechanisms to improve the coordination between the regional transmission planning process and the generator interconnection process.[40] NIPPC also encourages the Commission to consider mechanisms to improve the coordination between the regional planning process and the transmission service request queue as well as improve coordination between the interconnection process and the transmission service request process.

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38 ANOPR at P 62.
39 ANOPR at P 64.
40 ANOPR at P 65.

1. The Regional Transmission Planning Process Should Not be Based Primarily on Interconnection Queues

The Commission has noted the apparent frequency of interconnection projects dropping out of the interconnection queue necessitating subsequent restudies. In our anecdotal experience in the Pacific Northwest, some generation developers have a rule of thumb that as many as three in four projects that begin the development process will not make it to the end (though not all of these ever enter the interconnection queue). Project developers may drop out of the interconnection queue for a variety of reasons, including for reasons completely outside their control. Potential reasons for dropping out of the queue include permitting delays, litigation from opponents to development, financing problems, inability to obtain needed equipment, or delays in securing transmission service. The project developer can do all appropriate due diligence, but it is the transmission provider's analysis, as reflected in its studies, that identifies the necessary Network Upgrades. Only through the interconnection study process can a developer learn whether its project is feasible. One particularly problematic example occurs when an interconnection study identifies a non-jurisdictional transmission system as an "affected system." While some non-jurisdictional transmission owners have transmission tariffs which track the procedures and timelines set forth in the OATT, some do not. Many developers have proceeded diligently through the primary interconnection process only to be informed at the very end that an adjoining non-jurisdictional "affected system" also requires significant Network Upgrade costs before the project can proceed. Hence, linking transmission expansion to the interconnection queue makes little sense.

2. The Regional Transmission Planning Process Should Be Based on Forecasts of Load Growth, Generation Additions, and Transmission Needs

The Commission seeks comment on how the generator interconnection process could be integrated into regional planning in a timely manner.[41] NIPPC suggests that the fundamental paradigm of transmission planning and development should instead focus on future needs of consumers (considering policy momentum for decarbonizing the grid and reliability and resiliency needs). Under this paradigm, the focus is on predicting future growth of transmission needs based on current or expected transmission constraints and the need to connect zones with high potential for renewable energy development to load centers. Transmission planning should be much more like highway planning, where highways are expanded based on analysis of current chokepoints and anticipated future growth of demand from growing cities or industries. It would make little sense to base highway planning on whether individual owners of automobiles have signed up for highway service. For similar reasons, it makes little sense to base transmission planning and expansion only on the number of interconnection requests.

A similar problem occurs when customers drop out of the transmission service request queue. One reason (though not the only one) that developers exit a queue is that those developers – especially those planning to wheel their generation across multiple transmission providers to the eventual load – must manage the timelines for generator interconnection and transmission service expansions that are completely independent of each other. All too often a transmission customer must drop out of the transmission service or interconnection queue on one transmission provider's system because of delays in the study process on a different transmission provider's system or because new transmission facilities must be constructed to relieve

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41 ANOPR at P 67.

congestion on one segment of the requested transmission service. The Commission should consider a mechanism that would allow a transmission customer to link its interconnection service request to one or more transmission service requests across multiple systems. This type of multi-transmission provider service request could be studied as part of the regional transmission planning process. This would allow transmission providers (or the regional planning process) to identify all the Network Upgrades necessary to enable the customer's request and avoid the need for transmission customers to move in and out of the various queues while trying to coordinate the various tariff and construction timelines.

3. The Commission Should Require Transmission Providers to Coordinate the Timelines for Their Interconnection and Transmission Service Queues

NIPPC also supports the suggestion that transmission providers should conduct their generator interconnection process and regional transmission planning process on concurrent coordinated timeframes. NIPPC encourages the Commission to expand the requirement for concurrent coordinated timeframes of interconnection processes to also include concurrent timelines for transmission service requests.

J. THE CURRENT MECHANISM FOR FUNDING NETWORK UPGRADES IS INEFFICIENT AND INHIBITS NEEDED TRANSMISSION EXPANSIONS

Participant funding in interconnection-related Network Upgrades does fail to account for the significant benefits those upgrades may provide to other customers.[42] As noted above, the Commission's current policy, which requires interconnection customers to fund the full costs of Network Upgrades subject to refund over time, creates unnecessary and undue burdens on

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42 ANOPR at P 105.

project development and artificially disfavors independent power producers who cannot count on recovery of their costs from captive ratepayers.

If the Commission does not do away with requiring interconnection customers to fund Network Upgrades, it should consider more modest reforms. At the very least, NIPPC recommends requiring transmission providers to perform cluster studies for its interconnection queue; this would allow the transmission provider to allocate upgrade costs among customers who will be using the same facilities – without requiring the "first mover" to be responsible for all the upfront costs. As a similar example for transmission service, BPA's transmission expansion process uses a cluster study approach to aggregate demand for Network Upgrades and spreads those costs among multiple customers.[43] NIPPC recommends that the Commission require all transmission service providers to adopt a cluster study model for interconnection requests. The timelines for interconnection study clusters should be coordinated across all transmission providers.

NIPPC urges the Commission to also require transmission providers to adopt a cluster study process for all OATT transmission service requests that require upgrades. A cluster study process would ensure that the "first mover" does not bear a disproportionate share of the upfront costs of upgrades because the costs would be shared more evenly across all customers seeking transmission expansion. NIPPC also recommends that the Commission require transmission providers to coordinate the timing of their cluster study processes for interconnection and transmission service. Furthermore, NIPPC recommends that the Commission require

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43 *TSR Study and Expansion Process Business Practice Version 6*, Bonneville Power Administration at 2-6 (August 11, 2021), https://www.bpa.gov/transmission/Doing%20Business/bp/tbp/TSR-Study-Expansion-Process-BP.pdf.

transmission providers to coordinate the timing of their cluster studies with all the other transmission providers in the region. Doing so should substantially mitigate the challenges developers face in managing multiple queues with different timing. At the same time, the Commission should not allow the cluster study process to become another obstacle to project development.

Finally, NIPPC recommends that the Commission signal to states that their interconnection paradigms for state-jurisdictional qualifying facility interconnections under the Public Utility Regulatory Policies Act should be no more burdensome than the process established by the Commission under the OATT. Some states have followed a similar participant funding approach as the Commission is considering reforming. This recommendation would therefore help ensure that the process for interconnecting qualifying facilities is no more burdensome than for other generators.

K. THE COMMISSION SHOULD EXPAND THE TYPES OF BENEFITS TO BE CONSIDERED IN COST ALLOCATION

The Commission seeks comment on the types of benefits relevant for cost allocation.[44] NIPPC agrees that the current cost allocation mechanism – to the extent it has value in the non-RTO West, as discussed above – fails to fully consider all the benefits of transmission expansion to the current and future generations. NIPPC encourages the Commission to explore a broad range of additional benefits for consideration in cost allocation, including benefits that may be difficult to quantify.

1. Cost Allocation Should Consider Resiliency Benefits

NIPPC suggests the Commission consider the benefits to customers of increased resiliency to the transmission system. Even when infrastructure upgrades are driven by one set

[44] ANOPR at P 84.

of customers, all customers connected to the system are likely to receive indirect benefits. New generation resource zones provide geographic diversity to the generation mix – resulting in increased wholesale price competition for all load-serving entities. New transmission lines to new generation zones provide a resiliency benefit when lines to existing generation resources must be taken out of service due to emergencies or disasters – potentially benefiting all loads connected to the grid. The result of considering contingency and resiliency benefits is that all loads connected to the grid would receive some benefit from new transmission facilities even if those benefits may be difficult to quantify. Conceivably the Commission could establish a threshold of 5-10% of the costs of upgrades that would be allocated among all participants in the regional planning process.

2. Economic and Public Policy Benefits Should Not Be Considered Separately From Reliability Benefits

A flaw in the Commission's existing cost allocation methodology is to allow the cost of regional transmission facilities that address reliability needs to be allocated separately from the costs of regional transmission facilities needed to address economic and/or public policy requirements. Reliability, economics, and public policy are all drivers of transmission expansion. These drivers are not independent factors but exist on a continuum. If one simply delays making a decision to expand the transmission system long enough, then a public policy requirement can become an economic incentive (as loads attempt to add cost-effective resources to the existing grid to avoid administrative penalties); similarly, if one delays further, then an economic incentive can become a reliability imperative (in the form, for example, of a congested flowgate leading to local resource inadequacy). Allowing separate cost allocation processes based on false distinctions between public policy, economics, and reliability is detrimental to entities which make an effort to plan transmission upgrades long enough in advance to meet their public policy requirements efficiently and cost-effectively. On the other hand, entities which delay planning for expansion until upgrades are required for reliability are effectively leaning on the Network Upgrades funded by others or resigning themselves to adding generation on an expedited or even emergency basis to existing facilities. This latter outcome may ultimately be more expensive and less effective for all retail electric customers. Customers who proactively plan for new resources to meet their public policy needs should not be underwriting the upgrades that other customers will need to meet their own public policy or economic needs. NIPPC has suggested that transmission expansion should be driven by a holistic consideration of all the factors that are likely to drive future demand, including reliability, demand for new renewable resources, public policies, electrification of transportation and buildings, and any other factors reasonably likely to increase the demand for electricity and electric transmission. To the extent these factors are driving demand for new transmission facilities, these same factors should be considered in allocating the costs of those transmission facilities.

3. Cost Allocation Should Consider Benefits That Are Difficult to Quantify

Load-serving entities should be required to pay at least a share of the costs of regional transmission facilities even if the benefits are difficult to quantify. Examples of benefits that may be difficult to quantify include resiliency and economic development benefits. Increased extreme weather events (fires, floods, hurricanes, ice storms) are having an impact on transmission availability. While some weather-related disasters are widespread, others have only local impacts – in these cases an expanded transmission system that facilitates energy deliveries across long distances and between multiple markets enhances reliability. High quality renewable resources (wind, solar, geothermal, pumped hydro-storage) may be far from load centers and in different states. Developing these new sources of renewable generation yields significant local benefits including construction jobs, operations jobs, increased tax base, and other follow-on economic benefits. Because of these local economic benefits, it would not be unreasonable to allocate a portion of the costs of the transmission upgrades needed to the states where these resources are sited because without these upgrades none of the local economic development benefits would accrue to them. NIPPC also agrees with the Commission that the existing paradigm which considers the different types of benefits in silos (reliability, economic, public policy) fails to consider comprehensively the full spectrum of benefits from upgraded transmission facilities.[45]

One risk of continuing to allocate the cost of transmission upgrades to interconnection customers (or to interconnection and transmission service customers) is that load-serving entities that delay identification and acquisition of new generation – and the transmission upgrades necessary to deliver those resources to load – may benefit from the transmission upgrades funded by others without sharing in the commitment to take transmission service. Load customers who sit on the sidelines and delay planning and acquisition until the last moment should not benefit from investments made by load customers who do plan and acquire generation. Accordingly, the Commission should require regional planning processes to develop a cost allocation mechanism that measures all the benefits of regional transmission facilities – including benefits that are difficult to quantify – and allocates the cost of those facilities to all of those who benefit.[46] The Commission must ensure that load serving entities have no hidden incentive to delay planning to meet their future generation requirements.

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45 ANOPR at P 85.

46 Although, as discussed later in these comments, NIPPC questions the overall relevance of mandatory cost allocation in the non-RTO West.

4. The Allocation of Costs of Regional Transmission Upgrades Should Consider Benefits to All Customers in a Region, Not Just Those Directly Taking Service

NIPPC agrees that the portfolio approach to cost allocation would be an effective mechanism to ensure that broader benefits are considered when allocating the costs of transmission upgrades. As noted above, many benefits are difficult to quantify. A mechanism that attempts to allocate costs only to the most direct beneficiaries would allow other customers to benefit from upgrades without paying their share of the costs. NIPPC agrees that it makes much more sense to allocate a portfolio of upgrades that benefit the region to all customers in the region. Furthermore, a mechanism that allocates costs of transmission upgrades only using reliability and economic considerations is unlikely to yield the most cost-effective transmission solution for load serving customers of a region. A mechanism that fails to allocate costs of transmission infrastructure needed to meet public policy requirements will result in a less efficient and cost-effective combined cost of transmission and generation for load serving entities. Failing to plan – and allocate costs – based on public policy requirements will result (and has resulted in) a lack of timely planning, siting, permitting, and construction of transmission needed to meet regional needs for new transmission and generation resources. A cost allocation mechanism that focuses narrowly on reliability and economic factors results in a situation where new generation is limited to interconnecting to those parts of the system where it can be added to the existing system rather than expanding the transmission system to access the most cost-effective and efficient generation resources. As noted above, a new generation resource can often be permitted and constructed in 18 months. Permitting, siting, and constructing transmission upgrades – especially expansion to new generation resource zones – can take 10 years or more. In the absence of planning for transmission to be available somewhat in advance of its economic need, transmission upgrades will be a hodgepodge of near-term fixes that are likely to result in a higher overall cost than thoughtfully planned investments for the long-term needs of the system.

NIPPC suggests that states should not be completely exempt from sharing in the costs of transmission upgrades attributable to the public policy requirements of other states. Some states have moved more quickly than others to implement policies to mitigate or slow climate change. To some extent, all consumers of electricity in the region benefit from these climate policy reforms, even if their states have not yet adopted their own policies. Climate change is a global problem, but one that requires action at all levels – local, state, regional, national, and international. All citizens in a region benefit, to some degree, from state public policy requirements designed to slow climate change – and as beneficiaries should contribute to the costs of the transmission grid needed for the future – particularly since there are other material co-benefits to expanding and strengthening the grid that go well beyond mitigating climate change. Transmission expansion to new renewable energy zones also brings economic development benefits which may justify an allocation of the costs of these expansions. A default mechanism that allowed a portion of transmission upgrades needed to meet public policy requirements to be allocated to other states would likely incentivize a committee of state regulators to collaborate on an alternative voluntary allocation of costs. NIPPC recommends that the Commission explore further, in consultation with state commissions, how best to balance the broad regional benefits of transmission upgrades described in our comments with the respective authority of each state to set its own public policies within its jurisdiction.

5. The Commission Should Consider How Costs Allocated to All Loads in a Region Will Be Recovered in Rates

The Commission also seeks comment on a wide variety of potential cost allocation metrics and how to apply them to a cost allocation process that results in a fair and equitable allocation of the costs of the regional transmission system.[47] In most of the West, some of these potential cost allocation mechanisms may be irrelevant, at least at present. Others would require a careful meshing with the existing tariff framework. As discussed previously, outside of an RTO/ISO there is no transmission access charge that is allocated to customers. Rather, individual transmission providers charge their tariff rate for service. NIPPC expects this reality to continue at least for the pendency of this potential rulemaking as there are no near-term proposals likely to reach the Commission for a new West-wide RTO in the immediate future. The result of continued reliance on the OATT is that customers will continue to pay cost-based transmission rates. There is no other mechanism to recover the costs of transmission infrastructure other than through the OATT rates. Accordingly, any allocation of costs through a regional cost allocation mechanism must still be recovered through transmission rates.

The Commission should therefore consider how a mandatory cost allocation might take place in the OATT context. If a regional transmission plan includes a portfolio of transmission upgrades appropriate for regional cost allocation, how will these costs be reflected in individual transmission providers' OATT rates? One solution would be to spread the costs of upgrades subject to regional cost allocation across all transmission providers in proportion to their load ratio share – which they can then reflect in their own tariff rates. Transmission providers would then distribute these additional revenues to those transmission providers who built the regional

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[47] ANOPR at P 90.

transmission project. An alternative would be to dispense with regional cost allocation outside of RTO models and simply reflect the costs of regional transmission upgrades in the transmission providers' OATT rates. In this case, there would be no need to allocate costs on a regional basis as the beneficiaries are simply those who take the service. A pro rata portion of these upgrade costs would be allocated to the transmission providers' Network Service customers (the loads on its system) which would allow those loads to contribute to their share of the various resiliency, economic, and other difficult to quantify benefits discussed above. Following this model, however, would require the enhanced additional load/resource/transmission service forecast requirements and commitments from loads in advance of the development of generation resources to ensure that the most cost-effective and efficient transmission system was available when needed.

The Commission notes that since Order No. 2003 the composition of the generation fleet has rapidly shifted from large, centralized resources to a larger proportion of smaller renewable generators located far from loads.[48] The ANOPR suggests that these more distant generators require extensive interconnection-related Network Upgrades to interconnect to the transmission system. This is often true. New wind or solar resources often have extensive interconnection-related Network Upgrades to connect to the transmission system. As discussed earlier, the ANOPR overlooks the additional requirement for Network Upgrades for transmission service across the transmission systems of one or more intervening providers. As such, the ANOPR oversimplifies the complexities faced by a developer who must manage the interconnection-related process (and costs) where its generation resource is located but also the transmission

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48 ANOPR at P 100.

service queue (and upgrade costs) associated with transmission service on facilities between the generator's location and the load it seeks to serve.

L. TRANSMISSION PROVIDERS SHOULD FUND MOST NETWORK UPGRADE COSTS

The Commission seeks comment on whether transmission providers should provide upfront funding for all interconnection related Network Upgrades.[49] NIPPC would like to highlight the distinction between initial funding for Network Upgrade costs and how those initial costs are recovered over time. As a general matter, NIPPC believes that requiring transmission providers to provide the initial funding for Network Upgrades in many instances would reduce the financing burden on interconnection customers and would thereby encourage development of renewable resources, improve transmission development, and increase competition in the generation market. NIPPC also agrees that it is more efficient for interconnection facilities to be financed once (by the transmission provider) instead of twice (once by the interconnection customer who passes those costs through to its own customers and again by the transmission provider). This policy would also result in increased transparency of generation resource costs – otherwise a generator's costs would need to be high enough to also recover the cost of the financing for the interconnection related upgrades. NIPPC believes that if the Commission were to adopt the reforms discussed earlier (especially the suggestion to base planning on enhanced twenty-year load, resource, and transmission service forecasts and employ an open season process for customers to commit to taking service) transmission providers could provide the funding for Network Upgrades without undue risk – as the transmission customers would have committed to repaying the transmission provider for its investment by taking service on those upgraded lines. NIPPC notes again that this recommendation applies well at least to many

[49] ANOPR at P 120.

scenarios in the non-RTO West in which the transmission provider is also typically its own transmission customer receiving service on its own transmission system and adjacent systems.

M. THE COMMISSION SHOULD NOT REQUIRE LARGE NON-REFUNDABLE FEES

The Commission suggests that the current crediting process could be reformed by establishing a non-refundable fee for submitting an interconnection request.[50] NIPPC suggests it is unlikely that a non-refundable fee could be both high enough to realistically defray the costs of interconnection upgrades while also not be so large that it does not create barriers to entry for smaller developers. The Commission is rightfully concerned with discouraging speculative interconnection requests from developers seeking to identify points of interconnection with the least cost. The Commission, however, should also be concerned about creating a mechanism that allows interconnection customers to identify locations on the grid with the lowest Network Upgrade costs. If this information were freely available, interconnection customers would have no incentive to submit multiple requests for interconnection. One way to accomplish this would be to require transmission developers to identify those places on its system where interconnection can be accomplished at the lowest relative cost. Providing this information in conjunction with a variable fee (a higher fee where interconnection upgrade costs are forecast to be higher) would ensure that the grid is fully utilized before it needs to be expanded.

NIPPC agrees that the interconnection customer should retain the voluntary option to upfront fund 100% of the interconnection costs – especially if doing so preserves the ability to retain control over the pace of interconnection-related work. In some cases, the developer (and its load customer) may prefer this option. While this option would likely be rarely deployed for

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[50] ANOPR at P 135.

large expansions of the grid to new renewable resource zones, it should remain an option for customers seeking to interconnect to the existing grid.

N. EXPANDED LOAD/RESOURCE FORECASTS WITH TRANSMISSION REQUIREMENTS WOULD SIMPLIFY COST ALLOCATION IN NON-RTO REGIONS

The Commission seeks comment on potential revisions to the Order No. 2003 interconnection crediting policy which requires transmission customers to provide upfront funding for Network Upgrades.[51] An additional alternative would be the one laid out earlier in these comments to require loads to be more definitive about their load and resource forecasts for the future. NIPPC suggests that the Commission require load serving entities to submit their binding load and resource forecasts together with projected transmission service requirements for 20 years into the future in the regional planning process to ensure that transmission infrastructure is in place when needed. The costs of these upgrades would be recovered from the load-serving entity through cost-of-service OATT rates. Since the cost of the upgrades would be covered by the load customer, no additional interconnection network upgrade costs would be required from the generation developer. To the extent that transmission providers must expand their system to meet load and resource forecasts for other load serving entities, they would fund all of the necessary upgrade costs and recover them through their cost-of-service rates. This option could be expanded to allow the load-serving entity to reserve the associated transmission capacity for its future use and to identify and ensure priority interconnection for the specific geographic zone of generation resources that would be interconnected to the transmission provider's system. NIPPC reiterates its previous caution about ensuring that any such option must avoid enabling an IOU transmission provider to select its own generation resources that could later be rate-based.

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[51] ANOPR at P 131.

O. THE COMMISSION SHOULD RETAIN A CUSTOMER'S OPTION TO BUILD

NIPPC believes that interconnection customers should retain the option to build, as long as they use an independent contractor that is qualified to do the work. As the Commission notes, the option to build allows a developer some control over timelines and construction schedules with a potential for cost savings.[52]

P. THE COMMISSION SHOULD NOT IMPOSE A PENALTY FOR WITHDRAWAL FROM THE QUEUE

The Commission notes that a contributing factor to the interconnection queue backlog is a tendency among some interconnection customers to submit multiple interconnection requests at different points of interconnection with the intention of discovering the lowest cost location to site the generating facility and then withdrawing higher-cost interconnection requests from the queue.[53] The Commission sees this as an abuse and proposes a penalty to prevent this behavior.[54] NIPPC disagrees. NIPPC suggests that the goal of identifying locations with the lowest cost to interconnect is a valuable one and should not be discouraged. Locating generation where it can be integrated the cheapest ensures that the transmission system is not expanded unnecessarily and results in lower cost to loads. NIPPC suggests that a policy which imposes penalties or large fees on interconnection requests will discourage new market entrants especially smaller entrants who have less capacity to bear these costs. Instead, the Commission should ensure that developers have better access to information about where generation can be integrated onto the system most economically. The Commission's "or" policy requiring the transmission provider to charge rolled-in or incremental rates, but not both,[55] provides adequate

52 ANOPR at P 151.
53 ANOPR at P 153.
54 ANOPR at P 153.
55 FERC Order No. 2003 at ¶ 694.

incentive for developers to avoid unnecessary costly interconnections. Under this policy, developers know they will be subject to higher incremental transmission rates if they choose a site that requires expensive upgrades which do not lower overall transmission rates when rolled into the transmission rate base. If, for reasons unrelated to transmission costs, a developer must locate its project on a congested portion of the transmission system, then the availability of this information will at least put that developer on notice of the likely costs and help improve upfront decision-making about the viability of individual projects. By contrast, in the current system the project developer only learns of transmission constraints and the costs of Network Upgrades after an interconnection request is submitted and studies are complete.

Rather than the Commission's proposals to impose penalties or limits on the number of interconnection requests, NIPPC suggests that the Commission should require transmission providers to identify areas on their systems where projects can be added at low(er) cost. The overall goal should be full transparency into the cost of adding projects at different locations on the transmission providers' system. In the absence of this transparency, developers discover this information through other means such as multiple interconnection requests.

Q. THE COMMISSION SHOULD DEVELOP A FAST-TRACK INTERCONNECTION FOR "READY" PROJECTS FOR PROJECTS COMMITTED TO REGIONAL TRANSMISSION FACILITIES

NIPPC supports the Commission proposal to consider creating a fast-track interconnection (and transmission service request) process for projects fully committed to connecting to new regional transmission facilities.[56] NIPPC suggests that this fast-track reform could apply to project locations identified by load-serving entities in their enhanced twenty-year load, resource, and transmission service forecasts. In these submittals, loads could identify the

[56] ANOPR at P 155.

generation resources they seek to add to the fast-track process. NIPPC suggests that a carefully crafted fast-track process – especially when used in conjunction with a forward-looking resource procurement process and submitted into the regional planning process – would not constitute "queue-jumping" or "queue-clearing" as those terms are understood in the current interconnection paradigm. NIPPC also agrees that resources that are "ready" in the sense that they have a power purchase agreement or have been selected in a state procurement process could also qualify for a "fast-track" process. The Commission should undertake a careful evaluation of potential "readiness" criteria to ensure that any fast-track reforms recognize and balance the market value of existing queue positions held by developers with the broader system-wide value of accelerating transmission upgrades and expansion.

The Commission should note that NIPPC limits its support for a "fast-track" mechanism to projects committed to a regional transmission facility. While not perfect, the Commission's interconnection queue mechanism does contribute to a competitive market for generation by providing an assurance that developers can invest in project development without suddenly being displaced by other projects, and particularly by utility-owned generation. Queue jumping by utilities favoring their own generation resources – especially when one of the criteria for readiness could be a power purchase agreement from that utility – remains an abiding concern that could affect NIPPC's ultimate support for a fast-track process.

R. THE COMMISSION SHOULD REQUIRE INDEPENDENT OVERSIGHT OF REGIONAL TRANSMISSION PLANNING

NIPPC agrees that enhanced oversight is needed over transmission planning in the Non-RTO-West.[57] NIPPC also agrees that local transmission planning processes outside of the RTOs are not well publicized or understood. The results of local planning processes yield transmission

[57] ANOPR at P 163.

plans that have significant implications for both regional transmission plans and the timing, types, and locations of generation additions that can be brought on to the grid. NIPPC therefore agrees that an independent transmission monitor in non-RTO/ISO regions would be beneficial especially in the non-RTO West. Regional planning processes are long and complicated, and non-RTO planning regions do not provide the same level of independence, transparency, and stakeholder engagement of RTO planning regions. Special expertise is needed to review transmission planning processes, planning criteria, and the cost, load, and resource assumptions used in the transmission planning process. NIPPC agrees that an independent monitor would be valuable to state commissions and transmission customers to ensure that non-RTO regional planning processes are consistent with Commission expectations as well as the expectations of policy makers in the planning region. NIPPC also agrees that the independent monitor should scrutinize the regional transmission plans to determine whether a different portfolio of transmission facilities would lead to higher net benefits. Part of this review should be to evaluate whether alternative generation portfolios (such as consolidating generation resources into a smaller number of generation resource zones) result in a lower cost of transmission upgrades. NIPPC also recommends that the independent monitor review local transmission provider transmission plans as well as load serving entities' load and resource forecasts and forecast transmission requirements to ensure that they meet the planning requirements. The need for independent oversight of the entire transmission planning process is particularly important considering the extent of influence and control that vertically-integrated utilities have over the regional planning process. Any reforms to enhance regional planning, incorporate planning to renewable generation zones, modify cost allocation mechanisms, or incorporate a fast-track interconnection process must be accompanied by strong independent oversight to ensure that the utilities in control of those processes do not favor their own projects. NIPPC underscores this recommendation as essential to preserving the integrity of these other reforms.

S. THE COMMISSION SHOULD ENCOURAGE STATE PARTICIPATION IN REGIONAL TRANSMISSION PLANNING

NIPPC agrees that state oversight of transmission planning and cost allocation should be improved.[58] NIPPC suggests that the Commission should require regional planning processes to include the input of a committee of state regulators. The Commission should be confident that regional transmission upgrades and cost allocations approved by a committee of state regulators are prima facie prudent and result in just and reasonable rates. A regional state committee could also have a role in approving the load-serving entities' twenty-year load, resource, and transmission requirements discussed previously.

IV. CONCLUSION

For the reasons discussed above, the Commission should issue a Notice of Proposed Rulemaking to further develop the reforms recommended in these Comments.

Dated: October 12, 2021

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58 ANOPR at P 176.

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CERTIFICATE OF SERVICE

I hereby certify that I have this day, October 12, 2021, served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Irion Sanger

Irion Sanger