Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

FREEDOM OF INFORMATION ACT PROGRAM

May 15, 2025

In reply refer to: FOIA #BPA-2024-02018-F

SENT VIA EMAIL ONLY TO: aschick@opb.org

Tony Schick
Oregon Public Broadcasting/ProPublica
[redacted]

Dear Mr. Schick,

This communication concerns your request for Bonneville Power Administration (BPA) records submitted to the agency under the Freedom of Information Act, 5 U.S.C. § 552 (FOIA). BPA received your records request on May 31, 2024. The agency formally acknowledged your request on June 26, 2024.

Request & Clarifications
Based upon your original May 31, 2024, request and on subsequent emails exchanged with the agency during the week of June 3, 2024, your request is, 'I seek all emails and attachments dated from May 01, 2023, through June 30, 2023, with the following keyword combinations: "Renewable Northwest" + "Transmission" (or alternative spelling "Renewable NW"), "Renewable" + "Transmission" + "NIPCC", "Appropriate and Required: BPA and Building the Grid the Northwest Needs", or "Renewable" + "NIPCC" + "whitepaper".'

Clarifications
Via email exchanged with you between October 25 and 28, 2024, the agency shared preliminary search and de-duplication results. The agency mentioned that your precise search terms pulled in ±14,000 documents. The agency's Cyber office surmises that even with automated de-duping efforts, the remaining ±14,000 documents still contain many duplicate records. As a possible solution the agency suggested limiting the search with a higher duplication rate – that is, the original search deduplicated content that was 65% similar (a Cyber office default). You agreed that we would deploy a higher deduplication rate of 80% and run a second search.

Via emails exchanged with you between November 15, 2024, and December 17, 2024, the agency shared secondary search and de-duplication results. The agency's Cyber office reported that even with those de-duping efforts, the remaining results still contain many duplicate records.

As a possible solution the agency suggested limiting the search to a few targeted BPA personnel Outlook accounts. The Cyber office said that the Outlook accounts that produced the best results are the following:

- Bustamante, Richard - TO-DITT-2 - Vice President, Transmission System Operations
- Warner, Joshua - AIR-7 - Constituent Account Executive
- Cook, Joel - K-7 - Chief Operating Officer
- Baskerville, Sonya - AI-WASH - Intergovernmental Affairs Director

You agreed to have the search results responsive to your request limited to the four accounts above, and gather records from those four, only.

Record Preview & Scope Limitation
On March 26, we provided you with a list of record titles and the keyword searches that identified these records during collection. We asked you to identify specific records of interest. You agreed and limited your scope to fourteen records.

Please note, we discovered afterwards that the ‘Participant Guide BPA.docx’ is out of scope. It is not from the Outlook accounts specified above. It is a training document for contracting staff that was created by the agency’s General Counsel. As such, it will not be included in the final response.

Final Response
BPA’s Cyber Forensics team collected 177 pages of records responsive to your request. These records are being released with the following exemptions:

- Two applied under 5 U.S.C. § 552(b)(4) (Exemption 4).
- Eight applied under 5 U.S.C. § 552(b)(4) (Exemption 5).
- Six applied under 5 U.S.C. § 552(b)(6) (Exemption 6).

Explanation of Exemptions
The FOIA generally requires the release of all responsive agency records upon request. However, the FOIA permits or requires withholding certain limited information that falls under one or more of nine statutory exemptions (5 U.S.C. §§ 552(b)(1-9)). Further, section (b) of the FOIA, which contains the FOIA’s nine statutory exemptions, also directs agencies to publicly release any reasonably segregable, non-exempt information that is contained in those records.

<u>Exemption 4</u>
Exemption 4 protects “trade secrets and commercial or financial information obtained from a person [that is] privileged or confidential.” (5 U.S.C. § 552(b)(4)). Information is considered commercial or financial in nature if it relates to business or trade. This exemption is intended to protect the interests of both the agency and third-party submitters of information. Based on guidance available from the U.S. Department of Justice, we are withholding submitter commercial confidential information from public release – specifically, utility-customer account details. The FOIA does not permit a discretionary release of information otherwise protected by Exemption 4.

<u>Exemption 5</u>

Exemption 5 protects "inter-agency or intra-agency memorandums or letters which would not be available by law to a party other than an agency in litigation with the agency" (5 U.S.C. § 552(b)(5)). The deliberative process privilege protects records showing the deliberative or decision-making processes of government agencies. Records protectable under this privilege must be both pre-decisional and deliberative. A record is pre-decisional if it is generated before the adoption of an agency policy. A record is deliberative if it reflects the give-and-take of the consultative process, either by assessing the merits of a particular viewpoint, or by articulating the process used by the agency to formulate a decision.

Here, BPA relies on Exemption 5 here to protect pre-decisional staff deliberations on next steps for the NEPA process. Currently, no final decision has been made on what NEPA strategy BPA will use and if released, the harm would be to jeopardize the integrity of the NEPA process before it begins. BPA also relies on Exemption 5 to protect pre-decisional deliberations on an outreach strategy and approach for internal communication.

Attorney-client privilege protects confidential communications between an attorney and a client relating to a legal matter for which the client has sought professional advice. The privilege encompasses facts provided by the client and opinions provided by the attorney. In this case, BPA asserts Exemption 5 to protect advice related to an outreach strategy.

Records protected by Exemption 5 may be discretionarily released. BPA has considered and declined a discretionary release of some pre-decisional and deliberative information in the responsive records set because disclosure of that information would harm the interests and protections encouraged by Exemption 5.

<u>Exemption 6</u>

Exemption 6 serves to protect Personally Identifiable Information (PII) contained in agency records when no overriding public interest in the information exists. BPA does not find an overriding public interest in the release of the information redacted under Exemption 6—specifically, employee cell phone numbers. This information sheds no light on the executive functions of the agency and BPA finds no overriding public interest in its release. BPA cannot waive these redactions, as the protections afforded by Exemption 6 belong to individuals and not to the agency.

Lastly, as required by 5 U.S.C. § 552(a)(8)(A), information has been withheld only in instances where (1) disclosure is prohibited by statute, or (2) BPA foresees that disclosure would harm an interest protected by the exemption cited for the record. When full disclosure of a record is not possible, the FOIA statute further requires that BPA take reasonable steps to segregate and release nonexempt information. The agency has determined that in certain instances partial disclosure is possible and has accordingly segregated the records into exempt and non-exempt portions.

Non-Responsive Records
Several pages contain internal BPA communications that fall out of your revised request scope. Therefore, these instances are being withheld as not responsive.

Fee
There are no fees associated with processing your FOIA request.

Certification
Pursuant to 10 C.F.R. § 1004.7(b)(2), I am the individual responsible for the records search, the redactions applied thereto, and the records release described above. Your FOIA request BPA-2024-02018-F is now closed with the responsive agency information provided.

Appeal
The records release certified above is final. Pursuant to 10 C.F.R. § 1004.8, you may appeal the adequacy of the records search, and the completeness of this final release, within 90 calendar days from the date of this communication. Appeals should be addressed to:

Director, Office of Hearings and Appeals
HG-1, L'Enfant Plaza
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585-1615

The written appeal, including the envelope, must clearly indicate that a FOIA appeal is being made. You may also submit your appeal by e-mail to OHA.filings@hq.doe.gov, including the phrase "Freedom of Information Appeal" in the subject line. (The Office of Hearings and Appeals prefers to receive appeals by email.) The appeal must contain all the elements required by 10 C.F.R. § 1004.8, including a copy of the determination letter. Thereafter, judicial review will be available to you in the Federal District Court either (1) in the district where you reside, (2) where you have your principal place of business, (3) where DOE's records are situated, or (4) in the District of Columbia.

Additionally, you may contact the Office of Government Information Services (OGIS) at the National Archives and Records Administration to inquire about the FOIA mediation services they offer. The contact information for OGIS is as follows:

Office of Government Information Services
National Archives and Records Administration
8601 Adelphi Road-OGIS
College Park, Maryland 20740-6001
E-mail: ogis@nara.gov
Phone: 202-741-5770
Toll-free: 1-877-684-6448
Fax: 202-741-5769

Questions about this communication, or the status of your FOIA request, may be directed to FOIA Program Lead Jason E. Taylor at 503-230-3537 or jetaylor@bpa.gov.

Sincerely,

CANDICE PALEN

Digitally signed by CANDICE PALEN
Date: 2025.05.15 17:07:18 -07'00'

Candice D. Palen
Freedom of Information/Privacy Act Officer

What is an RTO/ISO

- Attributes of an RTO/ISO
  - Centralized least cost dispatch (Serve all load with the least expensive generation bid into the market)
  - Day-ahead market
  - Real-time market
  - Combined system into a single balancing area with reliability responsibility
  - Transmission Planning and Cost Allocation for new transmission
  - Resource Adequacy Program (resource planning on a seasonal or annual basis)
  - Resource Sufficiency Requirements (Resources available to market day ahead and real-time)
  - Governance Structure
  - Ancillary Services Market
  - Financial Transmission/Congestion Rights
  - GHG program in some markets

Existing Markets

History of Markets in the Northwest and West

- 1995-1998 Indigo
- 1998 CAISO founded
- 2000-2001 California Energy Crisis
- 1999-2003 RTO WEST
- 2004-2006 GRIDWEST
- 2006 TIG
- 2010-2013 NWPP real time market
- 2014 EIM go live with PacifiCorp
- 2018 Attempt to expand CAISO to a western RTO
- 2019-present EDAM
- 2022 BPA joins the EIM
- 2021-present SPP Markets Plus

The following are participants in Markets+ phase one development

- Advanced Power Alliance
- American Clean Power Association
- Arizona Electric Power Cooperative, Inc.
- Arizona Public Service Company
- Black Hills Colorado Electric, LLC
- Black Hills Power, Inc.
- Bonneville Power Administration
- Chelan (PUD No.1 of Chelan County)
- Cheyenne Light, Fuel & Power Co.
- Clean Energy Buyers Association
- Colorado Independent Energy Association
- Grant County Public Utility District
- Interwest Energy Alliance
- Liberty Utilities (Calpeco Electric), LLC
- Municipal Energy Agency of Nebraska
- National Resource Defense Counci
- Northwest Energy Coalition
- Northwest & Intermountain Power Producers Coalition
- NV Energy, Incl
- Pattern Energy
- Powerex Corp.
- Public Generating Pool
- Public Power Council
- Public Service Company of Colorado
- PUD No. 2 of Grant County, Washington
- Puget Sound Energy
- Renewable Northwest Project
- Salt River Project
- Sierra Club
- Snohomish Public Utility
- Tacoma Power
- The Energy Authority
- Tri-State
- Tucson Electric Power Company
- Western Energy Freedom Action
- Western Power Trading Forum
- Western Resource Advocates

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  - Governance Structure
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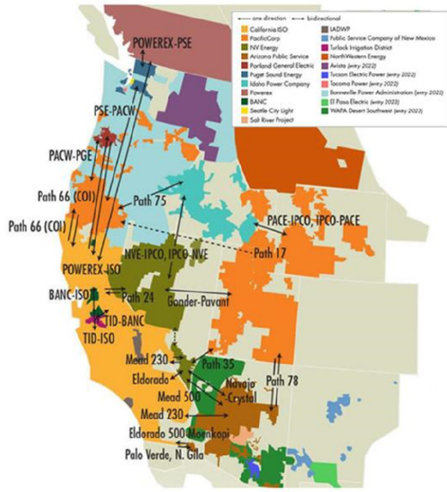
Existing Markets

Western Energy Imbalance Market



Path	Estimated Max Capacity (MW)
Path 24 *(west to east)*	100
Path 24 *(east to west)*	35-90
Eldorado	797
Path 35 *(west to east)*	580
Path 35 *(east to west)*	538
Gonder-Pavant	130
PACW to PGE	320
Path 66 *(ISO to PGE)*	627
Path 66 *(PGE to ISO)*	296
Path 66 *(ISO to PACW)*	331
Path 66 *(PACW to ISO)*	432
Path 17	0-400[1] [2]
PSE to PACW	300
Eldorado 500-Moenkopi	732
Palo Verde, N. Gila	3,151
Path 78 *(PACE to APS)*	625
Path 78 *(APS to PACE)*	660
Navajo-Crystal	522
Mead 500	349
Mead 230 *(APS <-> ISO)*	236
Mead 230 *(ISO to NVE)*	3,443
Mead 230 *(NVE to ISO)*	3,476
IPCO to PACW (Path 75)	1,500
PACW to IPCO (Path 75)	400-510
PACE to IPCO	2,557
IPCO to PACE	1,550
NVE to IPCO	262
IPCO to NVE	390-478
Powerex <-> PSE	150
Powerex <-> ISO	150
BANC <-> ISO	2,000-4,000
TID to ISO	1,400
TID to BANC	650

[1] Is an optional path available for PACE-PACW EIM transfers and the capacity is a subset of PACE-IPCO/IPCO-PACE and Path 75 capacity.

[2] When in use, the available capacity on PACE-IPCO/IPCO-PACE and Path 75 will be subsequently reduced by the used amount on Path 17, and not double counted.

Current as of October 2021

History of Markets in the Northwest and West

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- 1998 CAISO founded
- 2000-2001 California Energy Crisis
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- 2006 TIG
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- Tacoma Power
- The Energy Authority
- Tri-State
- Tucson Electric Power Company
- Western Energy Freedom Action
- Western Power Trading Forum
- Western Resource Advocates

May 2023

'Appropriate and Required': BPA and Building the Grid the Northwest Needs

For decades, the Bonneville Power Administration ("BPA") has played an integral role in the economy of the Northwest. While BPA is often regarded as the steward of the region's federal hydroelectric system—marketing power from 31 federal hydroelectric ("hydro") dams and several non-federal facilities—BPA also performs a critical function as a transmission provider. Indeed, BPA operates and maintains approximately 15,000 miles of high-voltage transmission lines in its service territory, or roughly 75% of the region's transmission system.

BPA did not become the dominant transmission provider in the Northwest by accident. This outcome was the result of repeated, focused attention by BPA, elected officials, market participants, and other stakeholders. It was not a foregone conclusion. Today, the Northwest is on the cusp of a significant transformation in how it sources power to meet the changing electricity needs of homes and businesses. The federal hydro system is a defining component of the region's electricity supply. But BPA's transmission system will receive increasing scrutiny. As utilities in the region shift the rest of their non-hydro resource mix toward a different fleet of non-emitting generation, the transmission grid will have to evolve just as rapidly. The ability of the region to meet these aggressive decarbonization goals is not assured and cannot come to pass unless the region makes significant investments through BPA and through other transmission providers to expand the availability of transmission infrastructure.

This whitepaper, produced by the Northwest & Intermountain Power Producers Coalition ("NIPPC")[1] and Renewable Northwest ("RNW"),[2] explores how to ensure that BPA maintains

Comment [N(-T1]: This is uber-true physically. We will have to decide to what degree our commercial transmission model needs to evolve to support this transition as well.

Comment [N(-T2]: Availability is both physical and commercial

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[1] NIPPC (www.nippc.org) is a membership organiza�on that represents compe��e power par�ipants in the Pacific Northwest and adjacent Intermountain region. NIPPC members include owners, operators, and developers of independent power genera�on and storage, power marketers, transmission developers, and affiliated companies. Many NIPPC members are transmission customers of BPA and bear their applicable share of costs for BPA's transmission upgrades.

[2] RNW (www.renewablenw.org) is a regional, non-profit renewable energy advocacy organiza�n based in Oregon, dedicated to decarbonizing the region by accelera�g the transi�n to renewable electricity. RNW members area

one of its core purposes—transmitting power needed across the Northwest, regardless of which entity generates or consumes it—at a time of rapid change in the industry. By adopting the reforms laid out here, or some similar combination of reforms, BPA can help ensure that the grid the Northwest needs will be in place and on time so that all consumers in the region continue to enjoy affordable, clean, and reliable electricity. This paper may be updated as new information surfaces.

Acknowledgments: This paper is the joint product of staff and consultants of NIPPC and RNW, including Henry Tilghman, Dina Dubson Kelley, Joni Sliger, Spencer Gray, and Rob Gramlich and Zachary Zimmerman with Grid Strategies.

combina�on of renewable energy businesses and environmental and consumer groups and include many transmission customers of BPA.

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Table of Contents

I. Executive Summary **4**

II. The Need for New Transmission in the Pacific Northwest **8**

III. BPA Transmission and its Role in the Northwest **10**

IV. BPA's Legal Authorities Related to Transmission **12**

V. BPA's Transmission Planning Processes **20**

- *A. Local Planning for Network and Point-to-Point Service* 20
- *B. BPA's Attachment K Process* 22
- *C. BPA's Subscription-Based Planning* 23
- *C. Interconnection Requests* 26
- *D. Regional Planning: NorthernGrid* 26

VI. Limitations of BPA's Existing Planning Processes **29**

VII. Additional Issues Unique to BPA That Impact Transmission Planning **34**

- *A. Regional Cost Allocation* 34
- *B. Transmission Siting* 34
- *C. The Assumption of Risk* 35

VIII. Avoiding the Consequences of Business as Usual **37**

IX. Comparison of Best Practices in Transmission Planning Elsewhere to BPA **39**

- *A. Proactively plan for future generation and load* 40
- *B. Account for the full range of transmission projects' benefits and use multi-value planning* 44
- *C. Address uncertainties and high-stress grid conditions explicitly through scenario-based planning* 48
- *D. Use comprehensive transmission network portfolios* 50
- *E. Jointly plan across neighboring interregional systems* 51
- *F. Stakeholder engagement and input* 53

X. Concluding Recommendations **55**

Appendix: BPA's Record of Transmission Innovation **58**

- Founding Ambitions 58
- Transmission Acquisitions 59
- Joint Transmission Construction and Ownership 59
- Private Sector Backstop 60
- Non-Wires Solutions 61
- Technical Innovation 62
- Contract Financing of Transmission 62

I. Executive Summary

BPA plays a significant role in the economy of the Pacific Northwest by delivering energy across its transmission grid. However, the transmission facilities that the Northwest relies upon to access clean and reliable power were mostly built decades ago. Aggressive state and corporate policies to mitigate climate change by changing the generation mix in favor of carbon-free (non-carbon emitting) resources, combined with the impacts to loads and hydro availability from a changing climate, will require significant investment in new transmission facilities to ensure that the output of new resources can be moved from where it can be generated to where it will be consumed. In earlier periods of rapid transformation of the energy industry, BPA played a leading role in developing a transmission grid that met the region's needs. The Northwest now needs BPA to resume that leadership role in the development of new transmission resources, alongside other transmission providers.

Unfortunately, BPA's current transmission planning and related processes are not well-suited to ensure that transmission gets built in time for the wave of change underway. If BPA does not implement process reforms, the ability of consumers, communities, and states as a whole to meet clean energy requirements and goals will be jeopardized. Likewise, with increasing concerns over resource adequacy and climate-related extreme weather events, new and upgraded transmission lines can help ensure system reliability. Fortunately, if BPA implements the recommendations set forth below, which are permissible under its existing legal authorities, BPA can reassert itself as the region's leader in providing a backbone transmission system, alongside a wider range of private transmission developers complementing BPA's work than in the past. BPA appears to have begun recognizing this need for change.

This whitepaper first explores the need for new transmission in the region, establishing that loads in the Northwest are forecast to increase dramatically and that the current resource mix will change dramatically in favor of non-carbon-emitting resources that require more transmission capacity for several reasons. Next, we explore BPA's enabling statutes, which give BPA broad authority and discretion to provide transmission to customers in the Northwest. An appendix provides additional historical context about instances of BPA innovation and leadership in the field of transmission. We then review BPA's existing planning processes and compare them to best practices in other jurisdictions in the U.S., showing the limitations of BPA's processes. These limitations include assumptions that are too conservative, planning over a time horizon that is too short, and too heavy a reliance on discrete customers to shoulder the financial cost of expanding the grid. Due to these limitations, there is a significant risk that transmission facilities will not be available when they are needed. Finally, we propose a suite of reforms. If BPA adopts these recommendations, the region will be much more likely to continue to enjoy access to safe, reliable, and affordable electricity in the future, even as it copes with a

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Comment [N(-T3]: The business model updates that Chris and I have been developing provides BPA flexibility to use varying models as makes sense for specific projects changing climate and implements policies designed to reduce the region's reliance on carbon-emitting generation resources.[3]

While this paper focuses on the details of how BPA plans and builds transmission and the nexus between BPA, independent power producers, and utilities, this focus does not imply that BPA should be considered once again the transmission builder of first resort for all or most transmission in the Northwest. Competitive merchant and utility transmission projects should have an essential role in assuming some development risk and responsibility for transmission expansion in the Northwest, particularly for projects that fall outside of BPA's existing rights-of-way or primary network. Similarly, regional projects involving more than one transmission provider should be an important part of BPA's solution set. Nevertheless, the region's currently dominant transmission provider has a significant and indispensable role of its own to play in upgrading and potentially expanding its existing backbone grid, such as upgrading line ratings, doubling circuits, and building tie lines in gaps between existing BPA segments.

Comment [N(-T4]: We might want to note that third-party transmission impacts already allow/require this to some degree and BPA has a substantial amount of transmission projects MW in process that require actions on the part of TPs other than ourselves. We should be aware, though, that those processes are somewhat embryonic – we are working with other TPs (PGE, Puget, etc to work those processes out as we go along- which may to some degree be the best way to do it, although with more maturity).

This paper does not address challenges and potential solutions to interconnecting new generation on BPA's system, given that BPA has already launched a proceeding to address that important problem. Nor does it address siting and permitting challenges that are a separate major impediment to expanding transmission capacity that affects all transmission providers, not just BPA.

Our proposed recommendations are summarized as follows:

1. **Planning reforms.** BPA should revise its planning process to:
   (A) consider a wider array of transmission projects' benefits;
   (B) regularly conduct proactive local and regional 20-year scenario planning, including a wide range of plausible (for example, at the 95th percentile) but uncertain extreme weather conditions and a range of new generation resources, with robust stakeholder input;
   (C) independently consider state policy requirements and other transmission demand drivers;
   (D) consider a wider range of transmission portfolio future scenarios, including co-optimizing storage and other technologies, in the 10- and 20-year planning timeframes, that may identify "no regrets" or "least regrets" portfolios; and
   (E) remain committed to regional and interregional planning with other transmission providers (recognizing that the best transmission solutions are sometimes regional or interregional, not contained within a single provider's system).

Comment [N(-T5]: This may be based on the misconception that projects need to be "fully subscribed", which is not true now (and wasn't during NOS either). It has always been my understanding that the administrator can consider any factors s/he feels are relevant in making project build decisions

Comment [N(-T6]: If BPA wanted to, we could share amounts of active MW that have identified 3rd party project impacts (B2H,...)

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[3] This whitepaper does not endeavor to provide an exhaustive list of all potential transmission reforms that BPA or the region's policymakers should consider pursuing. Rather, this paper seeks to provide recommendations that are well-balanced, taking into account BPA's wide spectrum of customers, and that can be implemented on a relatively expedient basis in order to meet the region's significant transmission needs. More foundational potential statutory and mission-related changes (such as opening up the Pacific Northwest Electric Power Planning and Conservation Act) are not addressed here.

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2. **Business case for commercial transmission.** In determining whether to move towards construction of new lines, BPA should:
   (A) develop an open and transparent policy specifying the system benefits and revenue thresholds it considers in determining whether to offer customers service at an embedded or incremental rate;
   (B) ensure that a wider array of benefits is considered and deducted from the revenue requirement that must be met through subscriptions;
   (C) lower the apparently very high threshold of subscriptions (binding commitments to take transmission service) required to proceed to most construction; and
   (D) separately develop an analytical framework to consider how to incorporate into its long-term planning facilities that appear repeatedly in multiple planning studies but lack a critical mass of subscribers committing financially to upgrades.

3. **Participant funding.** BPA should:
   (A) develop a formal policy identifying the criteria under which it will conduct engineering, siting, and other pre-construction studies for transmission line upgrades at its own expense and identifying how those costs will eventually be recovered from customers; and
   (B) revisit and consider lowering the currently high letter of credit/deposit requirement for Transmission Service Request Study and Expansion Process ("TSEP") subscribers, while addressing the need to protect against undue risks of stranded costs.

4. **Contracting innovation.** BPA should:
   (A) explore using BPA's Transmission Business Line itself as an anchor, or backstop, tenant by exercising a "put option" on some carefully chosen commercial transmission built by BPA;
   (B) explore whether investor-owned utilities ("IOUs") can and would be willing serve in some form as backstop subscribers for some new transmission capacity, perhaps until independent power producers ("IPPs") fill in the capacity on a given line in the course of delivering power to those IOU offtakers; and
   (C) explore joint venture and partnership opportunities that rely on private capital and private projects to take initial development, construction, or subscription risk in lieu of BPA.

5. **Risk calculations.** BPA should:
   (A) revisit the core question of how much risk the agency will assume in pursuing a renewed transmission construction agenda, including an analysis of potential benchmark levels of risk (for example, outcomes modeled at a 95th percentile);
   (B) review and share with stakeholders whether past transmission investments have actually resulted in any stranded assets (and whether the stranding was temporary or persistent); and
   (C) analyze and consider new revenue opportunities to the agency from having and selling more transmission capacity through a variety of existing and potentially new transmission products.

Comment [N(-T7]: As Cherilyn pointed out – BPA doesn't have to go all or nothing on this – we could also 1) choose to "pre-define" the customer's exposure to these costs – i.e., if customer pays X, BPA will cover any increased cost – remove risk of the unknown or 2) split these costs with customers in some manner, particularly when the costs are going to be high. Maintaining some portion of costs on customers allows BPA to achieve some pretty valuable queue management – since TSRs stay in the queue until they reach impactful decision points (customer has to commit to something). There would be consequences for giving up these benefits completely.

Comment [N(-T8]: Directly related to the process re-design work that Chris and I have been doing. One thought though- I doubt that BPA wants to (or should) DEFINE specific criteria, but think that more articulation of the factors that drive these decisions would be pretty helpful to the region (just my opinion). So would some earlier embedded/incremental rate determinations, which we built potential for into the new business model draft.

Comment [N(-T9]: I wonder if BPA's willingness to move forward with projects that are not fully subscribed is essentially this?

Comment [N(-T10]: This could look like a commitment to take transmission (either them or the generating party) that sinks to their service territory and uses a particular project (certain amount of actual impact on that project) within some timeframe and for some minimum number of year. Not sure that we actually need to do this though to obtain enough support for some of these projects!

Comment [N(-T11]: I don't love this idea – feels like it would result in giving up the value of some of the TX that we are building. But could note that if the requestor can choose to pay an incremental rate if that makes economic sense for them.

Comment [N(-T12]: I get that reviews can be helpful. However, we need to be careful about what we spend our limited resource on – probably need to make that point in this larger conversation.

Comment [N(-T13]: Worth noting that historically we've been reluctant to attribute Bridge CFS revenue to offsetting the cost of a project, but could think more about that.

6. **Process.** BPA should:

(A) conduct an iterative customer-facing initiative to consider and make the changes recommended above, including an active effort to solicit the perspective of state regulatory commissions, potentially as inputs into BPA's upcoming revision of its strategic plan and transmission business model;
(B) following such an initiative, conduct a formal tariff revision process to incorporate those reforms into its business practices or its transmission tariff, but in the tariff only to the extent a given reform requires such a revision; and
(C) advocate within NorthernGrid for the adoption of similar reforms in the planning processes of NorthernGrid and any successor organization.

7. **Transparency**. In considering and implementing the above-described processes and reforms, BPA should make the processes and decision points about reform transparent, including by ensuring that BPA's website acts as a repository of up-to-date information, as well as relevant historical documents.

8. **Compensation.** In order to support BPA recruiting and retaining the necessary transmission planning, business case, and associated transmission staff to carry out the reforms proposed in this whitepaper, Congress should pass competitive compensation reform for BPA.

Comment [N(-T14]: Huh – interesting. I'll note that if BPA needs a bigger talent pool, allowing remote work for jobs for which it is workable would definitely increase the BPAs access to talent. Acts of Congress are hard to come by. More liberal use of retention bonuses, etc might help some too. We do seem to be losing talent these days.

II. The Need for New Transmission in the Pacific Northwest

Multiple independent analyses and market data indicate that the Pacific Northwest needs to expand its transmission grid. Operating conditions are changing: climate change is leading to longer and more severe extreme weather, putting pressure on the grid as operators seek to move electricity from areas with surplus generation to areas experiencing extreme weather conditions. The generation fleet is transforming: public policy and market economics have led to the retirement of fossil fuel-powered generation in favor of generation resources that do not emit carbon into the atmosphere. Demand is growing: state energy policies are also expected to lead to the rapid adoption of electric vehicles and electrification of other sectors, putting further pressure on the transmission grid. Numerous national and regional studies have demonstrated that these climate and policy drivers will require new transmission facilities. For example:

- One national study by researchers at Princeton University found that in order to meet energy demand by 2050—and in particular, demand for renewable electricity—transmission capacity will have to increase by 60%.[4]
- Another study by researchers at the Massachusetts Institute of Technology found that the U.S. will require a 90% increase in transmission capacity to meet the cost-optimized scenario to maintain global warming between 1.5-2 degrees Celsius.[5]
- A report by the non-profit Energy Systems Integration Group, summarizing research from six different studies, found that meeting the Biden Administration's goal to reach 100 percent clean electricity by 2035 and net-zero emissions across the economy by 2050 will require a doubling or tripling of the size and scale of the nation's transmission system.[6]

In February, the U.S. Department of Energy ("DOE") released a draft study of national and regional transmission needs, after reviewing over 200 scenarios from six recent capacity expansion modeling studies:

- DOE estimated that the Pacific Northwest will need to add 56% more transmission capacity (8.5 terawatt-miles ("TW-mi")) by 2040 in an aggressive decarbonization scenario.[7]

[4] Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, 13-14 (Dec. 15, 2020), *available at*: https://netzeroamerica.princeton.edu/img/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf.
[5] Brown, P. R., and A. Boterud, Joule5(1), *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the U.S. Electricity System*, 115-134 (2020), *available at*: https://doi.org/10.1016/j.joule.2020.11.013.
[6] Energy Systems Integra�on Group, *Transmission Planning for 100% Clean Electricity*, 10 (Feb. 2021), *available at* https://www.esig.energy/wp-content/uploads/2021/02/Transmission-Planning-White-Paper.pdf.
[7] U.S. Department of Energy, *Draft National Transmission Needs Study* ("DOE Dra�Needs Study"), 89 (Feb. 2023) *available at:* https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf. The granular regional and interregional study results reviewed by DOE included the Princeton and MIT studies cited above.

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- DOE estimated a nearly equal amount (7.7 TW-mi) needed in the surrounding Mountain region.
- To provide a sense of scale, if that combined 16.2 TW-mi need was met with discrete moderate-length alternating current ("AC") lines, it would require building 61 new 200-mile long 500-kV lines.[8]
- In the same aggressive scenarios, DOE also estimated a need in 2040 for 37% more transfer capacity (1.9 GW) between the Northwest and California and 308% more transfer capacity (39.2 GW) between the Northwest and Mountain states.[9]

Finally, regional estimates of the expected and potential generation build-out in the Northwest underscore this driver of the need for new transmission:

- According to the Northwest Power and Conservation Council, the region will need 3,500 MW of new renewable generation by 2027 and 14,000 MW of renewable generation by 2040.[10]
- According to the Pacific Northwest Utilities Conference Committee ("PNUCC"), the region will need 9,400 MW of new renewable generation by 2032 with associated transmission.[11]
- Analysis by Evolved Energy Research on behalf of the Clean Energy Transition Institution found that deeply decarbonizing all sectors in the Northwest would lead to a 60% increase in load (because of electrifying other sectors) and therefore a need for 100,000 MW of new resources by 2050, a quantity that may be considered an upper bound.[12]

[8] Terawat-miles are a measurement unit common in models for transmission capacity expansion because they allow a single unit to cover all poten�l new lines in a region by elimina�g differences in their carrying capacity. AC lines that are shorter or have a higher nominal voltage have higher carrying capacity. For example, an uncompensated 200-mile 500-kV AC line has about the same carrying capacity as a 50-mile 345-kV line. (DOE Dra� Needs Study, 88).

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[9] DOE Dra� Needs Study, 96-97. "Transfer capacity" is some�es referred to interchangeably as "transfer capability," but *capacity* iden�es only the ra�gs of transmission lines that account for their thermal limits, whereas *capability* accounts for other network elements that might limit the reliable transfer of power from one area to another.

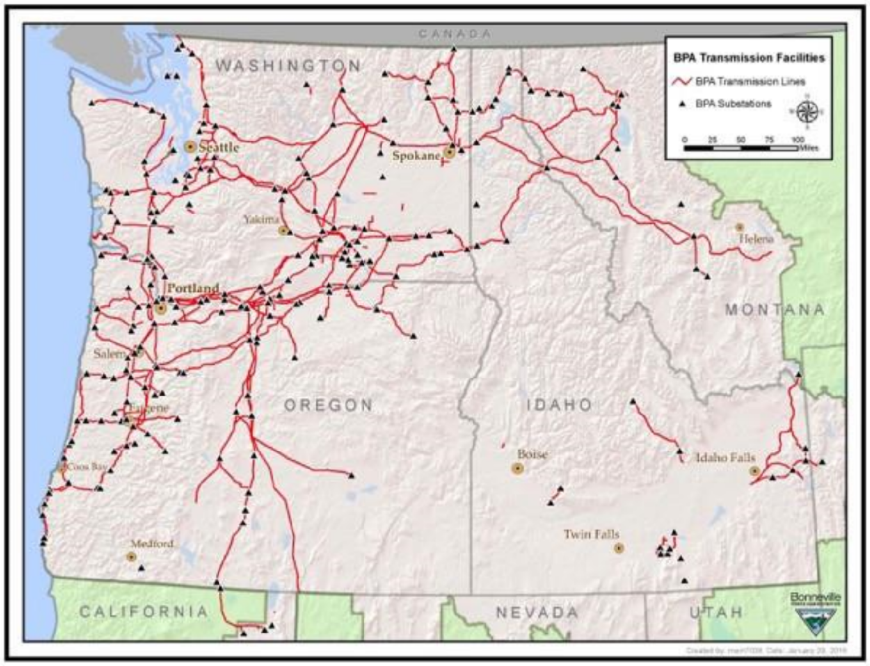
[10] Northwest Power and Conserva�n Council, *2021 Northwest Power Plan*, 71-77 (Mar. 2022), *available at*: https://www.nwcouncil.org/media/filer_public/4b/68/4b681860-f663-4728-987e-7f02cd09ef9c/2021powerplan_2022-3.pdf.

[11] Pacific Northwest U�ity Conference Commitee, *Northwest Regional Forecast of Power Loads and Resources 2022 through 2032* ("PNUCC 2022 Regional Forecast"), 11 (April 2022), *available at:* https://www.pnucc.org/wp-content/uploads/2022-PNUCC-Northwest-Regional-Forecast-final.pdf.

[12] Evolved Energy Research, *Northwest Deep Decarbonization Pathways Study*, 73-74 (May 2019), *available at:* https://uploads-ssl.webflow.com/5d8aa5c4ff027473b00c1516/6229312d39eca8b6b5�68_EER_Northwest_Deep_Decarboniza�on_Pathways_Study_Final_May_2019.pdf .

III. BPA Transmission and its Role in the Northwest

Figure 1. Map of BPA Transmission Facilities



Available at: https://www.bpa.gov/-/media/Aep/about/publications/maps/bpa-tlines-small.pdf

BPA's transmission forms the backbone for the electric grid in the Pacific Northwest and allows energy to flow from Montana to the West Coast and from Canada to California. BPA operates 15,179 circuit-miles of high voltage transmission lines and 259 substations across the states of Washington, Oregon, Idaho, and Montana, including interties to British Columbia, eastern Montana, and California. Facilities controlled by BPA represent 75% of the high voltage transmission capacity in the Pacific Northwest.[13] The region's load-serving entities—investor-owned utilities, consumer-owned utilities, and competitive retail service providers—depend on BPA transmission to deliver energy to their retail customers. As the mix of generation resources in the Pacific Northwest changes, the availability of transmission service to deliver energy from where it is needed to where it is consumed is becoming increasingly constrained.

[13] BPA, *BPA Facts* (Aug. 2021), ***available at:*** https://www.bpa.gov/-/media/Aep/about/publications/general-documents/bpa-facts.pdf.

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BPA has specific statutory obligations to the region (described more fully below in Section IV); these responsibilities include providing necessary transmission. However, unlike a transmission owner that is an investor-owned utility or a merchant transmission developer, BPA has no profit incentive to invest capital in new transmission.[14] This reality may contribute to suppressing BPA's current incentive to build more transmission.

NIPPC and RNW also strongly support competitive, private sector solutions to the Northwest's needs that help avoid or mitigate some stranded asset risks for BPA's rate base. But given BPA's dominant role in providing transmission service to the region, the private sector is ill-situated to solve by itself a transmission build-out of the magnitude anticipated. The Appendix explores how BPA has supported transmission in the past to meet the region's evolving energy needs. BPA itself has recently begun recognizing the evolving grid, changing demands on BPA, and the role that BPA might play in helping address the region's urgent transmission demands.[15] The remainder of this whitepaper explores what BPA is doing now to plan and build new transmission and suggests ways BPA could carry out these responsibilities more effectively.

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[14] Investor-owned u��es are guaranteed a rate of return on prudent investments. In contrast, as a government en�y that must limit its rates to covering its costs and lacks shareholders who put their equity at risk, BPA does not have a profit mo�e to expand the grid similar to a private company.

[15] *See* BPA, *The Evolving Grid: Update on the State of Transmission* (April 27, 2023), *slides available at*: https://www.bpa.gov/-/media/Aep/transmission/transmission-business-model/042723-evolving-grid-bpat-final.pdf, *workshop recording available at*: https://youtu.be/rbYbQf-wD6E. This recent presenta�on is highly informa�e about BPA's current transmission planning queue and upcoming construc�on agenda.

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IV. BPA's Legal Authorities Related to Transmission

A. Congress Has Given BPA Broad Discretion to Function in a Business-Like Manner, Including in Managing the Transmission System

Four statutes primarily govern BPA's operations: 1) the Bonneville Project Act of 1937 (the "Project Act");[16] 2) the Pacific Northwest Consumer Power Preference Act of 1964 (the "Preference Act");[17] 3) the Federal Columbia River Transmission System Act of 1974 (the "Transmission Act");[18] and 4) the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (the "Northwest Power Act").[19] Overall, these statutes afford BPA broad discretion, including over its management of the federal transmission system in the Pacific Northwest.

The Project Act recognizes that transmission is essential to "encourag[ing] the widest possible use of" federal power.[20] To that end, it has directed BPA since 1937 to "provide, construct, operate, maintain, and improve" such transmission facilities as BPA finds "necessary, desirable, or appropriate" for transmitting federal power.[21] In the words of the Ninth Circuit Court of Appeals (the "Ninth Circuit") in resolving a dispute about BPA's authority:[22]

> This delegation of authority is broad, allowing the [BPA] Administrator substantial discretion. This discretion is tempered only by the implied limitation that the Administrator's action not be inconsistent with other congressional decrees."[23]

The Preference Act directs BPA to provide for transmitting non-federal power any available transmission capacity that is in excess of federal power needs.[24] BPA is obligated to set "equitable rates" for such usage.[25] The Project Act had already provided BPA with broad

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[16] 16 U.S.C. §§ 832-832*l*.

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[17] 16 U.S.C. §§ 837-837*h*.

[18] 16 U.S.C. §§ 838-838*l*. This Act is also some�mes referred to as the Pacific Northwest Federal Transmission System Act or simply the Transmission System Act.

[19] 16 U.S.C. §§ 839-839*h*. This Act is also some�mes referred to as the Regional Act.

[20] 16 U.S.C. § 832a(b).

[21] Aug. 20, 1937, ch. 720, §2, 50 Stat. 732 (codified as amended at 16 U.S.C. § 832a(b)); *see also* 16 U.S.C. § 832e (direc�ng BPA to set customer rates for federal power "with a view to encouraging the widest possible diversified use of electric energy").

The Project Act, even as codified, refers specifically to BPA transmi�ng power from BPA's namesake, the Bonneville Dam. 16 U.S.C. § 832a(b). BPA's purview has since expanded to many other federal facili�es. *E.g.,* the Flood Control Act of 1944, Dec. 22, 1944, ch. 665, §5, 58 Stat. 890 (codified in relevant part in 16 U.S.C. § 825s)*; see also* 16 U.S.C. § 839e(a)(1), 839e(k) (referencing BPA's con�nuing obliga�ons under the Flood Control Act of 1944).

[22] The Northwest Power Act specifically vests the Ninth Circuit with jurisdic�on to hear challenges to BPA ac�ons. 16 USC § 839f.

[23] *California Energy Comm'n v. Bonneville Power Admin.*, 909 F.2d 1298, 1314 n.17 (9th Cir. 1990).

[24] 16 U.S.C. § 837e. The Transmission Act later affirmed this and required it to be done on a "fair and nondiscriminatory basis." 16 U.S.C. § 838d.

[25] 16 U.S.C. § 837e.

authority to negotiate contracts as BPA deemed "necessary,"[26] and BPA has since interpreted the Project Act to authorize it to establish generally applicable terms and conditions for transmission service of both federal and non-federal power.[27]

The Preference Act affirms BPA's historic focus on serving customers in the Pacific Northwest.[28] In that context, it generally prohibits BPA from constructing transmission facilities outside the Pacific Northwest.[29] Still, BPA may pursue such facilities as BPA "deems necessary to allow mutually beneficial power sales" with California.[30]

The Transmission Act granted BPA "even broader transmission authority."[31] It directs that:

> [BPA] shall operate and maintain the Federal transmission system within the Pacific Northwest and shall construct improvements, betterments, and additions to and replacements of such system within the Pacific Northwest as [BPA] determines are appropriate and required to:
>
> (a) integrate and transmit the electric power from existing or additional Federal or non-Federal generating units;
> (b) provide service to [BPA's] customers;
> (c) provide interregional transmission facilities; or
> (d) maintain the electrical stability and electrical reliability of the Federal system[.][32]

Thus, among other authority and obligations, the Transmission Act provides the statutory authority for BPA to build new transmission as needed to transmit non-federal power.

In addition, the Transmission Act freed BPA from relying on Congress's annual appropriations for transmission expenditures in the Pacific Northwest.[33] Under the Transmission Act, BPA

[26] 16 U.S.C. § 832a(b).
[27] *E.g.*, TC-20 Tariff Terms and Condi�ons Proceeding, Record of Decision, TC-20-A-03 at 8-9 (Mar. 1, 2019) [hereina�er TC-20 ROD].
[28] *E.g.,* 16 U.S.C. § 837f. Such provisions are generally consistent with BPA's longstanding obliga�on to serve those persons "within economic transmission distance of the Bonneville project." 16 U.S.C. § 837c(d).
[29] 16 U.S.C. § 837g.
[30] 16 U.S.C. § 837g-1. This provision has been codified with the Preference Act, but it was actually enacted about 20 years later in the context of Congress authorizing BPA's par�cipa�on in the development of the Third AC Inter� of the California-Oregon Inter�. Pub. L. 98–360, �tle III, July 16, 1984, 98 Stat. 416; see generally *Pacific Gas and Electric Company; Pacific Gas and Electric Company; Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company,* 63 FERC ¶ 63,018, 65,070 (June 30, 1993) (discussing this history).
[31] *Ass'n of Pub. Agency Customers v. BPA,* 126 F.3d 1158, 1170 (9th Cir. 1997).
[32] 16 U.S.C. § 838b.
[33] 16 U.S.C. § 838b. BPA does need some form of Congressional approval (but not appropria�ons) before construc�ng "major transmission facili�es" in the region, which the statute defines as facili�es "intended to be used to provide services not previously provided." 16 U.S.C. §§ 838a, 838b. There are prior examples of Congress approving such expenditures, either directly or by reference, such as in an appropria�ons legisla�ve vehicle. *E.g.,*

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became a self-financing agency primarily dependent upon revenues from the services it provides to sustain ongoing activity; this activity is capitalized primarily through funds borrowed directly from the U.S. Treasury and repaid with interest.[34] BPA must consider its obligations to repay Treasury funds when it sets customer rates.[35] Both the Transmission Act and the Northwest Power Act direct BPA to set customer rates consistent with "sound business principles."[36] BPA must also set rates "sufficient to assure repayment" of the federal investment in hydro generation, fish and wildlife recovery, and conservation.[37] Thus, BPA typically does not need specific Congressional authorization to move forward with projects in the Pacific Northwest once BPA has determined they are "appropriate and required" to meet BPA's statutory goals above. But BPA must charge rates sufficient to recover the costs of those projects.

The Northwest Power Act directs BPA to carry out its obligations "in a sound and businesslike manner."[38] It also, for the first time, specifically obligated BPA to undertake certain environmental and conservation endeavors.[39] The Ninth Circuit has noted that BPA's new "more typically governmental responsibilities" under the Northwest Power Act "suggest the propriety of even greater deference" to BPA's business-like decision-making.[40]

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The Northwest Power Act also specifically vested the Ninth Circuit with jurisdiction to hear challenges to BPA actions, but the Ninth Circuit has generally, to date, taken a very deferential approach.[41] The Ninth Circuit has described BPA's governing statutes as endow[ing] the

Consolidated Appropria�ons Act, 2014, Public Law 113-76, 128 Stat. 170 (approving BPA's request to spend its funds to construct a new high voltage line to serve customers in southern Idaho, southern Montana, and western Wyoming). Under the Transmission Act, BPA is s�l obligated to submit an annual budget to Congress; items included in the budget need no further appropria�on, and BPA's annual submission may include a request for approval of major transmission facili�es. *Id.* § 838i(a). Congress may impose limits on BPA, which BPA must adhere to. *Id.*, at § 838i(b).

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[34] *See generally* 16 U.S.C. §§ 838i, 838k.
[35] 16 U.S.C. § 838g.
[36] The Transmission Act directs BPA to set rates "with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles." 16 U.S.C. § 838g. BPA must also consider its need to recover costs and repay its debts. *Id.* The Northwest Power Act directs BPA to set rates "in accordance with sound business principles" and other statutory provisions like the one quoted above, which FERC must approve upon a finding that the rates: 1) "are sufficient to assure repayment" of the federal investment; 2) "are based upon … total system costs"; and 3) for transmission rates, "equitably allocate the costs of the Federal transmission system between federal and non-Federal power" users. 16 U.S.C. § 839e.
[37] 16 U.S.C. § 839e.
[38] 16 U.S.C. § 839f(b).
[39] *See generally* 16 U.S.C. §§ 839-839*h*.
[40] *Ass'n of Pub. Agency Customers*, 126 F.3d at 1170.
[41] 16 USC § 839f. The Supreme Court has also commented on the deferen�al review due to BPA, based in part on the complexity of BPA's work and BPA's in�mate involvement in the legisla�ve dra�ng of BPA's statutes. *Aluminum Co. of America v. Central Lincoln Peoples' Utility Dist.*, 467 U.S. 380, 390 (1984).

Administrator with broad-based powers to act in accordance with BPA's best business interests—powers not normally afforded government agencies.[42]

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The Ninth Circuit has recognized that Congress intended for "BPA to function more like a business than a governmental regulatory agency"[43] and that Congress "granted BPA an unusually expansive mandate to operate with a business-oriented philosophy."[44] In this context, the Ninth Circuit has recognized that its review has been "particularly deferential" to BPA.[45]

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Finally, Congress has also declared broad policies which BPA should pursue. One is to "encourage … the development of renewable resources within the Pacific Northwest."[46] Another is "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply."[47] These goals should inform BPA's exercise of its discretion and underscore BPA's important role in facilitating the development of renewable resources and the transmission needed to supply customers with electricity regardless of the generating source.

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In summary, BPA has statutory obligations to maintain and improve the federal transmission system in the Pacific Northwest, which it may carry out with an unusually high level of discretion. Unlike most agencies, BPA is generally not subject to the typical appropriations approval process for agency action. Instead, it must, in a sound business-like manner, set rates for the services it provides with an eye to providing service while still recouping its costs, including its repayment of the federal investment in hydro generation, fish and wildlife recovery, and conservation.[48] BPA aims to keep rates low, but that goal does not ultimately trump BPA's obligations to maintain and improve the transmission system.

B. BPA Must Provide Transmission Service in Accordance with its Adopted Terms and Conditions for Providing Service

Like most transmission providers, BPA has streamlined its contracting process for offering transmission service by adopting generically applicable terms and conditions for such service. These generic terms and conditions are commonly referred to as an "Open Access Transmission Tariff" or "OATT," an industry term that was widely adopted following the seminal open access

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[42] *Ass'n of Pub. Agency Customers*, 126 F.3d at 1170; *see also Bell v. BPA*, 340 F.3d 945, 949 (Ninth Cir. 2003) ("We will not second-guess the wisdom of BPA's winning business decisions, especially when it was responding to unprecedented market changes.").

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[43] *Ass'n of Pub. Agency Customers*, 126 F.3d at 1170; *see also, e.g.,* 16 U.S.C. § 832a(b), 832a(f).

[44] *Ass'n of Pub. Agency Customers*, 126 F.3d at 1171; *see also Indus. Customers of Northwest Utils. v. BPA*, 767 F.3d 912, 923-924 (2014) (noting BPA has "wide latitude" both "in spending" and in deciding "how best to further BPA's business interests consistent with its public mission.") (citing *Aluminum Co.,* 467 U.S. at 789)).

[45] *Pac. Northwest Generating Coop. v. Dep't of Energy*, 580 F.3d 792, 806 (2009).

[46] 16 U.S.C. § 839(1)(B).

[47] 16 U.S.C. § 839(2).

[48] *See supra* footnote 21.

directive of the Federal Energy Regulatory Commission ("FERC"), Order 888.[49] As noted earlier, BPA has broad authority to negotiate contracts under the Project Act,[50] and BPA has since interpreted the Project Act to authorize it to establish generally applicable terms and conditions for transmission service of both federal and non-federal power.[51] This section of this paper addresses BPA's foundational obligation to adhere to its OATT.

Unlike most transmission providers, BPA is generally[52] not subject to FERC oversight or directives for setting generically applicable transmission terms and conditions.[53] In the past, BPA voluntarily sought (and sometimes obtained) FERC's approval of BPA's OATT in order to obtain "safe harbor reciprocity status,"[54] which would require most other transmission providers to provide transmission service to BPA pursuant to their own FERC-approved OATTs.[55] In 2013, FERC declined to grant BPA safe harbor reciprocity status,[56] and in 2016, rather than address FERC's criticisms, BPA decided not to seek reciprocity status.[57] Nonetheless, this history provides useful context in understanding BPA's decision-making within a policy space in which FERC and other transmission providers have established certain principles and ideals, even though BPA is generally not directly beholden to FERC's directives.[58] *See footnote 105 for additional distinctions between BPA and transmission-owning utilities.*

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[49] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[50] 16 U.S.C. § 832a(b).

[51] *E.g.*, TC-20 ROD at 8-9.

[52] FERC can enforce BPA's obligation to offer transmission service at rates comparable to those BPA pays and on terms and conditions that are "not unduly discriminatory or preferential." 16 U.S.C. § 824j-1(b); *see also Iberdrola Renewables, Inc. v. BPA*, 137 FERC ¶ 61,185, at ¶ 61,949 (Dec. 7, 2011) (exercising this authority); *cf.* 16 U.S.C. § 824k (describing additional FERC authority over BPA's terms of transmission service).

[53] BPA is not a "public utility" under key provisions of the Federal Power Act. 16 U.S.C. §§ 824, 824d, 824e. However, it can (and has) obligated itself to at least consider FERC's standards under certain of those provisions. TC-20 ROD at 9-10.

[54] *See generally BPA, Order on Petition for Declaratory Order*, 145 FERC ¶ 61,150 at PP 2-7 (Nov. 21, 2013) (addressing a BPA request for reciprocity status and discussing BPA's history).

[55] *See* FERC Order No. 888, 61 Fed. Reg. 21,540 at 21,613-14 and 21,668-69 (May 10, 1996); FERC Order No. 888-A, 62 Fed. Reg. 12,274 at 12,338-40 (Mar. 14, 1997).

[56] *BPA, Order on Petition for Declaratory Order,* 145 FERC ¶ 61,150 at P 1 (Nov. 21, 2013). While FERC accepted several proposed changes to BPA's OATT, FERC identified additional changes that would need to be made before FERC could grant BPA safe harbor reciprocity status. These changes include updates to Schedules 9 and 10 regarding BPA's provision of Generator Imbalance Service; removal of the price cap on transmission capacity reassignments; and minor updates to Atachment C, which describes BPA's Available Transfer Capacity methodology.

[57] *See* TC-20 ROD, Appendix 1 at 1. It is possible that BPA could change its mind in the future.

[58] Importantly distinct from this discussion of transmission terms and conditions is BPA's obligation to comply with certain FERC-jurisdictional reliability and safety standards, such as those promulgated by the North American Electric Reliability Corporation ("NERC") or the Western Electricity Coordinating Council ("WECC"). *See generally* BPA, *Reliability & NERC Standards, available at:* https://www.bpa.gov/energy-and-services/transmission/reliability-nerc-standards.

In 2018, BPA launched its own proceeding (distinct from a FERC tariff update) to update BPA's OATT.[59] Under the Energy Policy Act of 1992, Congress declared that BPA "may" hold a hearing when establishing transmission terms and service and that, if BPA pursues that option, then BPA must follow certain procedural requirements.[60] BPA did so in 2018, and in that proceeding developed an OATT that commits BPA to follow Congress's specified procedures for future changes to BPA's OATT.[61] Further, while BPA may generally amend its OATT through proceedings that comply with the statutory procedures,[62] BPA committed to its customers that BPA would not make changes to its OATT before October 1, 2028 without complying with the statutory procedures.[63]

In short, when considering the specific terms and conditions of BPA's OATT, discussed elsewhere in this whitepaper, it bears emphasis that BPA has committed itself to following an administrative procedure before changing any provisions of its OATT.[64]

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C. BPA's Adopted Terms and Conditions for Providing Transmission Service Provide BPA a Reasonable Amount of Discretion to Manage Future Transmission Needs and Allocate Costs

BPA's OATT addresses both BPA's obligation to provide transmission service and transmission customers' obligations to agree to pay the costs that BPA incurs to provide transmission service. While BPA has general obligations to recover its costs, and bearing in mind statutory requirements applicable to BPA, BPA's OATT and related business practices afford BPA meaningful discretion in assessing when costs are properly attributable to a particular transmission customer(s) or should be spread broadly across the transmission system.[65]

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Recall that BPA's statutory mandates give BPA significant discretion in managing costs. As discussed above, BPA is a self-financing agency that primarily relies upon raising capital using its Treasury borrowing authority and third-party contractual commitments, and generates

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[59] TC-20 ROD, at 1.

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[60] Energy Policy Act of 1992, Pub. L. 102–486, �le VII, §722, Oct. 24, 1992, 106 Stat. 2916 (codified at 16 U.S.C. § 824k(i)).

[61] TC-20 ROD, at 11-13; *see also* BPA OATT § 9 ("Subject to applicable law, Bonneville commits to open access transmission service. Bonneville shall follow the statutory procedures in Sec�n 212(i)(2)(A) of the Federal Power Act to set generally applicable terms and condi�ns in its Tariff…"), *available at:* https://www.bpa.gov/-/media/Aep/transmission/open-access-transmission-tariff/bpa-open-access-transmission-tariff-20211001.pdf.

[62] BPA has in fact amended its OATT through proceedings that comply with the statutory procedures. *See generally TC-22 Tariff Proceeding*, Administrator's Final Record of Decision, TC-22-A-03 (July 2021); *TC-24 Tariff Proceeding*, Administrator's Final Record of Decision, TC-24-A-02 (Feb. 2023).

[63] TC-20 ROD, at 13. This date is significant for BPA; BPA an�ipates entering into new power customer agreements that will take effect that date. *See generally* BPA, *Provider of Choice (Post-2028), available at:* https://www.bpa.gov/energy-and-services/power/provider-of-choice.

[64] TC-20 ROD, at 11-13; *see also* OATT § 9 ("Subject to applicable law, Bonneville commits to open access transmission service. Bonneville shall follow the statutory procedures in Sec�n 212(i)(2)(A) of the Federal Power Act to set generally applicable terms and condi�ns in its Tariff…").

[65] Due to BPA's transmission system being composed of three dis�ct segments, costs and rates are developed for these separate segments and charged to those seeking service on one or more of these segments.

revenues from the services it provides to sustain ongoing activity. BPA's revenue sources include its primarily cost-based power sales to power customers (who also rely on BPA to transmit that power) and its sales of transmission services to transmission customers. Under the Northwest Power Act, BPA must "equitably allocate" transmission costs between federal and non-federal users (i.e., between power customers and transmission-only customers),[66] and BPA must charge transmission customers at rates "comparable" to those BPA pays itself to deliver federal power.[67] Rate proceedings must follow specific procedures,[68] and BPA must submit its rates to FERC for limited review.[69] Discontented stakeholders may challenge BPA's rate submission before FERC and appeal rate decisions to the Ninth Circuit.[70] The Ninth Circuit is generally deferential to both BPA and FERC's decisions on ratemaking.[71]

BPA evaluates transmission needs both in its regular system planning process (OATT Attachment K)[72] and in considering new requests for transmission service. In brief, BPA determines whether its system and the adjacent sub-grid are adequate to provide service both as a regular practice to continue offering service and in response to new requests for service. (These planning processes are described in more detail in the next section.)

BPA's OATT reflects BPA's statutory authority to satisfy transmission needs, even when they require new investments. Recall that BPA's obligations include to "integrate and transmit the electric power from existing or additional Federal or non-Federal generating units" and to "maintain the electrical stability and electrical reliability of the Federal system."[73] This is true for both Network Integration Transmission Service and for Point-to-Point Transmission Service.[74] For Network Integration Transmission Service, the OATT declares that BPA must

[66] 16 U.S.C. § 839e(a)(2)(C). The implica�ons of the equitable alloca�on requirement are beyond the scope of this whitepaper. Note that power customers are all, or almost all, transmission customers as well, whereas many transmission customers buy only transmission service from BPA.
[67] *See* 16 U.S.C. § 824j-1(b).
[68] 16 U.S.C. § 839e(i). Notwithstanding the procedural steps BPA is required to follow, BPA ratemaking proceedings are unusual in that a major transmission owner acts effec�vely as prosecutor, judge, and jury of its own transmission rate decisions.
[69] 16 U.S.C. § 839e(a)(2). FERC's review of BPA ratemaking decisions is statutorily limited to whether the rates are based on system costs, sufficient to assure repayment, and, for transmission, equitably allocated between federal and non-federal users. *See generally U.S. Secretary of Energy, Bonneville Power Administration*, 20 FERC ¶61,292 (1982) (discussing the limits of FERC's review of BPA rates). This is a much more limited review than for a regulated transmission owner. *See* 16 USC § 824d (providing FERC broad authority to review whether rates are "just and reasonable" and nondiscriminatory).
[70] 16 U.S.C. § 839f(e)(1)(G).
[71] *See Aluminum Co. of America v. BPA*, 903 F.2d 585, 590 (1989) (discussing how the Ninth Circuit's review focuses on whether there is "substan�al evidence" suppor�ng BPA's determina�on and how the court must affirm the agency unless the decision is "arbitrary, capricious, an abuse of discre�on, or in excess of statutory authority").
[72] See Sec�on V.A for a more detailed discussion of Atachment K planning.
[73] 16 U.S.C. § 838b.
[74] Point-to-Point Transmission Service is defined as "The reserva�on and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff." OATT § 1.77.
By contrast, Network Integra�on Transmission Service is defined as "The transmission service provided under Part III of the Tariff." OATT § 1.59. For instance, Sec�on 28.1 of Part III states "Network Integra�on Transmission Service

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"plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K."[75] Similarly, for Point-to-Point Transmission Service, the OATT declares that BPA generally is "obligated to expand or upgrade its Transmission System," but that the customer generally must finance "any necessary transmission facility additions."[76]

Under the systemwide planning process, any new facilities' costs "are allocated to transmission rates in rate proceedings."[77] For new service requests, BPA must determine whether the costs of new facilities should be assigned directly to the customer requesting upgrades or expansion or included in BPA's transmission rate base.[78]

D. In Summary, BPA Must Provide Transmission Service and Has Reasonable Discretion to Manage the Costs of Doing So in a Sound Business-Like Manner

Congress has broadly authorized BPA to provide transmission service in the Pacific Northwest. Within statutory parameters such as rates needing to cover BPA's costs and transmission costs needing to be equitably allocated,[79] BPA has broad discretion to implement policies and procedures that best fulfill Congress's goals and BPA's directives. These include "encourag[ing] … the development of renewable resources within the Pacific Northwest,"[80] a policy clearly aligned with the growing number of state mandates to decarbonize. Applicable directives also include operating, maintaining, and expanding the transmission system to integrate and transmit power from existing or additional federal or non-federal generation. Indeed, with the exception of competitive compensation reform, we have encountered no limitation that would prevent BPA from pursuing the reforms described in this whitepaper or that would require any act of Congress to change or expand BPA's authority. BPA has all the legal authority it needs to improve its transmission planning and ultimately pursue construction of transmission upgrades.

Comment [N(-T15]: This may reflect a lack of understanding re: BPA's OATT based transmission model – we often hear our customer (as well as BPA/staff, management) thinking that TX expansion works the same way that GI interconnection works – but the OATT provides that the customer does not pay the capital costs of expansion – BPA does. If there are costs that are "too high" those costs then become the bases for an incremental rate. Suspect that is not widely understood. FERC provided two different financial models for GI and transmission expansion. Also would be interesting to have some conversation about the point at which a project that supports expansion becomes a reliability build, which BPA socializes all costs for. Historically, reliability builds are those things identified in the TPP reliability studies. Could have a conversation about a class of projects that are for "reliability" even though they haven't shown up in those studies yet, maybe due to lag in load modeling inputs, etc? Interested in engr perspective on this.

Comment [N(-T16]: These decisions are made by Kelly – There have been few direct assignment decisions (would have to check with him for that history – maybe one or two though NOS/TSEP?)

is a transmission service that allows Network Customers to efficiently and economically u�ize their Network Resources (as well as other non-designated genera�on resources) to serve their Network Load located in the Transmission Provider's Control Area and any addi�onal load that may be designated pursuant to Sec�on 31.3 of the Tariff."

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[75] OATT § 28.2.

[76] OATT §§ 13.5, 15.4.

[77] OATT Atachment K § 8.2.

[78] Transmission customers are generally responsible for costs "to the extent consistent with [FERC] policy." OATT §§ 27, 34.

[79] 16 U.S.C. § 839e(a).

[80] 16 U.S.C. § 839(1)(B).

V. BPA's Transmission Planning Processes

BPA's OATT reflects BPA's statutory authority to satisfy transmission needs, including when new investments are required. This section describes BPA's several interrelated planning processes and their policy context in more detail.

To meet BPA's statutory and tariff obligations, BPA conducts multiple transmission planning processes consistent with FERC's open access requirements. BPA performs *local* planning to consider load growth and transmission demand over a 10-year time period. BPA also offers customers a *subscription-based* open season process, which aggregates requests for new service on the transmission system. In addition, BPA participates in *regional* planning through NorthernGrid, which considers regional transmission needs over a 10-year time horizon. While these planning processes are largely successful in meeting short-term regional reliability and economic needs by identifying incremental improvements to the grid, they are markedly less successful in identifying transmission upgrades that will be needed to meet public policy targets and mandates more than 10 years in the future and in moving those transmission projects towards construction.

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A. Local Planning for Network and Point-to-Point Service

FERC issued Order 890 in 2007 to require utilities under its jurisdiction to engage in coordinated, open, and transparent planning at both the regional and local level. FERC memorialized this obligation in "Attachment K" of its OATT.[81] BPA has incorporated these planning obligations into its own transmission tariff.[82] As envisioned by FERC, transmission providers have the obligation to plan the transmission system for their customers. The OATT defines two types of transmission service—Network Integration Service and Point-to-Point Service—and transmission providers like BPA must plan for service to customers in both categories.

1. Network Integration Service

Network Integration Service Customers (also referred to as "Network Service" or simply "Network" Customers) take Network Integration Service and rely on the transmission provider to serve their load using generation resources the customers have designated, in addition to these customers' obligation to invest in upgrades on adjacent sub-grids that BPA does not cover.[83] For its Network Customers, a transmission provider like BPA also has the obligation to

Comment [N(-T17]:

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[81] *Preventing Under Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (March 15, 2007).
[82] *See* BPA, *Transmission Services Open Access Transmission Tariff Attachment K*, 163, *available at*: https://www.bpa.gov/-/media/Aep/transmission/open-access-transmission-tariff/bpa-open-access-transmission-tariff-20211001.pdf.
[83] A Network Customer is a customer who has elected to take Network Integra�n Service from its transmission provider (BPA OATT Sec. 1.58). For customers who select Network Integra�n Service, BPA has the responsibility to integrate, dispatch and regulate the customers' current and planned Network Resources to serve their Network

plan its system to ensure that it can continue to serve these customers' needs as their loads grow in the future. The OATT establishes requirements for customers and their transmission provider to exchange information on load growth and future generation resources. For BPA, its Network Customers are mostly its public power customers, and particularly "load following" customers who obtain all the power they need from BPA.

Comment [N(-T18]: This doesn't strongly reflect the "endeavor to plan for " concept that is pretty foundational to BPA's ability to plan for NT customers

2. *Point-to-Point Service*

In contrast to Network Customers, customers with Point-to-Point Service simply secure the right to move energy from one point on the transmission provider's system to another. While FERC's *pro forma* OATT also requires transmission providers to expand the transmission grid to meet the requests of Point-to-Point Customers, if a Point-to-Point Customer seeks to move more energy across a transmission provider's system in the future, it must submit a request for new Point-to-Point Service.[84] Unlike Network Service where a transmission provider must proactively collect data for its Network Customers' future needs, the transmission provider does not have an obligation to plan to meet the future needs of existing Point-to-Point Customers; rather, it can rely on its customers to submit discrete new requests for service to meet their needs in the future. A transmission provider's obligation to expand its system to provide Point-to-Point Service is contingent upon the transmission customer agreeing to compensate the transmission provider for upgrade costs.[85] BPA has adopted these relevant provisions in its OATT.[86]

Comment [N(-T19]: There is a lot of detail and potential misperception that fits under this statement. This statement requires a much finer breakdown to avoid being misleading.

An underlying problem with the reliance of transmission providers on the Attachment K process is its roots in a reliability study that attempted to get ahead of electrical engineering problems.

Load (all capitalized terms are defined in BPA's OATT; Part III of the OATT describes the nature of Network Integra�on Service). BPA's Network Customers are generally its public power preference customers – though some of BPA's larger public power customers who elected to assume the reliability and planning obliga�ons of a transmission provider on their own rely on Point-to-Point Service from BPA. Network Customers have an obliga�on to provide data to BPA regarding their forecasted load growth and good faith es�mates of the size, loca�on, and type of future genera�on addi�ons (Atachment K Sec. 6.1.1). Some IOUs that have load pockets within BPA's footprint also take service for some of that load as Network Integra�on Service. Like most of BPA's preference customers, the IOU would therefore provide BPA its load and resource forecast specifically for that load pocket (but not the rest of the IOU's na�e load). *See supra* footnote 74 for the tariff defini�ons of the two types of transmission service.

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[84] Order 890 at P 419. Point-to-point customers are those who use transmission to deliver energy to a loca�on outside of BPA's footprint (including customers who deliver energy from outside of BPA's system all the way through BPA's system to a load outside of BPA's system, transac�ons o�en called "wheel throughs"). BPA has no obliga�on to consider that an exis�ng Point-to-Point customer's need for transmission service will grow in the future, un�that customer submits a new request for service. BPA's point-to-point customers include independent power producers, power marketers, and investor-owned u�i�es. In fact, most of BPA's largest transmission customers (in terms of sales) are, in whole or in part, point-to-point customers. For example, BPA ten largest transmission customers are responsible for 60% of BPA transmission sales. Of that amount, IOUs, IPPs, and marketers are responsible for 78%. (Moody's, *BPA Credit Opinion*, 5 (Apr. 6, 2022), ***available at:*** https://www.bpa.gov/-/media/Aep/finance/ra�g-agency-reports/moodysfullreportmay2022.pdf)

[85] Order 890 at P 419.

[86] BPA OATT §§ 15.4, 27.

Transmission providers have obligations to plan their system under NERC's reliability standards.[87] Hence the focus on "short circuit," "steady state," "voltage stability," and "transient stability" studies in Attachment K reports. In Order No. 890, FERC adopted new requirements for utilities to conduct an open and transparent planning process with obligations to meet customer demand for system expansion under certain conditions.[88] However, FERC's efforts to expand transmission planning to look beyond reliability needs to meet forecast load growth and incorporate broader policy goals has been only partially successful. FERC's current open rulemaking, "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection" (Docket No. RM21-17), discusses the limitations of the current local and regional planning processes and identifies potential solutions, including scenario-based planning, a 20-year planning time horizon, and changes to the determinations of benefits and cost allocation.

B. BPA's Attachment K Process

As mentioned above, BPA engages in a planning process that is consistent with[89] the requirements of FERC's Open Access Transmission Tariff Attachment K.[90] The Attachment K transmission planning process requires an open, coordinated, and transparent process with opportunities for public participation. This process leads to the annual revision and publication of a transmission plan—"BPA's Plan," as described in BPA's Attachment K.[91] Like all transmission providers with Attachment K processes, BPA plans its system to meet anticipated load growth over the next ten years. For purposes of its local planning, BPA considers both forecasts of future loads as well as its long-term firm transmission service obligations. The Attachment K planning process applies reliability standards to the forecasts of future needs to identify upgrades necessary on BPA's system to maintain a safe and reliable transmission system for the Northwest. These upgrades might consist of new lines to locations that did not previously have access to transmission service, but more often consist of reinforcements to existing lines or facilities that increase the amount of energy that can flow across a line or provide BPA with greater situational awareness of and control over its transmission grid.

FERC also intended the OATT to create a mechanism for Point-to-Point Customers to fund upgrades needed to serve their needs while at the same time protecting the transmission provider's Network Customers from upward rate pressure. In practice, however, it proved nearly impossible for the developer of a generation project to single-handedly fund the construction of a major transmission upgrade. The *pro forma* OATT process requires

[87] NERC, *Standard TPL-001-4 Transmission System Planning Performance Requirements, available at:* https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf.
[88] Order No. 890 at P 599.
[89] See Sec�on IV.B regarding BPA's decision to adopt a process "consistent with" FERC's Atachment K, notwithstanding its non-jurisdic�onal status.
[90] BPA, *Attachment K Planning*, see more informa�on at: https://www.bpa.gov/energy-and-services/transmission/atachment-k.
[91] The current (December 2022) BPA Plan is available at: https://www.bpa.gov/-/media/Aep/transmission/atachment-k/2022-bpa-transmission-plan.pdf [hereina�er *2022 Transmission Plan*].

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transmission providers to consider the incremental additions to the grid needed to meet customer requests one at a time in a strict sequence. FERC's *pro forma* OATT also required customers who needed new transmission lines to pay upfront for the costs of those lines (and receive credits for service on those lines once they are energized). Accordingly, the burden fell on the first customer in the sequence to make upfront financial commitments to fund all of the construction costs; subsequent customers who took service on the same facilities would provide refunds to the first customer. The customer at the head of the line would have the sole obligation to cover the costs of the transmission expansion, even when customers behind them would benefit from the same upgrades. The practical result of this policy for BPA was that as each customer reached the head of the line, it would drop out when presented with the estimated costs of the upgrades.

Comment [N(-T20]: This is fundamentally incorrect – it is a reference to the GI financial model, not the TX expansion financial model. Also, there are NO credits related to transmission service expansion (the capital comes from BPA

C. BPA's Subscription-Based Planning

Comment [N(-T21]: This is a bit of a weird title in my opinion- it does fit with the possibility of a misperception that projects need to be fully subscribed (or meet some subscription threshold) for BPA to decide to build/provide an embedded rate. Thought I get the point that BPA's TX expansion is driven in large part by requests.

1. Network Open Season (2008-2013)

To break this logjam, in 2008 BPA implemented a new process named Network Open Season ("NOS"). In BPA's open season model, the demand for transmission service from all the customers in the entire queue was aggregated, following a temporal window (usually annually) for customers to request long-term firm transmission service (typically for 5 years, with the right to renew ("roll-over") service). Where transmission upgrades needed to provide new service would result in sufficient future revenue from customers to cover the costs of the facilities, BPA committed to finance the construction from its Treasury borrowing authority. At the close of the 2008 NOS, 28 different customers with 153 separate transmission service requests ("TSRs") totaling 6,410 MW of new long-term transmission service had committed to contracts to support transmission upgrades needed to deliver that energy to load. Nearly 75% of those requests for transmission service were associated with new wind generation in the Columbia River Gorge. To meet the need for service reflected in the NOS requests, BPA determined that it could complete five separate transmission expansion upgrades (four of them at 500 kV) and offer service on those new facilities at BPA's embedded cost rate (i.e., without charging those customers an incremental rate for service). For one of those projects, BPA had already completed a preliminary environmental analysis under the National Environmental Policy Act ("NEPA"). For the other four projects, BPA elected to fund the necessary engineering and environmental studies itself.[92] BPA ran a NOS process annually for three years (2008, 2009, and 2010). As a result of the 2008-2010 NOS processes, BPA was able to expand its transmission

Comment [N(-T22]: This was NOT a specified requirement as I recall the process. Behind the scenes I recall a never written "rule of thumb" of putting projects through a "2% test – which my perception recalls as being used somewhat generously. Rebecca would have her own perceptions of this NOS decision-making, as would Sean, Matt, and whoever else is left in the agency that had any significant role in it. But the projects WERE reviewed within the region in external processes. Rollover assumptions were also key as I recall. At one point we used something close to 100% rollover assumption, then got really cautions and went in the opposite direction- assume no rollover. Now we're somewhere in between depending on the situation – put what we think are reasonable assumptions in the business case. Allows us to be smarter.

[92] BPA, 2008 NOS Administrator's Decision Leter (Feb. 16, 2009), *available at:* https://web.archive.org/web/20100527184244/htp://www.transmission.bpa.gov/customer_forums/open_season/docs/Decision_Leter_02_16_2009.pdf; *see also* Atachment A, *available at:* https://web.archive.org/web/20100527132623/htp://www.transmission.bpa.gov/customer_forums/open_season/docs/Atachment_A_-_Ra�nale_of_Rate_Treatment.pdf. The term "subscrip�n" is used less o�n now by �o describe its commercial transmission service policy, but it remains a useful and accurate industry term to summarize the planning paradigm.

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grid to enable 263 individual requests totaling 11,722 MW of new transmission service, including 7,105 MW of new wind generation.[93]

Comment [N(-T23]: A good portion of those original requests did not ever take service (again, PTSA reform)

Comment [N(-T24]: This summary of the history of NOS left out that BPA subsequently had to do PTSA reform for a whole lot of MW. We were able to maintain a sound business case for those projects by "re-homing" a lot of transmission (and collecting the securitization $). BPA was able to achieve this by essentially allowing a lot of redirects of transmission in the queue to new PODs. The level of system flexibility (essentially available capacity) that we used to enable that is NOT available today. I would hate to see that part of history get lost in these conversations. Let's make sure we do an effective job of learning from the past. We just need to also be careful not to assume that today's problems are a cookie-cutter of yesterday's problems.

2. *Transmission Service Expansion Process (2013 to Present)*

In 2013, BPA modified its NOS and renamed it the Transmission Service Request Study and Expansion Process ("TSEP"). Compared to the prior NOS process (See side note – PTSA reform was what drove that modification), TSEP generally applies more stringent standards to transmission customers requesting service, requires higher participant funding from them, and incorporates more conservative risk management for BPA than NOS did. The combination of these changes generally reduced BPA's exposure to potential subscribers dropping out of the process mid-stream. BPA made these changes as the result of lessons learned from challenges in the wholesale market for new renewable projects amid the Great Recession in 2009-2010 and state legislation in California that restricted most utility procurement to in-state generating resources.

Comment [N(-T25]: The NOS process assumed that all TSRs that started through a study process would want to take service in the end. That was incorrect then and likely is incorrect today as well. The market was part of the story, but I think we should be careful assuming that it is the full story.

BPA currently conducts its TSEP annually. Through TSEP, BPA considers customers' eligible requests for transmission service in BPA's transmission queue. While similar to NOS in that it conducts a cluster study of all eligible TSRs, unlike NOS, TSEP customers are now responsible for paying the costs of the preliminary engineering and environmental studies. Both Point-to-Point and Network Service Customers are eligible to participate in the TSEP, although most requests are for Point-to-Point Service. New requests for Network Transmission Service rarely show up in TSEP because BPA already has the obligation to meet the load growth requirements of Network Service Customers under Attachment K and because the vast majority of BPA's Network Service Customers are also its public power preference customers with the first rights to electricity from the federal hydro system.

Comment [N(-T26]: This is actually because NT customers only participate in these processes when they are seeking transmission for non-federal resources. As more NT customers seek transmission from non-federal resources, BPA should expect NT participation to increase.

Under TSEP, BPA aggregates all eligible transmission service requests and studies all of them in a single cluster. For some of those requests, BPA can offer service without building additional upgrades. When BPA cannot offer customers service over facilities that are in place or already under construction, BPA identifies the additional transmission upgrades that would be necessary to offer the requested service. For the transmission service requests that do require upgrades, BPA requires each of the customers who seek service to make financial commitments to cover their pro rata share of costs of preliminary engineering studies, and any environmental studies, while also committing to a term of service that ensures BPA will recover the costs of the upgrades over time. Customers must also post a security deposit or line of credit to ensure that they can meet their future financial obligations to BPA.[94] The pro-rated share of

Comment [N(-T27]: This statement is incorrect. BPA can make assumptions about rollover in our business cases when we believe that it is prudent to do so. In some cases, however, requiring customer to commit to a term of service that ensures cost recovery is probably the smart thing to do to ensure that costs don't get socialized.

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[93] BPA, *Federal Transmission Expansion in the West*, 20 (Feb. 7-8, 2012), *available at*: https://www.energy.gov/sites/default/files/2013/07/f2/Transmission_Drummond_0.pdf.

[94] Under a form of preliminary transmission contract (a Precedent Transmission Service Agreement) used under NOS, BPA used to require customers to post security worth 12 months of their transmission service request (see BPA OATT § 19.10).

BPA's current TSEP financial security requirement is more stringent: customers must post security (either cash or an irrevocable leter of credit) for up to their total pro rata share of upgrade costs, calculated as the ra� of the

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preconstruction study costs and posting financial security are the "participant funding" currently required by BPA. If customers commit to all of those requirements, then BPA will incorporate the necessary facility upgrades in its next Attachment K planning process (and associated annual Transmission Plan).

Once customers make these participant funding commitments, BPA combines expected load growth on its system over the next ten years with customer requests for new transmission service from TSEP.[95] At that point, BPA's Attachment K process combines transmission expansion needed to serve forecasted load growth on BPA's system (from mostly preference customers) with transmission service requests (from all other system users) that commit to the requirements of the TSEP.

3. *Embedded Rate v. Incremental Rate*

BPA conducts a separate analysis to determine whether it will offer service on the new facilities at its rolled-in (a.k.a., embedded) rate or instead charge those customers an incremental rate. As part of its reforms in adopting the NOS process in 2007, BPA also devised a Commercial Infrastructure Financial Proposal ("CIFP," also referred to as the Commercial Infrastructure Expansion Policy). Under NOS, the CIFP established a clear and transparent analytical framework to determine whether BPA would offer service at its embedded rate or whether it would require customers to commit to an incremental rate. First, the CIFP defined the benefits that BPA would consider in this analysis. BPA attempted to quantify benefits associated with (1) expected future uses, (2) reliability of the grid, and (3) other economic benefits, the whole group of which would be allocated to all of BPA's transmission customers through its regular rate process. BPA would then determine whether the new revenues associated with service on the expanded transmission system would cover the remaining costs. If the incremental revenues were sufficient to cover the remaining costs, then BPA would offer those applicable customers service at BPA's embedded rate. On the other hand, if the incremental revenues could not cover the remaining costs, BPA would offer those customers the opportunity to take service at an incremental rate above BPA's embedded cost rate.[96] In practice, an incremental rate can be a kiss of death for a development project because concentrating the costs of

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customer's requested megawats out of the total requested megawats by customers, mul�lied by the es�mated costs of BPA's Plan of Service. This security must be posted prior to BPA proceeding with preconstruc�on ac��s BPA releases the security incrementally over �me. For example, BPA notes in its Business Prac�e that for a 5-year term of transmission service with a 4-year period of construc�on, the deposit or leter of credit would be held for the dura�n of those 9 years, with the amount reduced propor�nally during each five years of actual service (post-construc�on). *See* BPA, TSEP Transmission Business Prac�e, Version 8 (3/24/2023), Sec�n H, *available at* https://www.bpa.gov/-/media/Aep/transmission/business-prac�es/tbp/tsr-study-expansion-process-bp.pdf.

[95] BPA, *2022 Transmission Plan*, Sec�n 3.1 (Dec. 2022).

[96] BPA, *Proposal for a New Approach for Allocating Transmission Costs and Financing Commercial Infrastructure*, 2 (Aug. 2007) *available at:* https://nippc.org/wp-content/uploads/2023/05/2008-NOS-Commercial_Infrastructure_Financing_Proposal_Summary.pdf. The 2007 CIFP was a product of a workgroup formed by the Transmission Issues Steering Commitee within BPA. For a number of years, BPA produced annual public documents evalua�g the system-wide benefits of commercial transmission, as outlined in the CIFP.

Comment [N(-T28]: Is this statement true? I don't know enough to evaluate it. What we can say is that if customers fund (under today's model), that work gets completed and BPA makes a subsequent decision re: whether to build and re: embedded v. incremental rate. This paragraph does show an understanding of BPA's TX expansion model. Not sure why other parts of the letter don't reflect it as well.

Comment [N(-T29]: It feels weird to me that they are pulling in Attach K here – are these statements accurate? Also, expected load growth over the next X years is part of the TSEP modeling process as I understand it (from the WECC cases, etc?

Comment [N(-T30]: Would be interested in Rebecca's take on this language. I thought of CIFA as a framework, but not so much a formula. Maybe incorrect?

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transmission construction on a single generator or a handful of generators can dramatically erode their affordability.

Comment [N(-T31]: Costs of TX contruction don't go to the generator – they go to the party who takes transmission service over the facility or to all TX ratepayers (if socialized)

Today under TSEP, BPA continues to apply a financial analysis to determine whether it will offer customers participating in TSEP service at BPA's embedded cost rate or whether it will require customers to commit to an incremental rate before BPA moves forward with a decision to pursue the Plan of Service[97] needed to satisfy the requests for transmission service. Under NOS, the details of this analysis were clearly defined and transparent. Under TSEP, however, the details of what benefits BPA determines it should allocate to the general customer base and the threshold for determining whether an incremental rate is appropriate are no longer transparently defined. NIPPC and RNW have explored this topic in some detail with BPA in the course of preparing this whitepaper, and there simply appears to be no public documentation of what suite of benefits are currently evaluated, nor, in establishing the need for transmission upgrades, how and whether such benefits accrue to the system as a whole or solely to those customers requesting service. While BPA still conducts this analysis for customers in the TSEP cluster study, BPA no longer publicly provides the specific benefit determinations and revenue thresholds used to determine whether an incremental rate will apply. A great deal hinges on this analysis; this is an obvious area for improvement. Section IX of this whitepaper provides additional detail about best practices in calculating transmission benefits.

Comment [N(-T32]: Fundamentally true – likely a significant weakness of the current process

Comment [N(-T33]:

C. Interconnection Requests

As part of its planning, BPA also considers the number of new generating projects that seek interconnection with BPA's grid.[98] The interconnection queue has its own separate study process. While developers often request both interconnection and transmission service from BPA in order to make a proposed new generating facility viable, plugging into the grid (interconnection) is different than moving power from one side of the grid to the other (transmission service). As of March 2022, BPA's interconnection queue contains 102 separate interconnection requests representing over 85 GW of new generation resources.[99] This paper does not address generator interconnection reform because BPA already has an important initiative underway in a tariff terms and conditions proceeding (TC-25) to address this topic.

D. Regional Planning: NorthernGrid

In addition to conducting the Attachment K and TSEP processes to develop plans of service for its own transmission system, BPA is also a member of the NorthernGrid regional planning

[97] A Plan of Service includes the specific upgrades and �ning that BPA proposes to meet customer needs. The Plan of Service could be driven by any combina�on of load growth, reliability needs, or customer demand for Point-to-Point service.

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[98] BPA, *2022 Transmission Plan*, Sec�on 3.1.3 (Dec. 2022).
[99] BPA, *TC-25 Tariff Proceeding Workshop*, slide 13 (Mar. 15-16, 2023), ***available at:*** https://www.bpa.gov/-/media/Aep/rates-tariff/TC-25/TC25workshopPPTfinal-externalrevisedMarch142023.pdf.

entity.[100] The NorthernGrid planning footprint includes Washington, Oregon, Idaho, most of Montana, Utah, and Wyoming, and portions of Nevada and California. NorthernGrid and its members conduct a biannual transmission planning process to explore whether regional transmission projects can more efficiently and cost-effectively meet members' needs compared to their individual Attachment K plans. The regional planning process is based on members' Attachment K plans and similarly explores a ten-year planning horizon.[101] Stakeholders and transmission developers who are not incumbent transmission providers can request that NorthernGrid (and other regional planning entities like WestConnect, NorthernGrid's counterpart in the Southwest) analyze specific future scenarios or proposed transmission lines in the biannual plan. NorthernGrid is under no obligation to accept these requests; Oregon utility regulators did successfully seek to include an offshore wind scenario in NorthernGrid's most recent study scope for the 2022-23 transmission planning cycle.[102] Accordingly, NorthernGrid is currently studying the transmission implications of the development of 3 GW of offshore wind on the southern Oregon coast by 2030. To its credit, BPA has also joined with a group of transmission owners in the region to voluntarily conduct a 20-year study (as opposed to the normal 10-year time horizon) of whether long-term transmission constraints exist in a low carbon future.[103]

True regional and interregional planning are the ideal ways to address transmission needs on a wide geographic basis. NIPPC and RNW support effective mechanisms to do so, which would require BPA and other transmission providers to work together in a transparent and public manner to determine the most important and cost-effective new transmission projects and determine cost allocation to pay for them. For example, the latest draft transmission plan (for 2022-2023) produced by the California Independent System Operator ("CAISO") would authorize 24 reliability-driven projects and 22 policy-driven transmission projects, with a total estimated cost of $9.3 billion, using forecast electricity demand from the state energy office (the California Energy Commission) and anticipated generating and storage resources forecast by the California Public Utility Commission.[104] The CAISO's draft plan demonstrates how an independent system operator("ISO") can proactively plan a portfolio of new transmission in an effective way that transmission owners, including BPA, have difficulty achieving.

Comment [N(-T34]: Interesting – might be worth reviewing the policy drivers and looking at what identified the locations of those projects based on policy

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[100] NorthernGrid is the regional planning en�y that IOUs have established in order to comply with the regional planning requirements of FERC Order Nos. 890 and 1000. BPA and other non-jurisdic�nal transmission providers (Seatle City Light, Chelan County PUD, Tacoma Power, Snohomish County PUD) have joined NorthernGrid not only to conduct regional planning voluntarily under Order 1000 but also to meet specific NERC and WECC reliability criteria that require coordina�on with adjoining transmission providers on specific topics. *See* NERC TPL-001-4 and TPL-001-WECC-CRT-3.2.

[101] NorthernGrid, *Regional Transmission Plan for the 2020-2021 NorthernGrid Planning Cycle*, 5 (Dec. 8, 2021), *available at:* https://www.northerngrid.net/private-media/documents/2020-2021_Regional_Transmission_Plan.pdf.

[102] NorthernGrid, *Economic Study Request Decision for 2022*, *available at*: https://www.northerngrid.net/private-media/documents/ESR_Decision_2022.pdf.

[103] Western Power Pool, *20-year Low Carbon Study,* (Nov. 23, 2022), *available at*: https://www.westernpowerpool.org/private-media/documents/20_Year_Study_Scope_2022.11.23.pdf.

[104] CAISO, *Draft 2022-2023 Transmission Plan*, 3 (Apr. 3, 2023), *available at:* http://www.caiso.com/Ini��eDocuments/Dra�2022-2023-Transmission-Plan.pdf.

Nevertheless, this ideal scenario of consistent, collaborative regional planning that encompasses BPA and IOUs remains elusive for the Northwest, both because FERC's Order 1000 has proven to be a weak forcing mechanism outside of regional transmission organizations ("RTOs") and ISOs, and because any successor rule that FERC may adopt will not address the fundamental lack of consistent requirements and jurisdiction over transmission owners in the region. It remains unclear when FERC may finalize a new planning rule. For these reasons, NIPPC and RNW support BPA pursuing changes to its internal transmission planning processes, while still encouraging the agency to collaborate as much as possible regionally and interregionally.

VI. Limitations of BPA's Existing Planning Processes

This section identifies principal limitations and drawbacks to BPA's current planning processes. Section IX critiques these same BPA processes by way of comparison to other transmission providers.

Insufficient Forecasts of Load Growth and Transmission Capacity Needs

NIPPC and RNW are concerned that the assumptions that BPA and transmission-owning utilities in the region are currently using to forecast load growth are too low.[105] The transmission planning reliability standards require BPA to base its assessment on standard base cases developed for the entire Western Interconnection.[106] NorthernGrid conducts its planning based on 0.6% annualized load growth for the entire footprint with individual utilities reporting changes in load from a 0.4% decline to a 1.1% increase.[107] PNUCC's regional load resource forecast, however, estimates annual load growth of about 0.9% over the next ten years with individual utilities ranging from a 0.9% decline to 2.9% increase.[108] PNUCC also notes that its load forecasts may underestimate actual load growth since utilities representing only 25% of the load in the region currently factor climate change into their planning estimates, and utilities representing only 30% of regional load incorporate the implications of electrification into their load estimates.[109]

Comment [N(-T35]: Personally, I will admit to sharing this concern. KSL forecast process also doesn't always seem to result in getting the load the have give the 80% seal of approval to actually getting into the cases that [redacted] some adjustments, but I wonder whether we are really robustly examining what the outer edges of load growth look like.

For example, in Washington, the state building code (with a court challenge pending) requires, as of July 1, 2023, that most new residential and commercial structures use only electricity.[110] Similarly, in Seattle, both the King County Transit System and the Port of Seattle have declared their intention to pursue 100% electric or non-emitting goals by 2035 and 2050, respectively.[111]

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[105] Note that BPA is o�en men�oned in the same breath as u��es. In its transmission func�on, BPA does resemble transmission-owning u��es and is subject to some of the same federal requirements. But except for several narrow legal applica�ons, BPA is not, in the usual sense of the term, a u�ity. It is a federal wholesale marketer of power to customers who are themselves u��es. How does this differ from a typical u�ity? BPA is not ver�ally integrated: it owns neither genera�on facili�es nor distribu�on lines. The power plants whose electricity BPA markets are owned by other en��s (the Bureau of Reclama�on, Corp of Engineers, and Energy Northwest). And except for a handful of now defunct industrial consumers, BPA neither sells nor delivers power at the retail level.

[106] WECC is the Regional En�y (a legal term in the Energy Policy Act of 2005) that enforces reliability standards in the Western Interconnec�on. These reliability standards are developed by NERC. WECC and NERC are both self-regulatory industry membership organiza�ons overseen in the U.S. by FERC.

[107] NorthernGrid, *Study Scope 2022-2023*, 3 (Sept. 21, 2022), *available at:* https://www.northerngrid.net/private-media/documents/NG_Study_Scope_2022-2023_Approved.pdf.

[108] PNUCC's membership includes most of the load-serving en��s in the Pacific Northwest. PNUCC annually conducts a study (the Northwest Regional Forecast) that examines the region's loads, resources, and future power supply.

[109] PNUCC, *2022 Northwest Regional Forecast*, 6 (Apr. 2022), *available at:* https://www.pnucc.org/wp-content/uploads/2022-PNUCC-Northwest-Regional-Forecast-final.pdf.

[110] *See* Washington State Building Code Council Summary Mee�ng Minutes (Nov. 4, 2022), https://sbcc.wa.gov/sites/default/files/2023-02/sm11042022C_ah.pdf.

[111] *See* King County, *Attachment 13 - King County Metro Transit's Zero Emission Fleet Transition Plan* (May 2022), *available at:* https://kingcounty.gov/~/media/depts/metro/accountability/reports/2022/zero-emission-bus-fleet-transi�on-plan-may-2022; *see* Port of Seatle, *Maritime Climate and Air Action Plan* (adopted November 16, 2021),

Utility resource plans are lagging this aggressive mix of electrification requirements and objectives across the region.

Clean energy laws in many states in the West will shift the resource mix from conventional fossil fuels to renewables and other non-carbon emitting generation. Since 2019, utilities in the Northwest have retired 2,100 MW of coal capacity, with another 2,800 MW of coal capacity scheduled for retirement by 2026.[112] Utilities currently indicate plans to add 9,400 MW of new renewable generation resources in the next ten years.[113]

One overall transmission challenge facing the region is the nature of variable renewables as standalone resources because their capacity factor (the percentage of time across all hours that the resource actually generates power) is generally lower than a dispatchable thermal power plant. Overall, this intermittency can lead to greater demand for transmission capacity but less total electricity carried on any given new segment or circuit of transmission. These challenges can be mitigated by pairing renewable resources with storage, by pooling more resources regionally through centralized dispatch (such as day-ahead and real-time centralized energy markets), by widening the geographic area of pooled resources to ensure more complementary generation profiles, and by changing from contract-path physical transmission rights to flow-based financial rights. Nevertheless, each of these solutions also has its own financial or political hurdles.

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Lack of Surplus Transmission Capacity under TSEP's Reactive Process

BPA's most recent TSEP Cluster Study Report shows that there is no longer any surplus of unallocated transmission from the east side of the Cascades (where many new wind and solar resources will need to be located) to the west side of the Cascades (where the load centers of Oregon and Washington are located).[114]

BPA is tentatively planning to move forward with six transmission projects that have commercial demand, as reflected in recent TSEP cluster studies. These projects (Portland Area Reinforcement, Cross-Cascades South, Chehalis-Cowlitz Tap, Cross-Cascades North, Ross-Rivergate, and Rock Creek-John Day) are important projects with reliability, commercial, and public policy benefits (enabling access to new non-emitting generation). They are all upgrades and reinforcements of existing lines, increasing their capacity, as opposed to brand new lines in new rights-of-way. The most significant project is a 70-mile rebuild of the existing Big Eddy-

detailing interim 2030 planned electrifica�on ac�ons (*e.g.*, electric for 100% of port-owned light-duty vehicles, 100% of home port cruise calls connected to power), *available at:* https://www.portseatle.org/page/char�ng-course-zero-port-seatles-mari�me-climate-and-air-ac�on-plan.

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112 *Id.*, at 8.

113 *Id.*, at 11.

114 BPA, *TSEP 2022 Cluster Study Report* ("2022 Cluster Study Report"), 57 (June 10, 2022). Transmission Service Requests which require service across the Cross Cascades North or Cross Cascades South paths can be accommodated only with significant upgrades of the exis�ng system that, once begun, would be completed only in 2030. *Note that the last two Cluster Study Reports (2022 and 2021) whose contents are merely summarized here can be obtained upon request from BPA.*

Chemawa 230-kV line as a 500-kV line (crossing the Cascades southeast of Portland). The estimated total construction cost of these projects is $612 million, enabling an incremental 4,260 MW of additional power to move across those upgraded parts of the network. (Note that this figure is in aggregate, not an additional 4,260 MW across the overall system or any single point.) The construction cost is supported in large part by $57 million of annual expected transmission revenue, based on signed preliminary engineering agreements with customers requesting transmission service.[115]

BPA deserves credit for pursuing these important projects. But much more is needed. As BPA acknowledged at its April 27, 2023, public workshop,[116] these projects may assist in allowing utilities west of the Cascades to meet their 2030 resource procurement requirements (an informal conclusion that has not been tested by other stakeholders or market participants); however, they will not address the significant incremental 2030-2045 need. Furthermore, BPA should publicly disclose its tentative plans to pursue such projects sooner. The projects described above appear to have been in consideration for at least the preceding year without a meaningful public discussion of that consideration.

Significantly, several large upgrades that were identified in the 2022 Cluster Study as necessary to meet customer demand were *not* included in the 2022 Transmission Plan or the list of projects above. For example, upgrades in central Oregon costing $382 million could enable at least 3,645 MW of new generation by 2033, but those transmission facilities were not included in the 2022 Transmission Plan.[117] The best way to understand this outcome is that TSEP is not merely a planning exercise. Rather, BPA also uses the TSEP to inform customers whether BPA will offer service at an embedded rate or at an incremental rate and to secure binding financial commitments from customers in advance of BPA engaging in engineering studies, environmental reviews, and construction. But as noted above, the analysis that BPA currently uses to determine whether it will offer service at an embedded cost rate is no longer transparent.

Lack of Transparency about Benefits Evaluation and Cost Allocation Methodology

This lack of transparency means that stakeholders[118] in the region have no insight into whether any specific proposed Plan of Service to expand the grid to a new region with high renewable energy potential is uneconomic at any scale, or whether the proposed Plan of Service could support enough future generation development (that has not yet appeared in TSEP) to allow BPA to offer service at its embedded rate. Additional transparency with respect to the internal business case developed by BPA for transmission projects that have commercial interest—including benefits quantified or considered, anticipated fulfilment of BPA's revenue requirement, and the risk of creating a stranded asset—would greatly assist stakeholders to

[115] BPA, *Evolving Grid*, 20-27. These slides include valuable high-level maps of each project.
[116] See a link to a recording in *supra* footnote 15.
[117] *See 2022 Cluster Study Report*, 57. The cluster study considered a total of 2,595 MW in the Central Oregon-South zone, at 40, and an addi�nal 750 MW in the Central Oregon-Buckley zone, at 43.
[118] Stakeholders in this context include not only genera�n project developers, but also load-serving en��es, pub u�ity commissions, and anyone else with an interest in ensuring that states meet their clean energy goals.

Comment [N(-T36]: Chris – did they get these numbers right? 57M in annual revenue seems low to me – would be only 2800 MW of service?

Comment [N(-T37]: I would be interested to understand this comment better. The cluster study report is available to anyone who requests it upon completion of the study. Then we go through the PEA process to determine what projects are live – admittedly, we are pretty dark on that part of the outcomes. Communication has not been our strong suite.

Comment [N(-T38]: Worth noting that what was put out did not include the entire portfolio of TSEP builds that are at some stage in the process. Doesn't mean that there isn't customer PEA funding though. I can see the confusion here.

Comment [N(-T39]: Because BPA doesn't do study work to determine the TTC, it is always a mystery (even internally) as to the degree to which a project can support more flow. This is a legitimate challenge. As I understand it, it is partly a resource issue, and partly a reflection of the fact that the generation/transmission model in place at the point of energization aren't known during the study.

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prioritize procurement from specific regions and stage expansion of the transmission grid more efficiently.

Comment [N(-T40]: This feels very true

Participant Funding and the Mismatch of Generation and Transmission Procurement

While BPA's TSEP reflects that developers are acting on the knowledge that the region needs new renewable generation located in places like central Oregon, eastern Washington, and Montana to meet clean energy targets, those developers are often not able to make the financial commitments to BPA to underwrite the costs of development and construction of the necessary upgrades. But the unwillingness or inability of these prospective transmission customers to commit now to repay BPA for transmission upgrades does not mean the added transmission capacity would go unused in years to come. Instead, it indicates that the demand on the *load* side (the utilities who would purchase the power) is not yet willing to execute contracts for generation resources that will be needed more than several years in the future.

Comment [N(-T41]: This is NOT a requirement – they do not even have this opportunity. Maybe they mean though paying the rate? Doesn't exactly read that way.

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Comment [N(-T42]: True in SOME cases. This is where what Chris and I have called "regional need" projects v. "customer need" projects distinction is pretty important. For some TX projects, if no/few LSEs eventually chose the resources that need those projects, there would be a poor business case.

Utility procurement processes based on integrated resource planning typically look to procure new generation capacity two to three years in advance of need (as most integrated resource planning is done on a two-year cycle). Few renewable energy developers are in a position to make the financial commitments now to build transmission that will enable new renewable generation to bid into procurement processes that will be held ten or fifteen years from now.

One root of the problem is that the Northwest's main power buyers (utilities) solicit new supplies of power only several years in advance and primarily to fill in the gap between their current supply and what their anticipated load and state laws require in the 2030-2045 timeframe. At the same time, the Northwest's main transmission provider (BPA) has a planning and project execution process that is reactive principally to power suppliers (developers) requesting transmission service that may require very expensive transmission upgrades that could take more than a decade to complete.

Not surprisingly, the temporal mismatch between the utility procurement processes and BPA's transmission service expansion process is resulting in physical bottlenecks and significant underinvestment in the BPA transmission system. Resource developers are often stuck in between: until they are confident a utility (or corporate consumer) will buy their power, they will be reluctant to allocate significant capital by signing an agreement with BPA to pay for service towards the cost of transmission upgrades needed to enlarge BPA's system. In many cases, the developer simply cannot take this risk. On the other hand, winning the competitive bidding process to sign a contract with an offtaker (a purchasing utility) often requires already having a transmission service agreement in place.

Comment [N(-T43]: True, but relevant to Sonya's point that having all TX customers take all this risk isn't necessarily a winning model either.

Comment [N(-T44]: Yes – this catch 22 is a core challenge to BPA's planning processes.

Pros and Cons of Reactive Planning

There are two positive effects of BPA's current approach worth recognizing. First, power producers have developed some (imperfect) expertise in identifying locations in the Northwest with the lowest cost upgrades needed to secure transmission service from BPA. This helps squeeze the most use out of the existing system as possible. It is a more refined approach, suitable for a mature grid, than the approach that created the transmission network in the first place: drawing and building ambitious new lines on a map to connect proposed dams and coal plants to big cities (*see the Appendix for more details on this history*). Second, because developers (or any entity requesting new transmission service) bear the upfront costs of BPA's upgrade studies and must provide financial commitments to BPA sufficient to ensure that their future payments for service will cover the actual construction costs, there is a controlling incentive for developers to avoid lumpy new transmission investments. Taken together, these effects help to suppress BPA's transmission rates by avoiding triggering new capital-intensive projects.

Comment [N(-T45]: Again, not sure that this statement is fully correct – if embedded rate project, MOST of the costs are covered via them paying their rates just like is the case for existing transmission capability. The up front costs to the customers are quite low compared to the cost of developing a project, so a little interesting that they sound focused on wanting to be excused from those costs. I wonder how much of an impediment those costs really are, particularly for "robust" projects. But maybe BPA is much more comfortable/knowledgeable about which projects are "robust" and which ones are more marginal.

The negative effects of this reactive approach are the flip side, and they are significant: the TSEP cluster studies show that BPA's transmission system is out of room for the major wave of power development needed to comply with state laws and related policies, and BPA's transmission planning, cost allocation, and project execution processes are not designed to respond effectively to that need.[119] Determining appropriate solutions to a conservatively reactive planning paradigm and the temporal procurement mismatch highlighted above will require joint effort and brainstorming among independent power producers, BPA, and load-serving entities, among others.

Lack of Treatment of Recurring Transmission Demand

Emblematic of the problems in TSEP is that BPA, at least publicly, treats each TSEP cluster in isolation. The TSEP cluster studies reflect demand from developers for transmission service from geographic areas where new generation can be developed most cost effectively. Sometimes transmission demand appears repeatedly over several years at the same points on the BPA network, but not with sufficient committed customer interest in a single year for BPA to justify proceeding. While BPA may be acting prudently in avoiding a construction plan in some of these cases, BPA has no public process where it openly considers transmission upgrades that have been identified in repeated TSEP cluster studies to meet recurring demand from transmission customers.

Comment [N(-T46]: I don't agree with this statement. The TSEP study is agnostic to how economic either the generation projects are or the transmission projects are. The economics of the generation projects are identified by the LSE processes (which projects do they select). The economics of the transmission projects develop over time, although projects look "better" or "worse depending on the initial costs, TSRs/MW, etc.

Comment [N(-T47]: If there is ANY actual financial interest in proceeding in a specific year, the project moves into PEA. Our model has always allowed for "hop on" in subsequent years if other parties want to participate later in that project with the TSRs. I'm not sure why this is a point of confusion.

[119] In Sec�n 5 of its 2022 Transmission Plan, BPA does iden�y the myriad policy and market changes driving the need for transmission, but reci�g these drivers is not the same as designing a process that is actually responsive to them.

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VII. Additional Issues Unique to BPA That Impact Transmission Planning

A. Regional Cost Allocation

As a federal agency with specific statutory authorities and requirements, BPA is not subject to FERC's requirements on transmission planning and cost allocation of transmission expansion. Nevertheless, BPA has voluntarily taken on a combination of standard FERC planning processes (such as Attachment K and regional planning through NorthernGrid) as well as processes unique to BPA (such as the TSEP). With respect to cost allocation, however, BPA is uniquely situated relative to other transmission providers in the Northwest. Most obviously, in deciding to join NorthernGrid to satisfy its regional transmission planning obligation, BPA (with FERC's approval of the methodology) is not subject to the standard mandatory cost allocation mechanisms when the NorthernGrid process identifies a regional transmission project (one that would be more economical than the member utilities' standalone plans). Instead, BPA has discretion in voluntarily choosing to take on a share of the costs of a regional transmission project—or not. If BPA were to decline to accept its share of such a project, BPA's share of those costs would be allocated to the other beneficiaries, likely with a negative impact to the cost-benefit analysis for the project. In any event, neither NorthernGrid nor its predecessor organizations have ever identified a regional transmission project appropriate for regional cost allocation.

B. Transmission Siting

BPA is also directly subject to NEPA, which requires federal agencies to determine if their proposed actions will have significant environmental effects and to consider the environmental, social, cultural, and economic effects of their proposed actions. Accordingly, virtually all BPA decisions related to transmission development are subject to NEPA and related reviews under the Endangered Species Act and the National Historic Preservation Act, a nearly blanket application that is not true of non-federal transmission providers. While important and necessary, these processes can take significant time and money to perform, adding time and cost to any proposed transmission project. In practice, most minor decisions by BPA are addressed through applying an administrative categorical exclusion. While other transmission providers are subject to NEPA and similar laws to the extent their projects are located on federal land or significantly affect the environment or cultural resources (and thereby require approval of a federal agency), BPA is unique in that its transmission upgrade decisions automatically trigger a review by BPA itself, often alongside federal land managers and fish and wildlife agencies.

Based on a review of the timeline for many of the major transmission upgrades by BPA since 2010, the environmental and cultural reviews of those projects, as indicated by their final environmental impact statements and records of decision, did not appear to materially delay BPA's construction of those projects (see *infra* footnote 208). Nevertheless, the effect of future reviews is likely to be more difficult in the case of the more significant volume and type of transmission upgrades contemplated in this whitepaper.

Comment [N(-T48]: Interesting perception

Finally, BPA's significant federal eminent domain authority is a powerful siting tool held by the agency. Historically, it has been a driving factor in regional entities seeking and securing BPA's participation in transmission projects. (See the Appendix for one high profile instance of this history with respect to the Colstrip line.)

C. The Assumption of Risk

Determining what the public interest is for a federal power marketer and transmission provider to assume various risks for developing new infrastructure requires careful, public deliberation. It is not self-evident. It may change over time, and it may differ significantly from the risk appropriate for a private company or non-federal public entity to assume. At present, BPA has a highly conservative approach to assuming risk for transmission expansion in the Northwest, an approach in contrast to much of the agency's history of constructing the high-voltage grid as we know it. NIPPC and RNW recommend that elected officials, BPA customers, and stakeholders in the region re-examine this core question in light of the generational change underway in the power sector.

Comment [N(-T49]: Since BPA is risking its capital, I'm not totally sure that I share this perception. The PEA/ESA costs are a relatively small portion of project costs.

For example, in addition to being a planning process that identifies transmission expansion needed to meet customers' requests for service, TSEP is also a contracting mechanism that insulates BPA from revenue shortfalls. After identifying the necessary upgrades to meet customers' requests, BPA then contacts those customers to determine if they would like to make the upfront financial commitments that will relieve BPA of any financial risk for undertaking the engineering studies, environmental assessments and, eventually, of using BPA's borrowing authority to cover construction costs. Customers are required to fund their pro rata share of the engineering and environmental studies; but they are also required to provide a deposit or letter of credit to BPA for their pro rata share of the total costs of the upgrades. TSEP customers must maintain this financial security through construction and until the end of the term of service in their TSR. BPA essentially uses an "open season" process that aggregates the demand for new transmission and allocates the responsibility to repay BPA's capital costs among all the customers who will take service on the upgrades. So even if BPA uses its own borrowing authority to finance construction of TSEP upgrades, BPA is not at risk because it can call upon customer financial guarantees to ensure that BPA receives the revenues it forecast in the financial analysis around whether to proceed with construction of the Plan of Service.[120]

Comment [N(-T50]: True only to the extent that BPA utilizes its rate treatment determination process well as well as securitization of "high risk" projects. But I do feel like there is a significant question regarding whether all of the main grid projects should really require securitization or whether BPA is essentially driving up regional delivered power costs for very little gain by requiring securitization of some of the projects.

Comment [N(-T51]: Unless they pay (through rates for the TSR charges) for their share of the direct costs of the project earlier – then can appeal for release of this obligation. But they are right that it can be a very lengthy period of time.

To illustrate the effect of this, imagine a transmission upgrade that will cost subscribing customers $100 million for a total of 1,000 MW of TSRs received in an annual TSEP window. Customer A has a 100 MW TSR (10% of the total), resulting in a total securitization of up to $10 million. Customer B has a 500 MW TSR (50% of the total), resulting in a securitization of $50 million. If Customer B drops out late in BPA's construction of the upgrade, it may forfeit that total security. This would be equivalent to losing the entire cost of a hotel room for cancelling

[120] BPA Business Prac�es, *TSEP Business Practice*, Sec�n H, 10-11, ***available at:*** https://www.bpa.gov/-/media/Aep/transmission/business-prac�es/tbp/tsr-study-expansion-process-bp.pdf.

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too close to a reservation date. If Customer B drops out early in the process, BPA may re-allocate the securitization to other customers. This would be equivalent to your hotel reservation cost increasing because a guest next door cancelled. Customer A's previous 10% of the total TSRs could now be 20%, requiring it to post another $10 million of security, perhaps jeopardizing Customer A's willingness to stay in the process. This can lead to a spiraling effect in which an upgrade is simply cancelled as customers successively drop out. BPA confronts the unfortunate choice to abandon a transmission expansion due to individual customers' commercial situations, regardless of the long-term (multi-decade) likelihood of the new transmission capacity actually being used.

Comment [N(-T52]: Important to be clear – customer security is due when they sign a contract to take that service (not before). So what they are securitizing in the revenue associated with that contract. They are not required to securitize earlier in the process. Still could be 10 – 15 years of security (although once they start taking service, the security amount is decreased each year essentially based on payments they've made).

Comment [N(-T53]: I'm not sure we know this to be true at any point in the process (though probably is upon initial contract offer and requests for security)– If the customer drops out after BPA has collected security and is well into the build process, I don't think BPA is necessarily going to increase the security amount (and wouldn't need to if we drew on someone else's since their costs would have been covered. The spiral effect is accurate at the point of initial contract offer however.

Nonetheless, TSEP is an improvement over the *pro forma* OATT, where a single customer would be on the hook for the cost of the expansion with the opportunity for refunds from subsequent customers who took service on the same lines. The reality is that no single generator is likely to be able to finance the construction of a major line that will benefit multiple customers. TSEP partially solved this problem by spreading the upfront financial commitments associated with a long-term service contract across a broader group of customers. The requirement that customers execute long-term contracts for service also insulates BPA from building facilities that do not generate revenue (and spreading those costs to customers who do not use the new facilities). The core issue of potential stranded transmission assets—bridges to nowhere, as it were, that BPA and its existing customers naturally wish to avoid—deserves closer scrutiny, given the robust history of transmission projects built well in advance of need (including BPA's own initial lines) that have generally been fully utilized and paid off over time.

The TSEP process works best when the time horizon is a relatively short 2-4 years from subscribers making the financial commitment to BPA energizing the facilities. This short horizon is typically available only for upgrades or expansion of existing facilities; it does not work for new lines to new geographic zones that typically require 10 or more years to plan, permit, and build. The reality is that the costs and risks to generation developers of tying up capital for more than a decade—waiting for BPA to finish a line or upgrade—are simply too great, even if they are able to share those costs with other developers. As a result, NIPPC and RNW believe that consumers in the Northwest may be missing out on some of the best and most affordable generating resources that the region has to offer.

Comment [N(-T54]: Even simple projects generally take more than 2 years

VIII. Avoiding the Consequences of Business as Usual

If sufficient transmission is not available, consumers in the region may face higher costs of meeting state energy targets, and regulated entities (utilities and competitive marketers) may be at risk of failing to meet the targets altogether.[121] At a macro level, the obvious cost of not having the most efficient, highest capacity factor renewable resources available because of transmission constraints is a reliance on relatively more expensive, less efficient, lower capacity factor resources, and related effects such as curtailment of those concentrated resources. In other words, the availability of transmission (or lack thereof) effectively limits competition among resource suppliers despite the demand for such resources. The challenge of coordinating aggregate demand for new transmission among so many different load-serving entities, all with different governance and regulatory approval requirements, is complex and likely beyond the ability of any single group of customers (or their state utility commission) to successfully navigate.

NIPPC and RNW are concerned that BPA's various planning processes are not identifying the need for new transmission sufficiently in advance to ensure that transmission facilities are in place on time. Construction of new transmission lines, or major upgrades to existing facilities, of course requires more than simply identifying a need. Significant time is required to conduct necessary site identification, environmental reviews, and related siting or permitting processes before construction can begin. For example, the Boardman to Hemingway project is a 290-mile, 500-kV transmission line that crosses eastern Oregon and southwestern Idaho. While construction is likely to begin in 2023, with energization in 2026, the project was first identified in Idaho Power's 2006 Integrated Resource Plan.[122] From the identification of a potential need to the expected energization date, twenty years will have elapsed. A ten-year time horizon (BPA's current policy) to identify transmission needs is simply insufficient time to ensure that the lines will be in place when they are needed. But making a simple adjustment to instead use a 20-year planning horizon would not solve the problem so long as individual generation developers shoulder the primary financial risk of expanding the transmission grid. New policies are also needed to share development and construction risk more appropriately and to ensure that detailed engineering and environmental studies are conducted on an appropriate timeline (including potential expanded use of third-party contractors) to ensure that new facilities are energized on time.

Comment [N(-T55]: That doesn't seem like the only impediment. Forecasting the location of new load/resource need years into the future is part of the challenge as well.

[121] Portland General Electric's ("PGE") 2023 Integrated Resource Plan and Clean Energy Plan, for example, notes on page 217 that "the delivery capabili�es of the Pacific Northwest's transmission system … have not kept pace with … changing demands," and as a result, the company may "not rely on BPA transmission to the same extent PGE has historically relied on BPA." PGE concludes on page 227 that the "contrast" between a "need for addi�onal genera�ng resources" and "lack of available long-term transmission" means the company must begin planning now for alterna�ve transmission solu�ons. PGE's plan is available at: https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp.

[122] *See* Idaho Power Company, *Boardman to Hemingway: A Clean Energy Superhighway*, and *B2H History* at www.Idahopower.com, https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/current-projects/boardman-to-hemingway and https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/current-projects/boardman-to-hemingway/b2h-history.

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BPA could play a much greater role in guiding regional transmission expansion. For example, Congress recently passed a new contracting authority for DOE that may be worth considering as an example of how BPA could underwrite some new transmission using its plenary authorities (as detailed above in Section IV). Under the Transmission Facilitation Program ("TFP"), DOE serves as a temporary anchor tenant for new transmission lines.[123] DOE's role is to evaluate the risk of whether a line will be fully utilized in the future, eliminate the need to allocate cost and risk among multiple beneficiaries in the near term, and thereby reduce the overall risk of the line for private investment. As customer demand for the facilities grows, DOE can then offload its position to actual transmission customers who will utilize the line. DOE received dedicated funding for this program and is directed to take a calculated, prudent risk. While BPA's risk appetite in performing a similar anchor tenant role may be smaller, because it has customers ultimately responsible for those costs (rather than just a freestanding revolving fund), BPA should not simply set its risk tolerance at zero (or close to zero) for transmission upgrades that the region will rely on over the coming decades. Readers should note that this position in favor of a greater—but calculated—risk tolerance by BPA in no way diminishes the value and opportunity for other transmission developers to play a leading role in the Northwest that complements BPA's role.

Comment [N(-T56]: Again, lines don't have to be "fully utilized" to be a sound project to build.

Comment [N(-T57]: Would be useful to better understand this program

In summary, BPA should adjust its current policies to take on more of the responsibility to expand the grid in the Pacific Northwest and, to some meaningful degree, in coordination with load-serving entities that require new resources. BPA has a statutory obligation to operate, maintain, and expand its transmission system to serve its customers—both new and existing—in the Pacific Northwest.[124] Congress's recent decision to expand BPA's borrowing authority suggests a congressional desire for BPA to continue to embrace this role in the region, a view underscored by the legislative debate about this provision.[125] On the other hand, BPA should not bear this responsibility alone; the major load-serving entities in the region could and should do more to support transmission upgrades and expansion farther in advance of their short-term procurement needs. In addition, private transmission development also has a significant complementary role to play in the Northwest. Nevertheless, Congress has seen fit to designate and maintain BPA as a transmission provider with significant statutory authority to meet the transmission needs of the region and given BPA unique financing capabilities to meet this responsibility.[126] BPA can and should lead.

Section X of this whitepaper lists a set of more granular recommendations based on the analysis above.

[123] Department of Energy, Grid Deployment Office, *Transmission Facilitation Program Fact Sheet* (Nov. 22, 2022), *available at*: https://www.energy.gov/sites/default/files/2022-11/11.22.22%20TFP%20Fact%20Sheet_final_0.pdf.
[124] See Sec�on IV.
[125] In the Infrastructure Investment and Jobs Act, Congress permanently increased BPA's borrowing authority by $10 billion. *See* 16 U.S. Code § 838m.
[126] See the earlier discussion in Sec�on IV.

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IX. Comparison of Best Practices in Transmission Planning Elsewhere to BPA

This section steps back to provide a national, comparative review of best transmission planning practices, set alongside BPA's current processes. The best practices detailed here inform the concluding recommendations in Section X, in some cases bolstering analysis and conclusions reached in preceding sections.

Over the past few years, the electric industry nationally has been undergoing a rapid transformation. FERC and many industry participants have acknowledged that transmission needs increase as more non-emitting generation is built. In addition, end-use electrification of transportation, heating, and industrial processes is adding load, increasing concerns around resource adequacy, resilience, and reliability. Robust long-haul transmission capacity is proving to be an indispensable tool during severe weather and drought periods to address supply shortfalls with power from neighboring areas.[127] In order to ensure future reliability and lower costs, most regions, encouraged by FERC, are moving towards longer term, more holistic transmission planning practices.

As previously discussed, BPA is facing a variety of changes in how its transmission system will be used in the future. These changes include thermal power plant retirements; significant new resource development, including the potential of floating offshore wind development, distributed generation, blended fuel resources, and new nuclear generation; increased extreme weather events; and aggressive state clean energy and emission reduction goals. BPA's current transmission planning processes are inadequate to address these challenges.

The TSEP and local planning processes that BPA employs are too conservative, too reactive, and largely overwhelmed by the current number of transmission service requests. Likewise, while BPA participates in regional planning through NorthernGrid, that process also does not regularly engage in proactive planning for the future resource mix.[128]

Fortunately, there is a set of well-established and common-sense transmission planning best practices against which any given transmission planner's approach, including BPA's, can be compared. One summary of these practices, in a Grid Strategies and Brattle report, *Transmission Planning for the 21st Century*, categorized these practices as: *proactive, multi-value, portfolio-based, and scenario-based planning.* The following should be considered best practices:

1) Proactively plan for future generation and load.

[127] Michael Goggin, *Transmission Makes the Power System Resilient to Extreme Weather* (July 2021), *available at*: https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.
[128] Nevertheless, see *supra* footnote 103 about a current voluntary effort of a subset of NorthernGrid members, including BPA, to carry out a one-�me longer term planning exercise.

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2) Account for the full range of transmission projects' benefits and use multi-value planning.
3) Address uncertainties and high-stress grid conditions explicitly through scenario-based planning.
4) Use comprehensive transmission network portfolios (as opposed to only line-specific assessments).
5) Jointly plan across neighboring interregional systems.[129]

In addition to these methodological practices, a best practice in terms of process is to engage states, utilities, consumers, and other stakeholders for review, comment, and development of consensus plans and fair allocation of costs. For the Pacific Northwest, in the absence of an RTO that addresses cost allocation, a long-term (20-year) transmission plan that identifies potential needs for transmission upgrades in the future becomes a necessary and critical input into the decision-making processes to move forward with any set of upgrades.[130]

This set of well-established and common-sense transmission planning best practices has been employed many times by different regions across the U.S. and has demonstrably lowered systemwide costs.[131] For example, the New York Independent System Operator ("NYISO") applies these best practices through a proactive, multi-value, scenario-based planning process in its Public Policy Transmission Planning Process ("PPTPP"). The Midcontinent Independent System Operator ("MISO") applies these planning best practices with its proactive, multi-value, scenario-based Multi-Value Projects ("MVP"), Renewable Integration Impact Assessment, and Long Range Transmission Planning ("LRTP")[132] planning processes. CAISO also utilizes a multi-value, scenario-based planning process along with a 20-year transmission outlook.[133]

The following subsections summarize transmission planning best practices in order to provide a basis for evaluating the quality of BPA's planning practices against the six commonly used best practices, and offer suggestions on where to focus reforms to modernize and improve BPA's planning practices.

A. Proactively plan for future generation and load

To ensure that the transmission system can keep up with changing needs and maintain reliability and affordability, it is essential for transmission planners to proactively plan for future

[129] Bratle Group & Grid Strategies, *Transmission Planning for the 21st Century*, 14 (2021), *available at*: https://gridprogress.files.wordpress.com/2021/10/transmission-planning-for-the-21st-century-proven-prac�es-that-increase-value-and-reduce-costs-7.pdf.
[130] A transmission plan in this context does not – and should not – yield an ac�nable construc�n program without significant stakeholder input from a broad spectrum of interests, including state public u�ity commissions. [131] Bratle Group & Grid Strategies, *Transmission Planning for the 21st Century*, at 73-77.
[132] MISO now refers to this planning process as "Transmission Evolu�n", *available at*: https://www.misoenergy.org/about/miso-strategy-and-value-proposi�n/miso-reliability-impera�e/.
[133] Bratle-Grid Strategies, *Transmission Planning for the 21st Century*, at 15.

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generation and load growth. This proactive approach contrasts with the reactive, incremental approach that much of the industry—including BPA—currently employs.

Proactive planning involves incorporating realistic projections of the generation mix, load levels (including estimates for electrification), and load profiles over the lifespan of the transmission investment. These projections should not only consider announced retirements but expected retirements as well. The projections should be based on the best available information, considering factors such as utilities' publicly stated decarbonization and/or clean energy targets, public policy mandates, and consumer preferences. Transmission planners should also incorporate these projections into long-term planning, considering a horizon of at least 20 years.

In recent years, both MISO and CAISO have taken steps to plan for future generation and load more proactively over a 20-year planning horizon. MISO in its Transmission LRTP planning process incorporated "load growth, electrification, carbon policy, generator retirements, renewable energy level, natural gas prices, and generation capital costs" to model capacity expansion over a 20-year period.[134] This past year, CAISO released its 20-year Transmission Outlook plan. CAISO used generation and load projections that meet California's 2045 public policy greenhouse gas reduction objectives, including projected generation retirements and estimates of distributed resources. The 20-year Transmission Outlook also incorporated projections of load growth due to electrification.[135]

BPA's performance on proactive planning

According to the methodology for BPA's Attachment K transmission planning process, BPA does not plan for future generation or load growth beyond the business-as-usual expected forecasts incorporated into the annual system assessment.[136] BPA's planning processes do not incorporate public policies from states in the region, realistic projections of the anticipated generation mix, or expected retirements, nor do they include planning over an appropriate time horizon. Although BPA has conducted a preliminary study on floating offshore wind[137] and is

[134] MISO, *MISO Futures Report*, 2 (2021), *available at*: https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf.
[135] CAISO, *20-Year Transmission Outlook*, 15-25 (2022), *available at*: http://www.caiso.com/Ini��eDocuments/20-YearTransmissionOutlook-May2022.pdf.
[136] *See generally* BPA, *2022 Transmission System Assessment Assumptions and Methodology* (April 2022), *available at*: https://www.bpa.gov/-/media/Aep/transmission/atachment-k/2022-system-assessment-assump�ons-methodology.pdf.
[137] However, BPA did, in response to customer requests, examine the upgrades needed to integrate offshore wind in its 2022 TSEP cluster study, BPA, *2022 Transmission Plan Open Access Transmission Tariff Attachment K Planning Process*, 13 (2022), *available at*: https://www.bpa.gov/-/media/Aep/transmission/atachment-k/2022-bpa-transmission-plan.pdf.

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obviously aware that the future generation mix will be changing due to public policy,[138] there is no evidence that these scenarios have been integrated into the Attachment K planning process.

In its Transmission Plan, BPA merely notes that it works with its Transmission Grid Modeling Group (and the Load Forecasting and Analysis Group) to update the base cases used in the system assessment and forecasted customer load, but BPA does not provide specific details on what inputs are used or modifications are made that result in forecasts of average and peak loads.[139] The Transmission Plan also notes that the base cases "modeled, at a minimum, those resources with firm transmission service. Beyond that, other resources were modeled as needed to meet the forecast customer demands (load forecast) and expected firm transmission service," with no additional details provided on how those other resources are modeled.[140]

At present, BPA incorporates "forecasted load growth, projected firm transmission service commitments, interconnection requests, and system reliability assessments."[141] BPA starts with WECC base cases in its planning processes to validate past System Assessments,[142] which consider generation additions and retirements reported by individual utilities over the next ten years.[143] WECC base cases are relatively conservative and only consider announced generation additions and retirements with a high degree of certainty.[144] In comparison, MISO's LRTP process includes its own independent estimates of generation retirements on top of what utilities report using age and other factors.[145] The BPA base cases also do not appear to include electrification estimates, fuel price forecasts, or hydroelectric power forecasts. BPA relies on utilities to incorporate those forecasts into the load estimates they report to WECC; however, many of the utilities within BPA's transmission service territory do not include electrification estimates in their IRPs.[146] In some cases, regulated utilities have disincentives to report anticipated generation retirements and the need for new resources because such reporting triggers subsequent regulatory actions, including resource solicitations, effects on depreciation schedules, and increased avoided cost pricing for the utility's competitors under the Public

[138] For example, BPA included an entire chapter summarizing the regulatory landscape and how it is shifting to promote carbon-free energy generation, but it is not clear how the changes are incorporated into generation and load forecasts, BPA, *2022 Transmission Plan*, at Chapter 5.

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[139] *Id.,* at 20.
[140] *Id.,* at 33.
[141] *Id.,* at 15.
[142] BPA, *2022 Transmission System Assessment Assumptions and Methodology*, 2-3 (2022), *available at*: https://www.bpa.gov/-/media/Aep/transmission/attachment-k/2022-system-assessment-assumptions-methodology.pdf.
[143] *See* WECC, *WECC Data Preparation Manual for Steady-State and Dynamic Base Case Data*, 6, (accessed Feb. 24, 2023), *available at*: https://www.wecc.org/Reliability/WECC_Data_Preparation_Manual.docx, and BPA, *2022 Transmission Plan*, at 20.
[144] WECC, *WECC Data Preparation Manual for Steady-State and Dynamic Base Case Data*, at 6.
[145] MISO, *MISO Futures Report*, at 14-15.
[146] *See* Renewable Northwest Comments on Notice of Proposed Rulemaking, *Building for the Future Through Regional Transmission Planning and Cost Allocation and Generator Interconnection*, FERC Docket No. RM21-17-000, 179 FERC ¶ 61,028, 20, 37-38 (Aug. 17, 2022), *available at*: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=F96CCE4A-B04C-C4C2-9FFD-82AB9F100000.

Utility Regulatory Policies Act.[147] BPA has also acknowledged that the peak load reference cases used for the load area assessment assumed minimal renewable generation on-line. This assumption was made because of the intermittent nature of wind and lack of significant solar resource.[148]

This assumption is almost impossible to square with the state clean electricity mandates in Oregon and Washington, the two states with the largest loads in BPA's footprint.

NorthernGrid's planning is similar to BPA's. Both processes rely on utilities to report future generation and load, although NorthernGrid notes in planning documents it is up to the discretion of individual utilities what is reported.[149] There is also no independent review of data submitted to NorthernGrid or use of third-party generation and load forecasts, which in past planning cycles, has resulted in members submitting varied future scenarios. While some utilities include resource additions and retirements from their IRPs, others submit data based only on what is currently in their queue.[150] For both BPA and NorthernGrid, their reliance on utilities creates a "planning lag," where neither consider state laws independently, instead relying on individual utility plans to comply with state law. For example, when a new state law is passed, any new requirements show up 1-2 years after the law is passed in the next utility IRP. This delay means NorthernGrid does not incorporate new state laws until the next regional

[147] *E.g.,* Washington Administrative Code 480-107-009 ("A utility must issue an all-source RFP if the IRP demonstrates that the utility has a resource need within four years."). Similarly, Oregon avoided cost methodologies effectively encourage utilities to not report accurate resource needs because that has historically kept avoided costs low. For example, after the passage of SB 1547, which doubled the state's RPS requirements, PacifiCorp filed an avoided cost update cutting renewable avoided prices by 43% claiming that it did not need new renewable resources for more than twenty years. *See In re PacifiCorp, Application to Update Schedule 37 Qualifying Facility Information*, Or. Pub. Util. Comm'n Docket No. UM 1729, Supplemental Application (Mar. 1, 2016). Idaho Power's 2021 avoided cost update is another example. In June 2021, Idaho Power Company updated its avoided costs to indicate no need for capacity until 2028. *In re Idaho Power Update to Avoided Cost Rates, Schedule 85,* Or. Pub. Util. Comm'n Docket No. Docket No. UM 1730, Idaho Power Company's 2021 Annual May Update of Avoided Cost Rates and Post 2019 Integrated Resource Plan ("IRP") Acknowledgment Avoided Cost Update – Schedule 85, Cogeneration and Small Power Production Standard Contract Rates at 2 (Apr. 30, 2021); Or. Pub. Util. Comm'n Docket No. Docket No. UM 1730, Order No. 21-198 at 1 (June 15, 2021). Meanwhile, in May 2021, Idaho Power Company discovered an imminent 2023 capacity need, but the company did not bring this issue before the Oregon commission until December 2021 thereby resulting in avoided costs remaining low. *See Idaho Power Application for Waiver of Competitive Bidding Rules,* Or. Pub. Util. Comm'n Docket No. Docket No. UM 2210, Application for Waiver of Competitive Bidding Rules at 1-2 (Dec. 9, 2021).

[148] BPA, *2022 Transmission Plan*, at 33.

[149] NorthernGrid, *Approved Study Scope for the 2022-2023 NorthernGrid Planning Cycle*, 9, 15, 20, (2022), *available at*: https://www.northerngrid.net/private-media/documents/NG_Study_Scope_2022-2023_Approved.pdf.

[150] NorthernGrid, *Approved Study Scope for the 2022-2023 NorthernGrid Planning Cycle*, at 9-10; In the current planning cycle, Puget Sound Energy ("PSE") submitted 4,090 MW of resource addi�ons and 370 MW in re�ements to NorthernGrid, which is similar to its IRP findings. Puget Sound Energy, *2021 PSE Integrated Resource Plan*, 2-6 (2021), *available at*: https://oohpseirp.blob.core.windows.net/media/Default/Reports/2021/Final/IRP21_Chapter%20Book%20Compressed_033021.pdf. Meanwhile, PGE submitted 19 MW of resource addi�ons and 0 MW re�ements to NorthernGrid, despite sta�ng in its IRP a need for 2,800 MW of new resources by 2030 and an exit from Colstrip by 2025. PGE, *PGE plans to nearly triple clean resources by 2030* (Oct. 15, 2021), *available at*: https://portlandgeneral.com/news/2021-10-15-pge-plans-to-nearly-triple-clean-resources-by-2030.

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transmission planning cycle, which could be two years after utility IRP implementation and three to four years after the policy became law.

To its credit, BPA has engaged with a group of regional utilities to conduct two special transmission studies. The first will incorporate a 20-year planning horizon to study the region's transmission needs in 2042 with low carbon resource requirements.[151] The second will consider whether there are transmission constraints under extreme weather conditions in 2030, including extreme summer heat waves, extreme winter cold snaps, and wildfire risks.[152] Both of these studies will likely provide important information regarding future transmission needs to ensure a safe and reliable grid.

While moving to a 20-year planning horizon will provide needed breathing room to a complicated process, merely expanding the ten-year time horizon to 15 or 20 years will not, as noted, solve the problem. Moving to a 20-year planning horizon and incorporating scenario planning would be an improvement by giving policy-makers in the region more time to weigh the respective costs and benefits of different portfolios of generation and transmission expansion. But regardless of the time horizon or the study methodology used to identify facilities that will be needed in the future, the region needs a new mechanism to allow BPA to begin conducting pre-construction studies, including environmental assessments, and perhaps even construction sooner in the process.

B. Account for the full range of transmission projects' benefits and use multi-value planning

To comprehensively identify investments that cost-effectively address all categories of needs and benefits, transmission planning best practices include a mechanism to account for the full range of transmission projects' benefits and use multi-value planning. FERC Order Nos. 890 and 1000 provide three reasons that can be used to demonstrate a need for new transmission: economic, reliability, and public policy.[153] To demonstrate need in any of these categories, there is a well-known set of twelve transmission-related benefits. FERC recognized these benefits in its transmission planning NOPR (RM21-17). This list of benefits is particularly useful for demonstrating the economic or public policy needs for a new transmission line and is outlined below:

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[151] Western Power Pool, *20-year Low Carbon Study* (Nov. 23, 2022), *available at*: https://www.westernpowerpool.org/private-media/documents/20_Year_Study_Scope_2022.11.23.pdf.

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[152] Western Power Pool, *2030 Low Carbon, Extreme Weather Study Scope* (Oct. 6, 2022), *available at*: https://www.westernpowerpool.org/private-media/documents/2030_Extreme_Study_Scope_2022.10.06_AuoA0s1.pdf.

[153] Advanced No�e of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, FERC Docket No. RM21-17-000, 176 FERC ¶ 61,024, P 13-16 (proposed July 27, 2021).

1. Avoided or deferred reliability transmission projects and aging infrastructure replacement;
2. either reduced loss of load probability or reduced planning reserve margin;
3. production cost savings;
4. reduced transmission energy losses;
5. reduced congestion due to transmission outages;
6. mitigation of extreme events and system contingencies;
7. mitigation of weather and load uncertainty;
8. capacity cost benefits from reduced peak energy losses;
9. deferred generation capacity investments;
10. access to lower cost generation;
11. increased competition; and
12. increased market liquidity.[154]

The CAISO Transmission Economic Assessment Methodology ("TEAM") is an example of a process that accounts for the full range of transmission projects' benefits and uses multi-value planning. The process considers various benefits, including production cost savings and reduced energy prices from both a societal and customer perspective, mitigation of market power, insurance value for high-impact low-probability events, capacity benefits due to reduced generation investment costs, operational benefits, reduced transmission losses, and emissions benefits. This approach is incorporated in CAISO's economic transmission planning and allows the ISO to identify projects that provide multiple benefits, which can result in more cost-effective solutions.[155]

BPA's performance in multi-value planning

In BPA's 2022 Transmission Plan, the majority of proposed projects are intended for reliability purposes.[156] While only a few projects seem to have purposes beyond reliability, the two major projects that were identified that will enable the integration of significant new renewable or non-emitting energy resources come from the TSEP process.[157] The Attachment K planning process, apart from TSEP projects, does not consider transmission benefits beyond the NERC and WECC reliability standards, and its focus seems to be on identifying solutions for identified violations.[158] The TSEP process, while identifying major transmission expansions that better reflect the changing resource mix, is still a reactive process that is focused on near-term customer needs. Furthermore, BPA requires its transmission customers to provide deposits and commit to funding preliminary engineering and environmental studies as well as make long-

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[154] No�e of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, FERC Docket No. RM21-17-000, 179 FERC ¶ 61,028, P 185 (Issued Apr. 21, 2022), *available at:* https://www.ferc.gov/media/rm21-17-000.

[155] CAISO, *2021-2022 Transmission Plan,* at 251-63 (2022). http://www.caiso.com/Ini��eDocuments/ISOBoardApproved-2021-2022TransmissionPlan.pdf.

[156] *See* Chapters 6 and 7 of BPA's 2022 Transmission Plan.

[157] *See id.,* at Chapter 6.

[158] *See* BPA, *2022 Transmission System Assessment Assumptions and Methodology*; *see also* Chapters 3 and 4 of BPA's 2022 Transmission Plan.

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term commitments to take transmission service (in general, the unwritten policy appears to be to require full, or close to full, subscription) all before BPA will make a decision to begin construction.[159] In addition, the TSEP process does not provide clear information regarding the transmission benefits and costs being considered, and detailed modeling methods are not publicly available.[160]

Comment [N(-T58]: Again, this is incorrect – only need a good business case.

Comment [N(-T59]: True

Table 1 below shows the multiple benefits that are considered in various transmission planning efforts around the country, compared to BPA's. This comparison is intended as a starting point for analyzing and benchmarking BPA's approach, but it does not assume that BPA's responsibilities are identical to these other transmission providers.

Table 1. Use of expanded transmission benefits in analysis[161]

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SPP 2016 RCAR, 2013 MTF	MISO 2011 MVP ANALYSIS	CAISO 2007 TEAM ANALYSIS OF DPV2 PROJECT	NYISO 2015 PPTN STUDY OF AC UPGRADES	BPA Attachment K planning and TSEP Process
Benefits Quantified 1. Avoided transmission project costs (1) 2. Production Cost Savings (reduced Ancillary Service Costs) (3) 3. Reduced transmission losses (4) 4. Lower transmission outage costs (5) 5. Capacity benefit energy cost benefit (8) **Other Benefits Quantified** 1. Value of reduced emissions 2. Value of reliability projects 3. Value of meeting policy goals 4. Increased wheeling revenues	**Benefits Quantified** 1. Reduced future transmission investment costs (1) 2. Reduced planning reserves (2) 3. Production Cost Savings (3) 4. Reduced transmission losses (4) 5. reduced operating reserves (8) 6. Reduced renewable generation investment costs (10)	**Benefits Quantified** 1. Production cost savings and reduced energy prices from both a societal and customer perspective (3) 2. Reduced transmission losses (4) 3. Insurance value for high impact low-probability events (6) 4. Capacity benefits due to reduced generation investment costs (10) 5. Mitigation of market power (11) **Other Benefits Quantified** 1. Operational benefits (Reliability Must-Run) 2. Emissions benefit	**Benefits Quantified** 1. Reduced refurbishment costs for aging transmission (1) 2. Production cost savings (includes savings not captured by normalized simulations) (3) 3. Capacity resource cost savings (8) 4. Reduced costs of achieving renewable & climate goals (10)	**Benefits Quantified** 1. It is not clear if BPA considered or quantified any expanded transmission benefits. 2. Within the TSEP process BPA identifies reliability and commercial upgrades. Reliability upgrades are then recovered through embedded transmission rates and commercial upgrades go through a cost allocation process.
Considered But Not Quantified	**Considered But Not Quantified** 1. Decreased wind volatility (7)	**Considered But Not Quantified** 1. Improved reserve sharing (2)	**Considered But Not Quantified**	**Benefits Not Publicly or Transparently Considered or Quantified[162]**

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[159] BPA Transmission Business Prac�e, *TSR Study and Expansion Process (version 7)*, 2 (Aug. 17, 2022); Steve Ernst, Clearing Up, *Upgrades to Cross-Cascades Lines May Put Clean-Energy Goals Within Reach* (Aug. 12, 2022), *available at*: https://www.newsdata.com/clearing_up/supply_and_demand/upgrades-to-cross-cascades-lines-may-put-cleanenergy-goals-within-reach/ar�le_eb0cfd5c-1a6d-11ed-adcc-473caa5bbe08.html.

[160] *See* BPA, *TSR Study and Expansion Process (TSEP): 2019 Cluster Study Overview*, slides 10-11 (2019), *available at*: https://www.bpa.gov/-/media/Aep/transmission/tsr-study-expansion-process/062019-2019-cluster-study-results.pdf.

[161] *See* Bratle-Grid Strategies, *Transmission Planning for the 21st Century* at 31. The benefits with numbers in parentheses in this table correspond to the list of benefits in FERC's recent transmission planning NOPR. Each transmission provider in the planning processes in this table also either quan�ied or considered but did not quan�y benefits beyond those listed by FERC. These are indicated without a number in parentheses.

[162] BPA's 2007 Commercial Infrastructure Financing Proposal, adopted and used in subsequent evalua�ns of poten�al benefits from commercial transmission construc�n, detailed some benefits previously considered by BPA (*see supra* at 25).

1. Reduced reserve margin; Reduced loss of load probability (2) 2. Reduced cost of extreme events (6) 3. Mitigation of uncertainty (7) 4. Increased competition/liquidity (11 & 12) 5. Improved congestion hedging 6. Reduced plant cycling costs 7. Societal economic benefits	2. Enhanced generation policy flexibility 3. Increased system robustness 4. Decreased nat. gas price risk 5. Decreased CO2 emissions 6. Increased local investment and job creation	2. Facilitation of the retirement of aging power plants 3. Encouraging fuel diversity 4. Increased voltage support	1. Protection against extreme market conditions (6) 2. Storm hardening and resilience (7) 3. Increased competition and liquidity (11 & 12) 4. Expandability benefits	1. Avoided or deferred reliability transmission projects and aging infrastructure replacement; 2. either reduced loss of load probability or reduced planning reserve margin; 3. production cost savings; 4. reduced transmission energy losses; 5. reduced congestion due to transmission outages; 6. mitigation of extreme events and system contingencies; 7. mitigation of weather and load uncertainty; 8. capacity cost benefits from reduced peak energy losses; 9. deferred generation capacity investments; 10. access to lower cost generation; 11. increased competition; and 12. increased market liquidity

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Competitive compensation reform

NIPPC and RNW underscore that expanding the number of benefits evaluated by BPA, along with incorporating the other best planning practices detailed in this section, will require a meaningful change in how BPA recruits and retains transmission planning staff in order to complete analyses using this deeper and broader set of planning criteria. One key determinant of BPA's transmission planning, business case, and project execution success is whether it pays these key personnel competitively with the rest of the industry. Today, BPA does not and, by statute, with rare exceptions that prove the rule, cannot. The region's congressional delegation can alleviate this root cause problem by working to enact competitive compensation reform for BPA, akin to what its sister federal agency, the Tennessee Valley Authority, received in 2004. Indeed, this is the single recommendation in this whitepaper that requires an act of Congress. (NIPPC and RNW have separately released recommendations and a detailed review of competitive compensation for BPA and do not repeat those details here.)

C. Address uncertainties and high-stress grid conditions explicitly through scenario-based planning

Best practices include adopting a scenario-based planning approach to effectively manage uncertainties and high-stress grid conditions that encompasses a wide range of plausible long-term futures and real-world system conditions, including challenging and extreme events. This approach involves assessing a set of diverse scenarios that go beyond current needs and account for the full spectrum of long-term uncertainties. The scenarios should consider various factors, such as fuel price trends, future load and generation size and location, economic and public policy-driven changes to market rules or industry structure, and technological advancements, to evaluate the transmission system's effectiveness in different future scenarios and identify any necessary modifications. Through scenario-based planning, transmission planners can anticipate potential challenges and develop mitigation plans. The scenarios should have a long-term time horizon and address high-uncertainty futures, enabling planners to identify "least-regrets" solutions that can effectively meet the grid's needs across these challenging and unpredictable scenarios.

MISO's Long Range Transmission Planning process, described above, is an excellent example of scenario-based planning that considered a wide range of factors. In MISO, Multi Value Projects and the most recent LRTP Tranche 1 projects were a set of transmission lines determined to be needed under multiple scenarios and were therefore deemed to be a "least regrets" set of lines.[163] MISO developed three different scenarios to capture the range of uncertainty over its 20-year planning horizon. These scenarios were then applied to the development of transmission plans.[164] MISO has used scenario-based planning in the past with its Multi-Value Projects, which included the "CapX2020" initiative and the Regional Generator Outlet Study projects. These projects all employed "least-regrets" comprehensive regional network solutions rather than incremental upgrades, which helped reduce the cost of generator interconnections along with many other quantified benefits.[165]

BPA's use of scenario-based planning

In conducting its transmission plan, BPA incorporates limited scenarios and sensitivities.[166] However, these scenarios and sensitivities are based on *expected* peaks and focus on

[163] MISO, *MTEP21 Report Addendum: Long Range Transmission Planning Tranch 1 Executive Summary*, 5-6, (2022), *available at*: https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Execu�e%20Summary625790.pdf; MISO, *Multi Value Project Portfolio Results and Analyses*, 5 (2012), *available at*: https://cdn.misoenergy.org/2011%20MVP%20Por�lio%20Analysis%20Full%20Report117059.pdf.
[164] *MISO Futures Report*, at 2.
[165] Bratle-Grid Strategies, *Transmission Planning for the 21st Century*, at 7; MISO, *MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary*, at 5-6; MISO, *Multi Value Project Portfolio Results and Analyses*, at 5.
[166] BPA, *2022 Transmission Plan,* at Sec�n 4.3.

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engineering criteria.[167] If it were to follow best practices, BPA would incorporate more extreme scenarios to identify the transmission facilities that will be needed to safely and reliably serve load in the region more than 10 years in the future at the lowest possible cost. BPA would also include public policy scenarios in its planning process, to consider proactively that states may adopt more aggressive public policies in response to a changing climate. BPA does not include scenarios for high levels of renewables, extreme weather events, or electrification. Instead, BPA uses only the nearer-term and narrow NERC criteria for its system assessment studies.[168] These system assessment studies are validated based on "[h]istorical load levels for peak and off-peak conditions" to ensure that they represent reasonable base case loads.[169]

BPA states "the peak load reference cases used for the load area assessment assume minimal renewable generation," due to the "intermittent nature of wind and lack of significant solar resources."[170] In addition, while BPA included offshore wind in its TSEP cluster study, it does not appear to have been a sufficiently rigorous analysis, since BPA considered only binding agreements rather than forecasts.[171] In any event, the transmission upgrades needed to move offshore wind to load were not included in the TSEP Reinforcements identified in the Transmission Plan.[172]

BPA also does not include extreme weather events. BPA addresses the historic 2021 "heat dome" stating, although there were some new historic peak loads reached during the 2021 summer heat wave in the Northwest, this was considered an extreme event and most of the new summer peaks were still within the load levels previously studied over the ten-year Planning Horizon.[173]

Interestingly, BPA provides "long-range needs" estimates outside of the 10-year planning horizon when reviewing transmission needs by path in Chapter 8. These needs are primarily focused on reliability, and BPA does not indicate any timeline for addressing them.[174]

Comment [N(-T60]: I wonder if there is some lack of understanding of the TSEP cases used v. the reliability cases used. Although some of the points here sound accurate. And if wider scenarios were used in reliability planning, more of the projects might then be treated financially as reliability projects.

Comment [N(-T61]: Not sure what this means- may not be accurate. We don't have binding agreements to consider in TSEP – it is focused on requests

Comment [N(-T62]: Again, this comment is reflective of a communication choice that BPA made to focus on the projects that the agency is the most excited about. That doesn't mean that there isn't PEA work in the queue related to off-shore wind.

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[167] *Id.*, *see generally* Figures 10 and 11 where sensi�i�s included are defined. These sensi�i�s include steady state and transient stability analysis for expected winter and summer peaks in two, five, and ten years and a two- year off-peak spring scenario.

[168] *Id.*, at 31-32.

[169] *Id.*, at 33.

[170] *Id.*

[171] BPA studied 1,600 MW of offshore wind resources in its 2022 TSEP process; however, that study was based upon customer requests for service and not upon any realis� scenario of Oregon's actual offshore wind poten�l. *Compare* BPA Press Release, *Over 11 GW studied in 2022 Cluster Study, almost doubling the 2021 requests* (Aug. 3,2022), *available at:* https://www.bpa.gov/about/newsroom/news-ar�les/2022/20220804-over-11-gw-studied-in-2022-cluster-study-almost-doubling-the-2021-reques, *with* Northwest Power and Conserva�n Council, *The Future of Offshore Wind Development,* (Aug. 31, 2022), *available at:* https://www.nwcouncil.org/news/2022/08/31/the-future-of-offshore-wind-development/, no�g that the Bureau of Oceanic Energy Management es�nates Oregon has 20 GW of offshore wind poten�l.

[172] BPA, *2022 Transmission Plan*, at 107.

[173] BPA, *2022 Transmission System Assessment Assumptions and Methodology*, at 3.

[174] BPA, *2022 Transmission Plan*, at 98.

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BPA does use limited form scenario-based power-flow cases in its TSEP cluster study. According to BPA:

> the objective of the scenario-based Needs Assessment[175] is to study a range of scenarios that adequately capture anticipated firm network path utilization. Scenarios were developed based on groupings of TSRs in the long-term transmission pending queue with similarly-situated point of receipt (POR) location and/or expected resource type, and by considering which market and weather conditions may induce the greatest firm transmission utilization from these requests on network paths.[176]

D. Use comprehensive transmission network portfolios

Best practices include evaluating comprehensive portfolios of transmission projects that consider other resources such as storage and other technologies to capture benefits such as network interactions. Storage can provide benefits to the grid by decreasing congestion, providing voltage support, and reducing local capacity requirements.[177] When storage and transmission are co-optimized, studies have found they are not substitutes but rather complementary, and optimal amounts of both technologies lead to the lowest system cost.[178] For example, MISO found in its Renewable Integration Impact Assessment report that a combined transmission and storage solution led to a lower system-wide cost than either technology on its own.[179] Considering transmission portfolios better addresses system needs, lowers systemwide costs, and when combined with portfolio-based cost recovery, can simplify cost allocation. Taking a project-by-project approach overlooks potential efficiencies in the highly interconnected transmission system and may lead to less support for cost allocation. To ensure the greatest system efficiencies, transmission planners should model the co-optimization of transmission, storage, and distributed energy resources and include a mix of alternating current ("AC") and direct current ("DC") transmission lines, reconductored lines, or new transmission lines, allowing for more stable and evenly distributed projects across the grid.

Comment [N(-T63]: I think there are some questions her about what drivers the storage is responding to and who controls its output under what conditions. What is true in an organized market with an ISO… isn't necessarily true in the Northwest.

Comment [N(-T64]: One (potentially weird) thought is that if BPA wants to continue to have other parties pay for PEA/ESA, we would identify the load that is driving a portion of the need for those projects and allocate some of those costs to them.

MISO has had great success using the portfolio approach to transmission planning and development, both via approval of the Multi-Value Projects across its service footprint over a decade ago and in the 2022 approval of the Tranche 1 projects that came out of the LRTP. The

[175] The "Needs Assessment" described here is specifically with respect to TSEP, not the broader forecast of transmission needs described in the Atachment K Transmission Plan.

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[176] *Id.*, at 106.

[177] *See* NY-BEST and Quanta Technology, *Storage as Transmission Asset Market Study White Paper on the Value and Opportunity for Storage as Transmission Asset in New York*, (Jan. 2023), *available at*: https://cdn.ymaws.com/ny-best.org/resource/resmgr/reports/SATA_White_Paper_Final_01092.pdf.

[178] Bratle-Grid Strategies, *Transmission Planning for the 21st Century*, at 64.

[179] *See* MISO, *MISO's Renewable Integration Impact Assessment (RIIA), Summer Report* (Feb. 2021), *available at*: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

Tranche 1 projects are designed to "ensure a reliable and efficient regional and interregional transmission system that enables the changing portfolio across the near and long term."[180]

ISO-NE does not use portfolio-based transmission planning, but through the use of postage stamp cost recovery, they do conduct portfolio-based cost recovery of network transmission costs, which is broadly based on the entire ISO-NE portfolio.[181]

BPA's approach with respect to project portfolios

As BPA is not producing a holistic plan to meet anticipated future generation and load, it is not comparing alternative portfolios of transmission to meet that anticipated need. It does seem to include portfolios of projects for the narrow, near-term set of projects that are in the TSEP, but those are only based on binding customer transmission agreements as described above. In contrast, NorthernGrid in its current 2022-2023 transmission planning cycle is incorporating portfolio-based planning by evaluating 26 different combinations of proposed regional projects to determine which combination best meets regional needs.[182]

Comment [N(-T65]: Incorrect – based on study agreements and PEAs, not binding agreements for TX service – that comes much later.

E. Jointly plan across neighboring interregional systems

Best practices include joint regional and interregional planning with neighboring systems using the above-described planning methods (proactive, multi-value, and scenario-based analysis). Unfortunately, most existing processes only evaluate transmission needs that are of the same type, such as reliability, market efficiency, or public policy, which may prevent the evaluation of needs that differ across regions. Therefore, to ensure interregional planning is effective, joint modeling and analysis of adjacent regions should be performed to evaluate transmission regional and interregional needs and analyze benefits based on a multi-value framework. This approach will ensure the recognition of regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

In its 2021-2022 Transmission Plan, CAISO has acknowledged that,

> the interregional coordination process has not met expectations and noted there are opportunities to remove certain barriers, foster collaboration with state regulators, and promote more rigor in, and reporting on, interregional coordination efforts. Accordingly, the ISO is exploring a few alternative courses of action to pursue potential interregional

[180] MISO, *Long Range Transmission Planning: Tranche 1*, slide 5 (2022), *available at:* https://cdn.misoenergy.org/20220325%20LRTP%20Workshop%20Item%2002%20Tranche%201%20Por�lio%20and%20Process%20Review623633.pdf.
[181] Bratle-Grid Strategies, *Transmission Planning for the 21st Century*, at 15.
[182] *See* NorthernGrid, *Approved Study Scope for the 2022-2023 NorthernGrid Planning Cycle,* at 21, 28.

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opportunities in addition to complying with all expectations, responsibilities and obligations under the ISO's interregional coordination tariff provisions.[183]

The Acadian Load Pocket ("ALP") Project in Louisiana is also an excellent and successful example of multi-jurisdictional planning. While not precisely interregional, it was developed along the seams of three transmission providers (two privately owned, one publicly owned) and was considered a multi-value project with different drivers and benefits for the parties involved, and each party was responsible for recovering costs through its own tariff.[184]

BPA's regional and interregional coordination

BPA is a member of NorthernGrid, which is responsible for conducting joint interregional coordination with the other FERC Order 1000 planning regions (CAISO and WestConnect). However, NorthernGrid's interregional coordination appears to be a "check-the-box" exercise.[185] In the most recent plan cited by BPA, NorthernGrid proposed 141 new and upgraded transmission line projects primarily for local load service and increased reliability, with only a few interregional lines proposed but not accepted as part of the plan.[186] BPA itself does not appear to participate significantly in joint interregional coordination exercises beyond NorthernGrid. There is little discussion within BPA's tariff about coordination with WECC and Northern Grid.[187] Additionally, coordination in the region on the Western Energy Imbalance Market, reserve sharing, or other one-off practices appears to be operational and near-term in nature.[188] The lack of meaningful interregional planning is similar to what occurs in other regions which to date have only included small near-term projects. This lack of interregional coordination on transmission planning stands in sharp contrast to BPA's robust engagement in recent processes to develop organized day-ahead markets in the West. It also contrasts with BPA's history of interregional engagement in joint transmission projects (*see the Appendix for more details*).

[183] CAISO, *2021-2022 Transmission Plan,* at 13.
[184] The Bratle Group, *A Roadmap to Improved Interregional Transmission Planning*, at 36-37 (Nov. 2021), *available at*: https://www.bratle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf.
[185] *See* NIPPC Comments on Advance No�e of Proposed Rulemaking, *Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional*, FERC Docket No. RM21-17-000, 176 FERC ¶ 61,024 at 4-5 (Oct. 12, 2021), *available at*: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=2BD8D9B6-8347-CE44-8624-7C7A31500000; *see* also Public Interest Organiza�ons Comments on Advance No�e of Proposed Rulemaking, *Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional*, FERC Docket No. RM21-17-000, 176 FERC ¶ 61,024 at 45-49 (Aug. 17, 2021), *available at*: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=60f22f6b-c401-c6bc-b293-7c76ae400001.
[186] BPA, *2022 Transmission Plan*, at 41.
[187] BPA, OATT, Atachment K at 163-83.
[188] *See* BPA, *Coordinated Transmission Agreement*, (accessed Feb. 24, 2023), *available at*: https://www.bpa.gov/energy-and-services/transmission/coordinated-transmission-agreement.

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F. Stakeholder engagement and input

Best practices associated with regional transmission planning include having an open planning process that engages many different perspectives through collaboration and stakeholder engagement. In Order No. 890, FERC established a set of transmission planning principles that emphasize the importance of transparency and providing opportunities for stakeholder engagement. The order highlighted several shortcomings in the existing criteria for transmission planning, including the lack of clarity around the transmission provider's planning obligations, the absence of requirements for customer, competitor, and state commission involvement in the planning process, and the lack of availability to customers of key assumptions and data underlying transmission plans. To address these issues, FERC directed all public utility transmission providers to produce a transmission planning process that adheres to nine principles and to clearly outline this process in Attachment K. The nine planning principles include coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects.[189] Subsequently, Order No. 1000 required revision of FERC-jurisdictional transmission providers' tariffs to include a transparent and detailed process that allows stakeholders to understand the selection of projects. Transmission planning best practices should include engaging states, utilities, consumers, advocates, environmental groups, and other stakeholders for review, comment, and development of consensus plans and fair allocation of costs. This collaborative approach helps to ensure that all perspectives are taken into account when making decisions and can lead to more informed and effective transmission planning decisions.

RTOs and ISOs create stakeholder committees and forums for transmission planning processes to take up issues of markets, policy mandates, and reliability. Not all RTO/ISOs handle this stakeholder aspect of transmission planning particularly well. Some do better than others. For example, MISO uses a comprehensive planning process that involves many stakeholders. The planning process allows MISO to address cost allocation, which can be contentious, but is needed for the development of large-scale transmission plans. One of the key drivers of the MISO Multi-Value Projects process was that states were asking MISO to study transmission options that could meet the region's renewable generation needs cost-effectively.[190] CAISO, in its transmission planning process has extensive coordination, particularly with California State Agencies including the California Energy Commission and the California Public Utilities Commission.[191] Both MISO and CAISO have extensive stakeholder advisory committees that support the ISOs in their transmission planning.[192]

[189] Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 444-561.
[190] Bratle-Grid Strategies, *Transmission Planning for the 21st Century*, at 69.
[191] CAISO, *2021-2022 Transmission Plan,* at 1.
[192] For example, MISO has 32 en��es, commitees, and other stakeholder groups, https://www.misoenergy.org/stakeholder-engagement/commitees/.

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BPA performance engaging stakeholders for review and comment

BPA does have an open tariff and transmission planning process. Currently, interested parties must ask to participate, but anyone–states, utilities, consumers, and other stakeholders–is able to participate in the planning process.[193] BPA's transmission planning stakeholder engagement process includes two stakeholder meetings per planning cycle, but no stakeholder committees.[194] BPA could improve transparency around its Attachment K transmission study process. Currently, interested stakeholders must request results for economic[195] and system assessment[196] studies. In addition, BPA's OASIS System Planning Portal redirects to BPA's Attachment K website where there is information missing on the 2022 process and some of the links on the website do not link to the correct document. For example, BPA has not posted results from the 2022 TSEP Cluster Study Process.[197]

Comment [N(-T66]: Available upon request

Conclusion

BPA's transmission planning process falls short in most of the key practices, other than stakeholder participation (not counting transparency). Stakeholder participation is about at the same level as many other regional planning entities. BPA does not, however, proactively plan for future generation and load, account for the full range of transmission projects' benefits or use multi-value planning, address uncertainties and high-stress grid conditions explicitly through scenario-based planning, use comprehensive transmission network portfolios (as opposed to only line-specific assessments), or jointly plan with neighboring interregional systems. Adopting the above-described best practices (also listed in the following section of recommendations) would significantly improve BPA's transmission planning process, better preparing BPA and the region to build the grid of the future.

[193] *See* BPA, *Attachment K Planning* (accessed Feb. 27, 2023), *available at*: https://www.bpa.gov/energy-and-services/transmission/atachment-k.
[194] BPA, *2022 Transmission Plan*, at 15.
[195] *Id.*, at 17.
[196] Access to the Systems Analysis Study requires a FISMA atesta�n, BPA, *2022 Systems Assessment Summary* (2022), *available at*: https://www.bpa.gov/-/media/Aep/transmission/atachment-k/request-for-2022-system-assessment.pdf.
[197] *See* BPA, *Attachment K Planning*.

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X. Concluding Recommendations

NIPPC and RNW offer the following recommendations based on the discussion and analysis above. These recommendations complement each other and may be considered as a suite of reforms.

1. **Planning reforms.** BPA should revise its planning process to:

    (A) consider a wider array of transmission projects' benefits, drawing from the best practices of other transmission providers detailed in Section IX;
    (B) regularly conduct proactive local and regional 20-year scenario planning, including a wide range of plausible (for example, at the 95th percentile) but uncertain extreme weather conditions and a range of new generation resources, with robust stakeholder input, and drawing from the best practices of other transmission providers detailed in Section IX;
    (C) independently consider state policy requirements and other transmission demand drivers, in dialogue with state authorities such as utility commissions that have primary responsibility for compliance with these state requirements;
    (D) consider a wider range of transmission portfolio future scenarios, including co-optimizing storage and other technologies, in the 10- and 20-year planning timeframes, that may identify "no regrets" or "least regrets" portfolios, and drawing from the best practices of other transmission providers detailed in Section IX; and
    (E) remain committed to regional and interregional planning with other transmission providers (recognizing that the best transmission solutions are sometimes regional or interregional, not contained within a single provider's system).

2. **Business case for commercial transmission.** In determining whether to move towards construction of new lines, BPA should:

    (A) develop an open and transparent policy (similar in form to the 2007 CIFP) specifying the system benefits and revenue thresholds it considers in determining whether to offer customers service at an embedded or incremental rate, consistent with recommendation 1.A above;
    (B) ensure that a wider array of benefits is considered and deducted from the revenue requirement that must be met through subscriptions, consistent with recommendation 1.A above;
    (C) lower the apparently very high threshold of subscriptions (binding commitments to take transmission service) required to proceed to most construction; and
    (D) separately develop an analytical framework to consider how to incorporate into its long-term planning facilities that appear repeatedly in multiple planning studies but lack a critical mass of subscribers committing financially to upgrades.

3. **Participant funding.** BPA should:

    (A) develop a formal policy identifying the criteria under which it will conduct engineering, siting, and other pre-construction studies for transmission line upgrades at

its own expense and identifying how those costs will eventually be recovered from customers; and
(B) revisit and consider lowering the currently high letter of credit/deposit requirement for TSEP subscribers, while addressing the need to protect against undue risks of stranded costs.

4. **Contracting innovation.** BPA should:
(A) explore using BPA's Transmission Business Line itself as an anchor, or backstop, tenant by exercising a "put option" on some carefully chosen commercial transmission built by BPA, drawing from the experience of DOE in implementing the new Transmission Facilitation Program; and
(B) explore whether IOUs can and would be willing to serve as backstop subscribers for some new transmission capacity, perhaps until IPPs fill in the capacity on a given line in the course of delivering power to those utility offtakers; and
(C) explore joint venture and partnership opportunities that rely on private capital and private projects to take initial development, construction, or subscription risk in lieu of BPA.

5. **Risk calculations.** BPA should:
(A) revisit the core question of how much risk the agency will assume in pursuing a renewed transmission construction agenda, including an analysis of potential benchmark levels of risk (for example, outcomes modeled at a 95th percentile);
(B) review and share with stakeholders whether past transmission investments have actually resulted in any stranded assets (and whether the stranding was temporary or persistent); and
(C) analyze and consider new revenue opportunities to the agency from having and selling more transmission capacity through a variety of existing or potentially new transmission products.

6. **Process.** BPA should:
(A) conduct an iterative customer-facing initiative to consider and make the changes recommended above (as well as other potential changes), including an active effort to solicit the perspective of state regulatory commissions, and potentially as inputs into BPA's upcoming revision of its strategic plan and transmission business model;[198]
(B) following such an initiative, conduct a formal tariff revision process to incorporate those reforms into its business practices or its transmission tariff, but in the tariff only to the extent a given reform requires such a revision; and
(C) advocate within NorthernGrid for the adoption of similar reforms in the planning processes of NorthernGrid and any successor organization.

[198] BPA should consider similar approaches or forums as past ini��es such as the Transmission Issues Steering Commitee that produced the 2007 CIFP and the Wind Integra�n Forum of that same era, the later of which was co-sponsored by BPA and the Northwest Power and Conserva�n Council.

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7. **Transparency**. In considering and implementing the above-described processes and reforms, BPA should make the processes and decision points about reform transparent, including by ensuring that BPA's website acts as a repository of up-to-date information, as well as relevant historical documents.

8. **Compensation.** In order to support BPA recruiting and retaining the necessary transmission planning, business case, and associated transmission staff to carry out the reforms proposed in this whitepaper, Congress should pass competitive compensation reform for BPA.

Appendix: BPA's Record of Transmission Innovation

This appendix details prominent examples in BPA's history of how the agency has leaned into its transmission mission in various ways—politically, financially, technically—to build more capacity and a stronger bulk power system, sometimes at the expense of competing interests. These examples demonstrate a record of innovation and ambition that can inform BPA's future direction.

Founding Ambitions

The basic authority for BPA to build a robust transmission network was heavily debated in Congress prior to the agency's creation. The Army Corps of Engineers, private utilities in the Northwest, and the Portland business community advocated for a limited transmission role, if any, for BPA. At the beginning, it was not even clear if Bonneville and Grand Coulee Dams would be interconnected. Even after BPA's creation in 1937, it was unclear how or by whom power would be marketed from Grand Coulee.[199]

When J.D. Ross became BPA's first administrator, he adopted an aggressive approach to transmission planning. Ross's view was that if BPA contented itself with building lines only incrementally as demand appeared, the demand might simply remain dormant. Ross therefore focused his attention on executing an ambitious construction agenda. Ross based this agenda on a 1935 master grid plan developed by Charles Carey for the Pacific Northwest Regional Planning Commission, a New Deal planning board. Carey went on to become BPA's chief construction engineer. Carey's plan, adopted in Ross's first annual report as administrator, featured two central double-circuit 220-kV lines: one between Grand Coulee Dam and Bonneville Dam, and the other between Bonneville Dam and the Portland area. This backbone segment formed one leg of a triangle that was the BPA network's core configuration. The other two legs joined Portland to Seattle and Seattle to Grand Coulee. Major radial lines extended from this central triangle to population centers and planned hydroelectric dams.[200]

Ross was a friend of President Franklin Roosevelt dating from his time leading Seattle City Light. This relationship was critical to both Ross's appointment as BPA Administrator and BPA's success building transmission. With Roosevelt's personal support, Ross obtained general fund appropriations for BPA's first major transmission line and additional funds from the Public Works Administration. He also secured a workforce from the Works Progress Administration to clear the initial rights-of-way. These combined acts significantly accelerated construction of the

[199] Philip Funigiello, *Toward a National Power Policy: The New Deal and the Electric Utility Industry, 1933-1941* (Pitsburgh: University of Pitsburgh Press, 1973), 174-96; Gus Norwood, *Columbia River Power for the People: A History of the Policies of the Bonneville Power Administration* (Washington, D.C.: United States Department of Energy, 1981), 47-54.

[200] Paul Hirt, *The Wired Northwest* (Lawrence, Kansas: University Press of Kansas, 2012), 279; Norwood, 55, 108-09. Norwood was the long�me head of the Northwest Public Power Associa�on who later wrote a history of BPA for the agency. He called the ini�al Grand Coulee-Bonneville inter� the "jugular vein" of BPA's transmission system.

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major line that integrated output from the two dams. They also coincided with BPA receiving authority in 1940 (in an Executive Order) to market Grand Coulee's power. Ross, despite a brief tenure at BPA cut short by his premature death, established the template for BPA becoming the leading builder of transmission in the Northwest.[201]

Transmission Acquisitions

In the 1930s, Oregon and Washington authorized local voters to create public utility districts ("PUDs"), part of a backlash against private utilities and what they charged for power. The creation of PUDs, filling a gap between municipal utilities and rural cooperatives, was a key part of the public power movement nationally. Their early formation in Washington, in particular, influenced the enabling act of BPA.

Many of the newly formed PUDs attempted to purchase utility assets directly from the existing private utilities within their boundaries, particularly Puget Sound Power & Light (now Puget Sound Energy). Sometimes they turned to condemnation proceedings when the private utility refused to sell its assets, a legal but slow, expensive, and contentious process that BPA sometimes encouraged.[202] In these cases, voters had elected to form a new utility but remained either captive ratepayers or merely unserved by the incumbent private utility. With the threat of condemnation looming, BPA sometimes stepped into these local disputes and directly assisted PUDs in negotiating purchases of private assets. BPA would buy the transmission lines itself, and the PUD would purchase the dams and local distribution lines.[203] This aggressive action, taking place decades before meaningful wholesale and retail competition to investor-owned utilities emerged in the private sector, may be considered a high tide of consumer-owned utility consolidation in the region.

Joint Transmission Construction and Ownership

The Pacific Northwest/Pacific Southwest Intertie is the major electrical link between the Northwest and both California and the Southwest. In 1964, Congress appropriated funding for the federal share of the intertie. Congress was spurred on by drought in California and a lack of local power; slumping industrial electric sales in the Northwest and a surfeit of federal power, with nowhere to sell it; and Canadian demands in the Columbia River Treaty negotiations for transmission to deliver power from the treaty dams in Canada to buyers in California and the Southwest. The joint development of the Intertie is the most outstanding instance of coordinated transmission planning, construction, and operations in the West.

The Intertie consists of two separate systems: The Pacific DC Intertie is a 1,000-kV DC line between BPA's system and Los Angeles, energized in 1970. It is co-owned by BPA (the northern 246-mile segment), the Los Angeles Department of Water and Power, and other southern

[201] Norwood, 65-67, 111-17.
[202] Funigiello, 213.
[203] Hirt, 283-91.

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California utilities. The California-Oregon Intertie consists of three separate 500-kV AC lines between the Northwest and northern California, first energized in 1968. Its various segments are co-owned by BPA (in Oregon) and a consortium of public and private utilities.[204]

The third line of the California-Oregon Intertie (known as the Third AC Intertie) was built 25 years later and energized in 1993. Its construction followed years of debate about persistent insufficient interregional capacity between California and the Northwest. In 1984, Congress authorized BPA and its sister agency the Western Area Power Administration ("WAPA") to participate in construction of this new segment, adding about 2,000 MW of transfer capacity between northern California and the Pacific Northwest (bringing the total AC capacity to 4,800 MW). In the intervening time between construction of the first two AC lines and this third line, BPA had become a self-financing agency rather than dependent on appropriations. BPA split ownership of the northern half of the line with Portland General Electric and Pacific Power & Light (now PacifiCorp). The southern half, in California, is co-owned by public and private California utilities, as well as WAPA.[205]

Private Sector Backstop

In the 1980s, BPA built its last major new backbone transmission line, the Colstrip line, a 350-mile double-circuit 500-kV line.[206] The line came about when the five private utility co-owners of the two new generating units at the Colstrip coal-fired plant failed to secure a transmission right-of-way across western Montana. The utilities had 1,480 MW of new generation under construction but no way to get it to their loads. They asked BPA to step in and build the line using a vacant right-of-way already held by BPA. BPA agreed to do so in 1977.

In the course of a contentious public debate in Montana about siting the line, BPA chose to adjust the route somewhat to avoid some viewsheds and land impacts. BPA also used a single-pole tower design in order to reduce the visual impact further. The line was built on a highly expedited timeline, given the impending operations of the Colstrip generators. For example, a 97-mile segment from Garrison to Townsend, Montana, was constructed in 15 months instead of a then-typical 30 months. The final segment was completed in 1987.[207]

[204] Northwest Power and Conserva�on Council, *Intertie* (accessed May 2, 2023), *available at*: https://www.nwcouncil.org/reports/columbia-river-history/inter�e/; Northwest Power Planning Council, *Pacific Intertie: The California Connection on the Electron Superhighway* (May 2001), *available at:* https://www.nwcouncil.org/media/filer_public/0d/23/0d23f7a3-3aa2-4acb-b05f-082a0186f8a5/2001_11.pdf.
[205] BPA, *Power of the River* (Washington, D.C.: Government Prin�ng Office, 2012), 93-97.
[206] Based on a review by NIPPC and RNW of BPA records of decision and archival material, approximately six new 500-kV lines have been constructed since then, all of significantly shorter lengths and connec�ng parts of the exis�ng BPA network: Kangley-Echo Lake (9 mi, energized in 2003); Grand Coulee-Bell (84 mi, 2004); Schultz-Wautoma (63 mi, 2005); McNary-John Day (79 mi, 2012); Big Eddy-Knight (28 mi, 2015); and Central Ferry-Lower Monumental (38 mi, 2015).
[207] *Power of the River*, at 71-78.

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Non-Wires Solutions

BPA has a long record of pursuing non-wires solutions rather than building new transmission lines. One well-known example illustrates this approach.

In the winter of 1989, a sudden deep freeze took out one of the Colstrip line's new substations and threatened the stability of the transmission lines into Puget Sound. An obvious solution to the grid stability in western Washington was to build a new line across the Cascades. BPA avoided the environmental and financial challenge at the time of doing so by instead building the Schultz substation (completed in 1994) on the east side of the Cascades. BPA connected four of its existing cross-Cascades 500-kV lines into Schultz, thereby creating eight segments that could operate independently and increasing the grid's reliability. BPA also added series compensators that increased the cross-Cascades transfer capacity by approximately 300 MW.[208]

Non-wires solutions are generally cheaper in the short run than building a new line, help maximize the use of existing infrastructure, and avoid greater development impacts on the environment and local communities than a new line. Non-wires options are therefore a valuable part of any transmission provider's portfolio of solutions and can help establish the provider's credibility when it does seek to build a new line.

Since the 1980s, BPA has focused significant attention on non-wires solutions that reduce the need for customers to pay high construction costs and reduce the siting challenges associated with new transmission lines. The most recent high-profile non-wires solution adopted by BPA was in 2017 to avoid building a new 79-mile 500-kV line in the I-5 Corridor between Castle Rock, Washington, and Troutdale, Oregon, relieving system congestion north of Portland. At the time, BPA concluded that the line would result in more capacity than was needed for a purely reliability purpose and that the price escalation was too high (the original project cost of $346 million in 2009 had increased to $1.2 billion by 2016).[209]

While non-wires solutions can be a useful tool, they can also be overlook the need for and benefits of new lines. Within four years of BPA's 2017 decision to avoid building between Castle Rock and Troutdale, both Oregon and Washington had passed state laws mandating use of 100% non-carbon emitting electricity generation, driving significant new demand for transmission capacity. In short, a non-wires philosophy can become overly conservative when it repeatedly forestalls needed physical investments. While it is a prudent policy as a first resort, its limits have become apparent recently in the Northwest.

[208] *Id.*, at 81.
[209] Ted Sickinger, The Oregonian, *BPA nixes costly and controversial I-5 power line proposal* (May 18, 2017), *available at:* https://www.oregonlive.com/business/2017/05/bpa_nixes_costly_and_controver.html; Elliot Mainzer, BPA, *Letter to parties interested in the I-5 Corridor Reinforcement Project* (May 17, 2017).

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Technical Innovation

BPA has frequently been a leader in the field of transmission engineering. The Pacific DC Intertie was the first high-voltage DC line in the U.S. BPA ownership of the line includes the northern converter station (Celilo). BPA, in collaboration with its co-owners, has upgraded this line multiple times, more than doubling its original design of 1,440 MW capacity to 3,220 MW by replacing mercury arc valves with silicon-based thyristor valves, installing new converters, and optimizing the equipment's operation.[210]

In the 1980s, BPA engineers redesigned the basic physical component of transmission lines—high-voltage conductors—by changing the circular shape of the internal aluminum strands into a trapezoid. The joined trapezoids eliminated air space, allowing the same conductor to carry about 20% more aluminum and therefore 20% more power.[211]

Beginning in the late 1990s, BPA developed the Wide Area Measurement System. BPA experimented with phasor measurement units ("PMUs"), devices that measure voltage and current on transmission lines dozens of times per second, as an improvement over the standard supervisory control and data acquisition system that collects data much more slowly. BPA engineers designed data concentrators and display software to optimize use of the PMUs, controlling for differences in the timing of delivery of microwave signals across the transmission network. The combined "syncrophasor" technology has been adopted widely across the power sector since then. This BPA innovation has created a more efficient and reliable grid, allowing control centers to quickly identify cascading split-second disruptions.[212]

Contract Financing of Transmission

When Congress made BPA self-financing in 1974, it gave BPA authority to borrow directly from the U.S. Treasury at a relatively low interest rate and created a revolving fund to manage this debt, other BPA income, and receipts from sales of power and transmission. BPA's borrowing authority is subject to a statutory cap that has been raised by Congress five times. BPA's primary source of capital to fund investments in its transmission system is this federal debt. In contrast, private transmission owners can raise capital by issuing equity or debt in commercial markets. Non-federal public transmission owners can typically issue bonds as well.

BPA has two other principal options for raising capital to build transmission. One is revenue from customers—essentially cash advances—that is generally the most expensive way to finance long-lived assets because current customers pay upfront for assets that will benefit future generations. The other is "lease-purchase" financing that takes the form of a contractual

[210] Power of the River, at 83-85, and BPA, *Fact Sheet, Celilo Converter Station* (April 2016), *available at*: https://www.bpa.gov/-/media/Aep/about/publica�ns/fact-sheets/fs-201604-Celilo-Converter-Sta�n.pdf.
[211] Power of the River, at 85.
[212] *Id.*, at 91-93.

obligation by BPA to a third-party that issues revenue bonds under its own name that are dedicated to building a BPA transmission line.

A lease-purchase contract specifies that BPA will construct a line owned by the third-party and then lease and operate the line with an option for BPA to purchase it at the end of the term of the debt. These contracts are BPA's way of underwriting debt issued by someone else. This type of contract financing is similar to the "net-billing" debt that BPA incurred in backing nuclear plants pursued by the Washington Public Power Supply System (now Energy Northwest), including Columbia Generating Station. The cost of lease-purchase capital is higher than Treasury debt, making this a more expensive way to finance transmission.[213]

Encouraged by Congress to explore alternative financing, BPA came up with lease-purchase financing in the early 2000s as a way to preserve the agency's limited Treasury borrowing authority. To date, BPA has raised lease-purchase capital through three third parties—Northwest Infrastructure Finance Corporation, an entity created by a private corporation that specializes in infrastructure financing; the Port of Morrow, a port district under Oregon law with broad authority to issue bonds; and the Idaho Energy Resources Authority, a state entity authorized under Idaho law to issue bonds on behalf of consumer-owned utilities to finance infrastructure. Credit analysts view these third parties as "conduit issuers" of debt.[214] The capital raised has been used to finance several BPA transmission lines since 2000, including new 500-kV lines like the 63-mile Schultz-Wautoma and 84-mile Grand Coulee-Bell lines.[215] Combined with BPA's Energy Northwest debt, BPA's outstanding non-federal debt ($7.1 billion) is in fact higher than its outstanding federal debt ($6.9 billion), despite the agency's lack of authority to directly issue debt to commercial markets.[216] This basic financial reality is due the agency's broad contracting authority to enter into financial obligations.

When Congress raised BPA's Treasury borrowing authority by $10 billion in 2021 in the Infrastructure Investment and Jobs Act (Sec. 40110, P.L. 117-58), it alleviated BPA's need for the foreseeable future to secure more expensive debt through lease-purchase contracts.[217] But lease-purchase transmission financing nevertheless represents an important example of financial innovation by BPA, via partnerships with both public and private entities, in order to build new transmission.

[213] The program is also known simply as "lease financing" and "third-party financing." *See* BPA, BPA's Lease Financing Program (2013), *available at*: https://www.bpa.gov/-/media/Aep/finance/lease-financing-program/lease-financing-program-overview-final.pdf.

[214] BPA, *Financial Plan Refresh: Grounding Workshop #2* (Nov. 16, 2021), *available at*: https://www.bpa.gov/-/media/Aep/finance/financial-plan-refresh/nov-16-workshop-presenta�n-new.pdf; Moody's Investor Service, *Bonneville Power Administration Credit Opinion* (Apr. 6, 2022), available at: https://www.bpa.gov/-/media/Aep/finance/ra�g-agency-reports/moodysfullreportmay2022.pdf.

[215] *Power of the River*, at 224.

[216] BPA, *Federal Columbia River Power System (FCRPS): Total Liabilities to Federal and Non Federal Parties as of 9/30/2022* (2022) *available at*: https://www.bpa.gov/-/media/Aep/finance/debt-op�niza�n/2022-debt-pie-chart.pdf.

[217] BPA, *Financial Plan Refresh Public Workshop*, slide 8 (Mar. 23, 2022) *available at:* https://www.bpa.gov/-/media/Aep/finance/financial-plan-refresh/20222321-Mar-23-Workshop-Presenta�n.pdf.

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NIPPC

RENEWABLE NORTHWEST

May 2023

‘Appropriate and Required’: BPA and Building the Grid the Northwest Needs

For decades, the Bonneville Power Administration (“BPA”) has played an integral role in the economy of the Northwest. While BPA is often regarded as the steward of the region’s federal hydroelectric system—marketing power from 31 federal hydroelectric (“hydro”) dams and several non-federal facilities—BPA also performs a critical function as a transmission provider. Indeed, BPA operates and maintains approximately 15,000 miles of high-voltage transmission lines in its service territory, or roughly 75% of the region’s transmission system.

BPA did not become the dominant transmission provider in the Northwest by accident. This outcome was the result of repeated, focused attention by BPA, elected officials, market participants, and other stakeholders. It was not a foregone conclusion. Today, the Northwest is on the cusp of a significant transformation in how it sources power to meet the changing electricity needs of homes and businesses. The federal hydro system is a defining component of the region’s electricity supply. But BPA’s transmission system will receive increasing scrutiny. As utilities in the region shift the rest of their non-hydro resource mix toward a different fleet of non-emitting generation, the transmission grid will have to evolve just as rapidly. The ability of the region to meet these aggressive decarbonization goals is not assured and cannot come to pass unless the region makes significant investments through BPA and through other transmission providers to expand the availability of transmission infrastructure.

Comment [N(-T1]: This is uber-true physically. We will have to decide to what degree our commercial transmission model needs to evolve to support this transition as well.

Comment [NJ(-T2]: If we stay in a responsive/reactive mode, I don’t know that we’ll EVER be able to evolve as rapidly as needed – this indicates to me the need to try to identify upgrades that will “lead” generation development

Comment [N(-T3]: Availability is both physical and commercial

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This whitepaper, produced by the Northwest & Intermountain Power Producers Coalition (“NIPPC”)[1] and Renewable Northwest (“RNW”),[2] explores how to ensure that BPA maintains

[1] NIPPC (www.nippc.org) is a membership organiza�on that represents compe��e power par�ipants in the Pacific Northwest and adjacent Intermountain region. NIPPC members include owners, operators, and developers of independent power genera�on and storage, power marketers, transmission developers, and affiliated companies. Many NIPPC members are transmission customers of BPA and bear their applicable share of costs for BPA’s transmission upgrades.

[2] RNW (www.renewablenw.org) is a regional, non-profit renewable energy advocacy organiza�on based in Oregon, dedicated to decarbonizing the region by accelera�g the transi�on to renewable electricity. RNW members area

one of its core purposes—transmitting power needed across the Northwest, regardless of which entity generates or consumes it—at a time of rapid change in the industry. By adopting the reforms laid out here, or some similar combination of reforms, BPA can help ensure that the grid the Northwest needs will be in place and on time so that all consumers in the region continue to enjoy affordable, clean, and reliable electricity. This paper may be updated as new information surfaces.

Acknowledgments: This paper is the joint product of staff and consultants of NIPPC and RNW, including Henry Tilghman, Dina Dubson Kelley, Joni Sliger, Spencer Gray, and Rob Gramlich and Zachary Zimmerman with Grid Strategies.

combina�on of renewable energy businesses and environmental and consumer groups and include many transmission customers of BPA.

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Table of Contents

***I. Executive Summary* 4**

***II. The Need for New Transmission in the Pacific Northwest* 8**

***III. BPA Transmission and its Role in the Northwest* 10**

***IV. BPA's Legal Authorities Related to Transmission* 12**

***V. BPA's Transmission Planning Processes* 20**

A. Local Planning for Network and Point-to-Point Service 20
B. BPA's Attachment K Process 22
C. BPA's Subscription-Based Planning 23
C. Interconnection Requests 26
D. Regional Planning: NorthernGrid 26

***VI. Limitations of BPA's Existing Planning Processes* 29**

***VII. Additional Issues Unique to BPA That Impact Transmission Planning* 34**

A. Regional Cost Allocation 34
B. Transmission Siting 34
C. The Assumption of Risk 35

***VIII. Avoiding the Consequences of Business as Usual* 37**

***IX. Comparison of Best Practices in Transmission Planning Elsewhere to BPA* 39**

A. Proactively plan for future generation and load 40
B. Account for the full range of transmission projects' benefits and use multi-value planning 44
C. Address uncertainties and high-stress grid conditions explicitly through scenario-based planning 48
D. Use comprehensive transmission network portfolios 50
E. Jointly plan across neighboring interregional systems 51
F. Stakeholder engagement and input 53

***X. Concluding Recommendations* 55**

***Appendix: BPA's Record of Transmission Innovation* 58**

Founding Ambitions 58
Transmission Acquisitions 59
Joint Transmission Construction and Ownership 59
Private Sector Backstop 60
Non-Wires Solutions 61
Technical Innovation 62
Contract Financing of Transmission 62

I. Executive Summary

BPA plays a significant role in the economy of the Pacific Northwest by delivering energy across its transmission grid. However, the transmission facilities that the Northwest relies upon to access clean and reliable power were mostly built decades ago. Aggressive state and corporate policies to mitigate climate change by changing the generation mix in favor of carbon-free (non-carbon emitting) resources, combined with the impacts to loads and hydro availability from a changing climate, will require significant investment in new transmission facilities to ensure that the output of new resources can be moved from where it can be generated to where it will be consumed. In earlier periods of rapid transformation of the energy industry, BPA played a leading role in developing a transmission grid that met the region's needs. The Northwest now needs BPA to resume that leadership role in the development of new transmission resources, alongside other transmission providers.

Unfortunately, BPA's current transmission planning and related processes are not well-suited to ensure that transmission gets built in time for the wave of change underway. If BPA does not implement process reforms, the ability of consumers, communities, and states as a whole to meet clean energy requirements and goals will be jeopardized. Likewise, with increasing concerns over resource adequacy and climate-related extreme weather events, new and upgraded transmission lines can help ensure system reliability. Fortunately, if BPA implements the recommendations set forth below, which are permissible under its existing legal authorities, BPA can reassert itself as the region's leader in providing a backbone transmission system, alongside a wider range of private transmission developers complementing BPA's work than in the past. BPA appears to have begun recognizing this need for change.

This whitepaper first explores the need for new transmission in the region, establishing that loads in the Northwest are forecast to increase dramatically and that the current resource mix will change dramatically in favor of non-carbon-emitting resources that require more transmission capacity for several reasons. Next, we explore BPA's enabling statutes, which give BPA broad authority and discretion to provide transmission to customers in the Northwest. An appendix provides additional historical context about instances of BPA innovation and leadership in the field of transmission. We then review BPA's existing planning processes and compare them to best practices in other jurisdictions in the U.S., showing the limitations of BPA's processes. These limitations include assumptions that are too conservative, planning over a time horizon that is too short, and too heavy a reliance on discrete customers to shoulder the financial cost of expanding the grid. Due to these limitations, there is a significant risk that transmission facilities will not be available when they are needed. Finally, we propose a suite of reforms. If BPA adopts these recommendations, the region will be much more likely to continue to enjoy access to safe, reliable, and affordable electricity in the future, even as it copes with a

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Comment [N(-T4]: The business model updates that Chris and I have been developing provides BPA flexibility to use varying models as makes sense for specific projects changing climate and implements policies designed to reduce the region's reliance on carbon-emitting generation resources.[3]

While this paper focuses on the details of how BPA plans and builds transmission and the nexus between BPA, independent power producers, and utilities, this focus does not imply that BPA should be considered once again the transmission builder of first resort for all or most transmission in the Northwest. Competitive merchant and utility transmission projects should have an essential role in assuming some development risk and responsibility for transmission expansion in the Northwest, particularly for projects that fall outside of BPA's existing rights-of-way or primary network. Similarly, regional projects involving more than one transmission provider should be an important part of BPA's solution set. Nevertheless, the region's currently dominant transmission provider has a significant and indispensable role of its own to play in upgrading and potentially expanding its existing backbone grid, such as upgrading line ratings, doubling circuits, and building tie lines in gaps between existing BPA segments.

This paper does not address challenges and potential solutions to interconnecting new generation on BPA's system, given that BPA has already launched a proceeding to address that important problem. Nor does it address siting and permitting challenges that are a separate major impediment to expanding transmission capacity that affects all transmission providers, not just BPA.

Our proposed recommendations are summarized as follows:

1. **Planning reforms.** BPA should revise its planning process to:
   (A) consider a wider array of transmission projects' benefits;
   (B) regularly conduct proactive local and regional 20-year scenario planning, including a wide range of plausible (for example, at the 95th percentile) but uncertain extreme weather conditions and a range of new generation resources, with robust stakeholder input;
   (C) independently consider state policy requirements and other transmission demand drivers;
   (D) consider a wider range of transmission portfolio future scenarios, including co-optimizing storage and other technologies, in the 10- and 20-year planning timeframes, that may identify "no regrets" or "least regrets" portfolios; and
   (E) remain committed to regional and interregional planning with other transmission providers (recognizing that the best transmission solutions are sometimes regional or interregional, not contained within a single provider's system).

Comment [N(-T5]: We might want to note that third-party transmission impacts already allow/require this to some degree and BPA has a substantial amount of transmission projects MW in process that require actions on the part of TPs other than ourselves. We should be aware, though, that those processes are somewhat embryonic – we are working with other TPs (PGE, Puget, etc to work those processes out as we go along- which may to some degree be the best way to do it, although with more maturity).

Comment [N(-T6]: This may be based on the misconception that projects need to be "fully subscribed", which is not true now (and wasn't during NOS either). It has always been my understanding that the administrator can consider any factors s/he feels are relevant in making project build decisions

Comment [N(-T7]: If BPA wanted to, we could share amounts of active MW that have identified 3rd party project impacts (B2H,...)

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[3] This whitepaper does not endeavor to provide an exhaus�e list of all poten�al transmission reforms that BPA or the region's policymakers should consider pursuing. Rather, this paper seeks to provide recommenda�ons that are well-balanced, taking into account BPA's wide spectrum of customers, and that can be implemented on a rela�ely expedient basis in order to meet the region's significant transmission needs. More founda�nal poten�al statutory and mission-related changes (such as opening up the Pacific Northwest Electric Power Planning and Conserva�on Act) are not addressed here.

2. **Business case for commercial transmission.** In determining whether to move towards construction of new lines, BPA should:

   (A) develop an open and transparent policy specifying the system benefits and revenue thresholds it considers in determining whether to offer customers service at an embedded or incremental rate;

   (B) ensure that a wider array of benefits is considered and deducted from the revenue requirement that must be met through subscriptions;

   (C) lower the apparently very high threshold of subscriptions (binding commitments to take transmission service) required to proceed to most construction; and

   (D) separately develop an analytical framework to consider how to incorporate into its long-term planning facilities that appear repeatedly in multiple planning studies but lack a critical mass of subscribers committing financially to upgrades.

3. **Participant funding.** BPA should:

   (A) develop a formal policy identifying the criteria under which it will conduct engineering, siting, and other pre-construction studies for transmission line upgrades at its own expense and identifying how those costs will eventually be recovered from customers; and

   (B) revisit and consider lowering the currently high letter of credit/deposit requirement for Transmission Service Request Study and Expansion Process ("TSEP") subscribers, while addressing the need to protect against undue risks of stranded costs.

4. **Contracting innovation.** BPA should:

   (A) explore using BPA's Transmission Business Line itself as an anchor, or backstop, tenant by exercising a "put option" on some carefully chosen commercial transmission built by BPA;

   (B) explore whether investor-owned utilities ("IOUs") can and would be willing serve in some form as backstop subscribers for some new transmission capacity, perhaps until independent power producers ("IPPs") fill in the capacity on a given line in the course of delivering power to those IOU offtakers; and

   (C) explore joint venture and partnership opportunities that rely on private capital and private projects to take initial development, construction, or subscription risk in lieu of BPA.

5. **Risk calculations.** BPA should:

   (A) revisit the core question of how much risk the agency will assume in pursuing a renewed transmission construction agenda, including an analysis of potential benchmark levels of risk (for example, outcomes modeled at a 95th percentile);

   (B) review and share with stakeholders whether past transmission investments have actually resulted in any stranded assets (and whether the stranding was temporary or persistent); and

   (C) analyze and consider new revenue opportunities to the agency from having and selling more transmission capacity through a variety of existing and potentially new transmission products.

Comment [N(-T8]: As Cherilyn pointed out – BPA doesn't have to go all or nothing on this – we could also 1) choose to "pre-define" the customer's exposure to these costs – i.e., if customer pays X, BPA will cover any increased cost – remove risk of the unknown or 2) split these costs with customers in some manner, particularly when the costs are going to be high. Maintaining some portion of costs on customers allows BPA to achieve some pretty valuable queue management – since TSRs stay in the queue until they reach impactful decision points (customer has to commit to something). There would be consequences for giving up these benefits completely.

Comment [N(-T9]: Directly related to the process re-design work that Chris and I have been doing. One thought though- I doubt that BPA wants to (or should) DEFINE specific criteria, but think that more articulation of the factors that drive these decisions would be pretty helpful to the region (just my opinion). So would some earlier embedded/incremental rate determinations, which we built potential for into the new business model draft.

Comment [N(-T10]: I wonder if BPA's willingness to move forward with projects that are not fully subscribed is essentially this?

Comment [N(-T11]: This could look like a commitment to take transmission (either them or the generating party) that sinks to their service territory and uses a particular project (certain amount of actual impact on that project) within some timeframe and for some minimum number of year. Not sure that we actually need to do this though to obtain enough support for some of these projects!

Comment [N(-T12]: I don't love this idea – feels like it would result in giving up the value of some of the TX that we are building. But could note that if the requestor can choose to pay an incremental rate if that makes economic sense for them.

Comment [N(-T13]: I get that reviews can be helpful. However, we need to be careful about what we spend our limited resource on – probably need to make that point in this larger conversation.

Comment [N(-T14]: Worth noting that historically we've been reluctant to attribute Bridge CFS revenue to offsetting the cost of a project, but could think more about that.

6. **Process.** BPA should:

   (A) conduct an iterative customer-facing initiative to consider and make the changes recommended above, including an active effort to solicit the perspective of state regulatory commissions, potentially as inputs into BPA's upcoming revision of its strategic plan and transmission business model;

   (B) following such an initiative, conduct a formal tariff revision process to incorporate those reforms into its business practices or its transmission tariff, but in the tariff only to the extent a given reform requires such a revision; and

   (C) advocate within NorthernGrid for the adoption of similar reforms in the planning processes of NorthernGrid and any successor organization.

7. **Transparency**. In considering and implementing the above-described processes and reforms, BPA should make the processes and decision points about reform transparent, including by ensuring that BPA's website acts as a repository of up-to-date information, as well as relevant historical documents.

8. **Compensation.** In order to support BPA recruiting and retaining the necessary transmission planning, business case, and associated transmission staff to carry out the reforms proposed in this whitepaper, Congress should pass competitive compensation reform for BPA.

Comment [N(-T15]: Huh – interesting. I'll note that if BPA needs a bigger talent pool, allowing remote work for jobs for which it is workable would definitely increase the BPAs access to talent. Acts of Congress are hard to come by. More liberal use of retention bonuses, etc might help some too. We do seem to be losing talent these days.

II. The Need for New Transmission in the Pacific Northwest

Multiple independent analyses and market data indicate that the Pacific Northwest needs to expand its transmission grid. Operating conditions are changing: climate change is leading to longer and more severe extreme weather, putting pressure on the grid as operators seek to move electricity from areas with surplus generation to areas experiencing extreme weather conditions. The generation fleet is transforming: public policy and market economics have led to the retirement of fossil fuel-powered generation in favor of generation resources that do not emit carbon into the atmosphere. Demand is growing: state energy policies are also expected to lead to the rapid adoption of electric vehicles and electrification of other sectors, putting further pressure on the transmission grid. Numerous national and regional studies have demonstrated that these climate and policy drivers will require new transmission facilities. For example:

- One national study by researchers at Princeton University found that in order to meet energy demand by 2050—and in particular, demand for renewable electricity—transmission capacity will have to increase by 60%.[4]
- Another study by researchers at the Massachusetts Institute of Technology found that the U.S. will require a 90% increase in transmission capacity to meet the cost-optimized scenario to maintain global warming between 1.5-2 degrees Celsius.[5]
- A report by the non-profit Energy Systems Integration Group, summarizing research from six different studies, found that meeting the Biden Administration's goal to reach 100 percent clean electricity by 2035 and net-zero emissions across the economy by 2050 will require a doubling or tripling of the size and scale of the nation's transmission system.[6]

In February, the U.S. Department of Energy ("DOE") released a draft study of national and regional transmission needs, after reviewing over 200 scenarios from six recent capacity expansion modeling studies:

- DOE estimated that the Pacific Northwest will need to add 56% more transmission capacity (8.5 terawatt-miles ("TW-mi")) by 2040 in an aggressive decarbonization scenario.[7]

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[4] Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, 13-14 (Dec. 15, 2020), *available at*: https://netzeroamerica.princeton.edu/img/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf.

[5] Brown, P. R., and A. Boterud, Joule5(1), *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the U.S. Electricity System*, 115-134 (2020), *available at*: https://doi.org/10.1016/j.joule.2020.11.013.

[6] Energy Systems Integra�on Group, *Transmission Planning for 100% Clean Electricity*, 10 (Feb. 2021), *available at* https://www.esig.energy/wp-content/uploads/2021/02/Transmission-Planning-White-Paper.pdf.

[7] U.S. Department of Energy, *Draft National Transmission Needs Study* ("DOE Dra�Needs Study"), 89 (Feb. 2023) *available at:* https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf. The granular regional and interregional study results reviewed by DOE included the Princeton and MIT studies cited above.

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- DOE estimated a nearly equal amount (7.7 TW-mi) needed in the surrounding Mountain region.
- To provide a sense of scale, if that combined 16.2 TW-mi need was met with discrete moderate-length alternating current (“AC”) lines, it would require building 61 new 200-mile long 500-kV lines.[8]
- In the same aggressive scenarios, DOE also estimated a need in 2040 for 37% more transfer capacity (1.9 GW) between the Northwest and California and 308% more transfer capacity (39.2 GW) between the Northwest and Mountain states.[9]

Finally, regional estimates of the expected and potential generation build-out in the Northwest underscore this driver of the need for new transmission:

- According to the Northwest Power and Conservation Council, the region will need 3,500 MW of new renewable generation by 2027 and 14,000 MW of renewable generation by 2040.[10]
- According to the Pacific Northwest Utilities Conference Committee (“PNUCC”), the region will need 9,400 MW of new renewable generation by 2032 with associated transmission.[11]
- Analysis by Evolved Energy Research on behalf of the Clean Energy Transition Institution found that deeply decarbonizing all sectors in the Northwest would lead to a 60% increase in load (because of electrifying other sectors) and therefore a need for 100,000 MW of new resources by 2050, a quantity that may be considered an upper bound.[12]

[8] Terawat-miles are a measurement unit common in models for transmission capacity expansion because they allow a single unit to cover all poten�al new lines in a region by elimina�g differences in their carrying capacity. AC lines that are shorter or have a higher nominal voltage have higher carrying capacity. For example, an uncompensated 200-mile 500-kV AC line has about the same carrying capacity as a 50-mile 345-kV line. (DOE Dra� Needs Study, 88).

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[9] DOE Dra�Needs Study, 96-97. “Transfer capacity” is some�nes referred to interchangeably as “transfer capability,” but *capacity* iden�es only the ra�gs of transmission lines that account for their thermal limits, whereas *capability* accounts for other network elements that might limit the reliable transfer of power from one area to another.

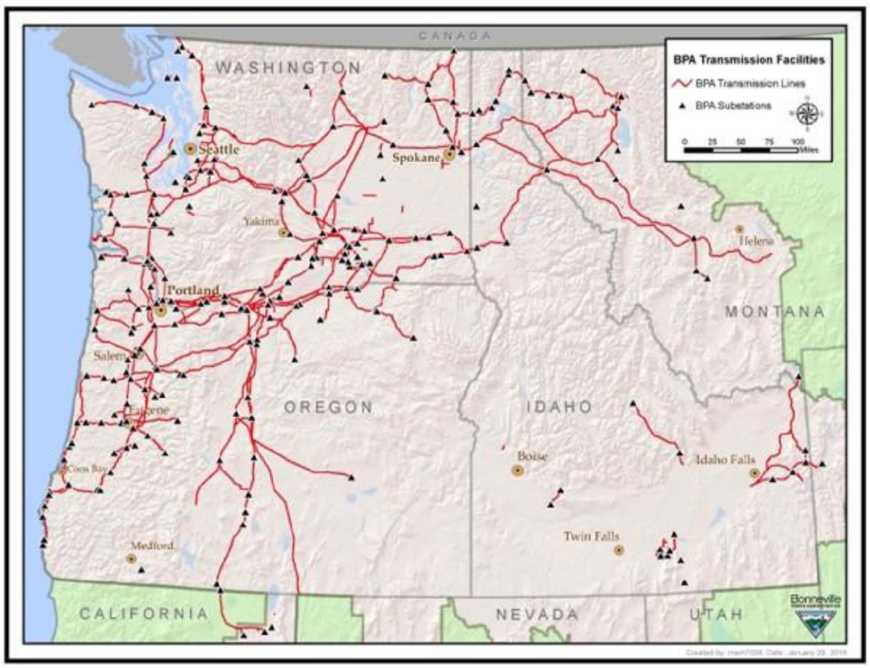
[10] Northwest Power and Conserva�n Council, *2021 Northwest Power Plan*, 71-77 (Mar. 2022), *available at*: https://www.nwcouncil.org/media/filer_public/4b/68/4b681860-f663-4728-987e-7f02cd09ef9c/2021powerplan_2022-3.pdf.

[11] Pacific Northwest U�ity Conference Commitee, *Northwest Regional Forecast of Power Loads and Resources 2022 through 2032* (“PNUCC 2022 Regional Forecast”), 11 (April 2022), *available at:* https://www.pnucc.org/wp-content/uploads/2022-PNUCC-Northwest-Regional-Forecast-final.pdf.

[12] Evolved Energy Research, *Northwest Deep Decarbonization Pathways Study*, 73-74 (May 2019), *available at:* https://uploads-ssl.webflow.com/5d8aa5c4ff027473b00c1516/6229312d39eca8b6b5�368_EER_Northwest_Deep_Decarboniza�on_Pathways_Study_Final_May_2019.pdf .

III. BPA Transmission and its Role in the Northwest

Figure 1. Map of BPA Transmission Facilities



Available at: https://www.bpa.gov/-/media/Aep/about/publications/maps/bpa-tlines-small.pdf

BPA's transmission forms the backbone for the electric grid in the Pacific Northwest and allows energy to flow from Montana to the West Coast and from Canada to California. BPA operates 15,179 circuit-miles of high voltage transmission lines and 259 substations across the states of Washington, Oregon, Idaho, and Montana, including interties to British Columbia, eastern Montana, and California. Facilities controlled by BPA represent 75% of the high voltage transmission capacity in the Pacific Northwest.[13] The region's load-serving entities—investor-owned utilities, consumer-owned utilities, and competitive retail service providers—depend on BPA transmission to deliver energy to their retail customers. As the mix of generation resources in the Pacific Northwest changes, the availability of transmission service to deliver energy from where it is needed to where it is consumed is becoming increasingly constrained.

[13] BPA, *BPA Facts* (Aug. 2021), ***available at:*** https://www.bpa.gov/-/media/Aep/about/publica�ons/general-documents/bpa-facts.pdf.

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BPA has specific statutory obligations to the region (described more fully below in Section IV); these responsibilities include providing necessary transmission. However, unlike a transmission owner that is an investor-owned utility or a merchant transmission developer, BPA has no profit incentive to invest capital in new transmission.[14] This reality may contribute to suppressing BPA's current incentive to build more transmission.

NIPPC and RNW also strongly support competitive, private sector solutions to the Northwest's needs that help avoid or mitigate some stranded asset risks for BPA's rate base. But given BPA's dominant role in providing transmission service to the region, the private sector is ill-situated to solve by itself a transmission build-out of the magnitude anticipated. The Appendix explores how BPA has supported transmission in the past to meet the region's evolving energy needs. BPA itself has recently begun recognizing the evolving grid, changing demands on BPA, and the role that BPA might play in helping address the region's urgent transmission demands.[15] The remainder of this whitepaper explores what BPA is doing now to plan and build new transmission and suggests ways BPA could carry out these responsibilities more effectively.

[14] Investor-owned u��es are guaranteed a rate of return on prudent investments. In contrast, as a government en�y that must limit its rates to covering its costs and lacks shareholders who put their equity at risk, BPA does not have a profit mo�e to expand the grid similar to a private company.

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[15] *See* BPA, *The Evolving Grid: Update on the State of Transmission* (April 27, 2023), *slides available at*: https://www.bpa.gov/-/media/Aep/transmission/transmission-business-model/042723-evolving-grid-bpat-final.pdf, *workshop recording available at*: https://youtu.be/rbYbQf-wD6E. This recent presenta�on is highly informa�e about BPA's current transmission planning queue and upcoming construc�on agenda.

IV. BPA's Legal Authorities Related to Transmission

A. Congress Has Given BPA Broad Discretion to Function in a Business-Like Manner, Including in Managing the Transmission System

Four statutes primarily govern BPA's operations: 1) the Bonneville Project Act of 1937 (the "Project Act");[16] 2) the Pacific Northwest Consumer Power Preference Act of 1964 (the "Preference Act");[17] 3) the Federal Columbia River Transmission System Act of 1974 (the "Transmission Act");[18] and 4) the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (the "Northwest Power Act").[19] Overall, these statutes afford BPA broad discretion, including over its management of the federal transmission system in the Pacific Northwest.

The Project Act recognizes that transmission is essential to "encourag[ing] the widest possible use of" federal power.[20] To that end, it has directed BPA since 1937 to "provide, construct, operate, maintain, and improve" such transmission facilities as BPA finds "necessary, desirable, or appropriate" for transmitting federal power.[21] In the words of the Ninth Circuit Court of Appeals (the "Ninth Circuit") in resolving a dispute about BPA's authority:[22]

> This delegation of authority is broad, allowing the [BPA] Administrator substantial discretion. This discretion is tempered only by the implied limitation that the Administrator's action not be inconsistent with other congressional decrees."[23]

The Preference Act directs BPA to provide for transmitting non-federal power any available transmission capacity that is in excess of federal power needs.[24] BPA is obligated to set "equitable rates" for such usage.[25] The Project Act had already provided BPA with broad

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[16] 16 U.S.C. §§ 832-832*l*.
[17] 16 U.S.C. §§ 837-837*h*.
[18] 16 U.S.C. §§ 838-838*l*. This Act is also some�mes referred to as the Pacific Northwest Federal Transmission System Act or simply the Transmission System Act.
[19] 16 U.S.C. §§ 839-839*h*. This Act is also some�mes referred to as the Regional Act.
[20] 16 U.S.C. § 832a(b).
[21] Aug. 20, 1937, ch. 720, §2, 50 Stat. 732 (codified as amended at 16 U.S.C. § 832a(b)); *see also* 16 U.S.C. § 832e (direc�ng BPA to set customer rates for federal power "with a view to encouraging the widest possible diversified use of electric energy").
The Project Act, even as codified, refers specifically to BPA transmi�ng power from BPA's namesake, the Bonneville Dam. 16 U.S.C. § 832a(b). BPA's purview has since expanded to many other federal facili�es. *E.g.,* the Flood Control Act of 1944, Dec. 22, 1944, ch. 665, §5, 58 Stat. 890 (codified in relevant part in 16 U.S.C. § 825s)*; see also* 16 U.S.C. § 839e(a)(1), 839e(k) (referencing BPA's con�nuing obliga�ons under the Flood Control Act of 1944).
[22] The Northwest Power Act specifically vests the Ninth Circuit with jurisdic�on to hear challenges to BPA ac�ons. 16 USC § 839f.
[23] *California Energy Comm'n v. Bonneville Power Admin.*, 909 F.2d 1298, 1314 n.17 (9th Cir. 1990).
[24] 16 U.S.C. § 837e. The Transmission Act later affirmed this and required it to be done on a "fair and nondiscriminatory basis." 16 U.S.C. § 838d.
[25] 16 U.S.C. § 837e.

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authority to negotiate contracts as BPA deemed "necessary,"[26] and BPA has since interpreted the Project Act to authorize it to establish generally applicable terms and conditions for transmission service of both federal and non-federal power.[27]

The Preference Act affirms BPA's historic focus on serving customers in the Pacific Northwest.[28] In that context, it generally prohibits BPA from constructing transmission facilities outside the Pacific Northwest.[29] Still, BPA may pursue such facilities as BPA "deems necessary to allow mutually beneficial power sales" with California.[30]

The Transmission Act granted BPA "even broader transmission authority."[31] It directs that:

> [BPA] shall operate and maintain the Federal transmission system within the Pacific Northwest and shall construct improvements, betterments, and additions to and replacements of such system within the Pacific Northwest as [BPA] determines are appropriate and required to:
>
> (a) integrate and transmit the electric power from existing or additional Federal or non-Federal generating units;
> (b) provide service to [BPA's] customers;
> (c) provide interregional transmission facilities; or
> (d) maintain the electrical stability and electrical reliability of the Federal system[.][32]

Thus, among other authority and obligations, the Transmission Act provides the statutory authority for BPA to build new transmission as needed to transmit non-federal power.

In addition, the Transmission Act freed BPA from relying on Congress's annual appropriations for transmission expenditures in the Pacific Northwest.[33] Under the Transmission Act, BPA

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[26] 16 U.S.C. § 832a(b).
[27] *E.g.*, TC-20 Tariff Terms and Condi�ons Proceeding, Record of Decision, TC-20-A-03 at 8-9 (Mar. 1, 2019) [hereina�er TC-20 ROD].
[28] *E.g.,* 16 U.S.C. § 837f. Such provisions are generally consistent with BPA's longstanding obliga�on to serve those persons "within economic transmission distance of the Bonneville project." 16 U.S.C. § 837c(d).
[29] 16 U.S.C. § 837g.
[30] 16 U.S.C. § 837g-1. This provision has been codified with the Preference Act, but it was actually enacted about 20 years later in the context of Congress authorizing BPA's par�cipa�on in the development of the Third AC Inter� of the California-Oregon Inter�. Pub. L. 98–360, �tle III, July 16, 1984, 98 Stat. 416; see generally *Pacific Gas and Electric Company; Pacific Gas and Electric Company; Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company,* 63 FERC ¶ 63,018, 65,070 (June 30, 1993) (discussing this history).
[31] *Ass'n of Pub. Agency Customers v. BPA,* 126 F.3d 1158, 1170 (9th Cir. 1997).
[32] 16 U.S.C. § 838b.
[33] 16 U.S.C. § 838b. BPA does need some form of Congressional approval (but not appropria�ons) before construc�ng "major transmission facili�es" in the region, which the statute defines as facili�es "intended to be used to provide services not previously provided." 16 U.S.C. §§ 838a, 838b. There are prior examples of Congress approving such expenditures, either directly or by reference, such as in an appropria�ons legisla�ve vehicle. *E.g.,*

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became a self-financing agency primarily dependent upon revenues from the services it provides to sustain ongoing activity; this activity is capitalized primarily through funds borrowed directly from the U.S. Treasury and repaid with interest.[34] BPA must consider its obligations to repay Treasury funds when it sets customer rates.[35] Both the Transmission Act and the Northwest Power Act direct BPA to set customer rates consistent with "sound business principles."[36] BPA must also set rates "sufficient to assure repayment" of the federal investment in hydro generation, fish and wildlife recovery, and conservation.[37] Thus, BPA typically does not need specific Congressional authorization to move forward with projects in the Pacific Northwest once BPA has determined they are "appropriate and required" to meet BPA's statutory goals above. But BPA must charge rates sufficient to recover the costs of those projects.

The Northwest Power Act directs BPA to carry out its obligations "in a sound and businesslike manner."[38] It also, for the first time, specifically obligated BPA to undertake certain environmental and conservation endeavors.[39] The Ninth Circuit has noted that BPA's new "more typically governmental responsibilities" under the Northwest Power Act "suggest the propriety of even greater deference" to BPA's business-like decision-making.[40]

The Northwest Power Act also specifically vested the Ninth Circuit with jurisdiction to hear challenges to BPA actions, but the Ninth Circuit has generally, to date, taken a very deferential approach.[41] The Ninth Circuit has described BPA's governing statutes as endow[ing] the

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Consolidated Appropria�ons Act, 2014, Public Law 113-76, 128 Stat. 170 (approving BPA's request to spend its funds to construct a new high voltage line to serve customers in southern Idaho, southern Montana, and western Wyoming). Under the Transmission Act, BPA is s�l obligated to submit an annual budget to Congress; items included in the budget need no further appropria�on, and BPA's annual submission may include a request for approval of major transmission facili�es. *Id.* § 838i(a). Congress may impose limits on BPA, which BPA must adhere to. *Id.*, at § 838i(b).

[34] *See generally* 16 U.S.C. §§ 838i, 838k.

[35] 16 U.S.C. § 838g.

[36] The Transmission Act directs BPA to set rates "with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles." 16 U.S.C. § 838g. BPA must also consider its need to recover costs and repay its debts. *Id.* The Northwest Power Act directs BPA to set rates "in accordance with sound business principles" and other statutory provisions like the one quoted above, which FERC must approve upon a finding that the rates: 1) "are sufficient to assure repayment" of the federal investment; 2) "are based upon … total system costs"; and 3) for transmission rates, "equitably allocate the costs of the Federal transmission system between federal and non-Federal power" users. 16 U.S.C. § 839e.

[37] 16 U.S.C. § 839e.

[38] 16 U.S.C. § 839f(b).

[39] *See generally* 16 U.S.C. §§ 839-839*h*.

[40] *Ass'n of Pub. Agency Customers*, 126 F.3d at 1170.

[41] 16 USC § 839f. The Supreme Court has also commented on the deferen�al review due to BPA, based in part on the complexity of BPA's work and BPA's in�mate involvement in the legisla�e dra�ng of BPA's statutes. *Aluminum Co. of America v. Central Lincoln Peoples' Utility Dist.*, 467 U.S. 380, 390 (1984).

Administrator with broad-based powers to act in accordance with BPA’s best business interests—powers not normally afforded government agencies.[42]

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The Ninth Circuit has recognized that Congress intended for “BPA to function more like a business than a governmental regulatory agency”[43] and that Congress “granted BPA an unusually expansive mandate to operate with a business-oriented philosophy.”[44] In this context, the Ninth Circuit has recognized that its review has been “particularly deferential” to BPA.[45]

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Finally, Congress has also declared broad policies which BPA should pursue. One is to “encourage … the development of renewable resources within the Pacific Northwest.”[46] Another is “to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply.”[47] These goals should inform BPA’s exercise of its discretion and underscore BPA’s important role in facilitating the development of renewable resources and the transmission needed to supply customers with electricity regardless of the generating source.

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In summary, BPA has statutory obligations to maintain and improve the federal transmission system in the Pacific Northwest, which it may carry out with an unusually high level of discretion. Unlike most agencies, BPA is generally not subject to the typical appropriations approval process for agency action. Instead, it must, in a sound business-like manner, set rates for the services it provides with an eye to providing service while still recouping its costs, including its repayment of the federal investment in hydro generation, fish and wildlife recovery, and conservation.[48] BPA aims to keep rates low, but that goal does not ultimately trump BPA’s obligations to maintain and improve the transmission system.

B. BPA Must Provide Transmission Service in Accordance with its Adopted Terms and Conditions for Providing Service

Like most transmission providers, BPA has streamlined its contracting process for offering transmission service by adopting generically applicable terms and conditions for such service. These generic terms and conditions are commonly referred to as an “Open Access Transmission Tariff” or “OATT,” an industry term that was widely adopted following the seminal open access

[42] *Ass’n of Pub. Agency Customers*, 126 F.3d at 1170; *see also Bell v. BPA*, 340 F.3d 945, 949 (Ninth Cir. 2003) (“We will not second-guess the wisdom of BPA’s winning business decisions, especially when it was responding to unprecedented market changes.”).

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[43] *Ass’n of Pub. Agency Customers*, 126 F.3d at 1170; *see also, e.g.*, 16 U.S.C. § 832a(b), 832a(f).

[44] *Ass’n of Pub. Agency Customers*, 126 F.3d at 1171; *see also Indus. Customers of Northwest Utils. v. BPA*, 767 F.3d 912, 923-924 (2014) (no�g BPA has “wide la�ude” both “in spending” and in deciding “how best to further BPA’s business interests consistent with its public mission.”) (ci�g *Aluminum Co.*, 467 U.S. at 789)).

[45] *Pac. Northwest Generating Coop. v. Dep’t of Energy*, 580 F.3d 792, 806 (2009).

[46] 16 U.S.C. § 839(1)(B).

[47] 16 U.S.C. § 839(2).

[48] *See supra* footnote 21.

directive of the Federal Energy Regulatory Commission ("FERC"), Order 888.[49] As noted earlier, BPA has broad authority to negotiate contracts under the Project Act,[50] and BPA has since interpreted the Project Act to authorize it to establish generally applicable terms and conditions for transmission service of both federal and non-federal power.[51] This section of this paper addresses BPA's foundational obligation to adhere to its OATT.

Unlike most transmission providers, BPA is generally[52] not subject to FERC oversight or directives for setting generically applicable transmission terms and conditions.[53] In the past, BPA voluntarily sought (and sometimes obtained) FERC's approval of BPA's OATT in order to obtain "safe harbor reciprocity status,"[54] which would require most other transmission providers to provide transmission service to BPA pursuant to their own FERC-approved OATTs.[55] In 2013, FERC declined to grant BPA safe harbor reciprocity status,[56] and in 2016, rather than address FERC's criticisms, BPA decided not to seek reciprocity status.[57] Nonetheless, this history provides useful context in understanding BPA's decision-making within a policy space in which FERC and other transmission providers have established certain principles and ideals, even though BPA is generally not directly beholden to FERC's directives.[58] *See footnote 105 for additional distinctions between BPA and transmission-owning utilities.*

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[49] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[50] 16 U.S.C. § 832a(b).

[51] *E.g.*, TC-20 ROD at 8-9.

[52] FERC can enforce BPA's obliga�on to offer transmission service at rates comparable to those BPA pays and on terms and condi�ons that are "not unduly discriminatory or preferen�al." 16 U.S.C. § 824j-1(b); *see also Iberdrola Renewables, Inc. v. BPA*, 137 FERC ¶ 61,185, at ¶ 61,949 (Dec. 7, 2011) (exercising this authority); *cf.* 16 U.S.C. § 824k (describing addi�onal FERC authority over BPA's terms of transmission service).

[53] BPA is not a "public u�ity" under key provisions of the Federal Power Act. 16 U.S.C. §§ 824, 824d, 824e. However, it can (and has) obligated itself to at least consider FERC's standards under certain of those provisions. TC-20 ROD at 9-10.

[54] *See generally BPA, Order on Petition for Declaratory Order,* 145 FERC ¶ 61,150 at PP 2-7 (Nov. 21, 2013) (addressing a BPA request for reciprocity status and discussing BPA's history).

[55] *See* FERC Order No. 888, 61 Fed. Reg. 21,540 at 21,613-14 and 21,668-69 (May 10, 1996); FERC Order No. 888-A, 62 Fed. Reg. 12,274 at 12,338-40 (Mar. 14, 1997).

[56] *BPA, Order on Petition for Declaratory Order,* 145 FERC ¶ 61,150 at P 1 (Nov. 21, 2013). While FERC accepted several proposed changes to BPA's OATT, FERC iden�fied addi�onal changes that would need to be made before FERC could grant BPA safe harbor reciprocity status. These changes include updates to Schedules 9 and 10 regarding BPA's provision of Generator Imbalance Service; removal of the price cap on transmission capacity reassignments; and minor updates to Atachment C, which describes BPA's Available Transfer Capacity methodology.

[57] *See* TC-20 ROD, Appendix 1 at 1. It is possible that BPA could change its mind in the future.

[58] Importantly dis�nct from this discussion of transmission terms and condi�ons is BPA's obliga�on to comply with certain FERC-jurisdic�onal reliability and safety standards, such as those promulgated by the North American Electric Reliability Corpora�on ("NERC") or the Western Electricity Coordina�ng Council ("WECC"). *See generally* BPA, *Reliability & NERC Standards, available at:* https://www.bpa.gov/energy-and-services/transmission/reliability-nerc-standards.

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In 2018, BPA launched its own proceeding (distinct from a FERC tariff update) to update BPA's OATT.[59] Under the Energy Policy Act of 1992, Congress declared that BPA "may" hold a hearing when establishing transmission terms and service and that, if BPA pursues that option, then BPA must follow certain procedural requirements.[60] BPA did so in 2018, and in that proceeding developed an OATT that commits BPA to follow Congress's specified procedures for future changes to BPA's OATT.[61] Further, while BPA may generally amend its OATT through proceedings that comply with the statutory procedures,[62] BPA committed to its customers that BPA would not make changes to its OATT before October 1, 2028 without complying with the statutory procedures.[63]

In short, when considering the specific terms and conditions of BPA's OATT, discussed elsewhere in this whitepaper, it bears emphasis that BPA has committed itself to following an administrative procedure before changing any provisions of its OATT.[64]

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C. BPA's Adopted Terms and Conditions for Providing Transmission Service Provide BPA a Reasonable Amount of Discretion to Manage Future Transmission Needs and Allocate Costs

BPA's OATT addresses both BPA's obligation to provide transmission service and transmission customers' obligations to agree to pay the costs that BPA incurs to provide transmission service. While BPA has general obligations to recover its costs, and bearing in mind statutory requirements applicable to BPA, BPA's OATT and related business practices afford BPA meaningful discretion in assessing when costs are properly attributable to a particular transmission customer(s) or should be spread broadly across the transmission system.[65]

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Recall that BPA's statutory mandates give BPA significant discretion in managing costs. As discussed above, BPA is a self-financing agency that primarily relies upon raising capital using its Treasury borrowing authority and third-party contractual commitments, and generates

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[59] TC-20 ROD, at 1.
[60] Energy Policy Act of 1992, Pub. L. 102–486, �le VII, §722, Oct. 24, 1992, 106 Stat. 2916 (codified at 16 U.S.C. § 824k(i)).
[61] TC-20 ROD, at 11-13; *see also* BPA OATT § 9 ("Subject to applicable law, Bonneville commits to open access transmission service. Bonneville shall follow the statutory procedures in Sec�on 212(i)(2)(A) of the Federal Power Act to set generally applicable terms and condi�ons in its Tariff…"), *available at:* https://www.bpa.gov/-/media/Aep/transmission/open-access-transmission-tariff/bpa-open-access-transmission-tariff-20211001.pdf.
[62] BPA has in fact amended its OATT through proceedings that comply with the statutory procedures. *See generally TC-22 Tariff Proceeding*, Administrator's Final Record of Decision, TC-22-A-03 (July 2021); *TC-24 Tariff Proceeding*, Administrator's Final Record of Decision, TC-24-A-02 (Feb. 2023).
[63] TC-20 ROD, at 13. This date is significant for BPA; BPA an�ipates entering into new power customer agreements that will take effect that date. *See generally* BPA, *Provider of Choice (Post-2028), available at:* https://www.bpa.gov/energy-and-services/power/provider-of-choice.
[64] TC-20 ROD, at 11-13; *see also* OATT § 9 ("Subject to applicable law, Bonneville commits to open access transmission service. Bonneville shall follow the statutory procedures in Sec�on 212(i)(2)(A) of the Federal Power Act to set generally applicable terms and condi�ons in its Tariff…").
[65] Due to BPA's transmission system being composed of three dis�ct segments, costs and rates are developed for these separate segments and charged to those seeking service on one or more of these segments.

revenues from the services it provides to sustain ongoing activity. BPA's revenue sources include its primarily cost-based power sales to power customers (who also rely on BPA to transmit that power) and its sales of transmission services to transmission customers. Under the Northwest Power Act, BPA must "equitably allocate" transmission costs between federal and non-federal users (i.e., between power customers and transmission-only customers),[66] and BPA must charge transmission customers at rates "comparable" to those BPA pays itself to deliver federal power.[67] Rate proceedings must follow specific procedures,[68] and BPA must submit its rates to FERC for limited review.[69] Discontented stakeholders may challenge BPA's rate submission before FERC and appeal rate decisions to the Ninth Circuit.[70] The Ninth Circuit is generally deferential to both BPA and FERC's decisions on ratemaking.[71]

BPA evaluates transmission needs both in its regular system planning process (OATT Attachment K)[72] and in considering new requests for transmission service. In brief, BPA determines whether its system and the adjacent sub-grid are adequate to provide service both as a regular practice to continue offering service and in response to new requests for service. (These planning processes are described in more detail in the next section.)

BPA's OATT reflects BPA's statutory authority to satisfy transmission needs, even when they require new investments. Recall that BPA's obligations include to "integrate and transmit the electric power from existing or additional Federal or non-Federal generating units" and to "maintain the electrical stability and electrical reliability of the Federal system."[73] This is true for both Network Integration Transmission Service and for Point-to-Point Transmission Service.[74] For Network Integration Transmission Service, the OATT declares that BPA must

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[66] 16 U.S.C. § 839e(a)(2)(C). The implica�ons of the equitable alloca�on requirement are beyond the scope of this whitepaper. Note that power customers are all, or almost all, transmission customers as well, whereas many transmission customers buy only transmission service from BPA.

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[67] *See* 16 U.S.C. § 824j-1(b).

[68] 16 U.S.C. § 839e(i). Notwithstanding the procedural steps BPA is required to follow, BPA ratemaking proceedings are unusual in that a major transmission owner acts effec�vely as prosecutor, judge, and jury of its own transmission rate decisions.

[69] 16 U.S.C. § 839e(a)(2). FERC's review of BPA ratemaking decisions is statutorily limited to whether the rates are based on system costs, sufficient to assure repayment, and, for transmission, equitably allocated between federal and non-federal users. *See generally U.S. Secretary of Energy, Bonneville Power Administration*, 20 FERC ¶61,292 (1982) (discussing the limits of FERC's review of BPA rates). This is a much more limited review than for a regulated transmission owner. *See* 16 USC § 824d (providing FERC broad authority to review whether rates are "just and reasonable" and nondiscriminatory).

[70] 16 U.S.C. § 839f(e)(1)(G).

[71] *See Aluminum Co. of America v. BPA*, 903 F.2d 585, 590 (1989) (discussing how the Ninth Circuit's review focuses on whether there is "substan�al evidence" suppor�ng BPA's determina�on and how the court must affirm the agency unless the decision is "arbitrary, capricious, an abuse of discre�on, or in excess of statutory authority").

[72] See Sec�on V.A for a more detailed discussion of Atachment K planning.

[73] 16 U.S.C. § 838b.

[74] Point-to-Point Transmission Service is defined as "The reserva�on and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff." OATT § 1.77.

By contrast, Network Integra�on Transmission Service is defined as "The transmission service provided under Part III of the Tariff." OATT § 1.59. For instance, Sec�on 28.1 of Part III states "Network Integra�on Transmission Service "plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K."[75] Similarly, for Point-to-Point Transmission Service, the OATT declares that BPA generally is "obligated to expand or upgrade its Transmission System," but that the customer generally must finance "any necessary transmission facility additions."[76]

Under the systemwide planning process, any new facilities' costs "are allocated to transmission rates in rate proceedings."[77] For new service requests, BPA must determine whether the costs of new facilities should be assigned directly to the customer requesting upgrades or expansion or included in BPA's transmission rate base.[78]

D. *In Summary, BPA Must Provide Transmission Service and Has Reasonable Discretion to Manage the Costs of Doing So in a Sound Business-Like Manner*

Congress has broadly authorized BPA to provide transmission service in the Pacific Northwest. Within statutory parameters such as rates needing to cover BPA's costs and transmission costs needing to be equitably allocated,[79] BPA has broad discretion to implement policies and procedures that best fulfill Congress's goals and BPA's directives. These include "encourag[ing] … the development of renewable resources within the Pacific Northwest,"[80] a policy clearly aligned with the growing number of state mandates to decarbonize. Applicable directives also include operating, maintaining, and expanding the transmission system to integrate and transmit power from existing or additional federal or non-federal generation. Indeed, with the exception of competitive compensation reform, we have encountered no limitation that would prevent BPA from pursuing the reforms described in this whitepaper or that would require any act of Congress to change or expand BPA's authority. BPA has all the legal authority it needs to improve its transmission planning and ultimately pursue construction of transmission upgrades.

Comment [N(-T16]: This may reflect a lack of understanding re: BPA's OATT based transmission model – we often hear our customer (as well as BPA/staff, management) thinking that TX expansion works the same way that GI interconnection works – but the OATT provides that the customer does not pay the capital costs of expansion – BPA does. If there are costs that are "too high" those costs then become the bases for an incremental rate. Suspect that is not widely understood. FERC provided two different financial models for GI and transmission expansion. Also would be interesting to have some conversation about the point at which a project that supports expansion becomes a reliability build, which BPA socializes all costs for. Historically, reliability builds are those things identified in the TPP reliability studies. Could have a conversation about a class of projects that are for "reliability" even though they haven't shown up in those studies yet, maybe due to lag in load modeling inputs, etc? Interested in engr perspective on this.

Comment [N(-T17]: These decisions are made by Kelly – There have been few direct assignment decisions (would have to check with him for that history – maybe one or two though NOS/TSEP?)

is a transmission service that allows Network Customers to efficiently and economically u�ize their Network Resources (as well as other non-designated genera�on resources) to serve their Network Load located in the Transmission Provider's Control Area and any addi�onal load that may be designated pursuant to Sec�on 31.3 of the Tariff."

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[75] OATT § 28.2.
[76] OATT §§ 13.5, 15.4.
[77] OATT Atachment K § 8.2.
[78] Transmission customers are generally responsible for costs "to the extent consistent with [FERC] policy." OATT §§ 27, 34.
[79] 16 U.S.C. § 839e(a).
[80] 16 U.S.C. § 839(1)(B).

V. BPA's Transmission Planning Processes

BPA's OATT reflects BPA's statutory authority to satisfy transmission needs, including when new investments are required. This section describes BPA's several interrelated planning processes and their policy context in more detail.

To meet BPA's statutory and tariff obligations, BPA conducts multiple transmission planning processes consistent with FERC's open access requirements. BPA performs *local* planning to consider load growth and transmission demand over a 10-year time period. BPA also offers customers a *subscription-based* open season process, which aggregates requests for new service on the transmission system. In addition, BPA participates in *regional* planning through NorthernGrid, which considers regional transmission needs over a 10-year time horizon. While these planning processes are largely successful in meeting short-term regional reliability and economic needs by identifying incremental improvements to the grid, they are markedly less successful in identifying transmission upgrades that will be needed to meet public policy targets and mandates more than 10 years in the future and in moving those transmission projects towards construction.

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A. Local Planning for Network and Point-to-Point Service

FERC issued Order 890 in 2007 to require utilities under its jurisdiction to engage in coordinated, open, and transparent planning at both the regional and local level. FERC memorialized this obligation in "Attachment K" of its OATT.[81] BPA has incorporated these planning obligations into its own transmission tariff.[82] As envisioned by FERC, transmission providers have the obligation to plan the transmission system for their customers. The OATT defines two types of transmission service—Network Integration Service and Point-to-Point Service—and transmission providers like BPA must plan for service to customers in both categories.

1. Network Integration Service

Network Integration Service Customers (also referred to as "Network Service" or simply "Network" Customers) take Network Integration Service and rely on the transmission provider to serve their load using generation resources the customers have designated, in addition to these customers' obligation to invest in upgrades on adjacent sub-grids that BPA does not cover.[83] For its Network Customers, a transmission provider like BPA also has the obligation to

Comment [N(-T18]:

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[81] *Preventing Under Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (March 15, 2007).

[82] *See* BPA, *Transmission Services Open Access Transmission Tariff Attachment K*, 163, *available at*: https://www.bpa.gov/-/media/Aep/transmission/open-access-transmission-tariff/bpa-open-access-transmission-tariff-20211001.pdf.

[83] A Network Customer is a customer who has elected to take Network Integra�on Service from its transmission provider (BPA OATT Sec. 1.58). For customers who select Network Integra�on Service, BPA has the responsibility to integrate, dispatch and regulate the customers' current and planned Network Resources to serve their Network

plan its system to ensure that it can continue to serve these customers' needs as their loads grow in the future. The OATT establishes requirements for customers and their transmission provider to exchange information on load growth and future generation resources. For BPA, its Network Customers are mostly its public power customers, and particularly "load following" customers who obtain all the power they need from BPA.

Comment [N(-T19]: This doesn't strongly reflect the "endeavor to plan for " concept that is pretty foundational to BPA's ability to plan for NT customers

Comment [NJ(-T20]: Agreed – the paradigm of late has been very short notice of NT load growth needs, to which we are struggling to react fast enough – coupled with the lack of information on how the loads will be served (i.e., where is the generation located) is hampering our efforts to plan and suggests we may need to find another source for these assumptions

2. *Point-to-Point Service*

In contrast to Network Customers, customers with Point-to-Point Service simply secure the right to move energy from one point on the transmission provider's system to another. While FERC's *pro forma* OATT also requires transmission providers to expand the transmission grid to meet the requests of Point-to-Point Customers, if a Point-to-Point Customer seeks to move more energy across a transmission provider's system in the future, it must submit a request for new Point-to-Point Service.[84] Unlike Network Service where a transmission provider must proactively collect data for its Network Customers' future needs, the transmission provider does not have an obligation to plan to meet the future needs of existing Point-to-Point Customers; rather, it can rely on its customers to submit discrete new requests for service to meet their needs in the future. A transmission provider's obligation to expand its system to provide Point-to-Point Service is contingent upon the transmission customer agreeing to compensate the transmission provider for upgrade costs.[85] BPA has adopted these relevant provisions in its OATT.[86]

Comment [N(-T21]: There is a lot of detail and potential misperception that fits under this statement. This statement requires a much finer breakdown to avoid being misleading.

An underlying problem with the reliance of transmission providers on the Attachment K process is its roots in a reliability study that attempted to get ahead of electrical engineering problems.

Load (all capitalized terms are defined in BPA's OATT; Part III of the OATT describes the nature of Network Integra�on Service). BPA's Network Customers are generally its public power preference customers – though some of BPA's larger public power customers who elected to assume the reliability and planning obliga�ons of a transmission provider on their own rely on Point-to-Point Service from BPA. Network Customers have an obliga�on to provide data to BPA regarding their forecasted load growth and good faith es�mates of the size, loca�on, and type of future genera�on addi�ons (Atachment K Sec. 6.1.1). Some IOUs that have load pockets within BPA's footprint also take service for some of that load as Network Integra�on Service. Like most of BPA's preference customers, the IOU would therefore provide BPA its load and resource forecast specifically for that load pocket (but not the rest of the IOU's na�e load). *See supra* footnote 74 for the tariff defini�ons of the two types of transmission service.

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[84] Order 890 at P 419. Point-to-point customers are those who use transmission to deliver energy to a loca�on outside of BPA's footprint (including customers who deliver energy from outside of BPA's system all the way through BPA's system to a load outside of BPA's system, transac�ons o�en called "wheel throughs"). BPA has no obliga�on to consider that an exis�g Point-to-Point customer's need for transmission service will grow in the future, un�that customer submits a new request for service. BPA's point-to-point customers include independent power producers, power marketers, and investor-owned u��es. In fact, most of BPA's largest transmission customers (in terms of sales) are, in whole or in part, point-to-point customers. For example, BPA ten largest transmission customers are responsible for 60% of BPA transmission sales. Of that amount, IOUs, IPPs, and marketers are responsible for 78%. (Moody's, *BPA Credit Opinion*, 5 (Apr. 6, 2022), *available at:* https://www.bpa.gov/-/media/Aep/finance/ra�g-agency-reports/moodysfullreportmay2022.pdf)

[85] Order 890 at P 419.

[86] BPA OATT §§ 15.4, 27.

Transmission providers have obligations to plan their system under NERC's reliability standards.[87] Hence the focus on "short circuit," "steady state," "voltage stability," and "transient stability" studies in Attachment K reports. In Order No. 890, FERC adopted new requirements for utilities to conduct an open and transparent planning process with obligations to meet customer demand for system expansion under certain conditions.[88] However, FERC's efforts to expand transmission planning to look beyond reliability needs to meet forecast load growth and incorporate broader policy goals has been only partially successful. FERC's current open rulemaking, "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection" (Docket No. RM21-17), discusses the limitations of the current local and regional planning processes and identifies potential solutions, including scenario-based planning, a 20-year planning time horizon, and changes to the determinations of benefits and cost allocation.

B. BPA's Attachment K Process

As mentioned above, BPA engages in a planning process that is consistent with[89] the requirements of FERC's Open Access Transmission Tariff Attachment K.[90] The Attachment K transmission planning process requires an open, coordinated, and transparent process with opportunities for public participation. This process leads to the annual revision and publication of a transmission plan—"BPA's Plan," as described in BPA's Attachment K.[91] Like all transmission providers with Attachment K processes, BPA plans its system to meet anticipated load growth over the next ten years. For purposes of its local planning, BPA considers both forecasts of future loads as well as its long-term firm transmission service obligations. The Attachment K planning process applies reliability standards to the forecasts of future needs to identify upgrades necessary on BPA's system to maintain a safe and reliable transmission system for the Northwest. These upgrades might consist of new lines to locations that did not previously have access to transmission service, but more often consist of reinforcements to existing lines or facilities that increase the amount of energy that can flow across a line or provide BPA with greater situational awareness of and control over its transmission grid.

FERC also intended the OATT to create a mechanism for Point-to-Point Customers to fund upgrades needed to serve their needs while at the same time protecting the transmission provider's Network Customers from upward rate pressure. In practice, however, it proved nearly impossible for the developer of a generation project to single-handedly fund the construction of a major transmission upgrade. The *pro forma* OATT process requires

Comment [NJ(-T22]: We're asking for security only… if the study and PEA costs are too high for developers, it begs the question of the viability of their business cases and whether they're "good" partners in informing BPA's expansion plans

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[87] NERC, *Standard TPL-001-4 Transmission System Planning Performance Requirements, available at:* https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf.
[88] Order No. 890 at P 599.
[89] See Sec�n IV.B regarding BPA's decision to adopt a process "consistent with" FERC's Atachment K, notwithstanding its non-jurisdic�nal status.
[90] BPA, *Attachment K Planning*, see more informa�n at: https://www.bpa.gov/energy-and-services/transmission/atachment-k.
[91] The current (December 2022) BPA Plan is available at: https://www.bpa.gov/-/media/Aep/transmission/atachment-k/2022-bpa-transmission-plan.pdf [hereina�er *2022 Transmission Plan*].

transmission providers to consider the incremental additions to the grid needed to meet customer requests one at a time in a strict sequence. FERC's *pro forma* OATT also required customers who needed new transmission lines to pay upfront for the costs of those lines (and receive credits for service on those lines once they are energized). Accordingly, the burden fell on the first customer in the sequence to make upfront financial commitments to fund all of the construction costs; subsequent customers who took service on the same facilities would provide refunds to the first customer. The customer at the head of the line would have the sole obligation to cover the costs of the transmission expansion, even when customers behind them would benefit from the same upgrades. The practical result of this policy for BPA was that as each customer reached the head of the line, it would drop out when presented with the estimated costs of the upgrades.

Comment [N(-T23]: This is fundamentally incorrect – it is a reference to the GI financial model, not the TX expansion financial model. Also, there are NO credits related to transmission service expansion (the capital comes from BPA

C. BPA's Subscription-Based Planning

Comment [N(-T24]: This is a bit of a weird title in my opinion- it does fit with the possibility of a misperception that projects need to be fully subscribed (or meet some subscription threshold) for BPA to decide to build/provide an embedded rate. Thought I get the point that BPA's TX expansion is driven in large part by requests.

1. Network Open Season (2008-2013)

To break this logjam, in 2008 BPA implemented a new process named Network Open Season ("NOS"). In BPA's open season model, the demand for transmission service from all the customers in the entire queue was aggregated, following a temporal window (usually annually) for customers to request long-term firm transmission service (typically for 5 years, with the right to renew ("roll-over") service). Where transmission upgrades needed to provide new service would result in sufficient future revenue from customers to cover the costs of the facilities, BPA committed to finance the construction from its Treasury borrowing authority. At the close of the 2008 NOS, 28 different customers with 153 separate transmission service requests ("TSRs") totaling 6,410 MW of new long-term transmission service had committed to contracts to support transmission upgrades needed to deliver that energy to load. Nearly 75% of those requests for transmission service were associated with new wind generation in the Columbia River Gorge. To meet the need for service reflected in the NOS requests, BPA determined that it could complete five separate transmission expansion upgrades (four of them at 500 kV) and offer service on those new facilities at BPA's embedded cost rate (i.e., without charging those customers an incremental rate for service). For one of those projects, BPA had already completed a preliminary environmental analysis under the National Environmental Policy Act ("NEPA"). For the other four projects, BPA elected to fund the necessary engineering and environmental studies itself.[92] BPA ran a NOS process annually for three years (2008, 2009, and 2010). As a result of the 2008-2010 NOS processes, BPA was able to expand its transmission

Comment [N(-T25]: This was NOT a specified requirement as I recall the process. Behind the scenes I recall a never written "rule of thumb" of putting projects through a "2% test – which my perception recalls as being used somewhat generously. Rebecca would have her own perceptions of this NOS decision-making, as would Sean, Matt, and whoever else is left in the agency that had any significant role in it. But the projects WERE reviewed within the region in external processes. Rollover assumptions were also key as I recall. At one point we used something close to 100% rollover assumption, then got really cautions and went in the opposite direction- assume no rollover. Now we're somewhere in between depending on the situation – put what we think are reasonable assumptions in the business case. Allows us to be smarter.

[92] BPA, 2008 NOS Administrator's Decision Leter (Feb. 16, 2009), *available at:* https://web.archive.org/web/20100527184244/htp://www.transmission.bpa.gov/customer_forums/open_season/docs/Decision_Leter_02_16_2009.pdf; *see also* Atachment A, *available at:* https://web.archive.org/web/20100527132623/htp://www.transmission.bpa.gov/customer_forums/open_season/docs/Atachment_A_-_Ra�nale_of_Rate_Treatment.pdf. The term "subscrip�n" is used less o�n now by �o describe its commercial transmission service policy, but it remains a useful and accurate industry term to summarize the planning paradigm.

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grid to enable 263 individual requests totaling 11,722 MW of new transmission service, including 7,105 MW of new wind generation.[93]

Comment [N(-T26]: A good portion of those original requests did not ever take service (again, PTSA reform)

Comment [N(-T27]: This summary of the history of NOS left out that BPA subsequently had to do PTSA reform for a whole lot of MW. We were able to maintain a sound business case for those projects by "re-homing" a lot of transmission (and collecting the securitization $). BPA was able to achieve this by essentially allowing a lot of redirects of transmission in the queue to new PODs. The level of system flexibility (essentially available capacity) that we used to enable that is NOT available today. I would hate to see that part of history get lost in these conversations. Let's make sure we do an effective job of learning from the past. We just need to also be careful not to assume that today's problems are a cookie-cutter of yesterday's problems.

2. *Transmission Service Expansion Process (2013 to Present)*

In 2013, BPA modified its NOS and renamed it the Transmission Service Request Study and Expansion Process ("TSEP"). Compared to the prior NOS process (See side note – PTSA reform was what drove that modification), TSEP generally applies more stringent standards to transmission customers requesting service, requires higher participant funding from them, and incorporates more conservative risk management for BPA than NOS did. The combination of these changes generally reduced BPA's exposure to potential subscribers dropping out of the process mid-stream. BPA made these changes as the result of lessons learned from challenges in the wholesale market for new renewable projects amid the Great Recession in 2009-2010 and state legislation in California that restricted most utility procurement to in-state generating resources.

Comment [N(-T28]: The NOS process assumed that all TSRs that started through a study process would want to take service in the end. That was incorrect then and likely is incorrect today as well. The market was part of the story, but I think we should be careful assuming that it is the full story.

BPA currently conducts its TSEP annually. Through TSEP, BPA considers customers' eligible requests for transmission service in BPA's transmission queue. While similar to NOS in that it conducts a cluster study of all eligible TSRs, unlike NOS, TSEP customers are now responsible for paying the costs of the preliminary engineering and environmental studies. Both Point-to-Point and Network Service Customers are eligible to participate in the TSEP, although most requests are for Point-to-Point Service. New requests for Network Transmission Service rarely show up in TSEP because BPA already has the obligation to meet the load growth requirements of Network Service Customers under Attachment K and because the vast majority of BPA's Network Service Customers are also its public power preference customers with the first rights to electricity from the federal hydro system.

Comment [N(-T29]: This is actually because NT customers only participate in these processes when they are seeking transmission for non-federal resources. As more NT customers seek transmission from non-federal resources, BPA should expect NT participation to increase.

Under TSEP, BPA aggregates all eligible transmission service requests and studies all of them in a single cluster. For some of those requests, BPA can offer service without building additional upgrades. When BPA cannot offer customers service over facilities that are in place or already under construction, BPA identifies the additional transmission upgrades that would be necessary to offer the requested service. For the transmission service requests that do require upgrades, BPA requires each of the customers who seek service to make financial commitments to cover their pro rata share of costs of preliminary engineering studies, and any environmental studies, while also committing to a term of service that ensures BPA will recover the costs of the upgrades over time. Customers must also post a security deposit or line of credit to ensure that they can meet their future financial obligations to BPA.[94] The pro-rated share of

Comment [N(-T30]: This statement is incorrect. BPA can make assumptions about rollover in our business cases when we believe that it is prudent to do so. In some cases, however, requiring customer to commit to a term of service that ensures cost recovery is probably the smart thing to do to ensure that costs don't get socialized.

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[93] BPA, *Federal Transmission Expansion in the West*, 20 (Feb. 7-8, 2012), *available at*: https://www.energy.gov/sites/default/files/2013/07/f2/Transmission_Drummond_0.pdf.

[94] Under a form of preliminary transmission contract (a Precedent Transmission Service Agreement) used under NOS, BPA used to require customers to post security worth 12 months of their transmission service request (see BPA OATT § 19.10).

BPA's current TSEP financial security requirement is more stringent: customers must post security (either cash or an irrevocable leter of credit) for up to their total pro rata share of upgrade costs, calculated as the ra� of the preconstruction study costs and posting financial security are the "participant funding" currently required by BPA. If customers commit to all of those requirements, then BPA will incorporate the necessary facility upgrades in its next Attachment K planning process (and associated annual Transmission Plan).

Once customers make these participant funding commitments, BPA combines expected load growth on its system over the next ten years with customer requests for new transmission service from TSEP.[95] At that point, BPA's Attachment K process combines transmission expansion needed to serve forecasted load growth on BPA's system (from mostly preference customers) with transmission service requests (from all other system users) that commit to the requirements of the TSEP.

3. *Embedded Rate v. Incremental Rate*

BPA conducts a separate analysis to determine whether it will offer service on the new facilities at its rolled-in (a.k.a., embedded) rate or instead charge those customers an incremental rate. As part of its reforms in adopting the NOS process in 2007, BPA also devised a Commercial Infrastructure Financial Proposal ("CIFP," also referred to as the Commercial Infrastructure Expansion Policy). Under NOS, the CIFP established a clear and transparent analytical framework to determine whether BPA would offer service at its embedded rate or whether it would require customers to commit to an incremental rate. First, the CIFP defined the benefits that BPA would consider in this analysis. BPA attempted to quantify benefits associated with (1) expected future uses, (2) reliability of the grid, and (3) other economic benefits, the whole group of which would be allocated to all of BPA's transmission customers through its regular rate process. BPA would then determine whether the new revenues associated with service on the expanded transmission system would cover the remaining costs. If the incremental revenues were sufficient to cover the remaining costs, then BPA would offer those applicable customers service at BPA's embedded rate. On the other hand, if the incremental revenues could not cover the remaining costs, BPA would offer those customers the opportunity to take service at an incremental rate above BPA's embedded cost rate.[96] In practice, an incremental rate can be a kiss of death for a development project because concentrating the costs of

Comment [N(-T31]: Is this statement true? I don't know enough to evaluate it. What we can say is that if customers fund (under today's model), that work gets completed and BPA makes a subsequent decision re: whether to build and re: embedded v. incremental rate. This paragraph does show an understanding of BPA's TX expansion model. Not sure why other parts of the letter don't reflect it as well.

Comment [N(-T32]: It feels weird to me that they are pulling in Attach K here – are these statements accurate? Also, expected load growth over the next X years is part of the TSEP modeling process as I understand it (from the WECC cases, etc?

Comment [N(-T33]: Would be interested in Rebecca's take on this language. I thought of CIFA as a framework, but not so much a formula. Maybe incorrect?

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customer's requested megawatts out of the total requested megawatts by customers, mul�lied by the es�mated costs of BPA's Plan of Service. This security must be posted prior to BPA proceeding with preconstruc�on ac��sBPA releases the security incrementally over �me. For example, BPA notes in its Business Prac�e that for a 5-year term of transmission service with a 4-year period of construc�on, the deposit or leter of credit would be held for the dura�n of those 9 years, with the amount reduced propor�nally during each five years of actual service (post-construc�on). *See* BPA, TSEP Transmission Business Prac�e, Version 8 (3/24/2023), Sec�n H, *available at* https://www.bpa.gov/-/media/Aep/transmission/business-prac�es/tbp/tsr-study-expansion-process-bp.pdf.

[95] BPA, *2022 Transmission Plan*, Sec�n 3.1 (Dec. 2022).

[96] BPA, *Proposal for a New Approach for Allocating Transmission Costs and Financing Commercial Infrastructure*, 2 (Aug. 2007) *available at:* https://nippc.org/wp-content/uploads/2023/05/2008-NOS-Commercial_Infrastructure_Financing_Proposal_Summary.pdf. The 2007 CIFP was a product of a workgroup formed by the Transmission Issues Steering Commitee within BPA. For a number of years, BPA produced annual public documents evalua�g the system-wide benefits of commercial transmission, as outlined in the CIFP.

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transmission construction on a single generator or a handful of generators can dramatically erode their affordability.

Comment [N(-T34]: Costs of TX contruction don't go to the generator – they go to the party who takes transmission service over the facility or to all TX ratepayers (if socialized)

Today under TSEP, BPA continues to apply a financial analysis to determine whether it will offer customers participating in TSEP service at BPA's embedded cost rate or whether it will require customers to commit to an incremental rate before BPA moves forward with a decision to pursue the Plan of Service[97] needed to satisfy the requests for transmission service. Under NOS, the details of this analysis were clearly defined and transparent. Under TSEP, however, the details of what benefits BPA determines it should allocate to the general customer base and the threshold for determining whether an incremental rate is appropriate are no longer transparently defined. NIPPC and RNW have explored this topic in some detail with BPA in the course of preparing this whitepaper, and there simply appears to be no public documentation of what suite of benefits are currently evaluated, nor, in establishing the need for transmission upgrades, how and whether such benefits accrue to the system as a whole or solely to those customers requesting service. While BPA still conducts this analysis for customers in the TSEP cluster study, BPA no longer publicly provides the specific benefit determinations and revenue thresholds used to determine whether an incremental rate will apply. A great deal hinges on this analysis; this is an obvious area for improvement. Section IX of this whitepaper provides additional detail about best practices in calculating transmission benefits.

Comment [N(-T35]: Fundamentally true – likely a significant weakness of the current process

Comment [NJ(-T36]: I believe some of this information is provided in the Cluster Study report, which is only shared with study participants, but I believe can be accessed via an NDA…?

Comment [N(-T37]:

C. Interconnection Requests

As part of its planning, BPA also considers the number of new generating projects that seek interconnection with BPA's grid.[98] The interconnection queue has its own separate study process. While developers often request both interconnection and transmission service from BPA in order to make a proposed new generating facility viable, plugging into the grid (interconnection) is different than moving power from one side of the grid to the other (transmission service). As of March 2022, BPA's interconnection queue contains 102 separate interconnection requests representing over 85 GW of new generation resources.[99] This paper does not address generator interconnection reform because BPA already has an important initiative underway in a tariff terms and conditions proceeding (TC-25) to address this topic.

D. Regional Planning: NorthernGrid

In addition to conducting the Attachment K and TSEP processes to develop plans of service for its own transmission system, BPA is also a member of the NorthernGrid regional planning

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[97] A Plan of Service includes the specific upgrades and �ning that BPA proposes to meet customer needs. The Plan of Service could be driven by any combina�on of load growth, reliability needs, or customer demand for Point-to-Point service.

[98] BPA, *2022 Transmission Plan*, Sec�on 3.1.3 (Dec. 2022).

[99] BPA, *TC-25 Tariff Proceeding Workshop*, slide 13 (Mar. 15-16, 2023), ***available at:*** https://www.bpa.gov/-/media/Aep/rates-tariff/TC-25/TC25workshopPPTfinal-externalrevisedMarch142023.pdf.

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entity.[100] The NorthernGrid planning footprint includes Washington, Oregon, Idaho, most of Montana, Utah, and Wyoming, and portions of Nevada and California. NorthernGrid and its members conduct a biannual transmission planning process to explore whether regional transmission projects can more efficiently and cost-effectively meet members' needs compared to their individual Attachment K plans. The regional planning process is based on members' Attachment K plans and similarly explores a ten-year planning horizon.[101] Stakeholders and transmission developers who are not incumbent transmission providers can request that NorthernGrid (and other regional planning entities like WestConnect, NorthernGrid's counterpart in the Southwest) analyze specific future scenarios or proposed transmission lines in the biannual plan. NorthernGrid is under no obligation to accept these requests; Oregon utility regulators did successfully seek to include an offshore wind scenario in NorthernGrid's most recent study scope for the 2022-23 transmission planning cycle.[102] Accordingly, NorthernGrid is currently studying the transmission implications of the development of 3 GW of offshore wind on the southern Oregon coast by 2030. To its credit, BPA has also joined with a group of transmission owners in the region to voluntarily conduct a 20-year study (as opposed to the normal 10-year time horizon) of whether long-term transmission constraints exist in a low carbon future.[103]

True regional and interregional planning are the ideal ways to address transmission needs on a wide geographic basis. NIPPC and RNW support effective mechanisms to do so, which would require BPA and other transmission providers to work together in a transparent and public manner to determine the most important and cost-effective new transmission projects and determine cost allocation to pay for them. For example, the latest draft transmission plan (for 2022-2023) produced by the California Independent System Operator ("CAISO") would authorize 24 reliability-driven projects and 22 policy-driven transmission projects, with a total estimated cost of $9.3 billion, using forecast electricity demand from the state energy office (the California Energy Commission) and anticipated generating and storage resources forecast by the California Public Utility Commission.[104] The CAISO's draft plan demonstrates how an independent system operator("ISO") can proactively plan a portfolio of new transmission in an effective way that transmission owners, including BPA, have difficulty achieving.

Comment [NJ(-T38]: This could be most efficiently conducted by an RTO/ISO, with broad access and control over generation dispatches, etc.

Comment [N(-T39]: Interesting – might be worth reviewing the policy drivers and looking at what identified the locations of those projects based on policy

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[100] NorthernGrid is the regional planning en�y that IOUs have established in order to comply with the regional planning requirements of FERC Order Nos. 890 and 1000. BPA and other non-jurisdic�onal transmission providers (Seattle City Light, Chelan County PUD, Tacoma Power, Snohomish County PUD) have joined NorthernGrid not only to conduct regional planning voluntarily under Order 1000 but also to meet specific NERC and WECC reliability criteria that require coordina�on with adjoining transmission providers on specific topics. *See* NERC TPL-001-4 and TPL-001-WECC-CRT-3.2.

[101] NorthernGrid, *Regional Transmission Plan for the 2020-2021 NorthernGrid Planning Cycle*, 5 (Dec. 8, 2021), *available at:* https://www.northerngrid.net/private-media/documents/2020-2021_Regional_Transmission_Plan.pdf.

[102] NorthernGrid, *Economic Study Request Decision for 2022*, *available at*: https://www.northerngrid.net/private-media/documents/ESR_Decision_2022.pdf.

[103] Western Power Pool, *20-year Low Carbon Study,* (Nov. 23, 2022), *available at*: https://www.westernpowerpool.org/private-media/documents/20_Year_Study_Scope_2022.11.23.pdf.

[104] CAISO, *Draft 2022-2023 Transmission Plan*, 3 (Apr. 3, 2023), *available at:* http://www.caiso.com/Ini��eDocuments/Dra�2022-2023-Transmission-Plan.pdf.

Nevertheless, this ideal scenario of consistent, collaborative regional planning that encompasses BPA and IOUs remains elusive for the Northwest, both because FERC's Order 1000 has proven to be a weak forcing mechanism outside of regional transmission organizations ("RTOs") and ISOs, and because any successor rule that FERC may adopt will not address the fundamental lack of consistent requirements and jurisdiction over transmission owners in the region. It remains unclear when FERC may finalize a new planning rule. For these reasons, NIPPC and RNW support BPA pursuing changes to its internal transmission planning processes, while still encouraging the agency to collaborate as much as possible regionally and interregionally.

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VI. Limitations of BPA's Existing Planning Processes

This section identifies principal limitations and drawbacks to BPA's current planning processes. Section IX critiques these same BPA processes by way of comparison to other transmission providers.

Insufficient Forecasts of Load Growth and Transmission Capacity Needs

NIPPC and RNW are concerned that the assumptions that BPA and transmission-owning utilities in the region are currently using to forecast load growth are too low.[105] The transmission planning reliability standards require BPA to base its assessment on standard base cases developed for the entire Western Interconnection.[106] NorthernGrid conducts its planning based on 0.6% annualized load growth for the entire footprint with individual utilities reporting changes in load from a 0.4% decline to a 1.1% increase.[107] PNUCC's regional load resource forecast, however, estimates annual load growth of about 0.9% over the next ten years with individual utilities ranging from a 0.9% decline to 2.9% increase.[108] PNUCC also notes that its load forecasts may underestimate actual load growth since utilities representing only 25% of the load in the region currently factor climate change into their planning estimates, and utilities representing only 30% of regional load incorporate the implications of electrification into their load estimates.[109]

Comment [N(-T40]: Personally, I will admit to sharing this concern. KSL forecast process also doesn't always seem to result in getting the load the have give the 80% seal of approval to actually getting into the cases that [redacted] some adjustments, but I wonder whether we are really robustly examining what the outer edges of load growth look like.

For example, in Washington, the state building code (with a court challenge pending) requires, as of July 1, 2023, that most new residential and commercial structures use only electricity.[110] Similarly, in Seattle, both the King County Transit System and the Port of Seattle have declared their intention to pursue 100% electric or non-emitting goals by 2035 and 2050, respectively.[111]

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[105] Note that BPA is o�en men�oned in the same breath as u��es. In its transmission func�on, BPA does resemble transmission-owning u��es and is subject to some of the same federal requirements. But except for several narrow legal applica�ons, BPA is not, in the usual sense of the term, a u�ity. It is a federal wholesale marketer of power to customers who are themselves u��es. How does this differ from a typical u�ity? BPA is not ver�ally integrated: it owns neither genera�on facili�es nor distribu�on lines. The power plants whose electricity BPA markets are owned by other en��es (the Bureau of Reclama�on, Corp of Engineers, and Energy Northwest). And except for a handful of now defunct industrial consumers, BPA neither sells nor delivers power at the retail level.

[106] WECC is the Regional En�y (a legal term in the Energy Policy Act of 2005) that enforces reliability standards in the Western Interconnec�on. These reliability standards are developed by NERC. WECC and NERC are both self-regulatory industry membership organiza�ons overseen in the U.S. by FERC.

[107] NorthernGrid, *Study Scope 2022-2023*, 3 (Sept. 21, 2022), ***available at:*** https://www.northerngrid.net/private-media/documents/NG_Study_Scope_2022-2023_Approved.pdf.

[108] PNUCC's membership includes most of the load-serving en��es in the Pacific Northwest. PNUCC annually conducts a study (the Northwest Regional Forecast) that examines the region's loads, resources, and future power supply.

[109] PNUCC, *2022 Northwest Regional Forecast*, 6 (Apr. 2022), ***available at:*** https://www.pnucc.org/wp-content/uploads/2022-PNUCC-Northwest-Regional-Forecast-final.pdf.

[110] *See* Washington State Building Code Council Summary Mee�ng Minutes (Nov. 4, 2022), https://sbcc.wa.gov/sites/default/files/2023-02/sm11042022C_ah.pdf.

[111] *See* King County, *Attachment 13 - King County Metro Transit's Zero Emission Fleet Transition Plan* (May 2022), *available at:* https://kingcounty.gov/~/media/depts/metro/accountability/reports/2022/zero-emission-bus-fleet-transi�on-plan-may-2022; *see* Port of Seatle, *Maritime Climate and Air Action Plan* (adopted November 16, 2021),

Utility resource plans are lagging this aggressive mix of electrification requirements and objectives across the region.

Clean energy laws in many states in the West will shift the resource mix from conventional fossil fuels to renewables and other non-carbon emitting generation. Since 2019, utilities in the Northwest have retired 2,100 MW of coal capacity, with another 2,800 MW of coal capacity scheduled for retirement by 2026.[112] Utilities currently indicate plans to add 9,400 MW of new renewable generation resources in the next ten years.[113]

One overall transmission challenge facing the region is the nature of variable renewables as standalone resources because their capacity factor (the percentage of time across all hours that the resource actually generates power) is generally lower than a dispatchable thermal power plant. Overall, this intermittency can lead to greater demand for transmission capacity but less total electricity carried on any given new segment or circuit of transmission. These challenges can be mitigated by pairing renewable resources with storage, by pooling more resources regionally through centralized dispatch (such as day-ahead and real-time centralized energy markets), by widening the geographic area of pooled resources to ensure more complementary generation profiles, and by changing from contract-path physical transmission rights to flow-based financial rights. Nevertheless, each of these solutions also has its own financial or political hurdles.

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Lack of Surplus Transmission Capacity under TSEP's Reactive Process

BPA's most recent TSEP Cluster Study Report shows that there is no longer any surplus of unallocated transmission from the east side of the Cascades (where many new wind and solar resources will need to be located) to the west side of the Cascades (where the load centers of Oregon and Washington are located).[114]

BPA is tentatively planning to move forward with six transmission projects that have commercial demand, as reflected in recent TSEP cluster studies. These projects (Portland Area Reinforcement, Cross-Cascades South, Chehalis-Cowlitz Tap, Cross-Cascades North, Ross-Rivergate, and Rock Creek-John Day) are important projects with reliability, commercial, and public policy benefits (enabling access to new non-emitting generation). They are all upgrades and reinforcements of existing lines, increasing their capacity, as opposed to brand new lines in new rights-of-way. The most significant project is a 70-mile rebuild of the existing Big Eddy-

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detailing interim 2030 planned electrifica�on ac�ons (*e.g.*, electric for 100% of port-owned light-duty vehicles, 100% of home port cruise calls connected to power), *available at:* https://www.portseatle.org/page/char�g-course-zero-port-seatles-mari�me-climate-and-air-ac�on-plan.

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[112] *Id.*, at 8.

[113] *Id.*, at 11.

[114] BPA, *TSEP 2022 Cluster Study Report* ("2022 Cluster Study Report"), 57 (June 10, 2022). Transmission Service Requests which require service across the Cross Cascades North or Cross Cascades South paths can be accommodated only with significant upgrades of the exis�ng system that, once begun, would be completed only in 2030. *Note that the last two Cluster Study Reports (2022 and 2021) whose contents are merely summarized here can be obtained upon request from BPA.*

Chemawa 230-kV line as a 500-kV line (crossing the Cascades southeast of Portland). The estimated total construction cost of these projects is $612 million, enabling an incremental 4,260 MW of additional power to move across those upgraded parts of the network. (Note that this figure is in aggregate, not an additional 4,260 MW across the overall system or any single point.) The construction cost is supported in large part by $57 million of annual expected transmission revenue, based on signed preliminary engineering agreements with customers requesting transmission service.[115]

Comment [N(-T41]: Chris – did they get these numbers right? 57M in annual revenue seems low to me – would be only 2800 MW of service?

BPA deserves credit for pursuing these important projects. But much more is needed. As BPA acknowledged at its April 27, 2023, public workshop,[116] these projects may assist in allowing utilities west of the Cascades to meet their 2030 resource procurement requirements (an informal conclusion that has not been tested by other stakeholders or market participants); however, they will not address the significant incremental 2030-2045 need. Furthermore, BPA should publicly disclose its tentative plans to pursue such projects sooner. The projects described above appear to have been in consideration for at least the preceding year without a meaningful public discussion of that consideration.

Comment [N(-T42]: I would be interested to understand this comment better. The cluster study report is available to anyone who requests it upon completion of the study. Then we go through the PEA process to determine what projects are live – admittedly, we are pretty dark on that part of the outcomes. Communication has not been our strong suite.

Significantly, several large upgrades that were identified in the 2022 Cluster Study as necessary to meet customer demand were *not* included in the 2022 Transmission Plan or the list of projects above. For example, upgrades in central Oregon costing $382 million could enable at least 3,645 MW of new generation by 2033, but those transmission facilities were not included in the 2022 Transmission Plan.[117] The best way to understand this outcome is that TSEP is not merely a planning exercise. Rather, BPA also uses the TSEP to inform customers whether BPA will offer service at an embedded rate or at an incremental rate and to secure binding financial commitments from customers in advance of BPA engaging in engineering studies, environmental reviews, and construction. But as noted above, the analysis that BPA currently uses to determine whether it will offer service at an embedded cost rate is no longer transparent.

Comment [N(-T43]: Worth noting that what was put out did not include the entire portfolio of TSEP builds that are at some stage in the process. Doesn't mean that there isn't customer PEA funding though. I can see the confusion here.

Lack of Transparency about Benefits Evaluation and Cost Allocation Methodology

This lack of transparency means that stakeholders[118] in the region have no insight into whether any specific proposed Plan of Service to expand the grid to a new region with high renewable energy potential is uneconomic at any scale, or whether the proposed Plan of Service could support enough future generation development (that has not yet appeared in TSEP) to allow BPA to offer service at its embedded rate. Additional transparency with respect to the internal business case developed by BPA for transmission projects that have commercial interest—including benefits quantified or considered, anticipated fulfilment of BPA's revenue requirement, and the risk of creating a stranded asset—would greatly assist stakeholders to

Comment [N(-T44]: Because BPA doesn't do study work to determine the TTC, it is always a mystery (even internally) as to the degree to which a project can support more flow. This is a legitimate challenge. As I understand it, it is partly a resource issue, and partly a reflection of the fact that the generation/transmission model in place at the point of energization aren't known during the study.

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[115] BPA, *Evolving Grid*, 20-27. These slides include valuable high-level maps of each project.
[116] See a link to a recording in *supra* footnote 15.
[117] *See 2022 Cluster Study Report*, 57. The cluster study considered a total of 2,595 MW in the Central Oregon-South zone, at 40, and an addi�nal 750 MW in the Central Oregon-Buckley zone, at 43.
[118] Stakeholders in this context include not only genera�n project developers, but also load-serving en��s, pub u�ity commissions, and anyone else with an interest in ensuring that states meet their clean energy goals.

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prioritize procurement from specific regions and stage expansion of the transmission grid more efficiently.

Comment [N(-T45]: This feels very true

Participant Funding and the Mismatch of Generation and Transmission Procurement

While BPA's TSEP reflects that developers are acting on the knowledge that the region needs new renewable generation located in places like central Oregon, eastern Washington, and Montana to meet clean energy targets, those developers are often not able to make the financial commitments to BPA to underwrite the costs of development and construction of the necessary upgrades. But the unwillingness or inability of these prospective transmission customers to commit now to repay BPA for transmission upgrades does not mean the added transmission capacity would go unused in years to come. Instead, it indicates that the demand on the *load* side (the utilities who would purchase the power) is not yet willing to execute contracts for generation resources that will be needed more than several years in the future.

Comment [N(-T46]: This is NOT a requirement – they do not even have this opportunity. Maybe they mean though paying the rate? Doesn't exactly read that way.

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Comment [N(-T47]: True in SOME cases. This is where what Chris and I have called "regional need" projects v. "customer need" projects distinction is pretty important. For some TX projects, if no/few LSEs eventually chose the resources that need those projects, there would be a poor business case.

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Utility procurement processes based on integrated resource planning typically look to procure new generation capacity two to three years in advance of need (as most integrated resource planning is done on a two-year cycle). Few renewable energy developers are in a position to make the financial commitments now to build transmission that will enable new renewable generation to bid into procurement processes that will be held ten or fifteen years from now.

One root of the problem is that the Northwest's main power buyers (utilities) solicit new supplies of power only several years in advance and primarily to fill in the gap between their current supply and what their anticipated load and state laws require in the 2030-2045 timeframe. At the same time, the Northwest's main transmission provider (BPA) has a planning and project execution process that is reactive principally to power suppliers (developers) requesting transmission service that may require very expensive transmission upgrades that could take more than a decade to complete.

Not surprisingly, the temporal mismatch between the utility procurement processes and BPA's transmission service expansion process is resulting in physical bottlenecks and significant underinvestment in the BPA transmission system. Resource developers are often stuck in between: until they are confident a utility (or corporate consumer) will buy their power, they will be reluctant to allocate significant capital by signing an agreement with BPA to pay for service towards the cost of transmission upgrades needed to enlarge BPA's system. In many cases, the developer simply cannot take this risk. On the other hand, winning the competitive bidding process to sign a contract with an offtaker (a purchasing utility) often requires already having a transmission service agreement in place.

Comment [N(-T48]: True, but relevant to Sonya's point that having all TX customers take all this risk isn't necessarily a winning model either.

Comment [N(-T49]: Yes – this catch 22 is a core challenge to BPA's planning processes.

Pros and Cons of Reactive Planning

There are two positive effects of BPA's current approach worth recognizing. First, power producers have developed some (imperfect) expertise in identifying locations in the Northwest with the lowest cost upgrades needed to secure transmission service from BPA. This helps squeeze the most use out of the existing system as possible. It is a more refined approach, suitable for a mature grid, than the approach that created the transmission network in the first place: drawing and building ambitious new lines on a map to connect proposed dams and coal plants to big cities (*see the Appendix for more details on this history*). Second, because developers (or any entity requesting new transmission service) bear the upfront costs of BPA's upgrade studies and must provide financial commitments to BPA sufficient to ensure that their future payments for service will cover the actual construction costs, there is a controlling incentive for developers to avoid lumpy new transmission investments. Taken together, these effects help to suppress BPA's transmission rates by avoiding triggering new capital-intensive projects.

The negative effects of this reactive approach are the flip side, and they are significant: the TSEP cluster studies show that BPA's transmission system is out of room for the major wave of power development needed to comply with state laws and related policies, and BPA's transmission planning, cost allocation, and project execution processes are not designed to respond effectively to that need.[119] Determining appropriate solutions to a conservatively reactive planning paradigm and the temporal procurement mismatch highlighted above will require joint effort and brainstorming among independent power producers, BPA, and load-serving entities, among others.

Lack of Treatment of Recurring Transmission Demand

Emblematic of the problems in TSEP is that BPA, at least publicly, treats each TSEP cluster in isolation. The TSEP cluster studies reflect demand from developers for transmission service from geographic areas where new generation can be developed most cost effectively. Sometimes transmission demand appears repeatedly over several years at the same points on the BPA network, but not with sufficient committed customer interest in a single year for BPA to justify proceeding. While BPA may be acting prudently in avoiding a construction plan in some of these cases, BPA has no public process where it openly considers transmission upgrades that have been identified in repeated TSEP cluster studies to meet recurring demand from transmission customers.

[119] In Sec�on 5 of its 2022 Transmission Plan, BPA does iden�fy the myriad policy and market changes driving the need for transmission, but reci�ng these drivers is not the same as designing a process that is actually responsive to them.

Comment [N(-T50]: Again, not sure that this statement is fully correct – if embedded rate project, MOST of the costs are covered via them paying their rates just like is the case for existing transmission capability. The up front costs to the customers are quite low compared to the cost of developing a project, so a little interesting that they sound focused on wanting to be excused from those costs. I wonder how much of an impediment those costs really are, particularly for "robust" projects. But maybe BPA is much more comfortable/knowledgeable about which projects are "robust" and which ones are more marginal.

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Comment [N(-T51]: I don't agree with this statement. The TSEP study is agnostic to how economic either the generation projects are or the transmission projects are. The economics of the generation projects are identified by the LSE processes (which projects do they select). The economics of the transmission projects develop over time, although projects look "better" or "worse depending on the initial costs, TSRs/MW, etc.

Comment [N(-T52]: If there is ANY actual financial interest in proceeding in a specific year, the project moves into PEA. Our model has always allowed for "hop on" in subsequent years if other parties want to participate later in that project with the TSRs. I'm not sure why this is a point of confusion.

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VII. Additional Issues Unique to BPA That Impact Transmission Planning

A. Regional Cost Allocation

As a federal agency with specific statutory authorities and requirements, BPA is not subject to FERC's requirements on transmission planning and cost allocation of transmission expansion. Nevertheless, BPA has voluntarily taken on a combination of standard FERC planning processes (such as Attachment K and regional planning through NorthernGrid) as well as processes unique to BPA (such as the TSEP). With respect to cost allocation, however, BPA is uniquely situated relative to other transmission providers in the Northwest. Most obviously, in deciding to join NorthernGrid to satisfy its regional transmission planning obligation, BPA (with FERC's approval of the methodology) is not subject to the standard mandatory cost allocation mechanisms when the NorthernGrid process identifies a regional transmission project (one that would be more economical than the member utilities' standalone plans). Instead, BPA has discretion in voluntarily choosing to take on a share of the costs of a regional transmission project—or not. If BPA were to decline to accept its share of such a project, BPA's share of those costs would be allocated to the other beneficiaries, likely with a negative impact to the cost-benefit analysis for the project. In any event, neither NorthernGrid nor its predecessor organizations have ever identified a regional transmission project appropriate for regional cost allocation.

B. Transmission Siting

BPA is also directly subject to NEPA, which requires federal agencies to determine if their proposed actions will have significant environmental effects and to consider the environmental, social, cultural, and economic effects of their proposed actions. Accordingly, virtually all BPA decisions related to transmission development are subject to NEPA and related reviews under the Endangered Species Act and the National Historic Preservation Act, a nearly blanket application that is not true of non-federal transmission providers. While important and necessary, these processes can take significant time and money to perform, adding time and cost to any proposed transmission project. In practice, most minor decisions by BPA are addressed through applying an administrative categorical exclusion. While other transmission providers are subject to NEPA and similar laws to the extent their projects are located on federal land or significantly affect the environment or cultural resources (and thereby require approval of a federal agency), BPA is unique in that its transmission upgrade decisions automatically trigger a review by BPA itself, often alongside federal land managers and fish and wildlife agencies.

Based on a review of the timeline for many of the major transmission upgrades by BPA since 2010, the environmental and cultural reviews of those projects, as indicated by their final environmental impact statements and records of decision, did not appear to materially delay BPA's construction of those projects (see *infra* footnote 208). Nevertheless, the effect of future reviews is likely to be more difficult in the case of the more significant volume and type of transmission upgrades contemplated in this whitepaper.

Comment [N(-T53]: Interesting perception

Finally, BPA's significant federal eminent domain authority is a powerful siting tool held by the agency. Historically, it has been a driving factor in regional entities seeking and securing BPA's participation in transmission projects. (See the Appendix for one high profile instance of this history with respect to the Colstrip line.)

C. The Assumption of Risk

Determining what the public interest is for a federal power marketer and transmission provider to assume various risks for developing new infrastructure requires careful, public deliberation. It is not self-evident. It may change over time, and it may differ significantly from the risk appropriate for a private company or non-federal public entity to assume. At present, BPA has a highly conservative approach to assuming risk for transmission expansion in the Northwest, an approach in contrast to much of the agency's history of constructing the high-voltage grid as we know it. NIPPC and RNW recommend that elected officials, BPA customers, and stakeholders in the region re-examine this core question in light of the generational change underway in the power sector.

For example, in addition to being a planning process that identifies transmission expansion needed to meet customers' requests for service, TSEP is also a contracting mechanism that insulates BPA from revenue shortfalls. After identifying the necessary upgrades to meet customers' requests, BPA then contacts those customers to determine if they would like to make the upfront financial commitments that will relieve BPA of any financial risk for undertaking the engineering studies, environmental assessments and, eventually, of using BPA's borrowing authority to cover construction costs. Customers are required to fund their pro rata share of the engineering and environmental studies; but they are also required to provide a deposit or letter of credit to BPA for their pro rata share of the total costs of the upgrades. TSEP customers must maintain this financial security through construction and until the end of the term of service in their TSR. BPA essentially uses an "open season" process that aggregates the demand for new transmission and allocates the responsibility to repay BPA's capital costs among all the customers who will take service on the upgrades. So even if BPA uses its own borrowing authority to finance construction of TSEP upgrades, BPA is not at risk because it can call upon customer financial guarantees to ensure that BPA receives the revenues it forecast in the financial analysis around whether to proceed with construction of the Plan of Service.[120]

To illustrate the effect of this, imagine a transmission upgrade that will cost subscribing customers $100 million for a total of 1,000 MW of TSRs received in an annual TSEP window. Customer A has a 100 MW TSR (10% of the total), resulting in a total securitization of up to $10 million. Customer B has a 500 MW TSR (50% of the total), resulting in a securitization of $50 million. If Customer B drops out late in BPA's construction of the upgrade, it may forfeit that total security. This would be equivalent to losing the entire cost of a hotel room for cancelling

Comment [N(-T54]: Since BPA is risking its capital, I'm not totally sure that I share this perception. The PEA/ESA costs are a relatively small portion of project costs.

Comment [N(-T55]: True only to the extent that BPA utilizes its rate treatment determination process well as well as securitization of "high risk" projects. But I do feel like there is a significant question regarding whether all of the main grid projects should really require securitization or whether BPA is essentially driving up regional delivered power costs for very little gain by requiring securitization of some of the projects.

Comment [N(-T56]: Unless they pay (through rates for the TSR charges) for their share of the direct costs of the project earlier – then can appeal for release of this obligation. But they are right that it can be a very lengthy period of time.

[120] BPA Business Prac�es, *TSEP Business Practice*, Sec�n H, 10-11, *available at:* https://www.bpa.gov/-/media/Aep/transmission/business-prac�es/tbp/tsr-study-expansion-process-bp.pdf.

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too close to a reservation date. If Customer B drops out early in the process, BPA may re-allocate the securitization to other customers. This would be equivalent to your hotel reservation cost increasing because a guest next door cancelled. Customer A's previous 10% of the total TSRs could now be 20%, requiring it to post another $10 million of security, perhaps jeopardizing Customer A's willingness to stay in the process. This can lead to a spiraling effect in which an upgrade is simply cancelled as customers successively drop out. BPA confronts the unfortunate choice to abandon a transmission expansion due to individual customers' commercial situations, regardless of the long-term (multi-decade) likelihood of the new transmission capacity actually being used.

Nonetheless, TSEP is an improvement over the *pro forma* OATT, where a single customer would be on the hook for the cost of the expansion with the opportunity for refunds from subsequent customers who took service on the same lines. The reality is that no single generator is likely to be able to finance the construction of a major line that will benefit multiple customers. TSEP partially solved this problem by spreading the upfront financial commitments associated with a long-term service contract across a broader group of customers. The requirement that customers execute long-term contracts for service also insulates BPA from building facilities that do not generate revenue (and spreading those costs to customers who do not use the new facilities). The core issue of potential stranded transmission assets—bridges to nowhere, as it were, that BPA and its existing customers naturally wish to avoid—deserves closer scrutiny, given the robust history of transmission projects built well in advance of need (including BPA's own initial lines) that have generally been fully utilized and paid off over time.

The TSEP process works best when the time horizon is a relatively short 2-4 years from subscribers making the financial commitment to BPA energizing the facilities. This short horizon is typically available only for upgrades or expansion of existing facilities; it does not work for new lines to new geographic zones that typically require 10 or more years to plan, permit, and build. The reality is that the costs and risks to generation developers of tying up capital for more than a decade—waiting for BPA to finish a line or upgrade—are simply too great, even if they are able to share those costs with other developers. As a result, NIPPC and RNW believe that consumers in the Northwest may be missing out on some of the best and most affordable generating resources that the region has to offer.

Comment [N(-T57]: Important to be clear – customer security is due when they sign a contract to take that service (not before). So what they are securitizing in the revenue associated with that contract. They are not required to securitize earlier in the process. Still could be 10 – 15 years of security (although once they start taking service, the security amount is decreased each year essentially based on payments they've made).

Comment [N(-T58]: I'm not sure we know this to be true at any point in the process (though probably is upon initial contract offer and requests for security)– If the customer drops out after BPA has collected security and is well into the build process, I don't think BPA is necessarily going to increase the security amount (and wouldn't need to if we drew on someone else's since their costs would have been covered. The spiral effect is accurate at the point of initial contract offer however.

Comment [N(-T59]: Even simple projects generally take more than 2 years

VIII. Avoiding the Consequences of Business as Usual

If sufficient transmission is not available, consumers in the region may face higher costs of meeting state energy targets, and regulated entities (utilities and competitive marketers) may be at risk of failing to meet the targets altogether.[121] At a macro level, the obvious cost of not having the most efficient, highest capacity factor renewable resources available because of transmission constraints is a reliance on relatively more expensive, less efficient, lower capacity factor resources, and related effects such as curtailment of those concentrated resources. In other words, the availability of transmission (or lack thereof) effectively limits competition among resource suppliers despite the demand for such resources. The challenge of coordinating aggregate demand for new transmission among so many different load-serving entities, all with different governance and regulatory approval requirements, is complex and likely beyond the ability of any single group of customers (or their state utility commission) to successfully navigate.

NIPPC and RNW are concerned that BPA's various planning processes are not identifying the need for new transmission sufficiently in advance to ensure that transmission facilities are in place on time. Construction of new transmission lines, or major upgrades to existing facilities, of course requires more than simply identifying a need. Significant time is required to conduct necessary site identification, environmental reviews, and related siting or permitting processes before construction can begin. For example, the Boardman to Hemingway project is a 290-mile, 500-kV transmission line that crosses eastern Oregon and southwestern Idaho. While construction is likely to begin in 2023, with energization in 2026, the project was first identified in Idaho Power's 2006 Integrated Resource Plan.[122] From the identification of a potential need to the expected energization date, twenty years will have elapsed. A ten-year time horizon (BPA's current policy) to identify transmission needs is simply insufficient time to ensure that the lines will be in place when they are needed. But making a simple adjustment to instead use a 20-year planning horizon would not solve the problem so long as individual generation developers shoulder the primary financial risk of expanding the transmission grid. New policies are also needed to share development and construction risk more appropriately and to ensure that detailed engineering and environmental studies are conducted on an appropriate timeline (including potential expanded use of third-party contractors) to ensure that new facilities are energized on time.

Comment [N(-T60]: That doesn't seem like the only impediment. Forecasting the location of new load/resource need years into the future is part of the challenge as well.

[121] Portland General Electric's ("PGE") 2023 Integrated Resource Plan and Clean Energy Plan, for example, notes on page 217 that "the delivery capabili�es of the Pacific Northwest's transmission system … have not kept pace with … changing demands," and as a result, the company may "not rely on BPA transmission to the same extent PGE has historically relied on BPA." PGE concludes on page 227 that the "contrast" between a "need for addi�onal genera�ng resources" and "lack of available long-term transmission" means the company must begin planning now for alterna�ve transmission solu�ons. PGE's plan is available at: https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp.

[122] *See* Idaho Power Company, *Boardman to Hemingway: A Clean Energy Superhighway*, and *B2H History* at www.Idahopower.com, https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/current-projects/boardman-to-hemingway and https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/current-projects/boardman-to-hemingway/b2h-history.

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BPA could play a much greater role in guiding regional transmission expansion. For example, Congress recently passed a new contracting authority for DOE that may be worth considering as an example of how BPA could underwrite some new transmission using its plenary authorities (as detailed above in Section IV). Under the Transmission Facilitation Program ("TFP"), DOE serves as a temporary anchor tenant for new transmission lines.[123] DOE's role is to evaluate the risk of whether a line will be fully utilized in the future, eliminate the need to allocate cost and risk among multiple beneficiaries in the near term, and thereby reduce the overall risk of the line for private investment. As customer demand for the facilities grows, DOE can then offload its position to actual transmission customers who will utilize the line. DOE received dedicated funding for this program and is directed to take a calculated, prudent risk. While BPA's risk appetite in performing a similar anchor tenant role may be smaller, because it has customers ultimately responsible for those costs (rather than just a freestanding revolving fund), BPA should not simply set its risk tolerance at zero (or close to zero) for transmission upgrades that the region will rely on over the coming decades. Readers should note that this position in favor of a greater—but calculated—risk tolerance by BPA in no way diminishes the value and opportunity for other transmission developers to play a leading role in the Northwest that complements BPA's role.

Comment [N(-T61]: Again, lines don't have to be "fully utilized" to be a sound project to build.

Comment [N(-T62]: Would be useful to better understand this program

In summary, BPA should adjust its current policies to take on more of the responsibility to expand the grid in the Pacific Northwest and, to some meaningful degree, in coordination with load-serving entities that require new resources. BPA has a statutory obligation to operate, maintain, and expand its transmission system to serve its customers—both new and existing—in the Pacific Northwest.[124] Congress's recent decision to expand BPA's borrowing authority suggests a congressional desire for BPA to continue to embrace this role in the region, a view underscored by the legislative debate about this provision.[125] On the other hand, BPA should not bear this responsibility alone; the major load-serving entities in the region could and should do more to support transmission upgrades and expansion farther in advance of their short-term procurement needs. In addition, private transmission development also has a significant complementary role to play in the Northwest. Nevertheless, Congress has seen fit to designate and maintain BPA as a transmission provider with significant statutory authority to meet the transmission needs of the region and given BPA unique financing capabilities to meet this responsibility.[126] BPA can and should lead.

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Section X of this whitepaper lists a set of more granular recommendations based on the analysis above.

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[123] Department of Energy, Grid Deployment Office, *Transmission Facilitation Program Fact Sheet* (Nov. 22, 2022), *available at*: https://www.energy.gov/sites/default/files/2022-11/11.22.22%20TFP%20Fact%20Sheet_final_0.pdf.
[124] See Sec�n IV.
[125] In the Infrastructure Investment and Jobs Act, Congress permanently increased BPA's borrowing authority by $10 billion. *See* 16 U.S. Code § 838m.
[126] See the earlier discussion in Sec�n IV.

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IX. Comparison of Best Practices in Transmission Planning Elsewhere to BPA

This section steps back to provide a national, comparative review of best transmission planning practices, set alongside BPA's current processes. The best practices detailed here inform the concluding recommendations in Section X, in some cases bolstering analysis and conclusions reached in preceding sections.

Over the past few years, the electric industry nationally has been undergoing a rapid transformation. FERC and many industry participants have acknowledged that transmission needs increase as more non-emitting generation is built. In addition, end-use electrification of transportation, heating, and industrial processes is adding load, increasing concerns around resource adequacy, resilience, and reliability. Robust long-haul transmission capacity is proving to be an indispensable tool during severe weather and drought periods to address supply shortfalls with power from neighboring areas.[127] In order to ensure future reliability and lower costs, most regions, encouraged by FERC, are moving towards longer term, more holistic transmission planning practices.

As previously discussed, BPA is facing a variety of changes in how its transmission system will be used in the future. These changes include thermal power plant retirements; significant new resource development, including the potential of floating offshore wind development, distributed generation, blended fuel resources, and new nuclear generation; increased extreme weather events; and aggressive state clean energy and emission reduction goals. BPA's current transmission planning processes are inadequate to address these challenges.

The TSEP and local planning processes that BPA employs are too conservative, too reactive, and largely overwhelmed by the current number of transmission service requests. Likewise, while BPA participates in regional planning through NorthernGrid, that process also does not regularly engage in proactive planning for the future resource mix.[128]

Fortunately, there is a set of well-established and common-sense transmission planning best practices against which any given transmission planner's approach, including BPA's, can be compared. One summary of these practices, in a Grid Strategies and Brattle report, *Transmission Planning for the 21st Century*, categorized these practices as: *proactive, multi-value, portfolio-based, and scenario-based planning.* The following should be considered best practices:

1) Proactively plan for future generation and load.

[127] Michael Goggin, *Transmission Makes the Power System Resilient to Extreme Weather* (July 2021), *available at*: https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.
[128] Nevertheless, see *supra* footnote 103 about a current voluntary effort of a subset of NorthernGrid members, including BPA, to carry out a one-�me longer term planning exercise.

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2) Account for the full range of transmission projects' benefits and use multi-value planning.
3) Address uncertainties and high-stress grid conditions explicitly through scenario-based planning.
4) Use comprehensive transmission network portfolios (as opposed to only line-specific assessments).
5) Jointly plan across neighboring interregional systems.[129]

In addition to these methodological practices, a best practice in terms of process is to engage states, utilities, consumers, and other stakeholders for review, comment, and development of consensus plans and fair allocation of costs. For the Pacific Northwest, in the absence of an RTO that addresses cost allocation, a long-term (20-year) transmission plan that identifies potential needs for transmission upgrades in the future becomes a necessary and critical input into the decision-making processes to move forward with any set of upgrades.[130]

This set of well-established and common-sense transmission planning best practices has been employed many times by different regions across the U.S. and has demonstrably lowered systemwide costs.[131] For example, the New York Independent System Operator ("NYISO") applies these best practices through a proactive, multi-value, scenario-based planning process in its Public Policy Transmission Planning Process ("PPTPP"). The Midcontinent Independent System Operator ("MISO") applies these planning best practices with its proactive, multi-value, scenario-based Multi-Value Projects ("MVP"), Renewable Integration Impact Assessment, and Long Range Transmission Planning ("LRTP")[132] planning processes. CAISO also utilizes a multi-value, scenario-based planning process along with a 20-year transmission outlook.[133]

Comment [NJ(-T63]: All ISOs... which we're not

The following subsections summarize transmission planning best practices in order to provide a basis for evaluating the quality of BPA's planning practices against the six commonly used best practices, and offer suggestions on where to focus reforms to modernize and improve BPA's planning practices.

A. Proactively plan for future generation and load

To ensure that the transmission system can keep up with changing needs and maintain reliability and affordability, it is essential for transmission planners to proactively plan for future

[129] Bratle Group & Grid Strategies, *Transmission Planning for the 21st Century*, 14 (2021), *available at*: https://gridprogress.files.wordpress.com/2021/10/transmission-planning-for-the-21st-century-proven-prac�es-that-increase-value-and-reduce-costs-7.pdf.

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[130] A transmission plan in this context does not – and should not – yield an ac�nable construc�n program without significant stakeholder input from a broad spectrum of interests, including state public u�ity commissions. [131] Bratle Group & Grid Strategies, *Transmission Planning for the 21st Century*, at 73-77.
[132] MISO now refers to this planning process as "Transmission Evolu�n", *available at*: https://www.misoenergy.org/about/miso-strategy-and-value-proposi�n/miso-reliability-impera�e/.
[133] Bratle-Grid Strategies, *Transmission Planning for the 21st Century*, at 15.

generation and load growth. This proactive approach contrasts with the reactive, incremental approach that much of the industry—including BPA—currently employs.

Proactive planning involves incorporating realistic projections of the generation mix, load levels (including estimates for electrification), and load profiles over the lifespan of the transmission investment. These projections should not only consider announced retirements but expected retirements as well. The projections should be based on the best available information, considering factors such as utilities' publicly stated decarbonization and/or clean energy targets, public policy mandates, and consumer preferences. Transmission planners should also incorporate these projections into long-term planning, considering a horizon of at least 20 years.

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In recent years, both MISO and CAISO have taken steps to plan for future generation and load more proactively over a 20-year planning horizon. MISO in its Transmission LRTP planning process incorporated "load growth, electrification, carbon policy, generator retirements, renewable energy level, natural gas prices, and generation capital costs" to model capacity expansion over a 20-year period.[134] This past year, CAISO released its 20-year Transmission Outlook plan. CAISO used generation and load projections that meet California's 2045 public policy greenhouse gas reduction objectives, including projected generation retirements and estimates of distributed resources. The 20-year Transmission Outlook also incorporated projections of load growth due to electrification.[135]

BPA's performance on proactive planning

According to the methodology for BPA's Attachment K transmission planning process, BPA does not plan for future generation or load growth beyond the business-as-usual expected forecasts incorporated into the annual system assessment.[136] BPA's planning processes do not incorporate public policies from states in the region, realistic projections of the anticipated generation mix, or expected retirements, nor do they include planning over an appropriate time horizon. Although BPA has conducted a preliminary study on floating offshore wind[137] and is

Comment [NJ(-T64]: We are working to collect more "uncertain" load forecasts, but most NT Customers aren't willing to provide or, if they are, to do so in sufficient advance… I wonder where NIPPC/RNW is thinking we should get this information…?

[134] MISO, *MISO Futures Report*, 2 (2021), *available at*: https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf.
[135] CAISO, *20-Year Transmission Outlook*, 15-25 (2022), *available at*: http://www.caiso.com/Ini��eDocuments/20-YearTransmissionOutlook-May2022.pdf.
[136] *See generally* BPA, *2022 Transmission System Assessment Assumptions and Methodology* (April 2022), *available at*: https://www.bpa.gov/-/media/Aep/transmission/atachment-k/2022-system-assessment-assump�ns-methodology.pdf.
[137] However, BPA did, in response to customer requests, examine the upgrades needed to integrate offshore wind in its 2022 TSEP cluster study, BPA, *2022 Transmission Plan Open Access Transmission Tariff Attachment K Planning Process*, 13 (2022), *available at*: https://www.bpa.gov/-/media/Aep/transmission/atachment-k/2022-bpa-transmission-plan.pdf.

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obviously aware that the future generation mix will be changing due to public policy,[138] there is no evidence that these scenarios have been integrated into the Attachment K planning process.

In its Transmission Plan, BPA merely notes that it works with its Transmission Grid Modeling Group (and the Load Forecasting and Analysis Group) to update the base cases used in the system assessment and forecasted customer load, but BPA does not provide specific details on what inputs are used or modifications are made that result in forecasts of average and peak loads.[139] The Transmission Plan also notes that the base cases "modeled, at a minimum, those resources with firm transmission service. Beyond that, other resources were modeled as needed to meet the forecast customer demands (load forecast) and expected firm transmission service," with no additional details provided on how those other resources are modeled.[140]

At present, BPA incorporates "forecasted load growth, projected firm transmission service commitments, interconnection requests, and system reliability assessments."[141] BPA starts with WECC base cases in its planning processes to validate past System Assessments,[142] which consider generation additions and retirements reported by individual utilities over the next ten years.[143] WECC base cases are relatively conservative and only consider announced generation additions and retirements with a high degree of certainty.[144] In comparison, MISO's LRTP process includes its own independent estimates of generation retirements on top of what utilities report using age and other factors.[145] The BPA base cases also do not appear to include electrification estimates, fuel price forecasts, or hydroelectric power forecasts. BPA relies on utilities to incorporate those forecasts into the load estimates they report to WECC; however, many of the utilities within BPA's transmission service territory do not include electrification estimates in their IRPs.[146] In some cases, regulated utilities have disincentives to report anticipated generation retirements and the need for new resources because such reporting triggers subsequent regulatory actions, including resource solicitations, effects on depreciation schedules, and increased avoided cost pricing for the utility's competitors under the Public

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[138] For example, BPA included an en�e chapter summarizing the regulatory landscape and how it is shi�ng to promote carbon-free energy genera�on, but it is not clear how the changes are incorporated into genera�on and load forecasts, BPA, *2022 Transmission Plan*, at Chapter 5.

[139] *Id.,* at 20.

[140] *Id.,* at 33.

[141] *Id.,* at 15.

[142] BPA, *2022 Transmission System Assessment Assumptions and Methodology*, 2-3 (2022), *available at*: https://www.bpa.gov/-/media/Aep/transmission/attachment-k/2022-system-assessment-assump�ns-methodology.pdf.

[143] *See* WECC, *WECC Data Preparation Manual for Steady-State and Dynamic Base Case Data*, 6, (accessed Feb. 24, 2023), *available at*: https://www.wecc.org/Reliability/WECC_Data_Prepara�n_Manual.docx, and BPA, *2022 Transmission Plan*, at 20.

[144] WECC, *WECC Data Preparation Manual for Steady-State and Dynamic Base Case Data*, at 6.

[145] MISO, *MISO Futures Report*, at 14-15.

[146] *See* Renewable Northwest Comments on No�e of Proposed Rulemaking, *Building for the Future Through Regional Transmission Planning and Cost Allocation and Generator Interconnection*, FERC Docket No. RM21-17-000, 179 FERC ¶ 61,028, 20, 37-38 (Aug. 17, 2022), *available at*: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=F96CCE4A-B04C-C4C2-9FFD-82AB9F100000.

Utility Regulatory Policies Act.[147] BPA has also acknowledged that the peak load reference cases used for the load area assessment assumed minimal renewable generation on-line. This assumption was made because of the intermittent nature of wind and lack of significant solar resource.[148]

This assumption is almost impossible to square with the state clean electricity mandates in Oregon and Washington, the two states with the largest loads in BPA's footprint.

NorthernGrid's planning is similar to BPA's. Both processes rely on utilities to report future generation and load, although NorthernGrid notes in planning documents it is up to the discretion of individual utilities what is reported.[149] There is also no independent review of data submitted to NorthernGrid or use of third-party generation and load forecasts, which in past planning cycles, has resulted in members submitting varied future scenarios. While some utilities include resource additions and retirements from their IRPs, others submit data based only on what is currently in their queue.[150] For both BPA and NorthernGrid, their reliance on utilities creates a "planning lag," where neither consider state laws independently, instead relying on individual utility plans to comply with state law. For example, when a new state law is passed, any new requirements show up 1-2 years after the law is passed in the next utility IRP. This delay means NorthernGrid does not incorporate new state laws until the next regional

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[147] *E.g.,* Washington Administrative Code 480-107-009 ("A utility must issue an all-source RFP if the IRP demonstrates that the utility has a resource need within four years."). Similarly, Oregon avoided cost methodologies effectively encourage utilities to not report accurate resource needs because that has historically kept avoided costs low. For example, after the passage of SB 1547, which doubled the state's RPS requirements, PacifiCorp filed an avoided cost update cutting renewable avoided prices by 43% claiming that it did not need new renewable resources for more than twenty years. *See In re PacifiCorp, Application to Update Schedule 37 Qualifying Facility Information*, Or. Pub. Util. Comm'n Docket No. UM 1729, Supplemental Application (Mar. 1, 2016). Idaho Power's 2021 avoided cost update is another example. In June 2021, Idaho Power Company updated its avoided costs to indicate no need for capacity until 2028. *In re Idaho Power Update to Avoided Cost Rates, Schedule 85,* Or. Pub. Util. Comm'n Docket No. Docket No. UM 1730, Idaho Power Company's 2021 Annual May Update of Avoided Cost Rates and Post 2019 Integrated Resource Plan ("IRP") Acknowledgment Avoided Cost Update – Schedule 85, Cogeneration and Small Power Production Standard Contract Rates at 2 (Apr. 30, 2021); Or. Pub. Util. Comm'n Docket No. Docket No. UM 1730, Order No. 21-198 at 1 (June 15, 2021). Meanwhile, in May 2021, Idaho Power Company discovered an imminent 2023 capacity need, but the company did not bring this issue before the Oregon commission until December 2021 thereby resulting in avoided costs remaining low. *See Idaho Power Application for Waiver of Competitive Bidding Rules,* Or. Pub. Util. Comm'n Docket No. Docket No. UM 2210, Application for Waiver of Competitive Bidding Rules at 1-2 (Dec. 9, 2021).

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[148] BPA, *2022 Transmission Plan*, at 33.

[149] NorthernGrid, *Approved Study Scope for the 2022-2023 NorthernGrid Planning Cycle*, 9, 15, 20, (2022), *available at*: https://www.northerngrid.net/private-media/documents/NG_Study_Scope_2022-2023_Approved.pdf.

[150] NorthernGrid, *Approved Study Scope for the 2022-2023 NorthernGrid Planning Cycle*, at 9-10; In the current planning cycle, Puget Sound Energy ("PSE") submitted 4,090 MW of resource addi�ns and 370 MW in re�ements to NorthernGrid, which is similar to its IRP findings. Puget Sound Energy, *2021 PSE Integrated Resource Plan*, 2-6 (2021), *available at*: https://oohpseirp.blob.core.windows.net/media/Default/Reports/2021/Final/IRP21_Chapter%20Book%20Compressed_033021.pdf. Meanwhile, PGE submitted 19 MW of resource addi�ns and 0 MW re�ements to NorthernGrid, despite sta�g in its IRP a need for 2,800 MW of new resources by 2030 and an exit from Colstrip by 2025. PGE, *PGE plans to nearly triple clean resources by 2030* (Oct. 15, 2021), *available at*: https://portlandgeneral.com/news/2021-10-15-pge-plans-to-nearly-triple-clean-resources-by-2030.

transmission planning cycle, which could be two years after utility IRP implementation and three to four years after the policy became law.

To its credit, BPA has engaged with a group of regional utilities to conduct two special transmission studies. The first will incorporate a 20-year planning horizon to study the region's transmission needs in 2042 with low carbon resource requirements.[151] The second will consider whether there are transmission constraints under extreme weather conditions in 2030, including extreme summer heat waves, extreme winter cold snaps, and wildfire risks.[152] Both of these studies will likely provide important information regarding future transmission needs to ensure a safe and reliable grid.

While moving to a 20-year planning horizon will provide needed breathing room to a complicated process, merely expanding the ten-year time horizon to 15 or 20 years will not, as noted, solve the problem. Moving to a 20-year planning horizon and incorporating scenario planning would be an improvement by giving policy-makers in the region more time to weigh the respective costs and benefits of different portfolios of generation and transmission expansion. But regardless of the time horizon or the study methodology used to identify facilities that will be needed in the future, the region needs a new mechanism to allow BPA to begin conducting pre-construction studies, including environmental assessments, and perhaps even construction sooner in the process.

B. Account for the full range of transmission projects' benefits and use multi-value planning

To comprehensively identify investments that cost-effectively address all categories of needs and benefits, transmission planning best practices include a mechanism to account for the full range of transmission projects' benefits and use multi-value planning. FERC Order Nos. 890 and 1000 provide three reasons that can be used to demonstrate a need for new transmission: economic, reliability, and public policy.[153] To demonstrate need in any of these categories, there is a well-known set of twelve transmission-related benefits. FERC recognized these benefits in its transmission planning NOPR (RM21-17). This list of benefits is particularly useful for demonstrating the economic or public policy needs for a new transmission line and is outlined below:

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[151] Western Power Pool, *20-year Low Carbon Study* (Nov. 23, 2022), *available at*: https://www.westernpowerpool.org/private-media/documents/20_Year_Study_Scope_2022.11.23.pdf.

[152] Western Power Pool, *2030 Low Carbon, Extreme Weather Study Scope* (Oct. 6, 2022), *available at*: https://www.westernpowerpool.org/private-media/documents/2030_Extreme_Study_Scope_2022.10.06_AuoA0s1.pdf.

[153] Advanced No�e of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, FERC Docket No. RM21-17-000, 176 FERC ¶ 61,024, P 13-16 (proposed July 27, 2021).

1. Avoided or deferred reliability transmission projects and aging infrastructure replacement;
2. either reduced loss of load probability or reduced planning reserve margin;
3. production cost savings;
4. reduced transmission energy losses;
5. reduced congestion due to transmission outages;
6. mitigation of extreme events and system contingencies;
7. mitigation of weather and load uncertainty;
8. capacity cost benefits from reduced peak energy losses;
9. deferred generation capacity investments;
10. access to lower cost generation;
11. increased competition; and
12. increased market liquidity.[154]

The CAISO Transmission Economic Assessment Methodology ("TEAM") is an example of a process that accounts for the full range of transmission projects' benefits and uses multi-value planning. The process considers various benefits, including production cost savings and reduced energy prices from both a societal and customer perspective, mitigation of market power, insurance value for high-impact low-probability events, capacity benefits due to reduced generation investment costs, operational benefits, reduced transmission losses, and emissions benefits. This approach is incorporated in CAISO's economic transmission planning and allows the ISO to identify projects that provide multiple benefits, which can result in more cost-effective solutions.[155]

BPA's performance in multi-value planning

In BPA's 2022 Transmission Plan, the majority of proposed projects are intended for reliability purposes.[156] While only a few projects seem to have purposes beyond reliability, the two major projects that were identified that will enable the integration of significant new renewable or non-emitting energy resources come from the TSEP process.[157] The Attachment K planning process, apart from TSEP projects, does not consider transmission benefits beyond the NERC and WECC reliability standards, and its focus seems to be on identifying solutions for identified violations.[158] The TSEP process, while identifying major transmission expansions that better reflect the changing resource mix, is still a reactive process that is focused on near-term customer needs. Furthermore, BPA requires its transmission customers to provide deposits and commit to funding preliminary engineering and environmental studies as well as make long-

[154] No�e of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, FERC Docket No. RM21-17-000, 179 FERC ¶ 61,028, P 185 (Issued Apr. 21, 2022), *available at:* https://www.ferc.gov/media/rm21-17-000.

[155] CAISO, *2021-2022 Transmission Plan,* at 251-63 (2022). http://www.caiso.com/Ini��eDocuments/ISOBoardApproved-2021-2022TransmissionPlan.pdf.

[156] *See* Chapters 6 and 7 of BPA's 2022 Transmission Plan.

[157] *See id.,* at Chapter 6.

[158] *See* BPA, *2022 Transmission System Assessment Assumptions and Methodology*; *see also* Chapters 3 and 4 of BPA's 2022 Transmission Plan.

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term commitments to take transmission service (in general, the unwritten policy appears to be to require full, or close to full, subscription) all before BPA will make a decision to begin construction.[159] In addition, the TSEP process does not provide clear information regarding the transmission benefits and costs being considered, and detailed modeling methods are not publicly available.[160]

Comment [N(-T66]: Again, this is incorrect – only need a good business case.

Comment [N(-T67]: True

Table 1 below shows the multiple benefits that are considered in various transmission planning efforts around the country, compared to BPA's. This comparison is intended as a starting point for analyzing and benchmarking BPA's approach, but it does not assume that BPA's responsibilities are identical to these other transmission providers.

Table 1. Use of expanded transmission benefits in analysis[161]

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SPP 2016 RCAR, 2013 MTF	MISO 2011 MVP ANALYSIS	CAISO 2007 TEAM ANALYSIS OF DPV2 PROJECT	NYISO 2015 PPTN STUDY OF AC UPGRADES	BPA Attachment K planning and TSEP Process
Benefits Quantified 1. Avoided transmission project costs (1) 2. Production Cost Savings (reduced Ancillary Service Costs) (3) 3. Reduced transmission losses (4) 4. Lower transmission outage costs (5) 5. Capacity benefit energy cost benefit (8) **Other Benefits Quantified** 1. Value of reduced emissions 2. Value of reliability projects 3. Value of meeting policy goals 4. Increased wheeling revenues	**Benefits Quantified** 1. Reduced future transmission investment costs (1) 2. Reduced planning reserves (2) 3. Production Cost Savings (3) 4. Reduced transmission losses (4) 5. reduced operating reserves (8) 6. Reduced renewable generation investment costs (10)	**Benefits Quantified** 1. Production cost savings and reduced energy prices from both a societal and customer perspective (3) 2. Reduced transmission losses (4) 3. Insurance value for high impact low-probability events (6) 4. Capacity benefits due to reduced generation investment costs (10) 5. Mitigation of market power (11) **Other Benefits Quantified** 1. Operational benefits (Reliability Must-Run) 2. Emissions benefit	**Benefits Quantified** 1. Reduced refurbishment costs for aging transmission (1) 2. Production cost savings (includes savings not captured by normalized simulations) (3) 3. Capacity resource cost savings (8) 4. Reduced costs of achieving renewable & climate goals (10)	**Benefits Quantified** 1. It is not clear if BPA considered or quantified any expanded transmission benefits. 2. Within the TSEP process BPA identifies reliability and commercial upgrades. Reliability upgrades are then recovered through embedded transmission rates and commercial upgrades go through a cost allocation process.
Considered But Not Quantified	**Considered But Not Quantified** 1. Decreased wind volatility (7)	**Considered But Not Quantified** 1. Improved reserve sharing (2)	**Considered But Not Quantified**	**Benefits Not Publicly or Transparently Considered or Quantified[162]**

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[159] BPA Transmission Business Prac�e, *TSR Study and Expansion Process (version 7)*, 2 (Aug. 17, 2022); Steve Ernst, Clearing Up, *Upgrades to Cross-Cascades Lines May Put Clean-Energy Goals Within Reach* (Aug. 12, 2022), *available at*: https://www.newsdata.com/clearing_up/supply_and_demand/upgrades-to-cross-cascades-lines-may-put-cleanenergy-goals-within-reach/ar�le_eb0cfd5c-1a6d-11ed-adcc-473caa5bbe08.html.
[160] *See* BPA, *TSR Study and Expansion Process (TSEP): 2019 Cluster Study Overview*, slides 10-11 (2019), *available at*: https://www.bpa.gov/-/media/Aep/transmission/tsr-study-expansion-process/062019-2019-cluster-study-results.pdf.
[161] *See* Bratle-Grid Strategies, *Transmission Planning for the 21st Century* at 31. The benefits with numbers in parentheses in this table correspond to the list of benefits in FERC's recent transmission planning NOPR. Each transmission provider in the planning processes in this table also either quan�ied or considered but did not quan�y benefits beyond those listed by FERC. These are indicated without a number in parentheses.
[162] BPA's 2007 Commercial Infrastructure Financing Proposal, adopted and used in subsequent evalua�ns of poten�l benefits from commercial transmission construc�n, detailed some benefits previously considered by BPA (*see supra* at 25).

1. Reduced reserve margin; Reduced loss of load probability (2) 2. Reduced cost of extreme events (6) 3. Mitigation of uncertainty (7) 4. Increased competition/liquidity (11 & 12) 5. Improved congestion hedging 6. Reduced plant cycling costs 7. Societal economic benefits	2. Enhanced generation policy flexibility 3. Increased system robustness 4. Decreased nat. gas price risk 5. Decreased CO2 emissions 6. Increased local investment and job creation	2. Facilitation of the retirement of aging power plants 3. Encouraging fuel diversity 4. Increased voltage support	1. Protection against extreme market conditions (6) 2. Storm hardening and resilience (7) 3. Increased competition and liquidity (11 & 12) 4. Expandability benefits	1. Avoided or deferred reliability transmission projects and aging infrastructure replacement; 2. either reduced loss of load probability or reduced planning reserve margin; 3. production cost savings; 4. reduced transmission energy losses; 5. reduced congestion due to transmission outages; 6. mitigation of extreme events and system contingencies; 7. mitigation of weather and load uncertainty; 8. capacity cost benefits from reduced peak energy losses; 9. deferred generation capacity investments; 10. access to lower cost generation; 11. increased competition; and 12. increased market liquidity

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Competitive compensation reform

NIPPC and RNW underscore that expanding the number of benefits evaluated by BPA, along with incorporating the other best planning practices detailed in this section, will require a meaningful change in how BPA recruits and retains transmission planning staff in order to complete analyses using this deeper and broader set of planning criteria. One key determinant of BPA's transmission planning, business case, and project execution success is whether it pays these key personnel competitively with the rest of the industry. Today, BPA does not and, by statute, with rare exceptions that prove the rule, cannot. The region's congressional delegation can alleviate this root cause problem by working to enact competitive compensation reform for BPA, akin to what its sister federal agency, the Tennessee Valley Authority, received in 2004. Indeed, this is the single recommendation in this whitepaper that requires an act of Congress. (NIPPC and RNW have separately released recommendations and a detailed review of competitive compensation for BPA and do not repeat those details here.)

C. Address uncertainties and high-stress grid conditions explicitly through scenario-based planning

Best practices include adopting a scenario-based planning approach to effectively manage uncertainties and high-stress grid conditions that encompasses a wide range of plausible long-term futures and real-world system conditions, including challenging and extreme events. This approach involves assessing a set of diverse scenarios that go beyond current needs and account for the full spectrum of long-term uncertainties. The scenarios should consider various factors, such as fuel price trends, future load and generation size and location, economic and public policy-driven changes to market rules or industry structure, and technological advancements, to evaluate the transmission system's effectiveness in different future scenarios and identify any necessary modifications. Through scenario-based planning, transmission planners can anticipate potential challenges and develop mitigation plans. The scenarios should have a long-term time horizon and address high-uncertainty futures, enabling planners to identify "least-regrets" solutions that can effectively meet the grid's needs across these challenging and unpredictable scenarios.

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MISO's Long Range Transmission Planning process, described above, is an excellent example of scenario-based planning that considered a wide range of factors. In MISO, Multi Value Projects and the most recent LRTP Tranche 1 projects were a set of transmission lines determined to be needed under multiple scenarios and were therefore deemed to be a "least regrets" set of lines.[163] MISO developed three different scenarios to capture the range of uncertainty over its 20-year planning horizon. These scenarios were then applied to the development of transmission plans.[164] MISO has used scenario-based planning in the past with its Multi-Value Projects, which included the "CapX2020" initiative and the Regional Generator Outlet Study projects. These projects all employed "least-regrets" comprehensive regional network solutions rather than incremental upgrades, which helped reduce the cost of generator interconnections along with many other quantified benefits.[165]

BPA's use of scenario-based planning

In conducting its transmission plan, BPA incorporates limited scenarios and sensitivities.[166] However, these scenarios and sensitivities are based on *expected* peaks and focus on

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[163] MISO, *MTEP21 Report Addendum: Long Range Transmission Planning Tranch 1 Executive Summary*, 5-6, (2022), *available at*: https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Execu�e%20Summary625790.pdf; MISO, *Multi Value Project Portfolio Results and Analyses*, 5 (2012), *available at*: https://cdn.misoenergy.org/2011%20MVP%20Por�lio%20Analysis%20Full%20Report117059.pdf.

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[164] *MISO Futures Report*, at 2.

[165] Bratle-Grid Strategies, *Transmission Planning for the 21st Century*, at 7; MISO, *MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary*, at 5-6; MISO, *Multi Value Project Portfolio Results and Analyses*, at 5.

[166] BPA, *2022 Transmission Plan,* at Sec�n 4.3.

engineering criteria.[167] If it were to follow best practices, BPA would incorporate more extreme scenarios to identify the transmission facilities that will be needed to safely and reliably serve load in the region more than 10 years in the future at the lowest possible cost. BPA would also include public policy scenarios in its planning process, to consider proactively that states may adopt more aggressive public policies in response to a changing climate. BPA does not include scenarios for high levels of renewables, extreme weather events, or electrification. Instead, BPA uses only the nearer-term and narrow NERC criteria for its system assessment studies.[168] These system assessment studies are validated based on "[h]istorical load levels for peak and off-peak conditions" to ensure that they represent reasonable base case loads.[169]

BPA states "the peak load reference cases used for the load area assessment assume minimal renewable generation," due to the "intermittent nature of wind and lack of significant solar resources."[170] In addition, while BPA included offshore wind in its TSEP cluster study, it does not appear to have been a sufficiently rigorous analysis, since BPA considered only binding agreements rather than forecasts.[171] In any event, the transmission upgrades needed to move offshore wind to load were not included in the TSEP Reinforcements identified in the Transmission Plan.[172]

BPA also does not include extreme weather events. BPA addresses the historic 2021 "heat dome" stating, although there were some new historic peak loads reached during the 2021 summer heat wave in the Northwest, this was considered an extreme event and most of the new summer peaks were still within the load levels previously studied over the ten-year Planning Horizon.[173]

Interestingly, BPA provides "long-range needs" estimates outside of the 10-year planning horizon when reviewing transmission needs by path in Chapter 8. These needs are primarily focused on reliability, and BPA does not indicate any timeline for addressing them.[174]

Comment [N(-T68]: I wonder if there is some lack of understanding of the TSEP cases used v. the reliability cases used. Although some of the points here sound accurate. And if wider scenarios were used in reliability planning, more of the projects might then be treated financially as reliability projects.

Comment [N(-T69]: Not sure what this means- may not be accurate. We don't have binding agreements to consider in TSEP – it is focused on requests

Comment [N(-T70]: Again, this comment is reflective of a communication choice that BPA made to focus on the projects that the agency is the most excited about. That doesn't mean that there isn't PEA work in the queue related to off-shore wind.

[167] *Id.*, *see generally* Figures 10 and 11 where sensi�i�s included are defined. These sensi�i�s include st�state and transient stability analysis for expected winter and summer peaks in two, five, and ten years and a two- year off-peak spring scenario.

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[168] *Id.*, at 31-32.
[169] *Id.*, at 33.
[170] *Id.*
[171] BPA studied 1,600 MW of offshore wind resources in its 2022 TSEP process; however, that study was based upon customer requests for service and not upon any realis� scenario of Oregon's actual offshore wind poten�l. *Compare* BPA Press Release, *Over 11 GW studied in 2022 Cluster Study, almost doubling the 2021 requests* (Aug. 3,2022), *available at:* https://www.bpa.gov/about/newsroom/news-ar�les/2022/20220804-over-11-gw-studied-in-2022-cluster-study-almost-doubling-the-2021-reques, *with* Northwest Power and Conserva�n Council, *The Future of Offshore Wind Development,* (Aug. 31, 2022), *available at:* https://www.nwcouncil.org/news/2022/08/31/the-future-of-offshore-wind-development/, no�g that the Bureau of Oceanic Energy Management es�nates Oregon has 20 GW of offshore wind poten�l.
[172] BPA, *2022 Transmission Plan*, at 107.
[173] BPA, *2022 Transmission System Assessment Assumptions and Methodology*, at 3.
[174] BPA, *2022 Transmission Plan*, at 98.

BPA does use limited form scenario-based power-flow cases in its TSEP cluster study. According to BPA:

> the objective of the scenario-based Needs Assessment[175] is to study a range of scenarios that adequately capture anticipated firm network path utilization. Scenarios were developed based on groupings of TSRs in the long-term transmission pending queue with similarly-situated point of receipt (POR) location and/or expected resource type, and by considering which market and weather conditions may induce the greatest firm transmission utilization from these requests on network paths.[176]

D. Use comprehensive transmission network portfolios

Best practices include evaluating comprehensive portfolios of transmission projects that consider other resources such as storage and other technologies to capture benefits such as network interactions. Storage can provide benefits to the grid by decreasing congestion, providing voltage support, and reducing local capacity requirements.[177] When storage and transmission are co-optimized, studies have found they are not substitutes but rather complementary, and optimal amounts of both technologies lead to the lowest system cost.[178] For example, MISO found in its Renewable Integration Impact Assessment report that a combined transmission and storage solution led to a lower system-wide cost than either technology on its own.[179] Considering transmission portfolios better addresses system needs, lowers systemwide costs, and when combined with portfolio-based cost recovery, can simplify cost allocation. Taking a project-by-project approach overlooks potential efficiencies in the highly interconnected transmission system and may lead to less support for cost allocation. To ensure the greatest system efficiencies, transmission planners should model the co-optimization of transmission, storage, and distributed energy resources and include a mix of alternating current ("AC") and direct current ("DC") transmission lines, reconductored lines, or new transmission lines, allowing for more stable and evenly distributed projects across the grid.

MISO has had great success using the portfolio approach to transmission planning and development, both via approval of the Multi-Value Projects across its service footprint over a decade ago and in the 2022 approval of the Tranche 1 projects that came out of the LRTP. The

Comment [N(-T71]: I think there are some questions her about what drivers the storage is responding to and who controls its output under what conditions. What is true in an organized market with an ISO... isn't necessarily true in the Northwest.

Comment [N(-T72]: One (potentially weird) thought is that if BPA wants to continue to have other parties pay for PEA/ESA, we would identify the load that is driving a portion of the need for those projects and allocate some of those costs to them.

Comment [NJ(-T73]: I think this is worth exploring!

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[175] The "Needs Assessment" described here is specifically with respect to TSEP, not the broader forecast of transmission needs described in the Atachment K Transmission Plan.
[176] *Id.*, at 106.
[177] *See* NY-BEST and Quanta Technology, *Storage as Transmission Asset Market Study White Paper on the Value and Opportunity for Storage as Transmission Asset in New York*, (Jan. 2023), *available at*: https://cdn.ymaws.com/ny-best.org/resource/resmgr/reports/SATA_White_Paper_Final_01092.pdf.
[178] Bratle-Grid Strategies, *Transmission Planning for the 21st Century*, at 64.
[179] *See* MISO, *MISO's Renewable Integration Impact Assessment (RIIA), Summer Report* (Feb. 2021), *available at*: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

Tranche 1 projects are designed to "ensure a reliable and efficient regional and interregional transmission system that enables the changing portfolio across the near and long term."[180]

ISO-NE does not use portfolio-based transmission planning, but through the use of postage stamp cost recovery, they do conduct portfolio-based cost recovery of network transmission costs, which is broadly based on the entire ISO-NE portfolio.[181]

BPA's approach with respect to project portfolios

As BPA is not producing a holistic plan to meet anticipated future generation and load, it is not comparing alternative portfolios of transmission to meet that anticipated need. It does seem to include portfolios of projects for the narrow, near-term set of projects that are in the TSEP, but those are only based on binding customer transmission agreements as described above. In contrast, NorthernGrid in its current 2022-2023 transmission planning cycle is incorporating portfolio-based planning by evaluating 26 different combinations of proposed regional projects to determine which combination best meets regional needs.[182]

Comment [N(-T74]: Incorrect – based on study agreements and PEAs, not binding agreements for TX service – that comes much later.

E. Jointly plan across neighboring interregional systems

Best practices include joint regional and interregional planning with neighboring systems using the above-described planning methods (proactive, multi-value, and scenario-based analysis). Unfortunately, most existing processes only evaluate transmission needs that are of the same type, such as reliability, market efficiency, or public policy, which may prevent the evaluation of needs that differ across regions. Therefore, to ensure interregional planning is effective, joint modeling and analysis of adjacent regions should be performed to evaluate transmission regional and interregional needs and analyze benefits based on a multi-value framework. This approach will ensure the recognition of regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

In its 2021-2022 Transmission Plan, CAISO has acknowledged that,

> the interregional coordination process has not met expectations and noted there are opportunities to remove certain barriers, foster collaboration with state regulators, and promote more rigor in, and reporting on, interregional coordination efforts. Accordingly, the ISO is exploring a few alternative courses of action to pursue potential interregional

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[180] MISO, *Long Range Transmission Planning: Tranche 1*, slide 5 (2022), *available at:* https://cdn.misoenergy.org/20220325%20LRTP%20Workshop%20Item%2002%20Tranche%201%20Por�lio%20and%20Process%20Review623633.pdf.
[181] Bratle-Grid Strategies, *Transmission Planning for the 21st Century*, at 15.
[182] *See* NorthernGrid, *Approved Study Scope for the 2022-2023 NorthernGrid Planning Cycle,* at 21, 28.

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> opportunities in addition to complying with all expectations, responsibilities and obligations under the ISO's interregional coordination tariff provisions.[183]

The Acadian Load Pocket ("ALP") Project in Louisiana is also an excellent and successful example of multi-jurisdictional planning. While not precisely interregional, it was developed along the seams of three transmission providers (two privately owned, one publicly owned) and was considered a multi-value project with different drivers and benefits for the parties involved, and each party was responsible for recovering costs through its own tariff.[184]

BPA's regional and interregional coordination

BPA is a member of NorthernGrid, which is responsible for conducting joint interregional coordination with the other FERC Order 1000 planning regions (CAISO and WestConnect). However, NorthernGrid's interregional coordination appears to be a "check-the-box" exercise.[185] In the most recent plan cited by BPA, NorthernGrid proposed 141 new and upgraded transmission line projects primarily for local load service and increased reliability, with only a few interregional lines proposed but not accepted as part of the plan.[186] BPA itself does not appear to participate significantly in joint interregional coordination exercises beyond NorthernGrid. There is little discussion within BPA's tariff about coordination with WECC and Northern Grid.[187] Additionally, coordination in the region on the Western Energy Imbalance Market, reserve sharing, or other one-off practices appears to be operational and near-term in nature.[188] The lack of meaningful interregional planning is similar to what occurs in other regions which to date have only included small near-term projects. This lack of interregional coordination on transmission planning stands in sharp contrast to BPA's robust engagement in recent processes to develop organized day-ahead markets in the West. It also contrasts with BPA's history of interregional engagement in joint transmission projects (*see the Appendix for more details*).

[183] CAISO, *2021-2022 Transmission Plan,* at 13.
[184] The Bratle Group, *A Roadmap to Improved Interregional Transmission Planning*, at 36-37 (Nov. 2021), *available at*: https://www.bratle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf.
[185] *See* NIPPC Comments on Advance No�e of Proposed Rulemaking, *Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional*, FERC Docket No. RM21-17-000, 176 FERC ¶ 61,024 at 4-5 (Oct. 12, 2021), *available at*: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=2BD8D9B6-8347-CE44-8624-7C7A31500000; *see* also Public Interest Organiza�ons Comments on Advance No�e of Proposed Rulemaking, *Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional*, FERC Docket No. RM21-17-000, 176 FERC ¶ 61,024 at 45-49 (Aug. 17, 2021), *available at*: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=60f22f6b-c401-c6bc-b293-7c76ae400001.
[186] BPA, *2022 Transmission Plan*, at 41.
[187] BPA, OATT, Atachment K at 163-83.
[188] *See* BPA, *Coordinated Transmission Agreement*, (accessed Feb. 24, 2023), *available at*: https://www.bpa.gov/energy-and-services/transmission/coordinated-transmission-agreement.

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F. Stakeholder engagement and input

Best practices associated with regional transmission planning include having an open planning process that engages many different perspectives through collaboration and stakeholder engagement. In Order No. 890, FERC established a set of transmission planning principles that emphasize the importance of transparency and providing opportunities for stakeholder engagement. The order highlighted several shortcomings in the existing criteria for transmission planning, including the lack of clarity around the transmission provider's planning obligations, the absence of requirements for customer, competitor, and state commission involvement in the planning process, and the lack of availability to customers of key assumptions and data underlying transmission plans. To address these issues, FERC directed all public utility transmission providers to produce a transmission planning process that adheres to nine principles and to clearly outline this process in Attachment K. The nine planning principles include coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects.[189] Subsequently, Order No. 1000 required revision of FERC-jurisdictional transmission providers' tariffs to include a transparent and detailed process that allows stakeholders to understand the selection of projects. Transmission planning best practices should include engaging states, utilities, consumers, advocates, environmental groups, and other stakeholders for review, comment, and development of consensus plans and fair allocation of costs. This collaborative approach helps to ensure that all perspectives are taken into account when making decisions and can lead to more informed and effective transmission planning decisions.

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RTOs and ISOs create stakeholder committees and forums for transmission planning processes to take up issues of markets, policy mandates, and reliability. Not all RTO/ISOs handle this stakeholder aspect of transmission planning particularly well. Some do better than others. For example, MISO uses a comprehensive planning process that involves many stakeholders. The planning process allows MISO to address cost allocation, which can be contentious, but is needed for the development of large-scale transmission plans. One of the key drivers of the MISO Multi-Value Projects process was that states were asking MISO to study transmission options that could meet the region's renewable generation needs cost-effectively.[190] CAISO, in its transmission planning process has extensive coordination, particularly with California State Agencies including the California Energy Commission and the California Public Utilities Commission.[191] Both MISO and CAISO have extensive stakeholder advisory committees that support the ISOs in their transmission planning.[192]

[189] Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 444-561.
[190] Bratle-Grid Strategies, *Transmission Planning for the 21st Century*, at 69.
[191] CAISO, *2021-2022 Transmission Plan,* at 1.
[192] For example, MISO has 32 en��es, commitees, and other stakeholder groups, https://www.misoenergy.org/stakeholder-engagement/commitees/.

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BPA performance engaging stakeholders for review and comment

BPA does have an open tariff and transmission planning process. Currently, interested parties must ask to participate, but anyone–states, utilities, consumers, and other stakeholders–is able to participate in the planning process.[193] BPA's transmission planning stakeholder engagement process includes two stakeholder meetings per planning cycle, but no stakeholder committees.[194] BPA could improve transparency around its Attachment K transmission study process. Currently, interested stakeholders must request results for economic[195] and system assessment[196] studies. In addition, BPA's OASIS System Planning Portal redirects to BPA's Attachment K website where there is information missing on the 2022 process and some of the links on the website do not link to the correct document. For example, BPA has not posted results from the 2022 TSEP Cluster Study Process.[197]

Comment [N(-T75]: Available upon request

Conclusion

BPA's transmission planning process falls short in most of the key practices, other than stakeholder participation (not counting transparency). Stakeholder participation is about at the same level as many other regional planning entities. BPA does not, however, proactively plan for future generation and load, account for the full range of transmission projects' benefits or use multi-value planning, address uncertainties and high-stress grid conditions explicitly through scenario-based planning, use comprehensive transmission network portfolios (as opposed to only line-specific assessments), or jointly plan with neighboring interregional systems. Adopting the above-described best practices (also listed in the following section of recommendations) would significantly improve BPA's transmission planning process, better preparing BPA and the region to build the grid of the future.

[193] *See* BPA, *Attachment K Planning* (accessed Feb. 27, 2023), *available at*: https://www.bpa.gov/energy-and-services/transmission/atachment-k.

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[194] BPA, *2022 Transmission Plan*, at 15.
[195] *Id.*, at 17.
[196] Access to the Systems Analysis Study requires a FISMA atesta�on, BPA, *2022 Systems Assessment Summary* (2022), *available at*: https://www.bpa.gov/-/media/Aep/transmission/atachment-k/request-for-2022-system-assessment.pdf.
[197] *See* BPA, *Attachment K Planning*.

X. Concluding Recommendations

NIPPC and RNW offer the following recommendations based on the discussion and analysis above. These recommendations complement each other and may be considered as a suite of reforms.

1. **Planning reforms.** BPA should revise its planning process to:

    (A) consider a wider array of transmission projects' benefits, drawing from the best practices of other transmission providers detailed in Section IX;
    (B) regularly conduct proactive local and regional 20-year scenario planning, including a wide range of plausible (for example, at the 95th percentile) but uncertain extreme weather conditions and a range of new generation resources, with robust stakeholder input, and drawing from the best practices of other transmission providers detailed in Section IX;
    (C) independently consider state policy requirements and other transmission demand drivers, in dialogue with state authorities such as utility commissions that have primary responsibility for compliance with these state requirements;
    (D) consider a wider range of transmission portfolio future scenarios, including co-optimizing storage and other technologies, in the 10- and 20-year planning timeframes, that may identify "no regrets" or "least regrets" portfolios, and drawing from the best practices of other transmission providers detailed in Section IX; and
    (E) remain committed to regional and interregional planning with other transmission providers (recognizing that the best transmission solutions are sometimes regional or interregional, not contained within a single provider's system).

2. **Business case for commercial transmission.** In determining whether to move towards construction of new lines, BPA should:

    (A) develop an open and transparent policy (similar in form to the 2007 CIFP) specifying the system benefits and revenue thresholds it considers in determining whether to offer customers service at an embedded or incremental rate, consistent with recommendation 1.A above;
    (B) ensure that a wider array of benefits is considered and deducted from the revenue requirement that must be met through subscriptions, consistent with recommendation 1.A above;
    (C) lower the apparently very high threshold of subscriptions (binding commitments to take transmission service) required to proceed to most construction; and
    (D) separately develop an analytical framework to consider how to incorporate into its long-term planning facilities that appear repeatedly in multiple planning studies but lack a critical mass of subscribers committing financially to upgrades.

3. **Participant funding.** BPA should:

    (A) develop a formal policy identifying the criteria under which it will conduct engineering, siting, and other pre-construction studies for transmission line upgrades at

its own expense and identifying how those costs will eventually be recovered from customers; and
(B) revisit and consider lowering the currently high letter of credit/deposit requirement for TSEP subscribers, while addressing the need to protect against undue risks of stranded costs.

4. **Contracting innovation.** BPA should:
(A) explore using BPA's Transmission Business Line itself as an anchor, or backstop, tenant by exercising a "put option" on some carefully chosen commercial transmission built by BPA, drawing from the experience of DOE in implementing the new Transmission Facilitation Program; and
(B) explore whether IOUs can and would be willing to serve as backstop subscribers for some new transmission capacity, perhaps until IPPs fill in the capacity on a given line in the course of delivering power to those utility offtakers; and
(C) explore joint venture and partnership opportunities that rely on private capital and private projects to take initial development, construction, or subscription risk in lieu of BPA.

5. **Risk calculations.** BPA should:
(A) revisit the core question of how much risk the agency will assume in pursuing a renewed transmission construction agenda, including an analysis of potential benchmark levels of risk (for example, outcomes modeled at a 95th percentile);
(B) review and share with stakeholders whether past transmission investments have actually resulted in any stranded assets (and whether the stranding was temporary or persistent); and
(C) analyze and consider new revenue opportunities to the agency from having and selling more transmission capacity through a variety of existing or potentially new transmission products.

6. **Process.** BPA should:
(A) conduct an iterative customer-facing initiative to consider and make the changes recommended above (as well as other potential changes), including an active effort to solicit the perspective of state regulatory commissions, and potentially as inputs into BPA's upcoming revision of its strategic plan and transmission business model;[198]
(B) following such an initiative, conduct a formal tariff revision process to incorporate those reforms into its business practices or its transmission tariff, but in the tariff only to the extent a given reform requires such a revision; and
(C) advocate within NorthernGrid for the adoption of similar reforms in the planning processes of NorthernGrid and any successor organization.

[198] BPA should consider similar approaches or forums as past ini��es such as the Transmission Issues Steering Commitee that produced the 2007 CIFP and the Wind Integra�n Forum of that same era, the later of which was co-sponsored by BPA and the Northwest Power and Conserva�n Council.

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7. **Transparency**. In considering and implementing the above-described processes and reforms, BPA should make the processes and decision points about reform transparent, including by ensuring that BPA's website acts as a repository of up-to-date information, as well as relevant historical documents.

8. **Compensation.** In order to support BPA recruiting and retaining the necessary transmission planning, business case, and associated transmission staff to carry out the reforms proposed in this whitepaper, Congress should pass competitive compensation reform for BPA.

Appendix: BPA's Record of Transmission Innovation

This appendix details prominent examples in BPA's history of how the agency has leaned into its transmission mission in various ways—politically, financially, technically—to build more capacity and a stronger bulk power system, sometimes at the expense of competing interests. These examples demonstrate a record of innovation and ambition that can inform BPA's future direction.

Founding Ambitions

The basic authority for BPA to build a robust transmission network was heavily debated in Congress prior to the agency's creation. The Army Corps of Engineers, private utilities in the Northwest, and the Portland business community advocated for a limited transmission role, if any, for BPA. At the beginning, it was not even clear if Bonneville and Grand Coulee Dams would be interconnected. Even after BPA's creation in 1937, it was unclear how or by whom power would be marketed from Grand Coulee.[199]

When J.D. Ross became BPA's first administrator, he adopted an aggressive approach to transmission planning. Ross's view was that if BPA contented itself with building lines only incrementally as demand appeared, the demand might simply remain dormant. Ross therefore focused his attention on executing an ambitious construction agenda. Ross based this agenda on a 1935 master grid plan developed by Charles Carey for the Pacific Northwest Regional Planning Commission, a New Deal planning board. Carey went on to become BPA's chief construction engineer. Carey's plan, adopted in Ross's first annual report as administrator, featured two central double-circuit 220-kV lines: one between Grand Coulee Dam and Bonneville Dam, and the other between Bonneville Dam and the Portland area. This backbone segment formed one leg of a triangle that was the BPA network's core configuration. The other two legs joined Portland to Seattle and Seattle to Grand Coulee. Major radial lines extended from this central triangle to population centers and planned hydroelectric dams.[200]

Ross was a friend of President Franklin Roosevelt dating from his time leading Seattle City Light. This relationship was critical to both Ross's appointment as BPA Administrator and BPA's success building transmission. With Roosevelt's personal support, Ross obtained general fund appropriations for BPA's first major transmission line and additional funds from the Public Works Administration. He also secured a workforce from the Works Progress Administration to clear the initial rights-of-way. These combined acts significantly accelerated construction of the

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[199] Philip Funigiello, *Toward a National Power Policy: The New Deal and the Electric Utility Industry, 1933-1941* (Pitsburgh: University of Pitsburgh Press, 1973), 174-96; Gus Norwood, *Columbia River Power for the People: A History of the Policies of the Bonneville Power Administration* (Washington, D.C.: United States Department of Energy, 1981), 47-54.

[200] Paul Hirt, *The Wired Northwest* (Lawrence, Kansas: University Press of Kansas, 2012), 279; Norwood, 55, 108-09. Norwood was the long�me head of the Northwest Public Power Associa�on who later wrote a history of BPA for the agency. He called the ini�al Grand Coulee-Bonneville inter� the "jugular vein" of BPA's transmission system.

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major line that integrated output from the two dams. They also coincided with BPA receiving authority in 1940 (in an Executive Order) to market Grand Coulee's power. Ross, despite a brief tenure at BPA cut short by his premature death, established the template for BPA becoming the leading builder of transmission in the Northwest.[201]

Transmission Acquisitions

In the 1930s, Oregon and Washington authorized local voters to create public utility districts ("PUDs"), part of a backlash against private utilities and what they charged for power. The creation of PUDs, filling a gap between municipal utilities and rural cooperatives, was a key part of the public power movement nationally. Their early formation in Washington, in particular, influenced the enabling act of BPA.

Many of the newly formed PUDs attempted to purchase utility assets directly from the existing private utilities within their boundaries, particularly Puget Sound Power & Light (now Puget Sound Energy). Sometimes they turned to condemnation proceedings when the private utility refused to sell its assets, a legal but slow, expensive, and contentious process that BPA sometimes encouraged.[202] In these cases, voters had elected to form a new utility but remained either captive ratepayers or merely unserved by the incumbent private utility. With the threat of condemnation looming, BPA sometimes stepped into these local disputes and directly assisted PUDs in negotiating purchases of private assets. BPA would buy the transmission lines itself, and the PUD would purchase the dams and local distribution lines.[203] This aggressive action, taking place decades before meaningful wholesale and retail competition to investor-owned utilities emerged in the private sector, may be considered a high tide of consumer-owned utility consolidation in the region.

Joint Transmission Construction and Ownership

The Pacific Northwest/Pacific Southwest Intertie is the major electrical link between the Northwest and both California and the Southwest. In 1964, Congress appropriated funding for the federal share of the intertie. Congress was spurred on by drought in California and a lack of local power; slumping industrial electric sales in the Northwest and a surfeit of federal power, with nowhere to sell it; and Canadian demands in the Columbia River Treaty negotiations for transmission to deliver power from the treaty dams in Canada to buyers in California and the Southwest. The joint development of the Intertie is the most outstanding instance of coordinated transmission planning, construction, and operations in the West.

The Intertie consists of two separate systems: The Pacific DC Intertie is a 1,000-kV DC line between BPA's system and Los Angeles, energized in 1970. It is co-owned by BPA (the northern 246-mile segment), the Los Angeles Department of Water and Power, and other southern

[201] Norwood, 65-67, 111-17.
[202] Funigiello, 213.
[203] Hirt, 283-91.

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California utilities. The California-Oregon Intertie consists of three separate 500-kV AC lines between the Northwest and northern California, first energized in 1968. Its various segments are co-owned by BPA (in Oregon) and a consortium of public and private utilities.[204]

The third line of the California-Oregon Intertie (known as the Third AC Intertie) was built 25 years later and energized in 1993. Its construction followed years of debate about persistent insufficient interregional capacity between California and the Northwest. In 1984, Congress authorized BPA and its sister agency the Western Area Power Administration ("WAPA") to participate in construction of this new segment, adding about 2,000 MW of transfer capacity between northern California and the Pacific Northwest (bringing the total AC capacity to 4,800 MW). In the intervening time between construction of the first two AC lines and this third line, BPA had become a self-financing agency rather than dependent on appropriations. BPA split ownership of the northern half of the line with Portland General Electric and Pacific Power & Light (now PacifiCorp). The southern half, in California, is co-owned by public and private California utilities, as well as WAPA.[205]

Private Sector Backstop

In the 1980s, BPA built its last major new backbone transmission line, the Colstrip line, a 350-mile double-circuit 500-kV line.[206] The line came about when the five private utility co-owners of the two new generating units at the Colstrip coal-fired plant failed to secure a transmission right-of-way across western Montana. The utilities had 1,480 MW of new generation under construction but no way to get it to their loads. They asked BPA to step in and build the line using a vacant right-of-way already held by BPA. BPA agreed to do so in 1977.

In the course of a contentious public debate in Montana about siting the line, BPA chose to adjust the route somewhat to avoid some viewsheds and land impacts. BPA also used a single-pole tower design in order to reduce the visual impact further. The line was built on a highly expedited timeline, given the impending operations of the Colstrip generators. For example, a 97-mile segment from Garrison to Townsend, Montana, was constructed in 15 months instead of a then-typical 30 months. The final segment was completed in 1987.[207]

[204] Northwest Power and Conserva�on Council, *Intertie* (accessed May 2, 2023), *available at*: https://www.nwcouncil.org/reports/columbia-river-history/inter�e/; Northwest Power Planning Council, *Pacific Intertie: The California Connection on the Electron Superhighway* (May 2001), *available at:* https://www.nwcouncil.org/media/filer_public/0d/23/0d23f7a3-3aa2-4acb-b05f-082a0186f8a5/2001_11.pdf.
[205] BPA, *Power of the River* (Washington, D.C.: Government Prin�ng Office, 2012), 93-97.
[206] Based on a review by NIPPC and RNW of BPA records of decision and archival material, approximately six new 500-kV lines have been constructed since then, all of significantly shorter lengths and connec�ng parts of the exis�ng BPA network: Kangley-Echo Lake (9 mi, energized in 2003); Grand Coulee-Bell (84 mi, 2004); Schultz-Wautoma (63 mi, 2005); McNary-John Day (79 mi, 2012); Big Eddy-Knight (28 mi, 2015); and Central Ferry-Lower Monumental (38 mi, 2015).
[207] *Power of the River*, at 71-78.

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Non-Wires Solutions

BPA has a long record of pursuing non-wires solutions rather than building new transmission lines. One well-known example illustrates this approach.

In the winter of 1989, a sudden deep freeze took out one of the Colstrip line's new substations and threatened the stability of the transmission lines into Puget Sound. An obvious solution to the grid stability in western Washington was to build a new line across the Cascades. BPA avoided the environmental and financial challenge at the time of doing so by instead building the Schultz substation (completed in 1994) on the east side of the Cascades. BPA connected four of its existing cross-Cascades 500-kV lines into Schultz, thereby creating eight segments that could operate independently and increasing the grid's reliability. BPA also added series compensators that increased the cross-Cascades transfer capacity by approximately 300 MW.[208]

Non-wires solutions are generally cheaper in the short run than building a new line, help maximize the use of existing infrastructure, and avoid greater development impacts on the environment and local communities than a new line. Non-wires options are therefore a valuable part of any transmission provider's portfolio of solutions and can help establish the provider's credibility when it does seek to build a new line.

Since the 1980s, BPA has focused significant attention on non-wires solutions that reduce the need for customers to pay high construction costs and reduce the siting challenges associated with new transmission lines. The most recent high-profile non-wires solution adopted by BPA was in 2017 to avoid building a new 79-mile 500-kV line in the I-5 Corridor between Castle Rock, Washington, and Troutdale, Oregon, relieving system congestion north of Portland. At the time, BPA concluded that the line would result in more capacity than was needed for a purely reliability purpose and that the price escalation was too high (the original project cost of $346 million in 2009 had increased to $1.2 billion by 2016).[209]

While non-wires solutions can be a useful tool, they can also be overlook the need for and benefits of new lines. Within four years of BPA's 2017 decision to avoid building between Castle Rock and Troutdale, both Oregon and Washington had passed state laws mandating use of 100% non-carbon emitting electricity generation, driving significant new demand for transmission capacity. In short, a non-wires philosophy can become overly conservative when it repeatedly forestalls needed physical investments. While it is a prudent policy as a first resort, its limits have become apparent recently in the Northwest.

[208] *Id.*, at 81.
[209] Ted Sickinger, The Oregonian, *BPA nixes costly and controversial I-5 power line proposal* (May 18, 2017), *available at:* https://www.oregonlive.com/business/2017/05/bpa_nixes_costly_and_controver.html; Elliot Mainzer, BPA, *Letter to parties interested in the I-5 Corridor Reinforcement Project* (May 17, 2017).

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Technical Innovation

BPA has frequently been a leader in the field of transmission engineering. The Pacific DC Intertie was the first high-voltage DC line in the U.S. BPA ownership of the line includes the northern converter station (Celilo). BPA, in collaboration with its co-owners, has upgraded this line multiple times, more than doubling its original design of 1,440 MW capacity to 3,220 MW by replacing mercury arc valves with silicon-based thyristor valves, installing new converters, and optimizing the equipment's operation.[210]

In the 1980s, BPA engineers redesigned the basic physical component of transmission lines—high-voltage conductors—by changing the circular shape of the internal aluminum strands into a trapezoid. The joined trapezoids eliminated air space, allowing the same conductor to carry about 20% more aluminum and therefore 20% more power.[211]

Beginning in the late 1990s, BPA developed the Wide Area Measurement System. BPA experimented with phasor measurement units ("PMUs"), devices that measure voltage and current on transmission lines dozens of times per second, as an improvement over the standard supervisory control and data acquisition system that collects data much more slowly. BPA engineers designed data concentrators and display software to optimize use of the PMUs, controlling for differences in the timing of delivery of microwave signals across the transmission network. The combined "syncrophasor" technology has been adopted widely across the power sector since then. This BPA innovation has created a more efficient and reliable grid, allowing control centers to quickly identify cascading split-second disruptions.[212]

Contract Financing of Transmission

When Congress made BPA self-financing in 1974, it gave BPA authority to borrow directly from the U.S. Treasury at a relatively low interest rate and created a revolving fund to manage this debt, other BPA income, and receipts from sales of power and transmission. BPA's borrowing authority is subject to a statutory cap that has been raised by Congress five times. BPA's primary source of capital to fund investments in its transmission system is this federal debt. In contrast, private transmission owners can raise capital by issuing equity or debt in commercial markets. Non-federal public transmission owners can typically issue bonds as well.

BPA has two other principal options for raising capital to build transmission. One is revenue from customers—essentially cash advances—that is generally the most expensive way to finance long-lived assets because current customers pay upfront for assets that will benefit future generations. The other is "lease-purchase" financing that takes the form of a contractual

[210] Power of the River, at 83-85, and BPA, *Fact Sheet, Celilo Converter Station* (April 2016), *available at*: https://www.bpa.gov/-/media/Aep/about/publica�ns/fact-sheets/fs-201604-Celilo-Converter-Sta�n.pdf.
[211] Power of the River, at 85.
[212] *Id.*, at 91-93.

obligation by BPA to a third-party that issues revenue bonds under its own name that are dedicated to building a BPA transmission line.

A lease-purchase contract specifies that BPA will construct a line owned by the third-party and then lease and operate the line with an option for BPA to purchase it at the end of the term of the debt. These contracts are BPA's way of underwriting debt issued by someone else. This type of contract financing is similar to the "net-billing" debt that BPA incurred in backing nuclear plants pursued by the Washington Public Power Supply System (now Energy Northwest), including Columbia Generating Station. The cost of lease-purchase capital is higher than Treasury debt, making this a more expensive way to finance transmission.[213]

Encouraged by Congress to explore alternative financing, BPA came up with lease-purchase financing in the early 2000s as a way to preserve the agency's limited Treasury borrowing authority. To date, BPA has raised lease-purchase capital through three third parties—Northwest Infrastructure Finance Corporation, an entity created by a private corporation that specializes in infrastructure financing; the Port of Morrow, a port district under Oregon law with broad authority to issue bonds; and the Idaho Energy Resources Authority, a state entity authorized under Idaho law to issue bonds on behalf of consumer-owned utilities to finance infrastructure. Credit analysts view these third parties as "conduit issuers" of debt.[214] The capital raised has been used to finance several BPA transmission lines since 2000, including new 500-kV lines like the 63-mile Schultz-Wautoma and 84-mile Grand Coulee-Bell lines.[215] Combined with BPA's Energy Northwest debt, BPA's outstanding non-federal debt ($7.1 billion) is in fact higher than its outstanding federal debt ($6.9 billion), despite the agency's lack of authority to directly issue debt to commercial markets.[216] This basic financial reality is due the agency's broad contracting authority to enter into financial obligations.

When Congress raised BPA's Treasury borrowing authority by $10 billion in 2021 in the Infrastructure Investment and Jobs Act (Sec. 40110, P.L. 117-58), it alleviated BPA's need for the foreseeable future to secure more expensive debt through lease-purchase contracts.[217] But lease-purchase transmission financing nevertheless represents an important example of financial innovation by BPA, via partnerships with both public and private entities, in order to build new transmission.

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[213] The program is also known simply as "lease financing" and "third-party financing." *See* BPA, BPA's Lease Financing Program (2013), *available at*: https://www.bpa.gov/-/media/Aep/finance/lease-financing-program/lease-financing-program-overview-final.pdf.

[214] BPA, *Financial Plan Refresh: Grounding Workshop #2* (Nov. 16, 2021), *available at*: https://www.bpa.gov/-/media/Aep/finance/financial-plan-refresh/nov-16-workshop-presenta�on-new.pdf; Moody's Investor Service, *Bonneville Power Administration Credit Opinion* (Apr. 6, 2022), available at: https://www.bpa.gov/-/media/Aep/finance/ra�ng-agency-reports/moodysfullreportmay2022.pdf.

[215] *Power of the River*, at 224.

[216] BPA, *Federal Columbia River Power System (FCRPS): Total Liabilities to Federal and Non Federal Parties as of 9/30/2022* (2022) *available at*: https://www.bpa.gov/-/media/Aep/finance/debt-op�miza�on/2022-debt-pie-chart.pdf.

[217] BPA, *Financial Plan Refresh Public Workshop*, slide 8 (Mar. 23, 2022) *available at:* https://www.bpa.gov/-/media/Aep/finance/financial-plan-refresh/20222321-Mar-23-Workshop-Presenta�on.pdf.

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Sent: Thursday, June 22, 2023 2:13 PM
To: Morrison,Bradford R (TFE)(BPA) - TSE-TPP-2; ADL_TSE_ONLY
Subject: RE: outreach to all customers

The Tech Forum announcement went out last Friday and Sarah said the same messaging can be used to send to all transmission customers:

BPA would like to thank all who attended the initial TC-25 Settlement discussion.

At that meeting, BPA proposed several dates for continued engagement and discussion. After considering customer feedback, BPA would like to propose the following schedule:

- June 20, 9 am to 11 am: Scalable Block an Cost Allocation – further education, examples and discussions (Webex only)
- June 21, 9 am to 4 pm: Cluster Study Process Review, Commercial Readiness, Site Control and Transition (Hybrid format)
- June 27, 1 pm to 4 pm: Transition and Wrap Up (Hybrid format)
- June 30, COB: All stakeholder counter-proposals due to BPA (via techforum@bpa.gov)

As a reminder, if parties are interested in participating in the settlement discussions, they should inform their transmission account executive as information and substantive updates regarding the settlement will not be issued via Tech Forum or through any other public information channel (i.e. BPA.gov).

However, if there are any schedule changes, those will be shared via Tech Forum.

From: Morrison,Bradford R (TFE)(BPA) - TSE-TPP-2 <brmorrison@bpa.gov>
Sent: Thursday, June 22, 2023 2:04 PM
To: Harris,Adelle L (TFE)(BPA) - TSE-TPP-2 <alharris@bpa.gov>; ADL_TSE_ONLY <adltseonly@bpa.gov>
Subject: RE: outreach to all customers

Are they planning to send a Techforum?

Brad Morrison
Transmission Account Executive
Bonneville Power Administration
brmorrison@bpa.gov
Office: 360-619-6279
Cell: (b)(6) [redacted]

From: Harris,Adelle L (TFE)(BPA) - TSE-TPP-2 <alharris@bpa.gov>
Sent: Thursday, June 22, 2023 2:02 PM
To: ADL_TSE_ONLY <adltseonly@bpa.gov>
Subject: RE: outreach to all customers

(b)(5) [redacted]

(b)(5) [redacted]

Adelle

From: Harris,Adelle L (TFE)(BPA) - TSE-TPP-2 <alharris@bpa.gov>
Sent: Thursday, June 22, 2023 8:42 AM
To: Zoller,Suzanne L (TFE)(BPA) - TSE-TPP-2 <slzoller@bpa.gov>; Altman,Brian D (TFE)(BPA) - TSE-TPP-2 <bdaltman@bpa.gov>; Lockman,Christopher L (TFE)(BPA) - TSE-TPP-2 <cllockman@bpa.gov>; ADL_TSE_ONLY <adltseonly@bpa.gov>
Subject: RE: outreach to all customers

Thanks for the feedback. I've asked for clarification. Rebecca was included on Sarah's email as well as my follow-up request for clarification. I'll let you know what I hear.

Adelle

From: Zoller,Suzanne L (TFE)(BPA) - TSE-TPP-2 <slzoller@bpa.gov>
Sent: Thursday, June 22, 2023 8:36 AM
To: Altman,Brian D (TFE)(BPA) - TSE-TPP-2 <bdaltman@bpa.gov>; Lockman,Christopher L (TFE)(BPA) - TSE-TPP-2 <cllockman@bpa.gov>; Harris,Adelle L (TFE)(BPA) - TSE-TPP-2 <alharris@bpa.gov>; ADL_TSE_ONLY <adltseonly@bpa.gov>
Subject: RE: outreach to all customers

(b)(5) [redacted]

From: Altman,Brian D (TFE)(BPA) - TSE-TPP-2 <bdaltman@bpa.gov>
Sent: Thursday, June 22, 2023 8:33 AM
To: Lockman,Christopher L (TFE)(BPA) - TSE-TPP-2 <cllockman@bpa.gov>; Harris,Adelle L (TFE)(BPA) - TSE-TPP-2 <alharris@bpa.gov>; ADL_TSE_ONLY <adltseonly@bpa.gov>
Subject: RE: outreach to all customers

Exactly!!!!

(b)(5) [redacted]

From: Lockman,Christopher L (TFE)(BPA) - TSE-TPP-2 <cllockman@bpa.gov>
Sent: Thursday, June 22, 2023 8:25 AM
To: Harris,Adelle L (TFE)(BPA) - TSE-TPP-2 <alharris@bpa.gov>; ADL_TSE_ONLY <adltseonly@bpa.gov>
Subject: RE: outreach to all customers

(b)(5) [redacted]

From: Harris,Adelle L (TFE)(BPA) - TSE-TPP-2 <alharris@bpa.gov>
Sent: Wednesday, June 21, 2023 3:16 PM
To: ADL_TSE_ONLY <adltseonly@bpa.gov>
Subject: FW: outreach to all customers

Hi Team!

Please see Sarah Kutil's request below. We need to be sure that customers are aware of the settlement discussions and that we're keeping documentation of our customer outreach. Per Laura's previous email; PPC, New Sun, NIPPC, Brite Night and Legal Counsel for Avangrid and Renewable Northwest attended the meeting in-person last Thursday.

If any of your customers express an interest to be part of the settlement discussions, please be sure to forward their contact info on to Rebecca and Katie.

Thanks!
Adelle

From: Kutil,Sarah M (BPA) - LT-7 <smkutil@bpa.gov>
Sent: Wednesday, June 21, 2023 12:46 PM
To: Harris,Adelle L (TFE)(BPA) - TSE-TPP-2 <alharris@bpa.gov>; Fredrickson,Rebecca E (BPA) - TSQ-TPP-2 <refredrickson@bpa.gov>; Kukreti,Rahul (BPA) - LT-7 <rxkukreti@bpa.gov>; Green,Ava W (BPA) - LT-7 <awgreen@bpa.gov>
Subject: outreach to all customers

Hi folks – I'm concerned that we're not seeing a lot of attendance in these settlement meetings. We need to reach out to all customers about the TC-25 settlement discussions and keep documentation of the outreach. That way, in the TC-25 case, we can propose the settlement agreement (which may only be signed by a relative handful of customers) and say that we reached out to all customers. This will be important if we get a latecomer in the proceeding who wants to object.

Adelle, is this something that the AEs can help us with?

Sarah Kutil (she/her)
Assistant General Counsel – Transmission
Bonneville Power Administration
503-459-6962

The Honorable John Hairston
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

June 21, 2023

TRANSMITTED BY EMAIL: jlhairston@bpa.gov

Dear Administrator Hairston:

We applaud President Biden and his Administration for stepping up to address the increasingly-dire climate crisis. The Pacific Northwest also is stepping up by phasing out coal and gas plants, and by transitioning buildings and vehicles to clean electricity. While we intend to maximize energy efficiency and demand-side alternatives, we will still need a massive build out of wind, solar and storage facilities for electricity supply and flexibility. Our electrical transmission system is the backbone for delivering this clean energy future.

No federal agency in the Pacific Northwest is more important than the Bonneville Power Administration (BPA) in preparing the region's transmission system to meet these challenges. BPA's grid is the foundation of the network for delivering clean electricity. This system may lack the necessary capacity to meet near-term needs by the end of the decade and faces even higher hurdles for the decade that follows.

As you know, transmission investments take time. Upgrades to existing transmission can take a minimum of seven to eight years. New transmission lines have taken 15 to 20 years. The Northwest Power and Conservation Council estimated that 6,000 new megawatts of clean electricity will be needed by 2030. Tens of thousands of new megawatts will be needed for the decade that follows. Increasing transmission capacity needs to begin now.

We call upon BPA to expedite these investments and reform its process for transmission expansion. There are both near-term and long-term priorities to be addressed simultaneously.

Near-term priorities are based on BPA's Transmission Service Request Study and Expansion Process (TSEP) 2022 Cluster Study report that reflect requests for transmission service into the I-5 corridor. We appreciate that BPA is first maximizing the utility of its existing transmission footprint before building

new lines. This approach supports BPA's fundamental "least cost" and "non-wire" principles. The Cluster Study is a good start. However, many additional actions are needed now to be prepared for the post 2030 demands.

Long-term activities include well-laid plans that account for the massive growth in electricity demand, while also identifying essential capacity expansions for existing and new lines. Oregon and Washington will increasingly rely on importing intermountain wind and desert solar to the I-5 corridor and other load centers. At the same time early work must get underway today to prepare for bringing in off-shore wind by the mid-2030's. BPA will need to change its usual way of doing business in pursuing transmission capacity expansions if it is going to meet near-term and long-term needs.

We highlight below one specific project that serves as an example of one near-term investment that is needed. It fulfills the principles of least cost, time and impact and that could be pursued in addition to the Cluster Study priority projects. This project is the Montana to Washington (M2W) capacity upgrade, critically needed to bring Montana wind to west coast load centers. We know that BPA is in negotiations for this project and more can be done to accelerate its development.

M2W represents a prime example of anticipating known needs for increasing access to important supply-side regions such as Montana. The 7,000 megawatts of existing wind projects in the Northwest are highly concentrated in the Columbia Basin. Montana diversifies this portfolio. In addition, the Columbia Basin wind peaks in spring and early summer when our electricity demand is low. By contrast, Montana wind peaks in the winter matching our highest electricity demand. Adding solar and storage facilities further enhances this powerful resource.

NGOs across the BPA service territory have been supporting the M2W upgrades for a decade. These NGOs include the NW Energy Coalition, Renewable Northwest, Sierra Club, Montana Environmental Information Center (MEIC), Earthjustice, Natural Resources Defense Council and Idaho Conservation League. In 2017, Sierra Club, MEIC and Earthjustice intervened in BPA's 2018 Rate Adjustment Proceeding to address the high transmission costs for the M2W intertie. One of the outcomes of this proceeding was the creation of the Montana Renewable Development Action Plan (MRDAP). One finding from the plan is noted here:

> BPA should undertake actions to increase available transfer capacity on the BPA network in order to allow imports from Montana to reach I-5 load centers.

The essential first step for moving M2W forward is to complete any necessary environmental review (e.g., through a categorical exclusion or an environmental assessment) and an updated engineering assessment. From earlier review, we anticipate environmental impacts from the upgrades to be minimal and the benefits are large, up to 550 to 600 megawatts of additional capacity and greater grid reliability.

When BPA released its project cancellation memo on the M2W upgrades in 2015, it stated that "If the underlying transmission service request and the proposed plan of service to address it are the same or very similar to the M2W Project, and there is minimal new information or changed circumstances

(b)(5) [redacted]

relative to the environment, BPA would likely be able to use much of the environmental analysis work completed for the M2W Project with minimal further data collection and analysis required."

Other than the earthquake retrofits that have been added, we understand that the project remains "the same or very similar." The need for the project, however, has increased sharply in light of rising demand for renewables and regional decarbonization requirements. As such, BPA should move quickly to take the necessary next step to bring this least cost, least time and least impactful project forward.

BPA must look at how it manages costs for transmission investments. Investments in projects like M2W will provide durable financial benefit to BPA power and transmission customers and provide greater grid stability. While clean energy developers should pay some upfront costs, financing must be arranged to allow investment now, which ultimately will be for the benefit of all BPA customers.

We look forward to your response that outlines your immediate next steps for the M2W upgrades.

Sincerely,

Nancy Hirsh
Executive Director
NW Energy Coalition
nancy@nwenergy.org

Angus Duncan
PNW Consultant
Natural Resources Defense Council
angusduncan99@gmail.com

Robin Everett
Deputy Regional Field Director
Sierra Club
robin.everett@sierraclub.org

Anne Hedges
Director of Policy and Legislative Affairs
Montana Environmental Information Center
ahedges@meic.org

Joseph Bogaard
Executive Director
Save Our wild Salmon (SOS) Coalition
joseph@wildsalmon.org

Mitch Cutter
Salmon & Steelhead Associate
Idaho Conservation League
mcutter@idahoconservation.org

Amanda Goodin
Supervising Senior Attorney
Earthjustice
agoodin@earthjustice.org

Robin Arnold
Markets & Transmission Director
Renewable Northwest
robin@renewablenw.org

The Honorable John Hairston
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

June 21, 2023

TRANSMITTED BY EMAIL: jlhairston@bpa.gov

Dear Administrator Hairston:

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As you know, transmission investments take time. Upgrades to existing transmission can take a minimum of seven to eight years. New transmission lines have taken 15 to 20 years. The Northwest Power and Conservation Council estimated that 6,000 new megawatts of clean electricity will be needed by 2030. Tens of thousands of new megawatts will be needed for the decade that follows. Increasing transmission capacity needs to begin now.

We call upon BPA to expedite these investments and reform its process for transmission expansion. There are both near-term and long-term priorities to be addressed simultaneously.

Comment [WP(-D1]: Very actively working on this with Evolving Grid, GI reform and the Six projects.

Near-term priorities are based on BPA's Transmission Service Request Study and Expansion Process (TSEP) 2022 Cluster Study report that reflect requests for transmission service into the I-5 corridor. We appreciate that BPA is first maximizing the utility of its existing transmission footprint before building

new lines. This approach supports BPA's fundamental "least cost" and "non-wire" principles. The Cluster Study is a good start. However, many additional actions are needed now to be prepared for the post 2030 demands.

Long-term activities include well-laid plans that account for the massive growth in electricity demand, while also identifying essential capacity expansions for existing and new lines. Oregon and Washington will increasingly rely on importing intermountain wind and desert solar to the I-5 corridor and other load centers. At the same time early work must get underway today to prepare for bringing in off-shore wind by the mid-2030's. BPA will need to change its usual way of doing business in pursuing transmission capacity expansions if it is going to meet near-term and long-term needs.

We highlight below one specific project that serves as an example of one near-term investment that is needed. It fulfills the principles of least cost, time and impact and that could be pursued in addition to the Cluster Study priority projects. This project is the Montana to Washington (M2W) capacity upgrade, critically needed to bring Montana wind to west coast load centers. We know that BPA is in negotiations for this project and more can be done to accelerate its development.

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NGOs across the BPA service territory have been supporting the M2W upgrades for a decade. These NGOs include the NW Energy Coalition, Renewable Northwest, Sierra Club, Montana Environmental Information Center (MEIC), Earthjustice, Natural Resources Defense Council and Idaho Conservation League. In 2017, Sierra Club, MEIC and Earthjustice intervened in BPA's 2018 Rate Adjustment Proceeding to address the high transmission costs for the M2W intertie. One of the outcomes of this proceeding was the creation of the Montana Renewable Development Action Plan (MRDAP). One finding from the plan is noted here:

> BPA should undertake actions to increase available transfer capacity on the BPA network in order to allow imports from Montana to reach I-5 load centers.

The essential first step for moving M2W forward is to complete any necessary environmental review (e.g., through a categorical exclusion or an environmental assessment) and an updated engineering assessment. From earlier review, we anticipate environmental impacts from the upgrades to be minimal and the benefits are large, up to 550 to 600 megawatts of additional capacity and greater grid reliability.

When BPA released its project cancellation memo on the M2W upgrades in 2015, it stated that "If the underlying transmission service request and the proposed plan of service to address it are the same or very similar to the M2W Project, and there is minimal new information or changed circumstances

Comment [WP(-D2]: Six projects and other projects in flight or completed in the last several years.

Comment [WP(-D3]: Note from Kotek and OR Senators asking for slow down. Not sure Tx should get ahead.

Comment [WP(-D4]: BPA is conscious of new demands and is modifying some existing processes to help accommodate. The demand is regional and we need regional solutions.

Comment [WP(-D5]: Not sure if it is least cost or not.

Comment [WP(-D6]: Not sure what we can publicly say about the who and what on M2W.

Comment [WP(-D7]: Diversity is a virtue and RFPs from utilities may bear this out.

Comment [WP(-D8]: This is ongoing and much progress was made with MRDAP, including IDing existing capacity that was not being used.

Comment [WP(-D9]: In process.

Comment [WP(-D10]: Do we know this?

Comment [WP(-D11]: Change has happened as well as stds etc. The old work in not too relevant. It was 8 years ago.

relative to the environment, BPA would likely be able to use much of the environmental analysis work completed for the M2W Project with minimal further data collection and analysis required."

Other than the earthquake retrofits that have been added, we understand that the project remains "the same or very similar." The need for the project, however, has increased sharply in light of rising demand for renewables and regional decarbonization requirements. As such, BPA should move quickly to take the necessary next step to bring this least cost, least time and least impactful project forward.

BPA must look at how it manages costs for transmission investments. Investments in projects like M2W will provide durable financial benefit to BPA power and transmission customers and provide greater grid stability. While clean energy developers should pay some upfront costs, financing must be arranged to allow investment now, which ultimately will be for the benefit of all BPA customers.

We look forward to your response that outlines your immediate next steps for the M2W upgrades.

Sincerely,

Nancy Hirsh
Executive Director
NW Energy Coalition
nancy@nwenergy.org

Angus Duncan
PNW Consultant
Natural Resources Defense Council
angusduncan99@gmail.com

Robin Everett
Deputy Regional Field Director
Sierra Club
robin.everett@sierraclub.org

Anne Hedges
Director of Policy and Legislative Affairs
Montana Environmental Information Center
ahedges@meic.org

Joseph Bogaard
Executive Director
Save Our wild Salmon (SOS) Coalition
joseph@wildsalmon.org

Mitch Cutter
Salmon & Steelhead Associate
Idaho Conservation League
mcutter@idahoconservation.org

Amanda Goodin
Supervising Senior Attorney
Earthjustice
agoodin@earthjustice.org

Robin Arnold
Markets & Transmission Director
Renewable Northwest
robin@renewablenw.org

Comment [WP(-D12]: ?

Comment [WP(-D13]: Are there more TSRs? Maybe in the next cluster study.

Comment [WP(-D14]: BPA continues to work with folks in queue that need M2W for service.

Comment [WP(-D15]: ?

Comment [WP(-D16]: Yes, balance must be struck. BPA provides significant value and will continue to do so moving forward.

Comment [WP(-D17]: What can be shared publically?

Customer comments re: FR/FS Cluster Study Process

NIPCC:

BPA staff indicates that it is leaning towards its Alternative 3 – a two phased cluster study. BPA staff indicated that it is currently completing 15 studies annually. Any interconnection reform should plan on increasing the number of studies that can be completed.

NIPPC recognizes that a principal benefit of the proposal is to provide customers with low barriers to enter the initial cluster study (Phase 1) in order to obtain preliminary information on the interconnection costs associated with their project.

It is not clear from the materials whether BPA intends to have a predictable cycle of interconnection processes (i.e. a standardized 18 month or 2 year cycle for interconnection cluster windows) or whether BPA intends to retain the flexibility to announce the next cluster study windows only after it completes an interconnection study cycle. NIPPC asks BPA to clarify its intentions with this regard. Depending upon how BPA answers this question, NIPPC's position on the topics below may change.

NIPPC has concerns with the staff proposal. First, is that the proposed timeline is too long. The proposed interconnection process appears to take at least 2-3 years from start to finish; even longer if re-studies are required. The proposed timeline for only the Phase 1 and Phase 2 cluster study cycle will last one year and seven months. NIPPC members note that this proposed timeline in substantially longer than other interconnection reform processes that FERC has approved. (MISO's process is approximately 12 months; PJM's process is approximately 23 months; SPP's process is approximately 24 months). NIPPC also notes that longer timelines to complete study cycles may encourage speculative requests as the market opportunities that may be available 5 years from now are more uncertain than the opportunities within the next two years.

NIPPC suggests shortening the time for Validation and Cure, and Customer Engagement in Phase 1 and shortening the time for Validation and Cure in Phase 2. NIPPC believes customers and BPA could conduct much of the Validation and Cure and Customer Engagement processes as interconnection requests are submitted; there is no need to wait to begin those processes only after the close of the Cluster Request window. BPA should also consider how much preliminary work on validation and customer engagement BPA can complete before the close of the cluster window.

In addition to shortening the time for Validation and Cure, NIPPC suggests that BPA could require the customer to submit the Study Deposit at the time of application (instead of during the Customer Engagement window) so that the deposit can be validated at the same time as the rest of the application. BPA should also consider establishing cluster areas before the Phase 1 cluster study and have scoping meetings for each cluster area to reduce the number of scoping meetings. Finally, BPA, if possible, should overlap the Facility Study and Environmental Study as much as possible, preferably beginning the Environmental Study as soon as facilities are identified in Facility Study. NIPPC understands that BPA staff conduct Facility studies and environmental studies concurrently on projects today. This approach should be implemented in the new process, as well.

Alternative Proposal for Consideration
As an alternative to reducing the timeline for the cluster study process, NIPPC asks BPA to consider the following proposal. Not all members of NIPPC support this concept; they would prefer BPA shorten the study timelines as noted above. Nevertheless, If BPA were to increase the time between the end of the Phase 1 Cluster Study and the start of the Phase 2 Cluster study, then generation developers could (in theory) incorporate the information from the Phase 1 study into their bids into Requests for Proposal and allow load serving entities to score those bids and develop their "short list" for resource acquisitions. Under this approach, there would be no commercial readiness requirements in the Phase 1 Cluster Study, and the interconnection customer could satisfy the commercial readiness requirements to participate in the Phase 2 Cluster Study by being included on the utility short list. As explained in NIPPC's IRP and RFP presentation, developers cannot submit a bid in an RFP without some insight into their interconnection costs. Under this approach, the developer would obtain the Phase 1 Cluster Study results and then have sufficient information to submit their bid to the utility. The utility would then need to review all the submitted bids and create a short list before the Phase 2 Cluster Study.

Projects chosen for the short list would be able to use that as demonstration of "readiness" for purposes of qualifying for the Phase 2 study NIPPC estimates that BPA would have to allow several months1 between the end of Phase 1 and the start of Phase 2 to allow sufficient time for the RFP scoring process to play out. NIPPC recognizes the limitations of this proposal. First, it assumes that public utility commissions and utilities would conform the timing of their own resource procurement and oversight processes to the timing of BPA's cluster study processes. Second, building in a longer time to allow development of a short list would extend the time for the cycle to complete. Nevertheless, in brainstorming how BPA's interconnection reform proposals can possibly mesh with utility procurement processes, this is the best solution NIPPC has been able to identify. NIPPC encourages BPA to consider this option and – just as important – seek input on this proposal from other stakeholders, including the utilities that run procurement processes and the commissions that oversee them. NIPPC recognizes that building in this additional time between Phase 1 and Phase 2 would extend the timeline to complete the process. If BPA were to consider this proposal, BPA would likely need to make a firm commitment to conduct study cycles on a predictable and consistent timeline of opening a new cluster window every two years.

Time Stamp as Tie-Breaker
Utilities in the region have not scored bids and developed their short list for procurement on consistent timelines.
NIPPC urges BPA to solicit comment from public utility commissions and investor owned utilities on how much time could be built into the process between the Phase 1 results and the deadline to enter Phase 2 to allow utilities to score of RFP bids and develop of a short list.

Staff has proposed using the time stamp of the demonstration of readiness requirements as a tie-breaker. NIPPC interprets this proposal as follows. When there are multiple projects in a

cluster which would face different interconnection costs (because of the "lumpiness" of the upgrades required) BPA would allocate the lower cost connections to customers based on the date they satisfied the readiness requirements.
NIPPC notes that readiness requirements first appear in the Phase 2 cluster. How would BPA reflect in the Phase 1 results that some projects would have lower costs than others? NIPPC also notes that this would trigger a "race" for customers to submit their evidence of readiness upon the completion of Phase 1. NIPPC encourages BPA to consider a mechanism to award a "tie-breaker" based on which customer values the interconnection position the most (not only the customer who presses "send" first). In the context of transmission service, the OATT provides for pre-emption and competition to award transmission service to the customer who is willing to take the service for the longest term. BPA should consider whether there are other similar attributes of interconnection service which could be used to break ties (such as an earlier commencement of service date or a customer's willingness to forego suspension of its interconnection).

During Interconnection Review Process
NIPPC encourages BPA to incorporate into its interconnection queue reform, specific options to allow customers the opportunity to modify their interconnection request to avoid or reduce the cost of upgrades.

Specifically, NIPPC suggests that BPA include information in its Phase 1 study reports on the reasons for which a project fails screens (the specific screens failed, the technical reason(s) for failure, details about the specific system threshold/limitation causing the failure) with enough detailed data to allow the customer to redesign its project to avoid or mitigate upgrade costs. Phase 1 cluster study results should provide developers with enough data to modify their design to eliminate or reduce the need for upgrades prior to the Phase 2 study process (rather than requiring restudy after study results are delivered). BPA should allow customers to propose design modifications without automatically submit a new interconnection application. BPA should consider allowing customers to submit alternative designs as part of its application, perhaps original design and two alternatives that address system constraints. If design modifications would require further study, BPA should consider how it might address those additional studies through post-results modifications (i.e. explicit process for modifications after posting of study results) rather than requiring a re-study of the entire cluster.

Cypress Creek Renewables:
CCR supports the intent of Phase I: to provide information to interconnection customers (ICs) quickly in order to accelerate queue withdrawal decisions, or alternatively to enable a subset of remaining ICs to proceed into the Phase II cluster study and Phase II re-study.

- To make the Phase I process more efficient, however, BPA should move the redundant short circuit analysis solely to Phase II. The Phase I power flow study is more appropriate to provide a relatively rapid assessment of network upgrades (NUs), whereas short circuit provides limited upgrade information based on impact to circuit breakers. CCR recommends BPA reduce the Phase I timeline adjustment to reflect a reduced scope of work. We concur with BPA that a separate non-binding informational study phase prior to Phase I as

originally proposed in the FERC NOPR in RM22-14-000 has no value to ICs and detracts from scarce staff resources.
- More broadly, the non-binding nature of all proposed cost estimates and estimated construction timelines throughout each Phase does not address current IC uncertainty around these critical factors inhibiting decision-making. Today, the IC has no reasonable expectation of timely study results due to the "Reasonable Effort" standard, which the FERC NOPR in RM22-14-000 is proposing to eliminate, but which is outside the scope of the BPA queue reform proposal. Cost and schedule uncertainty are the primary barriers to IC project underwriting and contracting, and as such represent a fundamental barrier to commercial readiness requirements considered in this process. Non-binding information without recourse for significant cost increases between study phases or significant timeline extensions beyond non-binding estimates does nothing to solve the problem.
- Accordingly, we recommend BPA consider binding cost and schedule elements during the facilities study phase, when project interconnection facilities costs are not dependent on actions of other interconnection customers.
- Without that binding information, ICs will continue to be unable to sign commercial term sheets (PPAs) that incorporate a certain cost and schedule, which are contemplated as commercial readiness demonstration requirements to enter Phase II, prior to the Facilities study. Non-binding cost and schedule information raises the risk that the IC will be unable to perform its obligations under its offtake agreement, to the detriment of both the IC and the off-taker; this also increases BPA's risk that associated transmission service rights will not align with the timing and cost of the interconnecting generating resource.
- CCR generally supports the tie-breaker methodology, but recommends BPA share results about priority interconnection in a transparent manner within the cluster. Commercial readiness requirements must be updated to increase risk to more speculative projects to enter and progress through the process, as well as reflect the realities of procurement and development processes
- The following tables summarize several process components contained in 'Staff leaning' proposals related to commercial readiness and cost allocation, among others. A CCR proposal that balances the interests of the BPA proposal with the realities of project development follows.

[See Table from comments submitted]

Seattle City Light:
City Light supports BPA's initial goals in implementing a First-Ready/First-Served cluster study process:

1. Increase the speed of interconnection queue processing.
2. Address queue backlogs and study delays.

City Light encourages BPA to take a step back to review the staff proposal and timeline from initial request until a requester receives a completed Facility Interconnection study in view of these goals and the following BPA TC-25 Tariff Principles:

-Prevent significant harm or provide significant benefit to BPA's mission or the region, including BPA's customers and stakeholders; or
-Align with industry best practice when the FERC pro forma tariff is lagging behind industry best practice, including instances of BPA setting the industry best practice.

City Light suggests that BPA may need additional resources to address interconnection reform in a manner consistent with these goals and principles. We encourage BPA to consider if more resources are needed across all transmission study/design processes and project management to serve customer needs. BPA should consider creatively addressing this need in the short term while planning additional FTE's and resources in the next Integrated Program Review process. As a BPA customer, City Light sees high value in BPA expanding its abilities and resources to efficiently address this growing long-term need.

First-Ready/First-Served Cluster Study Process
City Light agrees that there is value in identifying scalable plans where possible and using readiness "priority" to fit into expansion levels allowing projects to move forward and be completed.
City Light asks BPA to provide more details concerning the staff proposal to use "time stamps of demonstrated readiness requirements" as a tie breaker. City Light sees the risk of this "time stamp" process being an administrative burden and not appearing transparent or equitable. More details regarding how BPA intends to make this process transparent are needed for customers to adequately comment on this proposal.

Pinegate Renewables:
Pine Gate supports Alternative 3—the First Ready-First Served ("FR/FS") cluster study approach. Pine Gate agrees with BPA staff that this approach provides customers with more useful information early in the process, particularly information pertaining to interconnection costs. This approach has been successful in MISO and SPP, and was recently approved by FERC in PJM.

However, Pine Gate is concerned regarding the proposed study timeline to LGIA execution, which would take up to 45 months. This is significantly longer than what interconnection customers expect in the current BPA serial process. It is also much longer than the timelines that have been implemented in other markets, as shown in the table below:

PJM	710 days (~23 months)
MISO	373 days (~12 months)
SPP	2 years

Pine Gate's experience, prolonged timelines encourage more speculative projects to enter the interconnection queue because market conditions become increasingly uncertain with each future year.
Pine Gate offers the following suggestions for way to shorten the estimated timeline:
• Require the Study Deposit at the point of application submission (as opposed to at the Customer Engagement window) so it can be reviewed at the time of the rest of the application.

• Assign cluster areas before the Phase 1 cluster study and have scoping meetings for each cluster area to reduce the number of scoping meetings and so customers can be earlier informed about the cluster areas.
• Shorten the Customer Review periods in Phases 1 and 2 from 1 month to two weeks.
• Shorten Validation and Cure periods in Phase 2 and Facility Study from 2 months to 1 month.
• If possible, overlap the Facility Study and Environmental Study (if one is required) as much as possible, preferably beginning Environmental Study as soon as facilities are identified in Facility Study.

Furthermore, Pine Gate encourages BPA to explore ways in which it can overlaps cluster study processes, as is done in other markets. For example, in PJM, the Phase 1 process begins concurrently with the Phase 3 process for the previous cluster.5 Pine Gate also urges BPA to consider ways by which it can shorten the timelines for the Facilities Study phase. Given BPA's historical rate of processing 15 Facilities Studies per year and BPA's intent for the Facilities Study phase to remain serial, it is critical to find more efficiencies in how these studies are processed in order to prevent further backlogs. Finally, with respect to project downsize modifications, Pine Gate recommends that BPA permit reductions at Phase 1 and Phase 2 to provide interconnection customers needed flexibility and allow them to right-size their projects to accommodate reasonable network upgrade cost allocations. For example, in MISO and PJM, reductions of up to 100% Maximum Facility Output ("MFO") are permitted at Phase 1 and reductions of 10% MFO are permitted at Phase 2.

Renewable Northwest:
Bonneville's Phased Approach Appears to be Generally Workable, But the "Tie-Breaker" Concept Needs Additional Development
Bonneville's leaning to adopt a multi-phase cluster study, with two cluster study phases followed by a facility study phase where projects would be studied individually2 does not raise any red flags, but RNW cannot support Bonneville's proposal to use a readiness tie breaker without additional details. As Bonneville explained, the agency may use the time stamp from the demonstration of readiness requirements as a tie breaker "priority" demonstration to allow some projects within a sub-cluster to move forward more quickly the purpose of clustering projects in the first place. Allowing some projects to go forward with minimal upgrades may ultimately be the best approach, but Bonneville needs to provide more details on sub-clustering and how cost allocation would be handled. Readiness requirements are discussed in more detail below, but RNW will simply note here that this tie breaker concept would have dramatically different practical implications is applied to the transition queues. At a minimum, Bonneville needs to clarify whether the tie breakers will be used in the transition process.

Savion: Savion comments

NW Energy Coalition
for a clean and affordable energy future
NRDC
Save Our wild Salmon
SIERRA CLUB
EARTHJUSTICE
MEIC
IDAHO CONSERVATION LEAGUE
RENEWABLE NORTHWEST

The Honorable John Hairston
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

June 21, 2023

TRANSMITTED BY EMAIL: jlhairston@bpa.gov

Dear Administrator Hairston:

We applaud President Biden and his Administration for stepping up to address the increasingly-dire climate crisis. The Pacific Northwest also is stepping up by phasing out coal and gas plants, and by transitioning buildings and vehicles to clean electricity. While we intend to maximize energy efficiency and demand-side alternatives, we will still need a massive build out of wind, solar and storage facilities for electricity supply and flexibility. Our electrical transmission system is the backbone for delivering this clean energy future.

No federal agency in the Pacific Northwest is more important than the Bonneville Power Administration (BPA) in preparing the region's transmission system to meet these challenges. BPA's grid is the foundation of the network for delivering clean electricity. This system may lack the necessary capacity to meet near-term needs by the end of the decade and faces even higher hurdles for the decade that follows.

As you know, transmission investments take time. Upgrades to existing transmission can take a minimum of seven to eight years. New transmission lines have taken 15 to 20 years. The Northwest Power and Conservation Council estimated that 6,000 new megawatts of clean electricity will be needed by 2030. Tens of thousands of new megawatts will be needed for the decade that follows. Increasing transmission capacity needs to begin now.

We call upon BPA to expedite these investments and reform its process for transmission expansion. There are both near-term and long-term priorities to be addressed simultaneously.

Near-term priorities are based on BPA's Transmission Service Request Study and Expansion Process (TSEP) 2022 Cluster Study report that reflect requests for transmission service into the I-5 corridor. We appreciate that BPA is first maximizing the utility of its existing transmission footprint before building

new lines. This approach supports BPA's fundamental "least cost" and "non-wire" principles. The Cluster Study is a good start. However, many additional actions are needed now to be prepared for the post 2030 demands.

Long-term activities include well-laid plans that account for the massive growth in electricity demand, while also identifying essential capacity expansions for existing and new lines. Oregon and Washington will increasingly rely on importing intermountain wind and desert solar to the I-5 corridor and other load centers. At the same time early work must get underway today to prepare for bringing in off-shore wind by the mid-2030's. BPA will need to change its usual way of doing business in pursuing transmission capacity expansions if it is going to meet near-term and long-term needs.

We highlight below one specific project that serves as an example of one near-term investment that is needed. It fulfills the principles of least cost, time and impact and that could be pursued in addition to the Cluster Study priority projects. This project is the Montana to Washington (M2W) capacity upgrade, critically needed to bring Montana wind to west coast load centers. We know that BPA is in negotiations for this project and more can be done to accelerate its development.

M2W represents a prime example of anticipating known needs for increasing access to important supply-side regions such as Montana. The 7,000 megawatts of existing wind projects in the Northwest are highly concentrated in the Columbia Basin. Montana diversifies this portfolio. In addition, the Columbia Basin wind peaks in spring and early summer when our electricity demand is low. By contrast, Montana wind peaks in the winter matching our highest electricity demand. Adding solar and storage facilities further enhances this powerful resource.

NGOs across the BPA service territory have been supporting the M2W upgrades for a decade. These NGOs include the NW Energy Coalition, Renewable Northwest, Sierra Club, Montana Environmental Information Center (MEIC), Earthjustice, Natural Resources Defense Council and Idaho Conservation League. In 2017, Sierra Club, MEIC and Earthjustice intervened in BPA's 2018 Rate Adjustment Proceeding to address the high transmission costs for the M2W intertie. One of the outcomes of this proceeding was the creation of the Montana Renewable Development Action Plan (MRDAP). One finding from the plan is noted here:

> BPA should undertake actions to increase available transfer capacity on the BPA network in order to allow imports from Montana to reach I-5 load centers.

The essential first step for moving M2W forward is to complete any necessary environmental review (e.g., through a categorical exclusion or an environmental assessment) and an updated engineering assessment. From earlier review, we anticipate environmental impacts from the upgrades to be minimal and the benefits are large, up to 550 to 600 megawatts of additional capacity and greater grid reliability.

When BPA released its project cancellation memo on the M2W upgrades in 2015, it stated that "If the underlying transmission service request and the proposed plan of service to address it are the same or very similar to the M2W Project, and there is minimal new information or changed circumstances

relative to the environment, BPA would likely be able to use much of the environmental analysis work completed for the M2W Project with minimal further data collection and analysis required."

Other than the earthquake retrofits that have been added, we understand that the project remains "the same or very similar." The need for the project, however, has increased sharply in light of rising demand for renewables and regional decarbonization requirements. As such, BPA should move quickly to take the necessary next step to bring this least cost, least time and least impactful project forward.

BPA must look at how it manages costs for transmission investments. Investments in projects like M2W will provide durable financial benefit to BPA power and transmission customers and provide greater grid stability. While clean energy developers should pay some upfront costs, financing must be arranged to allow investment now, which ultimately will be for the benefit of all BPA customers.

We look forward to your response that outlines your immediate next steps for the M2W upgrades.

Sincerely,

Nancy Hirsh
Executive Director
NW Energy Coalition
nancy@nwenergy.org

Angus Duncan
PNW Consultant
Natural Resources Defense Council
angusduncan99@gmail.com

Robin Everett
Deputy Regional Field Director
Sierra Club
robin.everett@sierraclub.org

Anne Hedges
Director of Policy and Legislative Affairs
Montana Environmental Information Center
ahedges@meic.org

Joseph Bogaard
Executive Director
Save Our wild Salmon (SOS) Coalition
joseph@wildsalmon.org

Mitch Cutter
Salmon & Steelhead Associate
Idaho Conservation League
mcutter@idahoconservation.org

Amanda Goodin
Supervising Senior Attorney
Earthjustice
agoodin@earthjustice.org

Robin Arnold
Markets & Transmission Director
Renewable Northwest
robin@renewablenw.org

Sent: Thursday, May 4, 2023 1:40 PM
To: Cook,Jeffrey W (BPA) - TP-DITT-2
Subject: RE: RE: [EXTERNAL] RE: NIPPC and RN white paper on BPA transmission

Sounds like Sonya had a chance to see a couple of versions of the NIPPC white paper. [redacted]

Manary

From: Cook,Jeffrey W (BPA) - TP-DITT-2 <jwcook@bpa.gov>
Sent: Thursday, May 4, 2023 1:00 PM
To: Manary,Michelle L (BPA) - TS-DITT-2 <mlmanary@bpa.gov>; Sheckells,Katie (BPA) - TSB-TPP-2 <kksheckells@bpa.gov>
Cc: Shaheen,Richard L (BPA) - T-DITT-2 <rlshaheen@bpa.gov>
Subject: FW: RE: [EXTERNAL] RE: NIPPC and RN white paper on BPA transmission

fyi

Jeffrey W. Cook, PE
VP Transmission Planning and Asset Management
Bonneville Power Administration
360-418-8981
[redacted] (cell)

From: Baskerville,Sonya L (BPA) - AIN-WASH <slbaskerville@bpa.gov>
Sent: Thursday, May 4, 2023 12:20 PM
To: Cook,Jeffrey W (BPA) - TP-DITT-2 <jwcook@bpa.gov>; Bustamante,Richard (BPA) - TPP-OPP-3 <rxbustamante@bpa.gov>; Johnson,Anders L (BPA) - TPLE-TPP-2 <aljohnson@bpa.gov>; Aggarwal,Ravi K (TFE)(BPA) - TPL-TPP-2 <rkaggarwal@bpa.gov>
Subject: Fwd: RE: [EXTERNAL] RE: NIPPC and RN white paper on BPA transmission

FYI I think this is a good response and appears to support our evolving grid discussions. Thanks.

Sonya Baskerville
BPA National Relations
[redacted] m

---------- Forwarded message ----------
From: "Baumann, Jeremiah" <jeremiah.baumann@hq.doe.gov>
Date: May 4, 2023 2:11 PM
Subject: RE: [EXTERNAL] RE: NIPPC and RN white paper on BPA transmission
To: "Baskerville,Sonya L (BPA) - AIN-WASH" <slbaskerville@bpa.gov>,"Konieczny, Katherine (Kathy)" <katherine.konieczny@hq.doe.gov>,"Ardis, Melissa" <melissa.ardis@hq.doe.gov>,"Daly, Gabriel" <gabriel.daly@hq.doe.gov>,"Walsh, Samuel" <samuel.walsh@hq.doe.gov>,"Dennis, Jeffery" <jeffery.dennis@hq.doe.gov>,"Zevin, Avi" <avi.zevin@hq.doe.gov>
Cc: "Chong Tim,Marcus H (BPA) - L-7" <mhchongtim@bpa.gov>

Thanks for this Sonya – pretty interesting stuff. I'd bet that if the current discussions with stakeholders in the PNW do result in some kind of regional energy needs planning process line of work, that process (which presumably would include IOUs and other stakeholders) might support looking further at some of those issues around regional coordination, resources close to load, etc. And might elevate where exactly (geographically) new transmission needs might be, and help facilitate a discussion on what BPA's role should be, vs independent developers via TFP vs. IOUs etc ought to be taking on...

From: Baskerville,Sonya L (BPA) - AIN-WASH <slbaskerville@bpa.gov>
Sent: Thursday, May 4, 2023 2:48 PM
To: Konieczny, Katherine (Kathy) <katherine.konieczny@hq.doe.gov>; Ardis, Melissa <melissa.ardis@hq.doe.gov>; Daly, Gabriel <gabriel.daly@hq.doe.gov>; Walsh, Samuel <samuel.walsh@hq.doe.gov>; Dennis, Jeffery <jeffery.dennis@hq.doe.gov>; Baumann, Jeremiah <jeremiah.baumann@hq.doe.gov>; Zevin, Avi <avi.zevin@hq.doe.gov>
Cc: Chong Tim, Marcus <mhchongtim@bpa.gov>
Subject: [EXTERNAL] RE: NIPPC and RN white paper on BPA transmission

Hello, all. Just FYI that NIPPC and Renewable Northwest have issued a white paper on their perspectives on BPA transmission planning and construction. BPA was expecting this and had seen several drafts.

An overarching theme of this could be summed up as BPA ratepayers should subsidize regional transmission and take on the risk of overbuilding. That aspect of this will not go over well with many of our constituencies, particularly give IOUs and merchant transmission developers also have the ability to build transmission.

Nevertheless, there are aspects of the white paper and other issues that BPA and other transmission planners have been discussing for many years: regional coordination; appropriate cost allocation; market efficiencies; resources closer to load; etc. So we expect this paper will be more input in those ongoing discussions. Also, it is encouraging that DOE's TFP was addressed as an opportunity for any need for regional transmission over-build in advance of forecasted need.

Thanks.

Sonya Baskerville
BPA National Relations
(b)(6) [redacted] m

On Apr 26, 2023 12:22 PM, "Baskerville,Sonya L (BPA) - AIN-WASH" <slbaskerville@bpa.gov> wrote:
I knew I was forgetting someone. Thanks!

Sonya Baskerville
BPA National Relations
(b)(6) [redacted] m

On Apr 26, 2023 1:17 PM, "Daly, Gabriel" <gabriel.daly@hq.doe.gov> wrote:
Thanks, Sonya. Copying Avi here, too.

From: Baskerville,Sonya L (BPA) - AIN-WASH <slbaskerville@bpa.gov>
Sent: Wednesday, April 26, 2023 12:45 PM
To: Daly, Gabriel <gabriel.daly@hq.doe.gov>; Walsh, Samuel <samuel.walsh@hq.doe.gov>; Ardis, Melissa <melissa.ardis@hq.doe.gov>; Baumann, Jeremiah <jeremiah.baumann@hq.doe.gov>; Konieczny, Katherine (Kathy) <katherine.konieczny@hq.doe.gov>; Dennis, Jeffery <jeffery.dennis@hq.doe.gov>
Subject: Public meeting on BPA's proposed interconnection queue reform

Hey there. This is a reminder for some that BPA is hosting a public meeting tomorrow to discuss BPA's proposed approach to transmission interconnection queue reform. The link below will take you to the info for attending the public meeting if you'd like to listen in. Thanks.

https://www.bpa.gov/learn-and-participate/public-involvement-decisions/event-calendar/event-details?pageid=%7bB4AF319D-FE5F-4DE1-80A3-4D849C4AAEA8%7d

Sonya Baskerville
BPA National Relations
[redacted] m

Sent: Monday, May 1, 2023 11:08 AM
To: Hall,Lee J (BPA) - PES-6
Subject: RE: Operations Call Summary Notes 5.1.23

Ya……. Numbers aren't looking as good as last year.

Scruggs mentioned Randy Hardy's comment from clearing up……

> "We are in a virtual gold rush for development of new renewable energy projects and it's completely overwhelming—not just BPA—but all utilities," Randy Hardy, principal at Hardy Energy Consulting and former BPA administrator, told Clearing Up. "This is the consequence of the market responding to legislative mandates in Washington and Oregon and incentives in the Inflation Reduction Act." Hardy says delaying the 2023 cluster study report is a direct result of BPA not having enough staff in its transmission planning department "They are doing the best they can with limited staff, and facing exponential growth in the number of [transmission service requests]," Hardy said. "It's unfortunately the practical reality of what they are facing."
>
> Renewable Northwest and the Northwest and Intermountain Power Producers Coalition are working on federal legislation that would allow BPA to increase its salaries and staffing to handle the new era of transmission development.

And the diversity note – "Hiring panels should be diverse and well as the applicant pool are as well". I dare someone to kick back a cert because it's not diverse enough.

Not Responsive

[redacted]

Stakeholder	Comment/Question	Workshop	Topic	SMEs Assigned to Respond	Response Type: Written or Workshop	Status of Response	Posted Response
Clear Energy Group	Clearway supports the overall initiative with specific comments on the following aspects of the proposal: FR/FS Two-Phase Cluster Study Approach Clearway supports this approach.	Apr 26-27	First Ready First Served				
Clearway Energy Group	Clearway supports the study deposit is supposed to cover study activity costs. MW size of the project has little correlation to the study work. A 50 MW and a 500 MW generator request will require BPA to do the same amount of study work. We recommend $150k or $250k (or bigger) deposit, like CAISO, to enter the queue at once. A one-time sizeable deposit would give a better certainty of projected expenses during study process.	Apr 26-27	Study Deposits				
Clearway Energy Group	Clearway oppose removing the in lieu of deposit. Too stringent and unfair to expect projects to lock-in the land without knowing interconnection outcomes. Consider an in-lieu deposit to enter the queue and site control requirement at the receipt of the Facility Study.	Apr 26-27	Site Control				
Clearway Energy Group	Clearway supports allocating 100% of the cluster study costs by the number of customers participating in the cluster study. MW size of the project should not be used to determine study cost as it has little correlation to the study work and therefore cost responsibility.	Apr 26-27	Study Costs				
Clearway Energy Group	The option towards which BPA is leaning (Alternative 2) limits commercial readiness demonstration to multiple/s of study deposit amount and does not allow a procurement shortlist or a PPA as an option. BPA should consider the multiple of deposits in lieu of a well-defined set of commercial readiness criteria (and other allowable commercial readiness mentioned for Transition Cluster).	Apr 26-27	Commercial Readiness				
Clearway Energy Group	Network Upgrade Costs: a. Station equipment Network Upgrades: Should be allocated equally based on the number of Generating Facilities interconnecting at an individual station. b. Transmission and distribution Network Upgrade: i. Thermal - BPA should define a cut-off for allocating cost. e.g. only those generators with a DFAX of more than x% AND a flow impact of more than y% of the rating of the limiting facility will be allocated NU cost. ii. Voltage and Stability – Interconnection Customer's share of the proportional capacity of each individual Generating Facility in the Cluster. iii. Short circuit – Based on short circuit contribution of each individual project	Apr 26-27	Network Upgrade Costs				
Clearway Energy Group	Transition Process: Agree that advanced stage projects (with signed FS agreement) should be allowed an option to continue with Transitional Serial process. b. Downsizing Opportunity: All the projects not meeting advanced stage (before FS agreement) will be part of transition cluster. However, per BPA staff's leaning, these would need to demonstrate site control. Therefore, BPA should allow downsizing opportunity at the start of the transition cluster, so customer have an option to show site control for reduced MW and still be part of transitional cluster. c. Commercial Readiness Requirements to stay in the transition cluster are more stringent than the requirements to enter the permanent cluster study. This puts unreasonable burden on customers that have entered the queue and are experiencing delays. Commercial Readiness Requirements for transition cluster should be similar to that of subsequent cluster studies.	Apr 26-27	Transition Process				
Clearway Energy Group	General Comments: In case where multiple projects are connecting to the same transmission line as a Point of Interconnection (POI), BPA should clarify the exact location on the transmission line that will be considered as the POI. Clearway recommends that this information is disclosed during the Customer Engagement window and not at the end of Phase 1 cluster study.	Apr 26-27	Multiple Projects				
Cypress Creek Renewables	BPA's proposed First-Ready / First-Served (FR/FS) Cluster Study process is inefficient and lacks binding information CCR supports the intent of Phase I: to provide information to interconnection customers (ICs) quickly in order to accelerate queue withdrawal decisions, or alternatively to enable a subset of remaining ICs to proceed into the Phase II cluster study and Phase II re-study.	Apr 26-27	First Ready First Served				
Cypress Creek Renewables	To make the Phase I process more efficient, however, BPA should move the redundant short circuit analysis solely to Phase II. The Phase I power flow study is more appropriate to provide a relatively rapid assessment of network upgrades (NUs), whereas short circuit provides limited upgrade information based on impact to circuit breakers. CCR recommends BPA reduce the Phase I timeline adjustment to reflect a reduced scope of work. We concur with BPA that a separate non-binding informational study phase prior to Phase I as originally proposed in the FERC NOPR in RM22-14-000 has no value to ICs and detracts from scarce staff resources.	Apr 26-27	First Ready First Served				
Cypress Creek Renewables	CCR recommend BPA consider binding cost and schedule elements during the facilities study phase, when project interconnection facilities costs are not dependent on actions of other interconnection customers.	Apr 26-27	First Ready First Served				
Cypress Creek Renewables	CCR generally supports the tie-breaker methodology, but recommends BPA share results about priority interconnection in a transparent manner within the cluster.	Apr 26-27	First Ready First Served				

Cypress Creek Renewables	Commercial readiness requirements must be updated to increase risk to more speculative projects to enter and progress through the process, as well as reflect the realities of procurement and development processes	Apr 26-27	Commercial Readiness					
Cypress Creek Renewables	**Study Deposits:** The proposed milestone deposits and study deposits upon which one milestone payment is based are far too low given the size of the BPA queue, and the need to significantly increase BPA's resources to process queue applications more efficiently. Study deposit amounts should be based on the underlying request for service, based on a differentiated scope. Next, rather than a 'blend of the NOPR amount and amounts seen in benchmarking' (slide 58), it would be more consistent with other ISO/RTO practices, and send a more consistent price signal to the IC, to instead base the milestone demonstration for Phase II as a percentage (10%) of allocated NUs.	Apr 26-27	Commercial Readiness					
Cypress Creek Renewables	**Study Deposits:** We further recommend that BPA consider distinguishing the study deposit based on whether the IC requests ERIS or NRIS, given the different scope of work required for each. Such distinctions should be consistent with NOPR guidance to transmission providers to reflect the level of interconnection service.	Apr 26-27	Commercial Readiness					
Cypress Creek Renewables	**Study Deposits:** To reduce schedule and cost uncertainty described above, and in light of increased study deposits that should be allocated to improve staff resourcing, CCR suggests a portion of study deposits, above the amount spent, as well as a portion of the milestone payment, should be refunded to the IC if the cluster study, cluster re-study, or facilities study is more than 30 days late after the timeline to be established in the OATT. This proposal will improve not only commercial certainty and open commercial readiness demonstration options as discussed below, but also accelerate withdrawal and restudy timelines.	Apr 26-27	Commercial Readiness					
Cypress Creek Renewables	**Study Deposits:** Premature commercial contract demonstration in the form of a term sheet or selection in an RFP/IRP process creates significant risk for both the IC and LSE. Several comments filed in the FERC Interconnection process NOPR RM 22-14-000, which proposed a commercial readiness demonstration requirement as a requirement to queue entry and progression, are relevant to BPA's consideration of alternative 2 – commercial readiness: Early stage readiness requirements would force parties to enter into agreements prematurely, which will lead to inaccurate cost estimates incorporated into those agreements. (Pine Gate Renewables NOPR Comments at 29-30). LSEs and bidding generators would both be harmed. Bidding generators would have significant risk imposed upon them by virtue of seeking commercial arrangements without sufficient knowledge of interconnection costs and likely have a smaller scope of opportunities to even bid for LSE solicitations which would prioritize resources with more certainty to their interconnection costs. Likewise, LSEs could see higher bids from resources due to the uncertainty in interconnection upgrades. (American Clean Power NOPR Comments at 35).	Apr 26-27	Commercial Readiness					
Cypress Creek Renewables	The CRD options are in conflict with industry accepted timelines for development, finance, and construction. (Pine Gate Renewables NOPR Comments at 25-26).	Apr 26-27	Commercial Readiness					
Cypress Creek Renewables	As a form of **commercial readiness** demonstration, CCR would support a discretionary permit, moved to the facility study phase, as evidence of commercial readiness, with an exemption for projects sited on public lands. This option would be more compatible with development practices.	Apr 26-27	Commercial Readiness					
Cypress Creek Renewables	A **commercial term sheet is not workable** until after LGIA execution, given that the IC has no ability to sign commercial contracts for a delivery of energy based on a contracted COD given current BPA interconnection performance, and absent any penalties or other proposals to eliminate Reasonable Effort Standards. However, if BPA adopts a study and milestone refundability standard for delayed study results as suggested above, CCR would be willing to support a commercial term sheet as a demonstration of readiness during the Facilities study phase.	Apr 26-27	Commercial Readiness					
Cypress Creek Renewables	As defined on p. 50, CCR is supportive of full site control, but also recommends BPA set a reasonable separate application for the generator tie, e.g., 50% at application. Such a requirement will further force siting discipline.	Apr 26-27	Site Control					
Cypress Creek Renewables	**Withdrawal Penalties:** Should be equal on the milestone deposit amount as listed below. Penalties should be at risk after payment required in order to enter the subsequent phase. BPA should also consider withdrawal penalty exclusions. In response to the RM22-14-000 NOPR, the Clean Energy Associations suggested the Commission establish a maximum cost band that shrinks from the cluster phase (e.g. 150% of the upgrade cost) to the facilities study phase (e.g. 125%). If upgrade costs increase by 50% of the estimated figure from the cluster phase, or 25% from the facilities study phase, ICs would have the ability to withdraw without forfeiting at-risk deposit funds (although the portion of the deposit actually utilized for performing the studies would not be refunded).	Apr 26-27	Site Control					
Cypress Creek Renewables	NUs should be allocated based off proportional impact, not proportional capacity. Allocating based off capacity requires engineering judgment which can be subject to inconsistency and result in unfair cost allocation. Proportional impact (DFAX) is a fair way to assign upgrade costs by burdening the largest contributors with the largest share of the upgrade, and it is increasingly becoming the standard across most markets for that reason. Proportional capacity results in subsidizing projects by burdening lesser contributing projects to reduce the burden of higher contributing projects.**See page 4 & 5 for CCR proposal**.	Apr 26-27	Network Upgrade Costs					

Cypress Creek Renewables	Technical Studies Requirements should be complemented with efforts to increase transparency into GI criteria *BPA does not address how GI study processes will derive cost estimates delivered to the IC. Greater transparency into the GI process is more valuable than an interconnection capacity heat map. *Key GI study criteria assumptions that can significantly impact the cost estimate include which NERC TPL criteria are assumed, and whether and the extent to which the use of operational tools (re-dispatch methods) address thermal violations. *As part of the customer cure process, we recommend greater transparency into GI study criteria applied as part of its analysis.	Apr 26-27	Technical Study Requirements				
Cypress Creek Renewables	BPA's proposal requires greater precision, including a more specific queue entry cutoff for eligibility, and the point at which the transition would commence. A transition cluster that is too large may be challenging to assess, based on other RTO experience (MISO). Eligibility restrictions should be based on clear milestones. - Customers should be eligible for the transition serial queue only if they have a completed facilities study in hand by the effective date of the transition... -Customers that submitted an interconnection request after the queue reform launch, on or about March 15, 2023, should be excluded from transition cluster eligibility, given that they should have had reasonable expectation that new requirements would replace the queue entry requirements in place prior to reform.	Apr 26-27	Transition Process				
BrightNight	**Cluster Study:** BrightNight believes that non-financial forms should be included to demonstrate commercial readiness. In FERC NOPR and other FERC approved tariffs in the west, security deposits are in lieu of commercial readiness and not a form of commercial readiness itself. Different LSE's and other load entities reward projects with term sheets etc., which have been initially de-risked from the development and permitting side, even though there is some risk from the interconnection studies perspective. ...Reduce Phase 1 Studies...Having non-financial form of commercial readiness would not provide much motivation for the interconnection customers to further the commercial scope of the project until later in the queue.	Apr 26-27	Commercial Readiness				
BrightNight	**Cluster Study:** Cash deposits for commercial readiness should not be the sole milestones to enter the queue. Examples like largers queues in PAC, Tri state in the second cluster study... were seeing delays in for the latest clusters, where the initial studies are delayed till 2025. This was due to larger queues and withdrawals in the initial cluster cycles. This led to another queue reform, second one in 4 years.	Apr 26-27	Commercial Readiness				
BrightNight	**Cluster Study:** It is important to incentivize projects that have commercial success or are working towards it, we ask BPA include milestones below in-lieu: Term-sheet/PPA and TSR confirmed or designation as Network Resource	Apr 26-27	Commercial Readiness				
BrightNight	**Cluster Study:** BPA's assumption that only similar projects will be clustered could be short lived and with an influx of projects in any one cluster would end up creating too many micro clusters which would be impossible to study...Quick fix to some of these might be incorporating of simple impact rules e.g. • If an upgrade is originating from the interconnecting bus the project will bear full responsibility for the upgrade, similar to rule MISO has. •MISO has been one of the only cluster process that has been running relatively on time, they do still use DFAX criteria even with a 100GW+ queue, we would like to petition BPA to re-consider moving with the same criteria as MISO	Apr 26-27	Network Cost Allocation				
BrightNight	**General Comments:** Additionally, if there are projects at the same POI with TSR confirmed or requesting NRIS, the constraints triggered could be different based on the path selected and the project impacts on these constraints could be very different as well	Apr 26-27	General Comments				
Seattle City Light	City Light supports BPA's initial goals in implementing a First-Ready/First-Served cluster study process: 1. Increase the speed of interconnection queue processing. 2. Address queue backlogs and study delays.	Apr 26-27	First Ready First Served				
Seattle City Light	City Light encourages BPA to take a step back to review the staff proposal and timeline from initial request until a requester receives a completed Facility Interconnection study in view of these goals and the following BPA TC-25 Tariff Principles: -Prevent significant harm or provide significant benefit to BPA's mission or the region, including BPA's customers and stakeholders; or -Align with industry best practice when the FERC pro forma tariff is lagging behind industry best practice, including instances of BPA setting the industry best practice.	Apr 26-27	First Ready First Served				
Seattle City Light	City Light suggests that BPA may need additional resources to address interconnection reform in a manner consistent with these goals and principles. We encourage BPA to consider if more resources are needed across all transmission study/design processes and project management to serve customer needs. BPA should consider creatively addressing this need in the short term while planning additional FTE's and resources in the next Integrated Program Review process.	Apr 26-27	First Ready First Served				

Seattle City Light	Cluster Study: City Light agrees that there is value in identifying scalable plans where possible and using readiness "priority" to fit into expansion levels allowing projects to move forward and be completed.	Apr 26-27	First Ready First Served				
Seattle City Light	City Light supports the BPA staff proposal to require Site Control at the application to the Phase 1 of the Cluster Study process with no deposit in lieu of.	Apr 26-27	Site Control				
Seattle City Light	City Light supports not requiring commercial readiness at the application to Phase 1 of the cluster study process. City Light additionally supports the BPA staff proposal to require Commercial Readiness or deposit in lieu of at entrance to Phase 2 cluster study.	Apr 26-27	Commercial Readiness				
Seattle City Light	City Light suggests BPA reconsider the FERC approved method of allocating study costs assigning 50% of the costs on a pro rata MW cost and 50% of the costs allocated by the number of participants in the FR/FS Cluster Study. City Light believes having a "number of participants" cost component provides an incentive for entities to reduce the amount of redundant requests. It additionally provides a countervailing incentive against entities making multiple small requests representing a larger project to maximize their advantage in a proposed readiness priority queue.	Apr 26-27	Study Financials Cost Allocation				
Seattle City Light	City Light supports the BPA staff proposal to allocate Network costs based on those who use station equipment with transmission network costs allocated on proportionate capacity. City Light believes this aligns with cost causation and is consistent with industry norms.	Apr 26-27	Network Cost Allocations				
Seattle City Light	**Cluster Study:** City Light supports the BPA staff proposal to perform a phased cluster study approach and provide a publicly available interconnection capacity heat map. City Light suggests that a publicly available heat map showing the long-term available transfer capability of the AFC/ATC Less Pending Queued Request Inventory would additionally add value for customers and generation interconnection requesters.	Apr 26-27	Interconnection Information Access				
Seattle City Light	City Light supports the BPA staff proposal to remove Attachment A to Appendix 1 of BPA's LGIP and provide specific model requirements in BPA's Technical Requirements for Interconnection. City Light encourages BPA to prioritize developing the resources and abilities necessary to meet or exceed the recent NERC guidelines concerning inverter-based resources and EMT modeling. City Light supports BPA applying detailed EMT modeling and screening requirements in phase 2 of the proposed cluster study process.	Apr 26-27	Technical Study Requirements				
Seattle City Light	City Light is encouraged by BPA's staff leaning to support the addition of co-located resource definition and the addition of the extra flexibility in the Material Modification evaluation procedures. City Light requests more details concerning both topics to allow for evaluation of the proposal.	Apr 26-27	Study Flexibility				
Seattle City Light	Transition Process City Light supports the BPA objectives for the transition process: 1. Advancing existing requests to connect generation in order to meet customer needs efficiently, and 2. Moving quickly to new reforms that could make the LGIP more efficient overall.	Apr 26-27	Transition Process				
Seattle City Light	City Light recommends BPA consider both objectives in view of the planned Transitional Serial Facility Study Process. BPA staff has expressed that BPA can only support completing up to 15 total interconnection facility studies per year. With 40 requests currently waiting for a facility study and the likelihood of 5 or more entities completing a facility study agreement prior to the transition deadline, the appearance is that it will be 3 full years before the existing requests in this later stage of development are completed. City Light believes this is not reflective of the BPA Objectives for the transition process or the goals and principles of the GI Reform process.	Apr 26-27	Transition Process				
Seattle City Light	**Facility Study Phase:** 1. Consider what resources BPA could acquire on a temporary basis to complete the Transitional Serial Facility Study Process in 1 year and to address those projects completing the Transitional Cluster Study Process within the following year. 2. Evaluate locations where facility interconnections can be consolidated to one facility. 3. Consider allowing design/build options in partnership with resource developers that meet or exceed BPA engineering standards for interconnection facilities. 4. Consider development internally or externally of a standard BPA interconnection modular substation design for 100MVA or less, 300MVA or less, and 500MVA or less for both 230kV and 500kV interconnection requests. This could apply to either generator interconnection or line/load interconnection requests	Apr 26-27	Transition Process				
Gallatin Power	**Readiness:** Gallatin values BPA's objective of "advancing existing requests to connect generation in order to meet customer needs efficiently and responsively" with the proposed Transition Process. With this objective, BPA is recognizing the time and monetary investments that have already been expended by those currently in the interconnection queue in addition to BPA employees' time and resources used on completed studies and studies in process.	Apr 26-27	Transition Process				

Gallatin Power	Gallatin believes that the Transition Process as currently proposed would disadvantage projects currently in the System Impact Study phase. BPA is proposing that only Late-Stage requests, defined as "an Interconnection Customer that has executed a Facilities Study Agreement," be offered the opportunity to either elect the Transition Serial Facility Study Process or opt into the Transition Cluster Study Process.	Apr 26-27	Transition Process				
Gallatin Power	**Queue Positions:** projects currently in the System Impact Study phase. BPA is proposing that only Late-Stage requests, defined as "an Interconnection Customer that has executed a Facilities Study Agreement," be offered the opportunity to either elect the Transition Serial Facility Study Process or opt into the Transition Cluster Study Process. Including projects in the System Impact Study phase would eliminate wasting the resources and time BPA has already expended on these requests, which under the effective tariff timeline would be well underway or past the Facility Study phase.	Apr 26-27	Transition Process				
Gallatin Power	Gallatin also disagrees with the proposed commercial readiness demonstration requirement of entering the Transition Serial Facility Study Process or the Transition Cluster Study Process. Throughout the workshops and comment periods of this proceeding, multiple stakeholders have stated that the requirement is inconsistent and disconnected from industry accepted project developmental and contracting timelines and practices. A project cannot enter into a binding term sheet or long-term sales contract without firm interconnection cost estimates from BPA.	Apr 26-27	Commercial Readiness				
Gallatin Power	Gallatin would also like to request that BPA clarify the proposed effective date for these proposed reforms and the "cut-off" date for projects to be eligible for the Transition Process.	Apr 26-27	Transition Process				
NIPPC	NIPPC continues to support BPA's decision to explore interconnection queue reform including a transition to a cluster study for generator interconnection.	Apr 26-27	General Comments				
NIPPC	NIPPC reiterates its earlier comments that the more complete and more accurate information customers have regarding the costs of interconnection at a specific location the better….Interconnection costs that developer can rely on…more accurate preliminary information BPA provided to customers is, less likely customers submit interconnection queue requests intended to ascertain interconnection cost. BPA to provide customers a broad range of tools to access better and more complete information about the grids and it constraints prior to application.	Apr 26-27	Network Costs				
NIPPC	**Increase Number of Studies:** BPA staff indicates that it is leaning towards its Alternative 3 – a two phased cluster study. BPA staff indicated that it is currently completing 15 studies annually. Any interconnection reform should plan on increasing the number of studies that can be completed.	Apr 26-27	First Ready First Served				
NIPPC	NIPPC agrees to provide customers with low barriers to enter the initial cluster study Phase 1) . It is not clear from the materials whether BPA intends to have a predictable cycle of interconnection processes (i.e. a standardized 18 month or 2 year cycle for interconnection cluster windows) or whether BPA intends to retain the flexibility to announce the next cluster study windows only after it completes an interconnection study cycle. NIPPC asks BPA to clarify its intentions with this regard. Depending upon how BPA answers this question, NIPPC's position on the topics below may change.	Apr 26-27	First Ready First Served				
NIPPC	**Timeline:** Timeline is too long…appears to take 2-3 years, even longer if studies are required. NIPPC members note that this proposed timeline in substantially longer than other interconnection reform processes that FERC has approved. (MISO's process is approximately 12 months; PJM's process is approximately 23 months; SPP's process is approximately 24 months)....longer timelines to complete study cycles may encourage speculative requests as market opportunities that may be available 5 years from now are more uncertain.	Apr 26-27	First Ready First Served				
NIPPC	**Timeline:** NIPPC suggests shortening the time for Validation and Cure, and Customer Engagement in Phase 1 and shortening the time for Validation and Cure in Phase 2. NIPPC believes customers and BPA could conduct Validation and Cure as interconnection requested are submitted...no need to wait after Cluster Study windows closes...Consider how much validation work can be done before close of cluster window.	Apr 26-27	First Ready First Served				
NIPPC	**Timeline: S**hortening the time for Calidation and Cure, NIPPC suggests that BPA could require the customer to submit the Study Deposit at the time of application (instead of during the Customer Engagement window) so that the deposit can be validated at the same time as the rest of the application. BPA should also consider establishing cluster areas before the Phase 1 cluster study and have scoping meetings for each cluster area to reduce the number of scoping meetings. BPA, if possible should overlap Facility Study and Environmental Study as much as possible, preferably beginning the Environmental Study as soon as facilities are identified in Facility Study.	Apr 26-27	Readiness Requirements				

NIPPC	**Timeline:** NIPPC asks BPA to consider the following...(not all members at NIPPC support this concept)...they prefer shorten timeline. Nevertheless, If BPA were to increase the time between the end of the Phase 1 Cluster Study and the start of the Phase 2 Cluster study, then generation developers could (in theory) incorporate the information from the Phase 1 study into their bids into Requests for Proposal and allow load serving entities to score those bids and develop their "short list" for resource acquisitions. Under this approach, there would be no commercial readiness requirements in the Phase 1 Cluster Study, and the interconnection customer could satisfy the commercial readiness requirements to participate in the Phase 2 Cluster Study by being included on the utility short list. See NIPPC presentation from April 21 workshop.	Apr 26-27	Readiness Requirements				
NIPPC	**Timeline:** Projects chosen for the short list would be able to use that as demonstration of "readiness" for purposes of qualifying for the Phase 2 study. NIPPC estimates that BPA would have to allow several months1 between the end of Phase 1 and the start of Phase 2 to allow sufficient time for the RFP scoring process to play out. NIPPC recognizes the limitations of this proposal. Second, building in a longer time to allow development of a short list would extend the time for the cycle to complete. NIPPC encourages BPA to adopt this optional and seek input from other stakeholders. BPA were to consider this proposal, BPA would likely need to make a firm commitment to conduct study cycles on a predictable and consistent timeline of opening a new cluster window every two years.	Apr 26-27	Readiness Requirements				
NIPPC	**Interconnection Review Process:** NIPPC encourages BPA to incorporate into its interconnection queue reform, specific options to allow customers the opportunity to modify their interconnection request to avoid or reduce the cost of upgrades...Specifically include information in it Phase 1 study reports, project fails screens for failure,...details about specific system threshold/limitation...to allow customer to redesign its project to avoid or mitigate upgrade costs...Phase 1 should provide developers enough data to modify their design eliminate or reduce the need for upgrades prior to the Phase 2 study process...BPA should allow customers propose design modifications without automatically submit a new interconnection application.	Apr 26-27	Readiness Requirements				
NIPPC	**Application Process:** BPA should consider allowing customers to submit alternative designs as part of its application, perhaps original design and two alternatives that address system constraints. If design modifications would require further study, BPA should consider 5 how it might address those additional studies through post-results modifications (i.e.explicit process for modifications after posting of study results rather than requiring a re-study of the entire cluster.	Apr 26-27	Readiness Requirements				
NIPPC	**Site Control:** NIPPC supports the requirement for customers to demonstrate site control at the time of the application. NIPPC requests that BPA provide the text of its proposed definition of site control so that customers can provide comment on the specific proposal.	Apr 26-27	Readiness Requirements				
NIPPC	**Site Control:** NIPPC also encourages BPA to offer customers the option to provide a deposit in lieu of a demonstration of 100% site control. NIPPC suggests allowing customers to satisfy the site control requirement to enter the Phase 1 Cluster by tendering a deposit of $250,000. In order to participate in Phase 2 Cluster studies, customers would have to demonstrate 100% site control.	Apr 26-27	Readiness Requirements				
NIPPC	NIPPC supports the proposal to require a demonstration of readiness in order for customers to continue into the Phase 2 Cluster. NIPPC also supports the proposal to allow a customer to make a deposit in order to demonstrate commercial readiness. NIPPC, however, suggests that BPA allow customers to establish commercial readiness through other mechanisms. For example, a customer who is able to satisfy commercial readiness through one of the other mechanisms laid out in Alternative #3 should be allowed to rely on that mechanism rather than put up an additional deposit.	Apr 26-27	Commercial Readiness				
NIPPC	NIPPC supports the proposal to allocate study costs based on MW.	Apr 26-27	Study Costs				
NIPPC	**Proportion of Capacity:** NIPPC understands BPA staff's concerns regarding use of a proportional impact method, but believe those concerns can be addressed or mitigated. NIPPC appreciates that BPA staff is not familiar with performing DFAX analyses given 6 staff's use of PSLF powerflow software. Using such software, NIPPC believes that proportional impact analyses could be performed using the Power Transfer Distribution Factor.	Apr 26-27	Network Upgrade Costs				
NIPPC	**Proportion of Capacity:** Second, NIPPC understands BPA staff's concerns that distribution factors represent only a single point in time, that the scenarios to assess them can be subject to interpretation, and that using multiple scenarios may lead to interconnection customers cherry-picking their most favorable result. However, these concerns have been addressed by other transmission providers. For example, MISO develops a predefined set of bench cases set forth in section 6.1 of Business Practice Manual-15. SPP uses similar methodology.	Apr 26-27	Network Upgrade Costs				
NIPPC	NIPPC supports Alternative #2 which would allocate the costs of Network Upgrades based on the proportionate impact of each project using an analysis of distribution factors. NIPPC believes that Alternative #2 is more consistent with cost allocation in that the customer projects that have the most impact on the need for Network Upgrades pay a higher share of the costs than projects that drive less need for Network Upgrades.	Apr 26-27	Network Upgrade Costs				

NIPPC	Under the BPA proposed methodology, there is little incentive for customers to do the up-front research and pick areas of the grid that would require less costly upgrades. Also, this proposal is not consistent with industry standards: CAISO, MISO, SPP, NYISO, PSCo, Tri-State, Duke, and Dominion all use the proportional impact method by performing a distribution factor analysis. NIPPC recognizes this approach may not be be the easiest to implement,...acknowledges concerns over transparency, potential disputes....Other utilities use this methodology without issue.	Apr 26-27	Network Upgrade Costs				
NIPPC	NIPPC suggests that BPA develop and post a consistent set of cases representative of system conditions that BPA will use to calculate distribution factors.	Apr 26-27	Network Upgrade Costs				
NIPPC	NIPPC's primary concern with BPA's proposal is that interconnection customers in later cycles will not be paying their fair share of Network Upgrade costs. While NIPPC recognizes the challenges BPA would have in developing a precise allocation of earlier Network Upgrade costs for customers in later study cycles, NIPPC does believe that BPA should consider whether there is a formula that would allow BPA to calculate a reasonable approximation of the costs that late coming customers should contribute to their share of Network Upgrade costs.	Apr 26-27	Shared Network Upgrades				
NIPPC	NIPPC supports the staff proposals to allow interconnection requests to add co-located resources without making a new interconnection request. NIPPC also supports proposal to incorporate extra flexibility in the evaluation of material modification.	Apr 26-27	Study Flexibility				
NIPPC	NIPPC requests that BPA provide specific dates and timelines for the transition process. While NIPPC recognizes that the timing and dates may change, BPA should provide a preliminary timeline for its proposed transition. Many NIPPC members have sought clarification on the question of when the cut-off date would be for customers to qualify for the transition studies, BPA should answer this question.	Apr 26-27	Transition Process				
NIPPC	NIPPC also requests that BPA describe how it will prioritize interconnection studies in the interconnection queue between now and the start of the formal transition mechanism. Some utilities have paused considering new interconnection applications as they pursue interconnection queue reform; while others have not. NIPPC members fall on both sides of this issue.	Apr 26-27	Transition Process				
NIPPC	NIPPC requests that BPA clarify whether it will pause accepting new interconnection applications and/or prioritize customer interconnections in the later stages of the process. Customers should have the opportunity to comment on this issue.	Apr 26-27	Transition Process				
NIPPC	NIPPC has concerns about the proposed requirement for customers to demonstrate commercial readiness in order to remain within the transition serial and transition cluster processes. Many members feel strongly that BPA should not require commercial readiness demonstrations as a condition of entering a transitional serial or cluster process.	Apr 26-27	Transition Process				
NIPPC	The proposed commercial readiness demonstrations are particularly ill-suited for projects entering a transitional cluster study. It is not commercially possible for a project to enter into a binding term sheet or contract at this stage in the development cycle without firm information regarding network upgrade costs.	Apr 26-27	Transition Process				
NIPPC	NIPPC recommends that BPA include a deposit mechanism to allow a late-stage project to remain in the transition process. Customers who have progressed through the interconnection process to the point of executing a Facilities Study Agreement have already invested significant resources into their project. If they are unable to meet one of the readiness milestones, these projects would be ineligible for the transition cluster. But given the level of investment in these projects, these customers would likely enter the first cluster study after the transition where they would be able to provide a deposit in lieu of meeting one of the other readiness milestones. There seems to be no logical reason to force these late stage projects out of the transition cluster if they will simply enter the first Phase 1 cluster study.	Apr 26-27	Transition Process				
NIPPC	**Transition Process:** NIPPC also requests that BPA expand the number of ways that customers can demonstrate commercial readiness in order to remain in the transitional process. Among the additional criteria that BPA could accept as evidence of commercial readiness are: • Site and substation design drawings 30% complete. • Submitted NEPA application. • Procurement plan for all generating facility equipment, consistent with expected in-service date, including updated lead time for equipment.	Apr 26-27	Commercial Readiness				
Pine Gate Renewables	Pine Gate Renewables, LLC ("Pine Gate") appreciates the opportunity to submit comments following the April 26-27 workshop hosted by Bonneville Power Administration ("BPA") in this proceeding. Pine Gate appreciates BPA staff's engagement with stakeholders on these important issues and willingness to modify certain of the proposed revisions. In particular, Pine Gate appreciates BPA's consideration of stakeholders feedback regarding the proposed commercial readiness demonstrations, which are inconsistent with the way renewable energy projects are financed, developed, and constructed. Pine Gate submits these comments to further address other topics discussed during the April 26-27 workshop.	Apr 26-27	TC-25 Process/Workshops				
Pine Gate Renewables	Pine Gate agrees with BPA staff that an efficient transition process is critical to implementing successful generator interconnection queue reforms. Pine Gate further appreciates that the backlog in the BPA generator interconnection queue is significant and that an expedient transition is necessary for the long-term viability of the BPA interconnection process.	Apr 26-27	Transition Process				

Pine Gate Renewables	Pine Gate does not support BPA staff’s proposed transition process. Specifically, the staff proposal would materially disadvantage projects in the System Impact Study (“SIS”) phase that have expended significant capital and resources with the reasonable expectation that they would remain in the current serial interconnection process.	Apr 26-27	Transition Process				
Pine Gate Renewables	Proposal for Transition: Projects in the SIS/Facility study phases that have little or no network upgrade cost allocations should be permitted to remain in the transition serial process and be processed according to the timelines set forth in BPA’s current tariff. PJM Interconnection, L.L.C. (“PJM”) included this “fast lane” mechanism in its recent generator interconnection queue reforms...BPA should consider a comparable “fast lane” mechanism based on either a specific dollar threshold or a determination that network upgrades are limited to the substation at the project’s point of interconnection.	Apr 26-27	Transition Process				
Pine Gate Renewables	Pine Gate has observed that a large driver of BPA’s queue backlog stems from the extensive environmental review associated with transmission line upgrades and greenfield site development. Bonneville should therefore consider prioritizing processing requests that do not require line upgrades or greenfield site development in an effort to clear the backlog of projects more efficiently.	Apr 26-27	Transition Process				
Pine Gate Renewables	BPA should consider prioritizing interconnection requests that are currently in the SIS or Facility Study phases. This would likely require a pause on processing requests from 2023 or later until BPA has made substantial progress processing the backlog. Again, PJM undertook similar measures in its recent queue reform proceeding in an effort to reduce the backlog of projects.	Apr 26-27	Transition Process				
Pine Gate Renewables	BPA should not require commercial readiness demonstrations as a condition of entering a transitional serial or cluster process. As numerous stakeholders have expressed in this proceeding, the proposed readiness demonstrations are inconsistent with industry-accepted timelines for developing, financing, and constructing generation projects. Furthermore, the proposed commercial readiness demonstrations are particularly ill-suited for projects entering a transitional cluster study. It is not commercially possible for a project to enter into a binding terms sheet or contract at this stage in the development cycle without more firm information regarding network upgrade costs. ...Pine Gate requests BPA clarify the proposed effective date is also the "cut off" date.	Apr 26-27	Commercial Readiness				
Pine Gate Renewables	Pine Gate strongly supports Alternative 2—the proportional impact approach. The proportional impact approach is the industry-accepted measure for allocating network upgrade costs caused by generator interconnection requests.	Apr 26-27	Network Cost Allocation				
Pine Gate Renewables	Conversely, Pine Gate opposes the proportional capacity approach (Alternative 1). Perhaps most significantly, the proportional capacity approach is inconsistent with FERC’s cost causation principle. Whereas the proportional impact method identifies the “cost causers” and beneficiaries of specific network upgrades, the proportional capacity approach simply assumes that large projects are disproportionately benefitting from network upgrades, even though that may not be the case.	Apr 26-27	Network Cost Allocation				
Pine Gate Renewables	Pine Gate understands BPA staff’s concerns regarding use of a proportional impact method, but believes those concerns can be addressed or mitigated. First, Pine Gate appreciates that BPA staff is not familiar with performing DFAX analyses given staff’s use of PSLF powerflow software. Using such software, Pine Gate believes that proportional impact analyses could be performed using the Power Transfer Distribution Factor.	Apr 26-27	Network Cost Allocation				
Pine Gate Renewables	**Cluster Study:** Pine Gate supports Alternative 3—the First Ready-First Served (“FR/FS”) cluster study approach. Pine Gate agrees with BPA staff that this approach provides customers with more useful information early in the process, particularly information pertaining to interconnection costs. This approach has been successful in MISO and SPP, and was recently approved by FERC in PJM.	Apr 26-27	First Ready First Served				
Pine Gate Renewables	Pine Gate is concerned regarding the proposed study timeline to LGIA execution, which would take up to 45 months. This is significantly longer than what interconnection customers expect in the current BPA serial process. It is also much longer than the timelines that have been implemented in other markets, PJM, MISO, SPP.	Apr 26-27	First Ready First Served				
Pine Gate Renewables	**Timeline:** Pine Gate offers the following suggestions for way to shorten the estimated timeline: • Require the Study Deposit at the point of application submission (as opposed to at the Customer Engagement window) so it can be reviewed at the time of the rest of the application. • Assign cluster areas before the Phase 1 cluster study and have scoping meetings for each cluster area to reduce the number of scoping meetings and so customers can be earlier informed about the cluster areas. • Shorten the Customer Review periods in Phases 1 and 2 from 1 month to two weeks. • Shorten Validation and Cure periods in Phase 2 and Facility Study from 2 months to 1 month. • If possible, overlap the Facility Study and Environmental Study (if one is required) as much as possible, preferably beginning Environmental Study as soon as facilities are identified in Facility Study.	Apr 26-27	First Ready First Served				

Pine Gate Renewables	**Cluster Study:** Pine Gate encourages BPA to explore ways in which it can overlaps cluster study processes, as is done in other markets. For example, in PJM, the Phase 1 process begins concurrently with the Phase 3 process for the previous cluster.5 Pine Gate also urges BPA to consider ways by which it can shorten the timelines for the Facilities Study phase. Given BPA's historical rate of processing 15 Facilities Studies per year and BPA's intent for the Facilities Study phase to remain serial, it is critical to find more efficiencies in how these studies are processed in order to prevent further backlogs.	Apr 26-27	First Ready First Served				
Pine Gate Renewables	**Project Downsize modifications:** Pine Gate recommends that BPA permit reductions at Phase 1 and Phase 2 to provide interconnection customers needed flexibility and allow them to right-size their projects to accommodate reasonable network upgrade cost allocations. For example, in MISO and PJM, reductions of up to 100% Maximum Facility Output ("MFO") are permitted at Phase 1 and reductions of 10% MFO are permitted at Phase 2.	Apr 26-27	First Ready First Served				
Pine Gate Renewables	**Heat Map:** Pine Gate supports BPA's proposal to perform a two phased cluster study approach and provide a publicly available interconnection capacity heat map. That said, Pine Gate recognizes that BPA faces constrained resources. For this reason, Pine Gate recommends that BPA prioritize allocating resources to ensuring timely and accurate completion of the cluster study processes, as opposed to interconnection information access.	Apr 26-27	Interconnection Information Access				
Pine Gate Renewables	The proposed heat map would provide utility to interconnection customer, particularly if it is updated on a regular basis. Pine Gate recommends that BPA publish new data after Phase 1 and Phase 2 study results are posted. As contemplated in the NOPR, such information should include estimated incremental injection capacity (in MW) available at each bus under N-1 conditions as well as a table of results showing the estimated impact of the addition of a proposed project.6 6 See	Apr 26-27	Interconnection Information Access				
Pine Gate Renewables	Pine Gate supports the second modified alternative solution put forth by BPA staff that would require generators to submit detailed models within 30 days of receipt of the Phase 1 Cluster Study. Pine Gate also supports BPA's proposal to require dynamic models, which is consistent with standard practices in other markets. Pine Gate agrees with BPA that it is not appropriate to require Electromagnetic Transient ("EMT") models at initial application. Such models should be provided by the interconnection customer on an as-needed basis or, alternatively, at a later study stage. Furthermore, Pine Gate notes that BPA should provide interconnection customers prior notice of when an EMT model will be required given that such models often take a month or more to procure.	Apr 26-27	Modeling Requirements				
RNW	Renewable Northwest ("RNW") appreciates the opportunity to submit comments to the Bonneville Power Administration ("Bonneville") concerning the TC-25 workshops held on April 26 and 27, 2023 ("April Workshops"),1 where Bonneville explained its initial leanings with respect to potential interconnection queue reforms. The April Workshops provided a sense of where Bonneville is headed, but it is still difficult to ascertain whether the overall reform package provides a workable solution to the problems Bonneville is trying to address. RNW looks forward to continued discussions and offers some high-level feedback on the topics discussed at the April Workshops.	Apr 26-27	TC-25 Process/Workshops				
RNW	**Tie-Breaker:** Bonneville's Phased Approach Appears to be Generally Workable, But the "Tie-Breaker" Concept Needs Additional Development. RNW cannot support Bonneville's proposal to use a readiness tie breaker without additional details. As Bonneville explained, the agency may use the time stamp from the demonstration of readiness requirements as a tie breaker "priority" demonstration to allow some projects within a sub-cluster to move forward more quickly.3	Apr 26-27	First Ready First Served				
RNW	**Tie-Breaker:** RNW applauds Bonneville's creativity but is concerned that this concept may undercut the purpose of clustering projects in the first place. Allowing some projects to go forward with minimal upgrades may ultimately be the best approach, but Bonneville needs to provide more details on sub-clustering and how cost allocation would be handled. Readiness requirements are discussed in more detail below, but RNW will simply note here that this tie breaker concept would have dramatically different practical implications is applied to the transition queues. At a minimum, Bonneville needs to clarify whether the tie breakers will be used in the transition process.	Apr 26-27	First Ready First Served				
RNW	Network Upgrades Should be Allocated on Proportional Impact Rather Than Proportional Capacity. Bonneville's leaning to allocate network costs based on proportional capacity appears inconsistent with cost causation. At the Workshop, Bonneville explained its leaning to allocate station equipment costs per capita (i.e., based on the number of generating facilities interconnecting to an individual station) while transmission and distribution upgrades would be allocated based on proportional capacity of each facility in the cluster.4 RNW is unconvinced...BPA must explain why allocating costs by proportional capacity better aligns...and how PacifiCorp and Avista's approach is more consistent with the industry	Apr 26-27	Network Upgrade Costs				

RNW	Immediately Requiring Strict Site Control May Go Too Far. Bonneville's preference to require strict site control over allowing a deposit in lieu of site control to enter the Phase 1 Cluster Study will have a dramatic impact on queue eligibility. By contrast, the FERC NOPR would initially allow a deposit in lieu for projects with regulatory delays and then require a strict site control showing by the facilities study stage.7	Apr 26-27	Site Control				
RNW	RNW filed comments arguing in favor of a deposit in lieu for any reason, consistent with Bonneville's current practice and other FERC-approved tariffs.10 RNW now asks for more clarity about what will be required to demonstrate site control.	Apr 26-27	Site Control				
RNW	Should Bonneville continue to advocate for a strict site control requirement before the initial cluster study, the agency should provide some indication of how many projects will be expected to proceed from the current queue as compared to those that will be forced out. Without a sense of magnitude, it is difficult for RNW to provide support for this alternative.	Apr 26-27	Site Control				
RNW	Commercial Readiness Works for the Normal Cluster Process, But Will Unnecessarily Clear Out the Transition Queues. Bonneville's leaning to have no commercial readiness requirement for the Phase 1 Cluster Study and a financial commercial readiness requirement prior to entering the Phase 2 Cluster Study strikes a good balance.13...RNW finds this approach reasonable, but does not believe that Bonneville has fully justified the need for a financial-only option for demonstrating commercial readiness. RNW asks Bonneville to explain when and how amounts would or would not be fully refundable and whether putting commercial readiness money at-risk is warranted to spare BPA staff time determining the sufficiency of the commercial readiness demonstration. A better option would be to permit either a commercial readiness demonstration or pay the commercial readiness amounts proposed by Bonneville.	Apr 26-27	Commercial Readiness				
RNW	RNW reiterates its previous comments that requiring a sale agreement or resource plan selection is discriminatory towards independent power producers ("IPPs") that need to obtain interconnection costs before they are able to contract.16	Apr 26-27	Transition Process				
RNW	It is fundamentally unfair for Bonneville to add commercial readiness criteria as a requirement to proceed under the proposed transition process since Bonneville's delays are the reason so many active interconnection requests do not have completed facilities studies and therefore cannot secure a sale agreement or power purchase agreement. Bonneville may have added the site-specific equipment purchase order criteria to address these inequities, but RNW asks the agency to re-think this requirement...but Bonneville's leaning appears inefficient, not to mention inequitable.	Apr 26-27	Commercial Readiness				
RNW	**Queue Requests:** RNW again asks Bonneville to provide some indication as to how many of the current queue requests it anticipates will be allowed to proceed in the transition processes as compared to those forced out due to the non-financial commercial readiness criteria. RNW also asks Bonneville to better describe its rationale for the different commercial readiness standards and what the agency envisions will be the practical result of this proposal.	Apr 26-27	Commercial Readiness				
RNW	**Modeling Requirements:** Bonneville Should Begin Discussions on Affected System Study Requirements and Include the Application of Grid Enhancing Technologies as an Alternative to Major System Upgrades. If Bonneville is not going to include modeling requirements in its tariff, it should immediately begin a separate public process to update its modeling requirements with stakeholders.	Apr 26-27	Study Costs				
RNW	Queue Backlog: Bonneville Should Address How Staffing Issues May Have Impacted the Queue Backlog and Inform Stakeholders About How the Agency is Addressing Them. RNW appreciates the very brief discussion at the Workshop about issues with adequately staffing transmission engineers. While the TC-25 process reforms should help address Bonneville's current interconnection backlog and study delays, RNW is not convinced that process reforms alone will solve the current interconnection queue problem.	Apr 26-27	Study Requirements				
Savion	BPA's Generation Interconnection ("GI") study process must be designed to drive appropriate Interconnection Customer ("IC") behavior Must contain criteria discouraging speculative entry including: Meaningful site control requirements Sizable financial deposits that indicate "commitment" Clear data requirements Must be structured to minimize late-stage withdrawals	Apr 26-27	Study Process				
Savion	Savion is hesitant to model reforms after FERC NOPR, as they have not been implemented and are subject to material changes. Savion does not recommend this approach FERC NOPR have not implemented. Savion suggests BPA adopt a FERC approved First Ready First Served (FRFS) cluster study process akin to SPP's 3-stage DISIS process or MISO's 3-stage DPP process	Apr 26-27	First Ready First Served				
Savion	Savion suggests BPA adopt a FERC approved First Ready First Served (FRFS)cluster study process akin to SPP's 3-stage DISIS process. Alternatives to FRFR Processes is MISO's 3-stage DPP	Apr 26-27	First Ready First Served				

Savion	**Savion recommends** - Data Exchange Robust information exchange is important for both TPs and ICs. It allows TPs to better perform studies in a timely manner and it allows ICs to make informed decisions. At GI application, ICs should provide full detailed project model data including manufacturers' transient stability models, harmonics and short circuit data. If BPA intends to pursue EMTP studies, BPA should perform a system strength screening analysis and notify ICs at the initial kick-off call if they are required to provide plant specific EMTP data. ICs should provide the required data prior to the kick-off of the Phase 2 study. BPA should provide study model data to ICs early and often. This includes base case, study case and all input files (e.g., scripts, exclude files, topology changes, mon/con files). BPA should consider developing a GI queue dashboard comparable to what SPP and MISO have developed.	Apr 26-27	First Ready First Served				
Savion	**Study Deposits:** study cost correlated Should be sized to no more than 2X expected study cost ($300k max) Should be a single up-front payment to avoid accounting "gymnastics" Amounts not spent should be refundable **Security Deposits: upgrade cost correlated** Initial security (FS1) of $4k per MW Subsequent security amounts, FS2 and FS3, should be tied to NU cost allocation (i.e., cost-causer construct) Decision Point 1: FS2 = (10% x Total GI Cost Allocation) - FS1 100% of FS1 become "at-risk" at conclusion of DP1 Decision Point 2: FS3 = (20% x Total GI Cost Allocation) - (FS2 + FS1) 100% of FS1+FS2+FS3 become "at-risk" at conclusion of DP2	Apr 26-27	Readiness Requirements				
Savion	**Site Control:** Parameters: Wind: 30 acres / MW Solar: 6 acres / MW Battery: 0.1 acre / MW New POI: As specified by BPA At Application: 100% of gen facility + 50% gen-tie ROW In-Lieu-of-Payment: $100k/mile for entire gen-tie length with 50% nonrefundable. Refundable portion only refunded if site control is attained prior to withdrawal. At DP1: Continued evidence of site control At DP2: 100% of gen facility + 75% gen-tie ROW At IA execution: 100% of gen facility, gen-tie ROW and POI (if necessary) Exceptions should be incorporated where the IC is working in good faith with a government authority to secure site control.	Apr 26-27	Readiness Requirements				
Savion	We believe CRMs do not meaningfully protect against 3rd parties who may seek to exercise leverage via their continued participation in the contracts employed to meet the CRM. Requiring ICs to post some amount of at-risk financial security is a better gauge of an IC's belief in their project's viability. If BPA chooses to incorporate CRMs in its queue reform: Offtake agreements with C&I customers, Load Serving Entities, and Load Responsible Entities should all be eligible CRM venues. CRMs should be an additional option for study advancement, not the only option.	Apr 26-27	Commercial Readiness				
Savion	**Allocation of Study Costs:** Savion recommends Alternative 4 as the best approach - dividing study cost evenly across all GI requests. Savion's 2nd choice would be Alternative 2 - allocating study costs 50:50 according to 1) pro rata MWs, and 2) the number of requests. Savion opposes Alternative 3 - study costs should not be allocated purely on a pro rata MW basis, as this wrongly implies that larger GI requests always require more work hours to study than small GI requests. Poorly sighted small projects can trigger massive upgrades, including stability upgrades, whereas a well sighted large project may have minimal impact to heavily loaded elements. In any case, BPA must define how it will apply study costs for hybrid and co-located "non-additive" GI requests (i.e., Will calculation be based on MW impact at POI or nameplate MW?).	Apr 26-27	Study Financials Cost Allocation				

Savion	**Penalty Free Withdrawal:** At DP1 (FS1 posted previously, FS2 to be posted): FS1 payment is fully refundable if IC withdraws prior to end of DP1 FS1 becomes at-risk upon DP1 conclusion At DP2 (FS1 & FS2 posted previously, FS3 to be posted): FS2 payment is fully refundable if IC withdraws prior to end of DP2 FS2+FS3 become at-risk upon DP2 conclusion FS1 is refundable upon IC withdrawal if Phase 2 upgrade cost increases 25% or more AND increases by at least $10k/MW compared to Phase 1 upgrade cost At FacS Completion (FS1, FS2 & FS3 have all been posted): FS1+FS2+FS3 are refundable if upgrade cost increases 35% or more AND increases by at least $15k/MW compared to Phase 2 FS1+FS2+FS3 are refundable if upgrade cost increases 50% or more and increases by at least $20k/MW compared to Phase 1 In all withdrawal situations, if such withdrawal results in no cost allocation increases to other equally queued ICs, the withdrawing IC is reimbursed 100% of all FS payments as no harm has occurred.	Apr 26-27	Study Financials Cost Allocation				
Savion	**Cost Allocation of Shared Upgrades:** Cost allocation should follow FERC's cost-causation principles and should be closely correlated to the impact an IC's project has on the power system Steady-State Thermal Upgrades: Assign cost allocation via MW-Impact method using TDF Steady-State Voltage Upgrades: Assign cost allocation on per project voltage degradation Transient Stability Upgrades: Assign cost allocation on a pro-rata MW basis across all ICs contributing to the violation Communications Upgrades (e.g., fiber): Assign cost equally across all ICs benefitting from the upgrade	Apr 26-27	Study Financials Cost Allocation				
Savion	**Transitional Study:** A Transitional Study program is necessary to address BPA's GI queue backlog currently far exceeding system capacity We believe this can be accomplished by allowing ICs that have executed Facility Study Agreements to have the opportunity to advance to a LGIA by participating in a cluster study that is exclusive to them. The remaining ICs in BPA's GI queue that have not completed a System Impact Study could also advance to a LGIA by participating in a subsequent cluster study What might this look like? BPA's Transitional Study Alternatives Savion supports Alt 1: FERC NOPR – Transitional Cluster Savion rejects Alt 2: BPA Staff Proposal – FRFS Hybrid Transitional Process due to: Commercial Readiness Requirements concerns Drawbacks to serial study process (and the continued implication on both transitional projects and future projects)	Apr 26-27	Transition Process				
Savion	**ICs currently in Facility Study** AND meet the below criteria would qualify for an exclusive cluster study: To enter the Cluster Study: ICs must provide evidence demonstrating 100% of site control and gen-tie ROW for at least one year beyond the to-be-announced Transition Date ICs may lower project size to align with site control ICs must post Financial Security that is the greater of $5M or 20% of interconnection costs allocated in the SIS To proceed to GIA execution following Cluster Study completion: The same 100% site control should extend through the Project COD A Decision Point should be employed at the end of the Cluster Study whereby the IC must withdraw or place their financial security fully at-risk to execute a GIA	Apr 26-27	Transition Process				
Savion	**ICs currently in System Impact Study or earlier** and which meet the below criteria would qualify for another secondary cluster study. Criteria for the Secondary Cluster Study: ICs must provide evidence showing 100% control of the development site and 50% control of gen-tie ROW for at least one year beyond the to-be-announced Transition Date. ICs may lower project size to align with site control. ICs must post $4k/MW Financial Security. The Secondary Cluster Study process would then follow the typical study process outlined on slide 10	Apr 26-27	Transition Process				
wpd wind projects	wpd looks forward to working with BPA as it considers reasonable and effective queue reform and appreciates having an opportunity to participate and comment. Below are specific recommendations/alternatives for BPA to consider, regarding Staff leanings.	Apr 26-27	TC-25 Process/Workshops				

wpd wind projects	**Assigning Cluster Areas and POI:** Regarding BPA’s leaning to reserve the right to assign a Point of Interconnection (POI) to the customer after the cluster has been determined: **wpd recommendation:** wpd recommends that there be a preliminary review process whereby a potential interconnection customer can collaborate with BPA to determine the best, or at least mutually agreeable, POI for a given project. The results of this collaboration would enshrine that POI as an acceptable POI location to BPA. With this, a project developer can proceed with development, studies, easements knowing that the agreed upon POI would be acceptable when the customer eventually submits the interconnection application.	Apr 26-27	Point of Interconnection				
wpd wind projects	**Assigning Cluster Areas and POI:** wpd reasoning: The stated purpose of this queue reform is to reduce the number of “speculative” interconnection applications and to advance late-stage projects. As the POI (with associated gen-tie) is a critical component of any project, a project developer must make great efforts at great cost to ensure that the gen-tie and POI is feasible. If BPA unilaterally assigns an alternate POI at a project’s late-stage development, it may be in a location not feasible for the project to access for any number of reasons – including but not limited to, environmental/biological considerations, landowner interest along gen-tie, and cost or engineering feasibility. This adds unreasonable risk to a project as the developer cannot be sure of the POI until development has progressed enough to submit the interconnection application.	Apr 26-27	Point of Interconnection				
wpd wind projects	**Reduction of MW injection at POI after study results** Staff leaning: BPA has noted that it is evaluating allowing a decrease to project size (MW injection at POI). **wpd recommendation:** Wpd recommends that BPA provide opportunities for an interconnection applicant to reduce MW injection at the POI prior to continuing to the next study Phase (likely during the Validation and Cure period). Example reduction allowances can be found in many FERC approved tariffs; one recommendation (Tennessee Valley Authority) allows for a 60% decrease prior to proceeding to System Impact Study (Phase 2) then an additional 15% decrease prior to proceeding to Facilities Study (Phase 3).	Apr 26-27	Point of Interconnection				
wpd wind projects	**Unique commercial readiness requirements for late-stage queued projects.** Staff leaning: BPA has proposed to introduce new and unique commercial readiness requirements for existing queued projects that have executed Facilities Study Agreements (but where the Facility Study is in process and not yet received from BPA). These new requirements would retroactively require projects to achieve one of the following milestones in order to continue through the study process...If a project cannot demonstrate such milestones, then the project forced to withdrawal. **wpd recommendation:** wpd recommends that BPA not retroactively apply new commercial readiness requirements for currently queued projects with existing executed Facilities Study Agreements (transitional/late-stage projects). Wpd recommends that any late stage queued project be processed consistent with the existing signed Facilities Study Agreement and associated tariff process.	Apr 26-27	Commercial Readiness				
wpd wind projects	**Unique commercial readiness requirements for late-stage queued projects.** **wpd reasoning:** It is unreasonable to force changes to the terms of the executed Facilities Study Agreement(s). Late-stage projects that have executed Facilities Study Agreements have made planning and commercial decisions based on the expectation of the fulfillment of their Agreements. The proposed commercial readiness milestones are entirely infeasible for an interconnection customer to achieve within the proposed timeframe, requiring compliance to be achieved in less than one year from now. The proposed milestones are out of synch with the normal process of associated industries, whose collaboration is necessary to align to achieve any of these new and unique proposed milestones (financial risk associated with lending, offtake, procurement, etc). Requiring these milestones of late-stage queued project may force the withdrawal of many projects that have already undergone a significant and costly development effort.	Apr 26-27	Commercial Readiness				

#	Stakeholder	Comment/Question	Workshop	Topic	SMEs Assigned to Respond	Response Type: Written or Workshop	Status of Response	Initial thoughts/comments
297	Clearway Energy Group	**Scalable Plans** In general, Clearway supports the concept of scalable plans, although more work is needed to clarify this proposal. It would be helpful for stakeholders to see detailed language, along with an example, to describe how BPA will implement the scalable block plan.	25-May	Scalable Block Plans	Christina			The detailed language will be in a business practice. We have not developed this detailed language yet.
298	Clearway Energy Group	**Scalable Plans** BPA should find an alternative to the time-stamp approach proposed to assign priority in a tie-breaker situation. o A customer with a time stamp of a few hours later than another customer is no less 'ready' in the development process for a large-scale project with a multi-year development timeline, and it would not be reasonable for this customer to be assigned a block of upgrades with a later in-service date or higher cost. Given that the cluster window 'validation and cure' period would be open for only 45 days per BPA's proposal, it is unlikely that there would be any meaningful differences in projects' readiness between the first and last day of the window. o The proposal is not clear on whether the time stamp would be based on when a project first submits documentation meeting the readiness requirement, or when all deficiencies have been cured. If the time stamp is based on initial submittal, this would lead to a race by interconnection customers to submit documentation during the first minutes or hours of the cluster open window. o If the time stamp is based on an application being deemed complete with any deficiencies cured, this would impose a burden on BPA staff to communicate deficiencies to customers at the exact same time and with the same level of clarity. This would lead to less transparency and can raise questions about validity of such time stamps.	25-May	Scalable Block Plans	Christina			Good points and still working out these implementation details. We primarily need a means for stacking - don't necessarily care what that is.
299	Clearway Energy Group	**Scalable Plans** Rather than a time stamp, Clearway encourages BPA staff to consider prioritization based on degrees of project readiness. For example, the ranking system used by the CAISO in its annual Transmission Plan Deliverability (TPD) allocation process assigns projects to one of four groups based on progress toward readiness milestones, and deliverability is allocated to the most "ready" projects first.	25-May	Scalable Block Plans	Christina			This could be a good approach. Need to look into it further.
316	Seattle City Light	City Light appreciates BPA giving an example and details on implementing scalable plans with a readiness queue of cluster participants. City Light suggests BPA consider how to be transparent applying the planned readiness time stamp. Without the clear ability to consistently implement time stamping across all customers, BPA may need to retain the current queueing order for the purposes of defining scalable plans.	25-May	Scalable Block Plans	Christina			
320	NIPPC	NIPPC generally supports the concept of scalable block plans for locations with high levels of interconnection customer interests. NIPPC looks forward to reviewing **more detailed language describing how BPA will determine that a scalable block plan is appropriate for a location, how BPA will allocate costs within each block, and how BPA will treat project modifications and customer withdrawals within each block.**	25-May	Scalable Block Plans	Christina			Will use knowledge of the system and study results based on the requests in the area. Cost allocation proposal is proportional capacity and that would be applicable to each Scalable Plan Block. Modifications such as reduction in size or withdrawals could result in restacking (but ideally not re-studying)
338	Public Power Council	PPC understands the importance of concluding the TC-25 proceedings in advance of TC-26 initial workshops. At the same time, the abbreviated TC-25 workshop schedule has left outstanding questions and not left as much time for stakeholder engagement – both among the stakeholder community and with BPA – which would be helpful to ensure that issues are thoroughly vetted. We understand that other stakeholders are considering this, as well, and we look forward to proposals on how a short extension may allow additional time for BPA and customers to discuss these critical topics. Additional time for discussion and a more holistic description of BPA's proposal would be very helpful in assisting customers on whether they should support the proposed approach. Specifically, PPC seeks the following: • Additional information from BPA on how the TC-25 process fits in with upcoming or potential future processes to improve BPA's Line and Load Interconnection Process and TSEP. This should include a discussion on how various "transition" approaches may impact BPA's approach to a holistic review of BPA's transmission planning and execution efforts. • A more comprehensive discussion on how BPA's proposal will impact staff workload, including how BPA is ensuring that it will not impact other related processes. • BPA should provide a timeline for any transitional plans and commitments towards meeting its goals. • A comparison between today's policy and BPA's proposal that highlights: o What information is required from the customer and when to advance to the next study stage. o What financial obligations customers have to move through phases of the study process. o What information BPA is providing to customers to inform their decisions. o **When customers are required to make decisions about moving forward through the study process, and what information they have to inform that decision.** (This would be particularly helpful in understanding BPA's scalable plan approach)	25-May	Miscellaneous - GI Policy	Tammie			This (as it relates to scalable plans) depends on what time stamp ends up being used and the determination of that has not yet been finalized. In general though, customers need to decide by the end of the customer review period if they are going to move forward to the next study phase. After Phase 1 they will have high level costs for each of the blocks (if applicable) and at the end of Phase 2 they will have an estimate of their network cost allocation.
340	Public Power Council	PPC strongly supports the concept of the "scalable plan," but has questions around how it would be implemented. As raised above, additional clarity on what information customers have when they are making decisions would be helpful (for example, do they have to pay for the next phase of study before they know if they are in scalable plan 1 vs. scalable plan 2?) It would also be helpful to understand how the time stamping of "priority" occurs. It is unclear how that process is conducted and whether there are aspects related to the manual implementation of this process that could unintentionally disadvantage customers. If BPA cannot demonstrate that the time stamping can be implemented consistently across all customers, then it may need to retain current queueing order for the purposes of defining scalable plans.	25-May	Scalable Block Plans	Christina			Customers will receive Phase One Cluster Study Results which will identify scalable plan blocks (if applicable to the Cluster Area being studied) and high level cost esimates for the plans of service associated with each block. They can make allowable modifications such as reducing by 60% between Phase 1 and 2 Cluster Studies. Then they pay for and move into Phase 2. At the end of Phase 2 they find out more info about which block they are in and the costs they will be allocated. Between Phase 2 Cluster Study and FAS, they can reduce by another 15%. We are still determining which time stamp to use.
346	Renewable NW	*Bonneville's Proposal to Allow Scalable Plan Blocks Needs Additional Consideration* RNW appreciates the clarifications Bonneville provided regarding subclustering but urges Bonneville to provide a more **comprehensive explanation** of its intention before releasing tariff redlines on June 9, 2023. In addition to providing a written explanation as to how cost allocation would work, Bonneville should confirm when (and how) the timing of subclustering decisions would be made to ensure its current proposal includes sufficient time to allow for these internal decision points. For example, when will customers decide whether to move forward with a smaller interconnection service plan and/or whether other customers have agreed to fund a larger interconnection service plan? How will those decisions affect cost allocation estimates and/or Bonneville's ability to move the cluster study forward?	25-May	Scalable Block Plans	Christina			The tariff will not include the details of the scalable approach. The proposed language is written in a way that will not inhibit us from developing scalable plans where necessary, but detailed language will reside in a BP. Customers will receive Phase One Cluster Study Results which will identify scalable plan blocks (if applicable to the Cluster Area being studied) and high level cost esimates for the plans of service associated with each block. They can make allowable modifications such as reducing by 60% between Phase 1 and 2 Cluster Studies. Then they pay for and move into Phase 2. At the end of Phase 2 they find out more info about which block they are in and the costs they will be allocated. Between Phase 2 Cluster Study and FAS, they can reduce by another 15%.
355	NewSun Energy	Support Sub-Cluster Approach with Scalable Block Approach subject to (1) senioritybased queue application, to provide clarity on allocation of existing capacity, benefits of incremental upgrades, and cost responsibility for applicable traunches of current and future upgrades (as per current practices; and, as further discussed below in "Changes Recommended"); and (2) BPA's (as per current practices) study approach to identify all primary MW breakpoints. This is our top concern and recommendation for viability and efficacy of GI Reforms.	25-May	Scalable Block Plans	Christina			Trying to base it off of "readiness priority" but final determination on time stamp is TBD.

#	Stakeholder	Comment/Question	Workshop	Topic	SMEs Assigned to Respond	Response Type: Written or Workshop	Status of Response
293	Clearway Energy Group	**Site Control** Clearway would support the BPA staff proposal to require 100% site control at Phase 1 only if there is also an option to provide a deposit in lieu of site control at Phase 1. Clearway supports requiring 100% site control at the Phase 2 stage. In the event that BPA requires site control at Phase 1 without allowing an in-lieu deposit, then Clearway recommends that the Phase 1 requirement be set at 50% site control, following the model used by the CAISO and Public Service Company of Colorado (PSCo), among others. Acreage per MW: Clearway shares the same view as BPA staff that these numbers should not be written into tariff language, but should instead be part of BPA's Business Practices to allow for easier updates. Future technology changes and design efficiencies will enable projects to accommodate the same MW in less acreage, and all parties' interests are served in making these numbers easy to update. Additionally, such numbers must be advisory rather than strict requirements. If a customer can show documentation that given MWs in fact can be accommodated in lesser acreage, this documentation should satisfy the requirement.	25-May	Readiness Requirements	Kevlyn		
294	Clearway Energy Group	**Commercial Readiness** Clearway notes that the commercial readiness requirements for the transition cluster are more stringent than the requirements that will apply to the cluster post-transition – that is, projects in the transition cluster will be required to demonstrate commercial readiness at a significantly earlier stage than projects in the subsequent cluster. This puts an unreasonable burden on customers that have already entered the queue and are experiencing delays in the interconnection process. Clearway recommends matching commercial readiness for the transition cluster to the requirements that BPA staff is proposing for subsequent clusters, including the option for an in-lieu deposit.	25-May	Transition	Katie		
295	Clearway Energy Group	**Commercial Readiness** Clearway also encourages BPA to consider allowing a Transmission Service Agreement (TSA) to serve as a demonstration of commercial readiness, since a project that has an executed TSA has made a significant investment in future development that is comparable to the other readiness milestones proposed by BPA. This would require the timing for the TSEP process with the interconnection process, so that TSAs would be offered before the commercial readiness demonstration is required.	25-May	Readiness Requirements	Kevlyn		
296	Clearway Energy Group	**Commercial Readiness** Clearway supports the proposal to require a commitment of 20% of network upgrade cost at the time of the facility study; a surety bond or parent guarantee from a creditworthy entity should also be allowed as options for this financial commitment.	25-May	Readiness Requirements	Kevlyn		
297	Clearway Energy Group	**Scalable Plans** In general, Clearway supports the concept of scalable plans, although more work is needed to clarify this proposal. It would be helpful for stakeholders to see detailed language, along with an example, to describe how BPA will implement the scalable block plan.	25-May	Scalable Block Plans	Christina		
298	Clearway Energy Group	**Scalable Plans** BPA should find an alternative to the time-stamp approach proposed to assign priority in a tie-breaker situation. o A customer with a time stamp of a few hours later than another customer is no less 'ready' in the development process for a large-scale project with a multi-year development timeline, and it would not be reasonable for this customer to be assigned a block of upgrades with a later in-service date or higher cost. Given that the cluster window 'validation and cure' period would be open for only 45 days per BPA's proposal, it is unlikely that there would be any meaningful differences in projects' readiness between the first and last day of the window. o The proposal is not clear on whether the time stamp would be based on when a project first submits documentation meeting the readiness requirement, or when all deficiencies have been cured. If the time stamp is based on initial submittal, this would lead to a race by interconnection customers to submit documentation during the first minutes or hours of the cluster open window. o If the time stamp is based on an application being deemed complete with any deficiencies cured, this would impose a burden on BPA staff to communicate deficiencies to customers at the exact same time and with the same level of clarity. This would lead to less transparency and can raise questions about validity of such time stamps.	25-May	Scalable Block Plans	Christina		
299	Clearway Energy Group	**Scalable Plans** Rather than a time stamp, Clearway encourages BPA staff to consider prioritization based on degrees of project readiness. For example, the ranking system used by the CAISO in its annual Transmission Plan Deliverability (TPD) allocation process assigns projects to one of four groups based on progress toward readiness milestones, and deliverability is allocated to the most "ready" projects first.	25-May	Scalable Block Plans	Christina		
300	Clearway Energy Group	Clearway opposes the proposal to stop paying interest on study deposits. This queue reform appears to be heading toward requiring much larger deposits than are required from interconnection customers today. Clearway echoes the concerns and suggestions raised by NIPPC and Renewable Northwest in their comments. It would be reasonable – and would not create costs for any other BPA customers – for study deposits to be placed in an interest-bearing account and paid back with interest.	25-May	Study Financials	Rebecca		
301	Clearway Energy Group	The study deposit should be sized to cover actual study activity costs. This has little correlation to the MW size of the project: A 50 MW and a 500 MW generator request will require BPA to do the same amount of study work. Clearway recommends increasing the study deposit to $150k or $250k upfront, modeled on the CAISO study deposits. A one-time sizeable deposit would provide more certainty of projected expenses during the study process and will also reduce burden on BPA and customer's accounting team.	25-May	Readiness Requirements	Kevlyn		
302	Clearway Energy Group	Clearway recommends allocating 100% of the cluster study costs by the number of customers participating in the cluster study. The MW size of the project should not be used to determine study cost, as it has little correlation to the study work and therefore cost responsibility.	25-May	Study Financials	Rebecca		
303	Clearway Energy Group	The cost of station equipment network upgrades should be allocated equally based on the number of Generating Facilities interconnecting at an individual station. Transmission and distribution network upgrade costs should be assigned based on MW impact and Transfer Distribution Factors (TDF/DFAx), following the logic of cost causation.	25-May	Network Costs	Rebecca		
304	Clearway Energy Group	Implementing a site control requirement for the transition cluster will create a challenge for projects in the queue that have some site control but not the full 50% or 100% that is required. Clearway suggests offering a downsizing opportunity for projects entering the transitional cluster, allowing a customer to downsize the project MWs to match the reduced area. This possibility was mentioned during the most recent stakeholder meeting but has not yet appeared in a written proposal.	25-May	Transition	Katie		
305	Clearway Energy Group	In a case where multiple projects are connecting to the same transmission line as a Point of Interconnection (POI), BPA should clarify the exact location on the transmission line that will be considered as the final POI for study purposes. Clearway recommends that this information be made available during the Customer Engagement window and not at the end of the Phase 1 cluster study. The time in between would allow customers to better plan for their gen-tie route and land permits.	25-May	Technical Study Requirements	Cherilyln/Christina		
306	Cypress Creek Renewables	*BPA's proposed site control requirement and study deposits and security payments based on those deposits are too low and will not incentivize 'first ready' projects* Regarding site control, a requirement that the generating facility demonstrate site control for both 75% of the generating facility and 50% of the Generator Tie (Gen Tie) would represent a more meaningful demonstration of readiness than BPA's staff proposal that 100% of the generating facility be secured at interconnection application. This is because the Gen Tie can only occur via a limited number of paths to pre identified points of interconnection (typically identified through injection capacity analyses and other analyses), whereas developers have much more flexibility as to the project configuration on the site itself.	25-May	Readiness Requirements	Kevlyn		
307	Cypress Creek Renewables	*BPA's proposed site control requirement and study deposits and security payments based on those deposits are too low and will not incentivize 'first ready' projects* BPA's proposed financial and security payments are far below requirements in place in other utilities and RTOs, and will not be sufficient to deter more 'speculative' projects from entering the initial phase. We recommend the following in prior comments: o Initial Security of $6,000/MW to enter Phase I o Subsequent security amounts of network upgrade cost allocation, ie, 10% of cost allocation to enter Phase II, and 20% of cost allocation to enter Facilities study. Such an amount forces developers and independent power producers to be much better prepared to capitalize security posting requirements in order to construct and operate the facility over its life. BPA should be promoting project milestone requirements that align with the long-term costs and benefits of operating projects. Additional milestone payments should be aligned with the project's impact to the system, rather than the commercial readiness requirements that are proposed in the May TC-25 update that include either commercial contract or payment -in – lieu that is a multiple of a study deposit.	25-May	Readiness Requirements	Kevlyn		

308	Cypress Creek Renewables	We further recommended increasing financial risk based on allocated cost. BPA's proposal that the penalty for withdrawal be 'partially or fully non-refundable depending on study phase and timing and the impact of withdrawal' does not provide enough clarity on assumed risk levels, and as such is not consistent with the third component of a goal of interconnection reform to increase risk throughout the process. Our proposal increases risk based on increasing % at risk of the initial security, followed by an increased amount at risk based on the results of your network upgrade allocation.	25-May	Study Financials	Rebeccca		
309	Cypress Creek Renewables	*BPA's proposed transition requirements must be narrowed to create a more manageable transition cluster process, and it must freeze work on new applications received after a specified date.* Cypress agrees with [BPA's] proposal, and suggests the following additions: - To qualify for the transition cluster following the transition serial process, the IC must have submitted an interconnection request by the March 15 and 16 2023 TC-25 workshop, when BPA first laid out alternatives to status quo requirements. - Customers submitting interconnection requests after that date would have a reasonable expectation that request requirements would change. - We recommend BPA freeze staff work on any applications received to date after March 15 2023 in order to focus resources on those requests prior to the transition.	25-May	Transition	Katie		
310	Cypress Creek Renewables	*BPA's proposal to allocate network upgrade costs based on proportional capacity as opposed to proportional impact will result in unjust and unreasonable rates* There is a clear consensus among stakeholders supporting proportional impact as a more just and reasonable method to assess and assign network upgrade costs compared to proportional capacity. To reiterate our prior comments, allocating cost based off capacity requires engineering judgment which can be subject to inconsistency and result in unfair cost allocation. Proportional impact (DFAX) is a fair way based on cost-causation to assign upgrade costs by burdening the largest contributors with the largest share of the upgrade, and it is increasingly becoming the standard across most markets for that reason, (e.g., PacifiCorp, MISO, others). Proportional capacity results in subsidizing projects by burdening lesser contributing projects to reduce the burden of higher contributing projects. Costs allocated to interconnection customers, refunded through a 'crediting' framework, will result in unjust and unreasonable rates. If Bonneville's preference for proportional capacity is justified by 'ease of administration,' an understandable objective given the scale of the queue, it must consider the impact of its methodology on the entirety of the process. A proportional capacity method will incentivize smaller projects with higher impacts (that would be incentivized to proceed with lower cost allocation), requiring additional cost and time to build the identified facilities, resulting in further cost and delays to the process. In either case, given the strong stakeholder position in support of proportional impact, and the potential for allocating costs via proportional capacity to result in unjust and unreasonable rates, Bonneville has yet to explain its preference, and should do so in future written process communications, prior to including this method in proposed tariff redlines.	25-May	Network Costs	Rebecca		
311	Cypress Creek Renewables	*BPA should address study delays more directly in this TC-25 process through attention to process efficiency and resourcing, and as a reinforcing mechanism, Cypress recommends BPA consider refunds of study and milestone payments if such delays occur* In its responses to general comments, BPA notes funding for additional resources (FTE) to implement the GI process will be discussed in IPR starting in 2024. It also states that 'the only feasible way to reduce the overall process timeline is to reduce customer time.' First, without attention to resourcing in this TC-25 reform process, there exists a strong potential for study delays to persist in the new cluster process after the identified timelines due to continued insufficient resourcing combined with a lack of transmission capacity. We recognize the challenge BPA and other transmission providers face with respect to resourcing. In lieu of addressing resourcing head-on in this process, and as a reinforcing mechanism, CCR suggests a portion of increased study deposits above the amount spent, as well as a portion of the milestone payment, which should be increased to support additional resourced needed, should be refunded to the IC if the Phase II cluster study, cluster re-study, or facilities study is more than 30 days late after the timeline to be established in the OATT. This proposal will improve not only commercial certainty and open commercial readiness demonstration options as discussed below, but also accelerate withdrawal and restudy timelines.	25-May	Readiness Requirements	Kevlyn		
312	Cypress Creek Renewables	*BPA should address study delays more directly in this TC-25 process through attention to process efficiency and resourcing, and as a reinforcing mechanism, Cypress recommends BPA consider refunds of study and milestone payments if such delays occur* In its responses to general comments, BPA notes funding for additional resources (FTE) to implement the GI process will be discussed in IPR starting in 2024. It also states that 'the only feasible way to reduce the overall process timeline is to reduce customer time.' With respect to the second issue, we respectfully disagree. In our previous comments, we identified that a short circuit analysis completed in Phase I and then again in Phase II is redundant. We stated: 'BPA should move the redundant short circuit analysis solely to Phase II. The Phase I power flow study is more appropriate to provide a relatively rapid assessment of network upgrades (NUs), whereas short circuit provides limited upgrade information based on impact to circuit breakers. CCR recommends BPA reduce the Phase I timeline adjustment to reflect a reduced scope of work. ' We request BPA staff specifically address why this process recommendation does not reduce the Phase I process timeline in future written process communications.	25-May	*FR/FS*	Christina		
313	Seattle City Light	City Light requests BPA provide time for a more in-depth discussion of how BPA's proposal will impact staff workload, including how BPA is ensuring that it will not impact other related processes. City Light additionally requests BPA consider the value of additional customer engagement to increase the amount of understanding and alignment prior to the posting of the DRAFT TC-25 Tariff.	25-May	TC-25 Process/Workshops	Tammie		
314	Seattle City Light	City Light suggests that the need to apply additional resources to the GI Reform process is immediate and urgent. We propose that BPA should exercise budgetary discretion on this urgent need prior to the next Integrated Program Review (IPR). City Light believes this is a critical component of the GI Reform implementation being a successful process. This would add great value to BPA customers' ability to manage load growth and carbon requirements in a least cost way.	25-May	Miscellaneous - Staffing	Tammie		
315	Seattle City Light	City Light supports the updated BPA Commercial Readiness Requirements proposed and believes BPA has provided adequate in-lieu-of deposit options for the phase II and phase III/FAS stages of the process. City Light suggests that BPA consider resource developer feedback regarding the time necessary to secure deposit funds and credit instruments within the deposit time requirements. And City Light recommends BPA work with public power entities to ensure that the readiness requirements fit within their planning processes so that projects serving public power needs are not disadvantaged for not going through an IRP.	25-May	Readiness Requirements	Kevlyn		
316	Seattle City Light	City Light appreciates BPA giving an example and details on implementing scalable plans with a readiness queue of cluster participants. City Light suggests BPA consider how to be transparent applying the planned readiness time stamp. Without the clear ability to consistently implement time stamping across all customers, BPA may need to retain the current queueing order for the purposes of defining scalable plans.	25-May	Scalable Block Plans	Christina		
317	Seattle City Light	City Light thanks BPA for being aware of the impacts of cost shifts between transmission customer groups. City Light requests BPA explore the possibility of establishing an escrow account that would directly accrue interests for those customers making deposits.	25-May	Study Financials	Rebecca		
318	Gallatin Power	Gallatin recommends tying the Transition Close Date to the proposed effective date of the tariff, which would be the date of the Final Record of Decision, currently estimated to be April 2024. Gallatin reiterates that the Transition Process, as presently proposed, would disadvantage projects currently in the System Impact Study Phase as described in the Gallatin comments submitted May 10, 2023. By tying the Transition Close Date to the Final Record of Decision, BPA will have additional time to complete the System Impact Studies currently in process, avoiding wasting BPA employees' time and monetary investments already expended on projects that would be in the Facilities Study Phase had current tariff timelines been achieved. Gallatin also recommends offering projects with little to no network upgrades the ability to participate in the Transition Process to help expedite projects through the queue, which is favorable to both BPA and the projects.	25-May	Transition	Katie		
319	Gallatin Power	BPA should reconsider the proposed commercial readiness demonstration requirement for entering the Transition Process as it needs to be more consistent and connected with industry accepted project development and contracting timelines and practices. In addition, the proposed Transition Close Date, which is potentially very near term, creates a potentially unachievable timeline for many late-stage projects forcing them to be withdrawn from the interconnection queue and harshly penalized due to a new and previously unknown requirement.	25-May	Readiness Requirements	Kevlyn		
320	NIPPC	NIPPC generally supports the concept of scalable block plans for locations with high levels of interconnection customer interests. NIPPC looks forward to reviewing more detailed language describing how BPA will determine that a scalable block plan is appropriate for a location, how BPA will allocate costs within each block, and how BPA will treat project modifications and customer withdrawals within each block.	25-May	Scalable Block Plans	Christina		
321	NIPPC	In earlier comments, NIPPC had suggested shortening time periods to speed up the interconnection study cycle. NIPPC had suggested that BPA could reduce the proposed windows for customers to consider study results and establish eligibility for subsequent phases. BPA, however, asserts 'the only feasible way to reduce the overall process timeline is to reduce customer time.' Commenters, however, have recommended other process efficiencies, including elimination of the redundant short circuit study in Phase 1, when a power flow study would serve the same purpose and reduce the Phase 1 timeline. In consideration of BPA's inability to reduce the study timelines it controls in order to reduce the overall study cycle, NIPPC no longer supports shorter timelines for customers to act between phases of the study cycle.	25-May	First Ready First Served	Tammie		

322	NIPPC	For the region to have any chance of meeting its clean energy goals as reflected in state laws, BPA must be able to meet its target timelines consistently and with accurate study results. Any delays will impact not only BPA's interconnection customers, but their customers – who must comply with corporate targets or state clean energy laws – as well. Any failure to complete studies on time will not simply delay project commercial operation dates but also may result in failure of loads in the region to meet their clean energy targets. NIPPC encourages BPA to consider whether there are any incentives BPA could deploy (or penalties that could be imposed) to ensure that BPA staff and management meet the interconnection deadlines. Potential incentives and penalties for delayed or inaccurate study results could include providing customers with a refund of all or a portion of their study costs or allowing customers to withdraw from the cluster and receive their commercial readiness deposits back. NIPPC urges BPA to consider whether there are other incentives or penalties that BPA could impose on itself for failing to meet timelines and that also do not unduly shift study costs to other customers. Ultimately any uncertainty in the timeline for interconnecting a new generation project will lead to contractual uncertainty between the developer and its customer in turn impacting the commercial readiness demonstrations that developers must make as part of these reforms.	25-May	Readiness Requirements	Kevlyn		
323	NIPPC	NIPPC also recommends that BPA continue to complete studies on the existing serial queue for as long as possible in order to mitigate the impacts to customers who have been in the queue for years and made decisions based on study results they have received.	25-May	Transition	Katie		
324	NIPPC	NIPPC supports the staff proposal to implement a two-phase cluster study for interconnections but continues to encourage BPA to look for efficiencies to reduce the overall process timeline.	25-May	First Ready First Served	Tammie		
325	NIPPC	**Application Fee** NIPPC supports the staff proposal to charge interconnection customers a $10,000 application fee.	25-May	Readiness Requirements	Kevlyn		
326	NIPPC	**Site Control** NIPPC supports the staff proposal to require interconnection customers to demonstrate 100% site control of the project generation site at the time of application. NIPPC encourages BPA to use this queue reform as an opportunity to codify its approach on site control for projects that are located on federal lands. BPA should clarify whether a government-issued document, such as a Cost Recovery Agreement, proof of a SF299, or a Plan of Development will meet BPA's site control requirements.	25-May	Readiness Requirements	Kevlyn		
327	NIPPC	**Study Deposits** NIPPC supports the staff proposal for deposits requirements at Phase 1 ($25,000 plus $500/MW up to $100,000) and at Phase 2 ($50,000 plus $1,000/MW up to $250,000). NIPPC also supports the proposed requirement to base the Facilities Study deposit on the plan of service identified in the Phase 2 study. Many NIPPC members, however, would support even higher study deposits to reduce even further the number of interconnection requests in the queue. These members believe that increasing the study and milestone deposits would better align with requirements in other markets which have adopted the 'first-ready' concept that guides this queue reform effort.	25-May	Readiness Requirements	Kevlyn		
328	NIPPC	**Interest on Deposits** NIPPC does not support the staff proposal to pay no interest on customer deposits. NIPPC agrees with staff that interest payments to interconnection customers should not impact BPA's broader customer rates; BPA's transmission rates should not collect revenues from its overall transmission customer base to pay interest on interconnection customer deposits. At the same time, NIPPC also believes that the broader base of BPA transmission customers should not benefit from interconnection customers' deposits. Accordingly, NIPPC encourages BPA to pay interest on interconnection deposits based on the actual interest income BPA receives from keeping those deposits in its cash accounts (NIPPC does assume here that BPA keeps customers' deposits in an interest-bearing account; if BPA does not earn interest on customer deposits, then BPA should revise its internal procedures to ensure that customer deposits do earn interest.). BPA should also allow customers to submit interconnection deposits into an interest-bearing escrow account.	25-May	Study Financials	Rebecca		
329	NIPPC	**Commercial Readiness** NIPPC supports the proposal to require a demonstration of commercial readiness. NIPPC agrees it is important to provide customers with a deposit option in lieu of a specific demonstration of readiness. NIPPC believes that the specific readiness criteria in the tariff language should be broad enough to reflect the resource procurement processes of all potential load serving entities, including those employed by investor owned utilities, consumer owned utilities, retail choice energy service providers and large end-use customers.	25-May	Readiness Requirements	Kevlyn		
330	NIPPC	**Network Upgrade Costs:** NIPPC encourages BPA to allocate the costs of Network Upgrades based on the proportional impact of each project to the proposed plan of service using distribution factors. The proportional impact model is the industry standard across the major interconnection queues. The distribution factor method assigns upgrade costs by burdening the project with the most impact a larger share of the upgrade costs. This method also encourages generators to find good Points of Interconnection with more headroom; whereas an allocation method based on capacity only encourages smaller applications. Customers can make more informed decisions when they can tie their costs to specific upgrades, rather than to the size of the other generators in that subcluster. The proportional capacity method results in projects with lower upgrade costs to subsidize projects with higher interconnection costs.	25-May	Network Costs	Rebecca		
331	NIPPC	**Network Upgrade Costs** Accuracy of the estimates of Network Upgrade costs identified in the study results will be critical to the success of these reforms. NIPPC supports allowing customers to withdraw from a cluster without risking their readiness deposits if study costs increase above a certain threshold from one phase to the next. NIPPC encourages BPA to consider additional incentives or penalties to ensure the accuracy of study results, including whether a portion of interconnection cost overruns should be allocated to transmission's overall capital program instead of to the interconnection customers and/or allow the customer to qualify for transmission credits for network upgrade costs that exceed the estimate in BPA's Phase 1 study report.	25-May	Network Costs	Rebecca		
332	NIPPC	**Study Financials** NIPPC supports the staff proposal for allocation of study costs among participants in the cluster study.	25-May	Study Financials	Rebecca		
333	NIPPC	**Information Access** NIPPC supports the staff proposal for information access. The most critical component of the proposal is to allow customers to use the Phase 1 study process to identify their likely interconnection costs. NIPPC also anticipates that after several study cycles a well-maintained heat map will provide customers with good, useful information about potential interconnection costs. NIPPC also encourages BPA to make the results of its cluster studies available to developers.	25-May	Technical Study Requirements	Christina		
334	NIPPC	**Transition** NIPPC remains concerned about elements of the proposed transition process. NIPPC supports the staff proposals on study deposits and site control. NIPPC, however, continues to believe that the lack of a deposit option for an interconnection customer to demonstrate commercial readiness for the transition cluster will be unnecessarily disruptive in the near term. NIPPC urges BPA staff to reconsider and allow customers in the current interconnection queue to submit a deposit in lieu of readiness.	25-May	Transition	Katie		
335	Pine Gate Renewables	*BPA should prioritize processing late-stage projects by pushing back the Transition Close Date and pausing all work on feasibility studies.* According to BPA's timeline, the TC-25 proceeding is expected to take nine months. BPA should utilize that significant window of time to process applications in System Impact or Facility Studies that have the best chance to qualify for the transitional serial process or to receive an LGIA. For these reasons, we recommend that BPA determines which projects are in the transitional serial process only when BPA is ready to begin the transition cluster process. Additionally, prioritization of late-stage projects needs to begin today. Pine Gate recommends that BPA's staff and workflows focus exclusively on requests in SIS or Facility Studies. We believe that projects in a Feasibility Study today are not going to receive meaningful cost estimates in time to execute commercial deals and qualify for the transition. Customers with early-stage projects already assume that they will have to re-do their studies in the cluster process, so any study results in the serial process will be meaningless. On the other hand, projects in the SIS-phase and later already have an expectation of costs and have a good chance of seeing those costs in their final agreements. PJM has implemented this as part of its queue reform transition – it stopped processing requests submitted after September 30, 2020 to move as many projects out of the queue as possible, including all of the legacy requests over five years old.	25-May	Transition	Katie		

336	Pine Gate Renewables	*BPA should expand its requirements to enter the transition to better accommodate late-stage projects while still managing the number of transitional requests.* Pine Gate continues to have serious concerns with staff's leaning to have commercial readiness demonstrations to enter the transition, particularly for the transitional cluster. As other stakeholders have expressed in their comments...these types of commercial readiness demonstrations are infeasible as long as costs and timelines remain uncertain for years to come, which may happen in all transitional groups. Pine Gate understands BPA's concerns that the transition groups will be too large to manage and hinder queue reform. However, BPA's proposal only creates more uncertainty on where and how many projects will land in the transition groups, as it depends on BPA's ability to process the queue, and the customer's ability to demonstrate commercial readiness. Pine Gate recommends that BPA use one or any of the following alternatives to the BPA's commercial readiness demonstrations to provide a high yet feasible bar for entry into the transition: 1. Offer a deposit in lieu of commercial readiness. - While some customers have voiced a preference for low deposits, Pine Gate believes that high deposits are a useful and necessary barrier to reduce speculative projects. - For the transitional serial group, the deposit should be same as the proposed requirement of the Facility Study deposit in BPA's new process (20% of the allocated network facility cost). The current proposed BPA deposit for Phase 2 is too low – instead, Pine Gate suggests 10% of allocated network upgrade costs (which is the practice in PJM, MISO, and SPP). - Another option is to refer to current industry practices. For example, PJM requires a deposit of $4,000/MW to enter the transition. MISO is discussing increasing the initial milestone deposit to $6,000 to 8,000/MW.	25-May	Transition	Katie		
337	Pine Gate Renewables	*Pine Gate continues to support Alternative #2 – Proportional Impact, for Network Cost Allocation.* The proportional impact method is utilized by most utilities and RTOs/ISOs for a reason. This method aligns with cost causation principles, by protecting well-sited projects from shouldering the costs of sub-optimally sited projects. Potential customers are encouraged to find sites with more system headroom that will create a smaller impact on the grid. In contrast, the proportional capacity method only encourages smaller-sized projects. This is ultimately not in BPA's interest as more unnecessary network upgrades will have to be built. BPA's proposed interconnection capacity heat map will not even be utilized if developers are not encouraged to find sites with more headroom. Additionally, while the proportional capacity method is easy to calculate in an excel file, it lacks the transparency that is useful for BPA and its customers. Pine Gate cannot estimate expected costs because they are entirely based on the number of other requests and project sizes in that sub-cluster. Alternative #2 is also supported by several other commenters...We ask BPA to reconsider this and review how ISOs/RTOs have mitigated the concerns that BPA has expressed. If BPA still supports proportional capacity, we ask BPA to clearly demonstrate in the next workshop why the proportional capacity method is a better approach.	25-May	Network Costs	Rebecca		
338	Public Power Council	PPC understands the importance of concluding the TC-25 proceedings in advance of TC-26 initial workshops. At the same time, the abbreviated TC-25 workshop schedule has left outstanding questions and not left as much time for stakeholder engagement – both among the stakeholder community and with BPA – which would be helpful to ensure that issues are thoroughly vetted. We understand that other stakeholders are considering this, as well, and we look forward to proposals on how a short extension may allow additional time for BPA and customers to discuss these critical topics. Additional time for discussion and a more holistic description of BPA's proposal would be very helpful in assisting customers on whether they should support the proposed approach. Specifically, PPC seeks the following: • Additional information from BPA on how the TC-25 process fits in with upcoming or potential future processes to improve BPA's Line and Load Interconnection Process and TSEP. This should include a discussion on how various "transition" approaches may impact BPA's approach to a holistic review of BPA's transmission planning and execution efforts. • A more comprehensive discussion on how BPA's proposal will impact staff workload, including how BPA is ensuring that it will not impact other related processes. • BPA should provide a timeline for any transitional plans and commitments towards meeting its goals. • A comparison between today's policy and BPA's proposal that highlights: o What information is required from the customer and when to advance to the next study stage. o What financial obligations customers have to move through phases of the study process. o What information BPA is providing to customers to inform their decisions. o When customers are required to make decisions about moving forward through the study process, and what information they have to inform that decision. (This would be particularly helpful in understanding BPA's scalable plan approach)	25-May	Miscellaneous - GI Policy	Tammie		
339	Public Power Council	Generally, the option to either meet certain readiness conditions or supply additional deposit seems appropriate and should allow "serious" projects to move forward. Having the option available of either a deposit or demonstration of readiness criteria should help prevent smaller producers from being unduly burdened by additional study costs if they are ready to move forward, while not allowing projects that do not have sufficient funding to move forward to displace other viable projects in the queue. BPA should work with public power entities to ensure that the readiness requirements fit within their planning processes so that projects serving public power needs are not disadvantaged for not going through an IRP process. It is important that withdrawal is an attractive option for projects that are unlikely to move forward. Thus, BPA should make the withdrawal process simple and not charge withdrawal fees.	25-May	Readiness Requirements			
340	Public Power Council	PPC strongly supports the concept of the "scalable plan," but has questions around how it would be implemented. As raised above, additional clarity on what information customers have when they are making decisions would be helpful (for example, do they have to pay for the next phase of study before they know if they are in scalable plan 1 vs. scalable plan 2?) It would also be helpful to understand how the time stamping of "priority" occurs. It is unclear how that process is conducted and whether there are aspects related to the manual implementation of this process that could unintentionally disadvantage customers. If BPA cannot demonstrate that the time stamping can be implemented consistently across all customers, then it may need to retain current queueing order for the purposes of defining scalable plans.	25-May	Scalable Block Plans	Christina		
341	Public Power Council	**Interest on Deposits** PPC appreciates BPA highlighting this issue and the potential for cost shifts to entities not in the interconnection queue. We agree with the principle that there should not be cost shifts to entities not in the interconnection queue, but those that are seeking interconnection should also be kept as whole as possible for an interest earned on deposits made for studies and construction. PPC is interested in further discussions about potentially establishing an escrow account that would directly accrue interest for those customers making deposits. This seems most consistent with avoiding cost shifts between customers seeking interconnection and other BPA customers.	25-May	Study Financials	Rebecca		
342	Renewable NW	*Bonneville Should Continue to Provide Interest on Study Deposits* RNW agrees that subjecting all transmission customers to costs associated with certain study deposits would be inconsistent with cost causation and should be avoided, but urges Bonneville to find a more equitable solution. While the FERC interest rate may be too high, it is difficult to understand which of the other alternatives Bonneville considered would be appropriate without understanding how much Bonneville would typically earn while holding the unused cash deposits. Just as it would be unfair to subject all transmission customers to these costs, it would likewise be unfair to provide Bonneville a windfall from holding the deposits. This is particularly true in situations where studies are delayed and the timing is extended. Assuming Bonneville is not willing to refund study deposit amounts beyond the amounts unspent to compensate for study delays, RNW requests Bonneville provide more information as to which of the other alternatives would be commensurate with its expected earnings. Alternatively, Bonneville could place the deposits in an interest-bearing account and then pay the specified interest rate earned as opposed to estimating a proxy amount. Another approach could be to allow customers to put their deposits in escrow and earn their own interest rate. At bottom, Bonneville has not justified removing all interest on study deposits from its tariff and should provide some equitable amount of interest to interconnection customers.	25-May	Study Financials	Rebecca		
343	Renewable NW	*Bonneville Has Not Adequately Explained its Preference to Allocate Network Upgrades on Proportional Capacity as opposed to Proportional Impact* Nearly all stakeholders agree that Bonneville's proposal to allocate network costs based on proportional capacity appears inconsistent with cost causation, yet Bonneville chose not to update its leaning or even discuss this topic at the Workshop...RNW reiterates that network upgrade cost allocation is one the most significant reforms being considered, and strongly urges Bonneville to provide time for additional discussion on the merits of the two approaches. RNW members support using a distribution factor ("DFAX") threshold similar to those used by other transmission providers. RNW understands that Bonneville's transmission system and interconnection studies may be unique. To the extent that Bonneville believes there are reasons the agency should deviate from the industry standard, those reasons should be discussed openly. Given the severity and complexity of this issue, RNW believes an entire customer-led workshop may be warranted.	25-May	Network Costs	Rebecca		

344	Renewable NW	*New Acreage Requirements for Site Control Should be Established Well in Advance of the Transition Cluster Request Window* Bonneville is proposing to require strict site control to enter the Phase 1 Cluster Study but has yet to provide important eligibility details. At the Workshop Bonneville clarified that it would be setting acreage requirements in a business practice instead of its tariff to provide the agency flexibility as technology advances. RNW urges Bonneville to begin that process as soon as possible so that stakeholders can provide input on appropriate site control requirements and interconnection customers in the existing serial queue can make better business decisions.	25-May	Readiness Requirements	Kevlyn		
345	Renewable NW	*Bonneville Should Consider New Readiness Demonstration Alternatives* Bonneville's commercial readiness requirement for the transition study processes is discriminatory and must be reconsidered. For the transition processes, i.e., both the Transition Serial Study process and the Transition Cluster Study process, Bonneville's leaning is to require a commercial readiness demonstration in the form of a sale agreement, resource plan selection or site-specific equipment purchase order. At the Workshop, Bonneville described this requirement as essential to its goal of transitioning quickly to a new process. RNW appreciates Bonneville's desire to allow more "ready" projects to move forward quickly but urges Bonneville to consider other alternatives as indicia of readiness. For example, would Bonneville consider more stringent site control requirements—perhaps something similar to those required to enter the Public Service Company of Colorado ("Pasco") transition cluster? Bonneville should explain why increased at-risk financial security and/or transmission demonstrations are insufficient to demonstrate project viability and allow the agency to transition quickly to the new process. Additionally, RNW asks Bonneville to explain why projects with little or no network upgrades needed could not also be expedited through the transition process.	25-May	Transition	Katie		
346	Renewable NW	*Bonneville's Proposal to Allow Scalable Plan Blocks Needs Additional Consideration* RNW appreciates the clarifications Bonneville provided regarding subclustering but urges Bonneville to provide a more comprehensive explanation of its intention before releasing tariff redlines on June 9, 2023. In addition to providing a written explanation as to how cost allocation would work, Bonneville should confirm when (and how) the timing of subclustering decisions would be made to ensure its current proposal includes sufficient time to allow for these internal decision points. For example, when will customers decide whether to move forward with a smaller interconnection service plan and/or whether other customers have agreed to fund a larger interconnection service plan? How will those decisions affect cost allocation estimates and/or Bonneville's ability to move the cluster study forward?	25-May	Scalable Block Plans	Christina		
347	Renewable NW	*Bonneville Still Needs to Set a Reasonable Expectation for Interconnection Customers in the Existing Queue* RNW reiterates its earlier requests to identify how many projects Bonneville expects to process before the transition, as well as under the proposed processes, so that customers can understand how theses policy and process changes are likely to impact their projects and stakeholders can compare the intended processing timeline to Bonneville's "status quo" projections. At the Workshop Bonneville announced its proposed transition dates...but has yet to provide any expectations with respect to how many projects might end up in the transition processes. Bonneville should provide some realistic expectation as to when the agency believes it will complete the transition clusters and what will happen (if anything) to requests that are not eligible for the transition processes. It is imperative that interconnection customers understand the full significance of the transition queue eligibility requirements when considering these policy alternatives. For example, knowing how many projects currently have an executed Facilities Study ("FAS") agreement but no FAS report may help inform the best path forward. To date, Bonneville has not provided any expectation as to when the first "normal" cluster study is expected to begin and/or when the agency expects to complete either of the transition processes.	25-May	Transition	Katie		
348	Shell Energy	Any durable recalibration of interconnection processes should first and foremost promote a level playing field across all project sizes and developer/customer profiles.	25-May	First Ready First Served	Tammie		
349	Shell Energy	Late-stage study withdrawals increase uncertainty and result in inefficient use of limited staff resources; however, maintaining offramp decision points is prudent. For this reason, Shell Energy supports a phased first-ready-first-served cluster study with escalating at risk deposits in later phase(s).	25-May	Readiness Requirements	Kevlyn		
350	Shell Energy	Commercial readiness criteria may indicate project viability; however, they are not the only indication. Any readiness criteria must be broad enough to reflect the procurement nuances of all loads, whether an IOU, POU, end-use customer or competitive energy service provider. Access to transmission, if applicable, remains important while contract-path OATT rights are the status-quo and can be one measure to indicate readiness; however, should not be required to demonstrate readiness. In addition, financial security should satisfy readiness requirements.	25-May	Readiness Requirements	Kevlyn		
351	Shell Energy	Robust and transparent data exchange is critical, such as an interconnection overview webpage/application and dissemination of data/results to the interconnection customer.	25-May	Technical Study Requirements	Christina		
352	Shell Energy	Shell Energy agrees site control, including generation tie lines if applicable should be required at the time of application.	25-May	Readiness Requirements	Kevlyn		
353	Shell Energy	Regarding interest, customer deposits should accrue interest but only at the actual interest rate being paid in escrow or other accounts BPA holds customer funds within. This would represent a pass-through to the customer at presumably market interest rates, thus reducing any concerns of submitting unviable requests to earn an administratively determined interest rate on deposits.	25-May	Study Financials	Rebecca		
354	Shell Energy	Shell Energy can live with a framework which allocates study costs 50:50 between pro-rata MW and number of requests.	25-May	Study Financials	Rebecca		
355	NewSun Energy	Support Sub-Cluster Approach with Scalable Block Approach subject to (1) senioritybased queue application, to provide clarity on allocation of existing capacity, benefits of incremental upgrades, and cost responsibility for applicable traunches of current and future upgrades (as per current practices; and, as further discussed below in "Changes Recommended"); and (2) BPA's (as per current practices) study approach to identify all primary MW breakpoints. This is our top concern and recommendation for viability and efficacy of GI Reforms.	25-May	Scalable Block Plans	Christina		
356	NewSun Energy	Support, Reasonable and Non-Punitive Deposit Amounts. Thank you for listening. Some further modification are needed, as noted below in commercial readiness criteria provisions (which should expand options and reduce amounts), to avoid burdens or biases, but BPA's initial leanings are reasonable for the Future long-term cluster policy.	25-May	Readiness Requirements	Kevlyn		
357	NewSun Energy	Support, No Withdrawal Penalties. Thank you for not adding these bad policies, which create undesirable perversions or distortions of incentives. TOs should make it easy and non-punitive to drop out.	25-May	Study Financials	Rebecca		
358	NewSun Energy	Support, Ensuring Refundability of All Amounts. Again, as discussed in workshops, BPA should make it easy for projects to withdraw.	25-May	Study Financials	Rebecca		
359	NewSun Energy	Support, No Informational Studies, but should have year-round application windows, closed at discrete closing dates (as may be identified from time-to-time), so scoping meetings can beneficially occur, with queue seniority applied, and maximal time for interconnection customers to adapt, drop, downsize, make informed decisions as applicable, maximally before (not during) cluster study process.	25-May	FR/FS	Christina		
360	NewSun Energy	Support, Preservation of 3-Phase Study Format (2-Phase Clusters by Sub-Cluster, then individual Facilities Studies), with downsize optionality preserved before and during. This is critical, useful, helpful, and provides full valued benefits of the current 3-step FERC OATT pro forma approach that has served the market well—but for when flood volumes of requests have made it make more sense to study customers in groups, for bandwidth leverage benefits. Support the general results identified for initial and updated staff leanings Clarify: BPA should affirmatively clarify additional flexibility customers have to downsize without penalty (i) during the pre-cluster window, at any time, to leverage scoping and other information, avoid upgrades or non-viable approaches; (ii) after/between study phases, including as a result of others dropping out (which might change size of best-suited projects, which BPA should facilitate customers' ability to right size, especially where it beneficially avoids triggering certain upgrades and associated costs, time, and bandwidth impacts).	25-May	First Ready First Served	Tammie		
361	NewSun Energy	Support, Not Identifying Fixed Schedule Yet for Completion of Transition Process and Start of Long-Term Cluster Study. BPA should retain its flexibility here and focus on maximally facilitating success for the existing queue.	25-May	Transition	Katie		

362	NewSun Energy	Preservation and utilization of seniority-based queue application to studies and cost allocation, to provide clarity on allocation of existing capacity, benefits of incremental upgrades, and cost responsibility for applicable traunches of current and future upgrades. No Tie-Breaker mechanism: With queue time stamp seniority applied (as above), other tie-breaker concepts are no longer necessary (and which had their own issues naturally and best avoided by current practices). To the extent multiple projects are moving forward, we expect, practically speaking that other timelines differentiation will naturally result from parties' respective receipt of facilities studies, execution and processing of BPA LGIA and related documents, including BPA's completion of NEPA for its interconnection, interactions with TSEP, and other factors that will naturally, organically provide other timeline outcome differentiation for which projects actually can move forward at any time. Additionally BPA already has policies for managing when a junior time-stamp (grid capacity) project decides to move forward earlier, which address remaining issues. Maintains TSEP consistency in terms of BPA methods across tariffs and practices. TSEP applies (and proves the merits and workability of) a seniority based cluster, that subdivides costs among groups of triggering MW. Justified by notable BPA differences from other TOs and RTOs: BPA is a PTP dominant, bilateral transactions, bilateral transmission based system. Its practices and histories are different. As are its needs to maintain compatibility with these practices, as well as avoid conflicts. BPA also has beneficial GI study practices (as noted elsewhere here and in NewSun's workshop comments and slides) that beneficially avoid some of the pitfalls and problems other TOs/RTOs contended with (or had rate-basing biases to not 'solve' optimally).	25-May	First Ready First Served	Christina		
363	NewSun Energy	Must Beneficially Consider Relevant Transmission Rights & TSEP Funding in evaluation of any commercial readiness criteria. This omission from BPA's proposals is material and an incorrect, impractical, unsupportable break from current well-based policies.	25-May	Readiness Requirements	Kevlyn		
364	NewSun Energy	Re-Highlighting Financial & Regulatory Compliance Harm Exposure for Select Cases if GI Queue Positions Removed: o Transmission Liabilities: Parties have assumed transmission liabilities based on current transmission and interconnection OATTs, which include TSR filings (TSEP) and TSA execution informed by the same, often explicitly. o CETA 2030 Compliance Viability (and other clean energy standards): LSEs could bear exposure to fines if GIRs are removed from the queue, especially current more senior positions. Any future long-term cluster GIRs are extremely unlikely, practically-speaking, given other BPA interconnection implementation timelines, to be online by 2030, if not included in the current pre-transition/serial and transition cluster groups. Any new GIR study starting a couple years from now (say 2026), given other BPA bandwidth constraints and the high volume of queue positions that will be being interconnected (relative to limited project manager bandwidth, NEPA, etc) just won't happen by 2030. Thus the priority must be to maximize the viability and success path of existing queue positions and existing underway development.	25-May	First Ready First Served	Christina		
365	NewSun Energy	Application and Windows (Recommendation): - Year-round application windows and scoping meetings for long-term cluster (per above). Many practical benefits, for customers, staff, bandwidth management, and better study outcomes. - Downsizing flexibility (as above), preserve and clarify, including between phases and if others drop. - Year-round validation, but with hard-stop cures at close-of-window plus XX days (recommend 30 days). Maintain as much simplicity and compatability with current practices. Ensure all applications received before: EOY 2022 get Feasibility Study EOY 2021 get SIS EOY 2020 get Facilities Study	25-May	First Ready First Served	Tammie		
366	NewSun Energy	Transition Cluster (Recommendation) **Start Point: Mid-2024 + After Other Efforts Completed:** o Recommend BPA provide ample space to complete the following, finish up catchup efforts, and avoid double/triple stacking bandwidth likelihood (or risks) depending on when BPA TSEP and other effort finish up, including given the inherent benefits of these being completed before launching into the first/transition cluster. o Later of: - [6/15/2024] - Completion of targeted catch-ups for serial queue - Current TSEP Full-Wrap-Up, including through all PEA fundings and drop-outs, plus 60 days. - Load modeling assumptions update per BPA resource assessment process - Line re-ratings effort - [Load designation commitment by LSEs deadline] - [XX days after E&Ps and LGIAs tendered from catch-up effort] o Regardless, we think the effort to start and close the transition cluster during Q1 of 2024 is too compressed, too unrealistic, too burdensome on existing customers, and denies many practical benefits of waiting and ensuring both completion of targeted serial study efforts (which will inform assumptions, including dropouts or persistence queue positions, beneficial to have pinned down in transition cluster, but need time to complete and process). **Eligibility:** Notwithstanding BPA focused efforts and commitment to catch up on as many feasibility and SIS studies prior to starting the Transition Cluster itself: o BPA should ensure a set of auto-qualified queue positions, safe-harbored	25-May	Transition	Katie		
367	NewSun Energy	**Commercial Readiness Criteria (Recommendation)** - Recommend against having them, except Site Control. - If having them, should be a (much) longer list, avoid discriminatory and impractical and too limited of list. Each of the listed proposed have problems that making keeping list asis problematic. - Should not be large cash amounts. Support having 2X study amounts as max. - If funding other obligations elsewhere, ability to demonstrate and count towards criteria (i.e. 2X), including via TSEP, PEAs, development funding, landowner payments, and other development costs, including interest, security, equipment orders, design work, etc. - Cannot be only PPA or term sheet/LOI. - 60 days to provide is way too short, implausibly impracticable, especially with PPA . - Should provide extra cure rights and time for transition cluster - Remove 20% of Network Upgrades. If anything like this, should be lesser of 5% and a cap. But problematic given how long these amounts (cash) would be held, perhaps 5-10 years in some cases, practically. - Must add transmission TSAs and TSEP PEA fundings, for any beneficially relevant transmission (including given short-term redirectability) for majority MW portion of applicable - Should removed IRP identification from the list. This is biased and discriminatory in favor of IOU LSEs in particular. And regulatory oversight of IOUs' ability to so designate (at least in Oregon) is functionally meaningless and would create rights to selfdeal and self-favor for IOU LSEs, as well as create relative disadvantages for all other market participants, including IPPs and public power and other unregulated LSEs and major loads not bearing those regulatory processes or means. - Site Control o Phase 1, prefer site control deposit in lieu, or lower % acreage threshold (25%). o Phase 2, 50%	25-May	Readiness Requirements	Kevlyn		
368	NewSun Energy	**Interest Payment (Recommendation)** BPA should continue paying interest. It should pay the FERC rate.nInterest payments must be meaningful and failure to pay them, especially where some better capitalized parties can merely post parent guarantees or letters of credit which smaller companies cannot (or must pay with cash-backed instruments) creates biases and discrimination and undue burdens on certain parties, due to differential cost of such postings, especially when held for protracted times, as would be likely in many of BPA's current proposals.	25-May	Study Financials	Rebecca		