Order 1920 Draft Ex Ante Cost Allocation Case Study

March 25, 2026

GRIDWORKS

Western Interstate Energy Board

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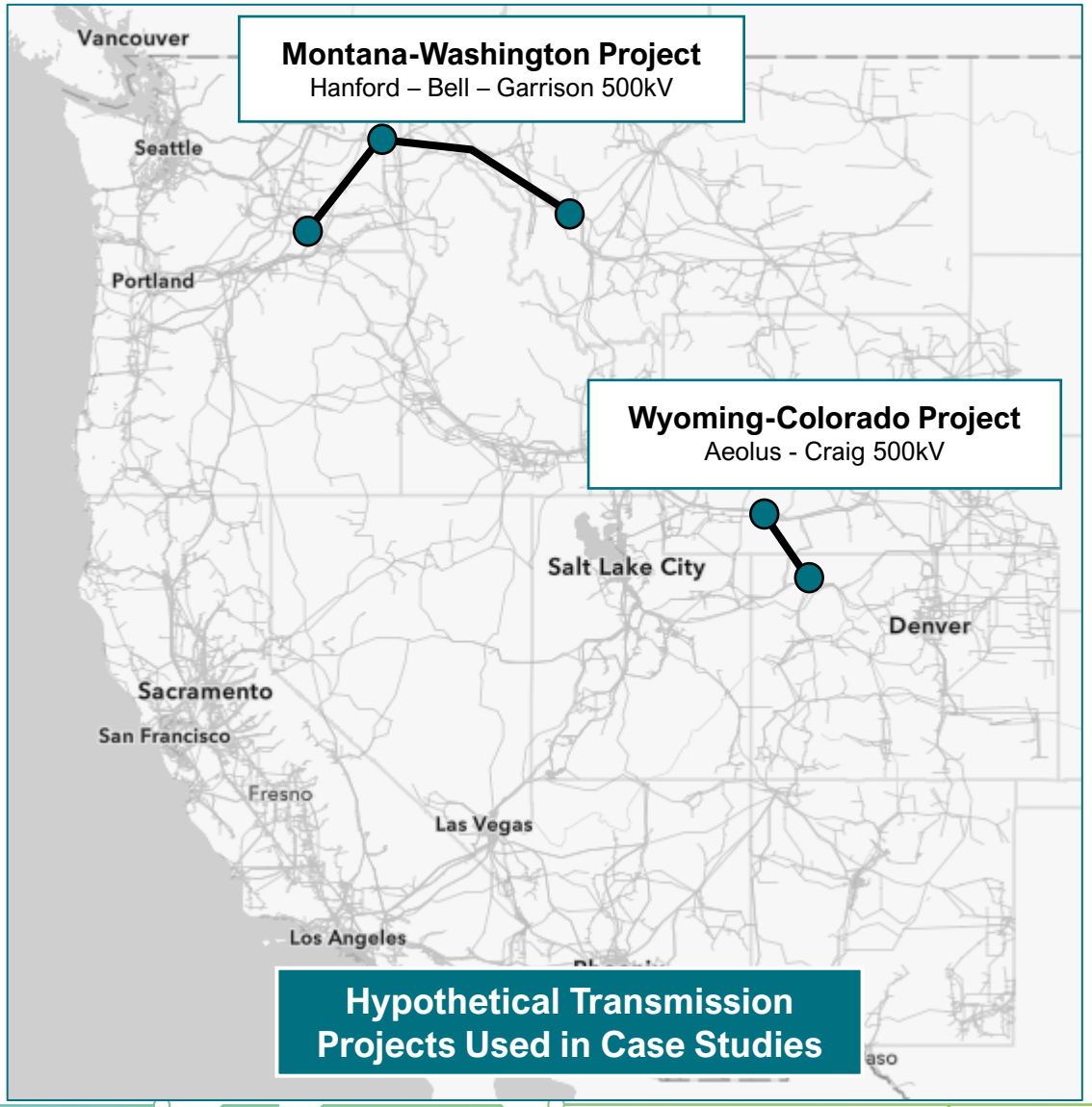
ENERGY STRATEGIES

Case Study Background

- **The Order 1920 Ad Hoc Subcommittee has been developing a draft *ex ante* cost allocation approach for Relevant State Entities within the NorthernGrid and WestConnect regions**
- **Gridworks engaged Energy Strategies to run case studies to help evaluate cost allocation outcomes for two (2) hypothetical transmission projects under the draft *ex ante* approaches being developed for NorthernGrid (here) and WestConnect (here)**
- **Case studies build on the work previously performed under the *State Exploration of Western Cost Allocation Frameworks* (see Technical Report), while seeking to better align with the FERC seven benefits by incorporating a *new* benefit category – capacity benefits from reduced peak energy losses**



The Relevant State Entities Have Been Considering Draft *Ex Ante* Cost Allocation Approaches for WestConnect and NorthernGrid

Example:

Steps	% of Costs Assigned in this Step	Costs Assigned Under Each Step for a $500 Million Project		
		500kV + 30% Subscription	**345kV + 0% Subscription**	**230kV + 50% Subscription**
1. Subscription	**0-100%** of **Total Cost** (based on voluntary subscription decisions)	**$150 M** (30% * $500)	**$100 M** (0% * $500)	**$250 M** (50% * $500)
2. Benefits Apportionment	<200kV: **100%** of **Post-Subscription Cost** 200-300kV: **90%** of **Post-Subscription Cost** >300kV: **75%** of **Post-Subscription Cost** Allocated by quantifying seven (7) FERC-identified benefits. Each Enrolled Transmission Owner (ETO) is responsible for its share of the proportioned benefits multiplied by the remaining % of Post-Subscription Costs	**$262.5 M** (70% * 75% * $500)	**$350 M** (100% * 75% * $500)	**$225 M** (50% * 90% * $500)
3. Zonal Allocation	<200kV: **0%** of **Post-Subscription Cost** 200-300kV: **10%** of **Post-Subscription Cost** >300kV: **25%** of **Post-Subscription Cost** The 1920 Ad Hoc Subcommittee is discussing methods to use for zonal allocation, including share of coincident peak (MW) and a DFAX-based approach to allocating costs.	**$87.5 M** (70% * 25% * $500)	**$125 M** (100% * 25% * $500)	**$25 M** (50% * 10% * $500)

Reminder: Case Study Did Not Focus on Benefit-Cost Analysis

Project Identification

- Regional transmission planning organization selects a project for evaluation

Benefit-Cost Analysis

- Used to determine ***whether a project is beneficial overall***
- If the benefit-cost ratio is >1, it indicates the project(s) may be beneficial, though some processes use a higher ratio as a threshold for approving a project (e.g., 1.25)

Cost Allocation

- Used to determine ***how a project will be paid for***
- Only takes place once a project has already been determined to be beneficial overall

For simplification purposes, we assume that the hypothetical projects used in this case study **have already been identified as meeting the benefit-cost threshold**

State Exploration Captured Most, but not all, of the Seven FERC Benefits; This Study Added Capacity Savings from Reduced Losses

	FERC Order 1920 Benefit Category	*State Exploration* Case Study Benefit Category	Discussion
☑	**Avoided or deferred reliability transmission facilities and aging infrastructure replacement**	Avoided transmission investments	• Case study captured avoided transmission investments due to the construction of the regional projects at hand
☑	**Reduced loss of load probability (LOLP) or reduced planning reserve margin (PRM)**	Resource adequacy (RA) benefits	• Case study captured reduced RA needs due to the construction of a transmission line to increase transfer capacity between regions, which is a different but related, capacity savings benefit
☑	**Production cost savings**	Operational & congestion benefits	• Case study captured production cost savings using the Adjusted Production Cost (APC) metric
☑	**Reduced transmission energy losses**	Operational & congestion benefits	• Case study captured reduced transmission energy losses as part of the APC calculation
☒	**Reduced congestion due to transmission outages**	Operational & congestion benefits	• Case study captured reduced congestion through the APC metric • **Transmission contingencies were not evaluated in the case studies for the *State Exploration*, and were not able to be included in this updated 1920 Study either**
☑	**Mitigation of extreme weather events and unexpected system conditions**	Resiliency benefits	• Case study simulated short-term operational conditions under extreme weather events with and without a given transmission project. Transmission benefits are calculated as reductions in load payments (area load*LMP) plus the value of reductions in unserved load • Additional research and methodology refinement are advised
⊕	**Capacity cost benefits from reduced peak energy losses**	N/A – **Not included in the *State Exploration***	• **This updated work for the 1920 Subcommittee includes this benefit category (which was NEW for the 1920 Study)** and is assessed comparing peak power flows in a case without and with the project at hand to determine reduced losses

NEW Benefit Methodology: Capacity Savings From Reduced Peak Losses

- **This 1920 case study adds "capacity savings from reduced peak losses" as a new benefit category**
- **The benefits were quantified by using powerflow analysis to determine how much incremental generation capacity (MW) is avoided as a result of reduced transmission losses (due to the transmission upgrade)**
  - Power flow analysis is used to quantify the reduction in transmission losses attributable to the upgrade under peak load conditions
  - The avoided generation capacity (MW) for each relevant entity is then calculated using an avoided cost framework, assuming that reduced peak losses translate directly into a reduction in required installed capacity
  - The avoided capacity is valued using an assumed cost $140/kW-year (same as used for other benefits categories in the *State Exploration* which quantified benefits from capacity savings)

- **Note: A summary of the other benefits methodologies used in the *State Exploration* is included as an Appendix to this slide deck**

1920 Study Assumptions: Who Is Eligible for Cost Allocation?

Voluntary subscribers: Any party, within or from outside the relevant planning region, may choose to subscribe to a project.

- For the avoidance of doubt, costs are not allocated to subscribers from outside the planning region or non-jurisdictional transmission providers under any of the other cost allocation steps

Benefit allocation and zonal allocation are limited to enrolled transmission owners (ETOs) in the relevant regional transmission planning organization

- In cases where modeling identifies benefits for ETOs outside of the relevant planning region, benefits are reported, but costs are only assigned based on those benefits to TOs within the relevant planning region (e.g., WestConnect or NorthernGrid)

Non-jurisdictional TOs are excluded from mandatory cost assignment. Several WestConnect and NorthernGrid entities (e.g., BPA, WAPA, and municipal utilities) are non-FERC-jurisdictional. Any quantified benefits (or zonal allocation) that would accrue to these entities are effectively ignored

- These entities may still choose to *voluntarily* subscribe to capacity in the line but are not allocated benefits based on the levels of quantified benefits in the studies

De minimis thresholds: ETOs that receive less than 2.5% of the overall capacity/costs of a project through benefits apportionment or zonal allocation are not required to pay any costs associated with the project unless they choose to subscribe to capacity associated with the project

1920 Study Assumptions: Zonal Cost Allocation

- Per the draft ex ante cost allocation approach, **only ETOs located in the balancing areas (BAs) through which the project traverses and transmission owners in adjoining BAs** are assigned costs under the zonal category

- For the purposes of this case study, “adjoining BAs” are assumed to include **all BAs within 100 miles of the transmission line**
  - For the avoidance of doubt, BAs must also belong to the relevant planning region

- In the case study results shown today, zonal costs were allocated based on **coincident peak loads (MW) of the adjacent BAs**
  - However, the group is also discussing other methods to use for zonal allocation, including a DFAX-based approach to zonal cost allocation
    - Note that PJM allocates cost responsibility for its RTEP reliability baseline upgrades, at least in part, using a directionally-weighted solution-based DFAX methodology (see Section A.3.1 of PJM Manual 14B), which could serve as an example of using DFAX for cost allocation purposes

1920 Study Assumptions: Avoidance of Double Counting

- **ETOs that subscribe to capacity on a project are credited for the amount they commit to pay pursuant to the subscription process**
- **ETOs will still pay an additional amount if their apportioned benefits (i.e., the benefits they would've been assigned absent subscription) exceeds (>) their subscribed capacity**
- **All ETOs "adjacent" to the project (per the definition on the previous slide) are assigned costs under the zonal step – regardless of subscription**

1920 Study Assumptions: No Opt-Outs

- **The frameworks examined under the *State Exploration* allowed for Transmission Zones to "opt out" of cost allocation**
  - As part of the *State Exploration* case studies, we assumed that entities could choose to opt out of assigned costs/transmission capacity
    - This generally was assumed to be utilized by non-jurisdictional entities (e.g., WAPA); however, those entities are *not* assigned costs under these 1920 Ex Ante case study

- **As part of the draft 1920 approaches, ETOs may voluntarily acquire additional transmission rights (i.e., be assigned additional costs) at any time after the subscription process**
  - However, **ETOs may not opt out of transmission rights/costs**

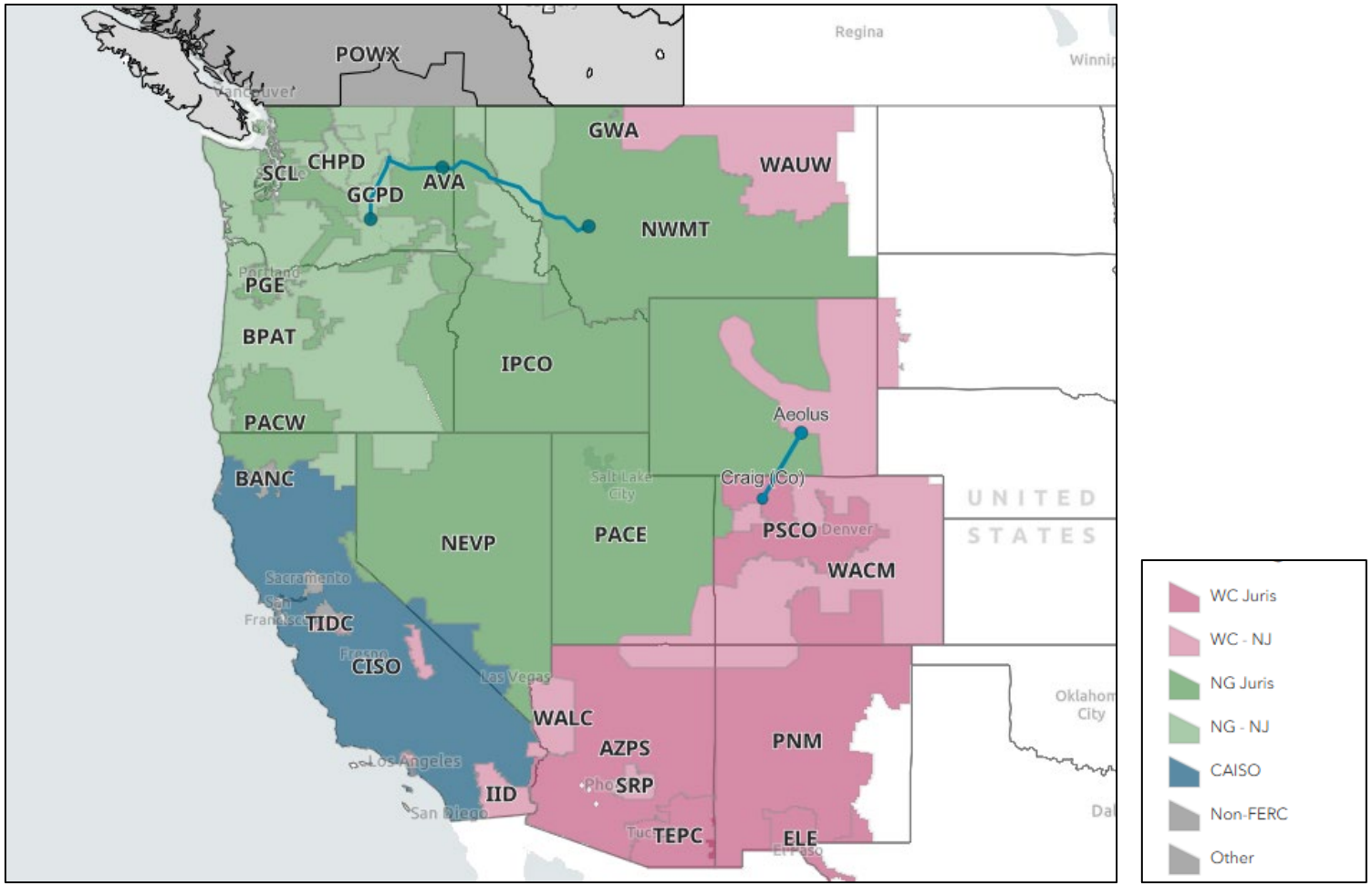
Case Studies Were Performed Using Two (2) Hypothetical Multi-State Transmission Projects from the *State Exploration*

Montana-Washington Project	
Description	~200-mile 500kV transmission line between Hanford and Bell & ~260-mile 500kV transmission line between Bell and Garrison
Primary Driver	Public policy/ resource access
Capacity	2,000 MW
Cost	$2,705 million
Planning Region	NorthernGrid
Adjacent BAs	AVA, NWMT, PACW, PSE

Wyoming-Colorado Project*	
Description	~130-mile 500kV transmission line between Aeolus and Craig
Primary Driver	Reliability/ resilience, market integration and operational savings
Capacity	1,150 MW
Cost	$650.8 million
Planning Region*	WestConnect
Adjacent BAs	PSCo, WACM

***Note: This project was assumed to have originated in WestConnect, but it also touches NorthernGrid and could have originated in that planning region**

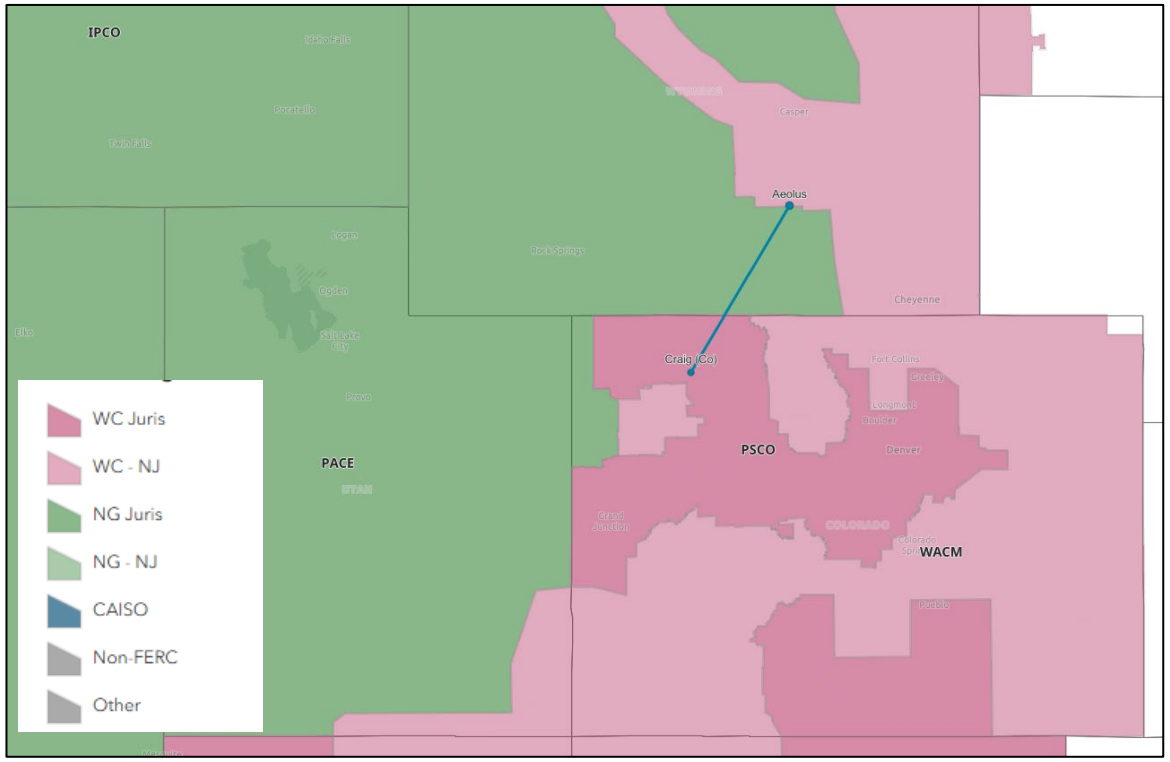
Map of Transmission Projects Used in Case Studies



Wyoming-Colorado Project - Overview

Allocation Under *Ex Ante* Approach		
Assumed Subscribed Capacity (MW)	PacifiCorp	100 MW / $57M
	PSCo	100 MW / $57M
	Idaho Power	150 MW / $85M
	Other Subscribers	100 MW / $57M
	Total	**450 MW / $255M**
% of Post-Subscription Cost allocated based on Quantified Benefits	**75%** ($297 M)	
% of Post-Subscription Cost allocated to Transmission Owners in adjoining BAs	**25%** ($99 M)	

Map of Project Area with Balancing Area Boundaries



Subscribers and subscription amounts are **hypothetical** and intended to be illustrative of a potential subscription. To facilitate comparison, Energy Strategies applied the same subscription levels assumed in the *State Exploration of Western Transmission Cost Allocation Frameworks*

Wyoming-Colorado Project - Benefits

Transmission Zones that are not FERC-jurisdictional and not part of the relevant planning region (in this case, WestConnect) will not be allocated costs *even if those benefits are substantial*

	Operational & Congestion Benefits	Resource Adequacy Benefits	Avoided Transmission Investments	Resiliency Benefits	Capacity Savings from Reduced Peak Losses	Total Benefits ($M)	ETO in Relevant Planning Region?
AZPS	$0.21	$0.00	$0.00	$0.23	$0.00	**$0.45**	**Y**
EPE	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	**Y**
IPCo	$0.00	$5.51	$0.00	$0.20	$0.00	**$5.71**	**N**
PACE	$10.97	$14.82	$0.00	$0.18	$8.41	**$34.18**	**N**
PACW	$6.25	$0.00	$0.00	$0.05	$0.07	**$6.37**	**N**
PNM	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	**Y**
PSCo	$2.77	$3.00	$0.00	$0.08	$2.24	**$8.10**	**Y**
TEPC	$0.00	$0.00	$0.00	$0.19	$0.00	**$0.19**	**Y**
WACM	$2.35	$1.85	$0.00	$0.06	$7.44	**$11.70**	**N**

Northern Grid

Not FERC jurisdictional

Wyoming-Colorado Project - Benefits

APS and TEP receive minor benefits from the project but are not apportioned costs because their total allocations fall below the *de minimis* threshold

	Operational & Congestion Benefits	Resource Adequacy Benefits	Avoided Transmission Investments	Resiliency Benefits	Capacity Savings from Reduced Peak Losses	Total Benefits ($M)	ETO in Relevant Planning Region?
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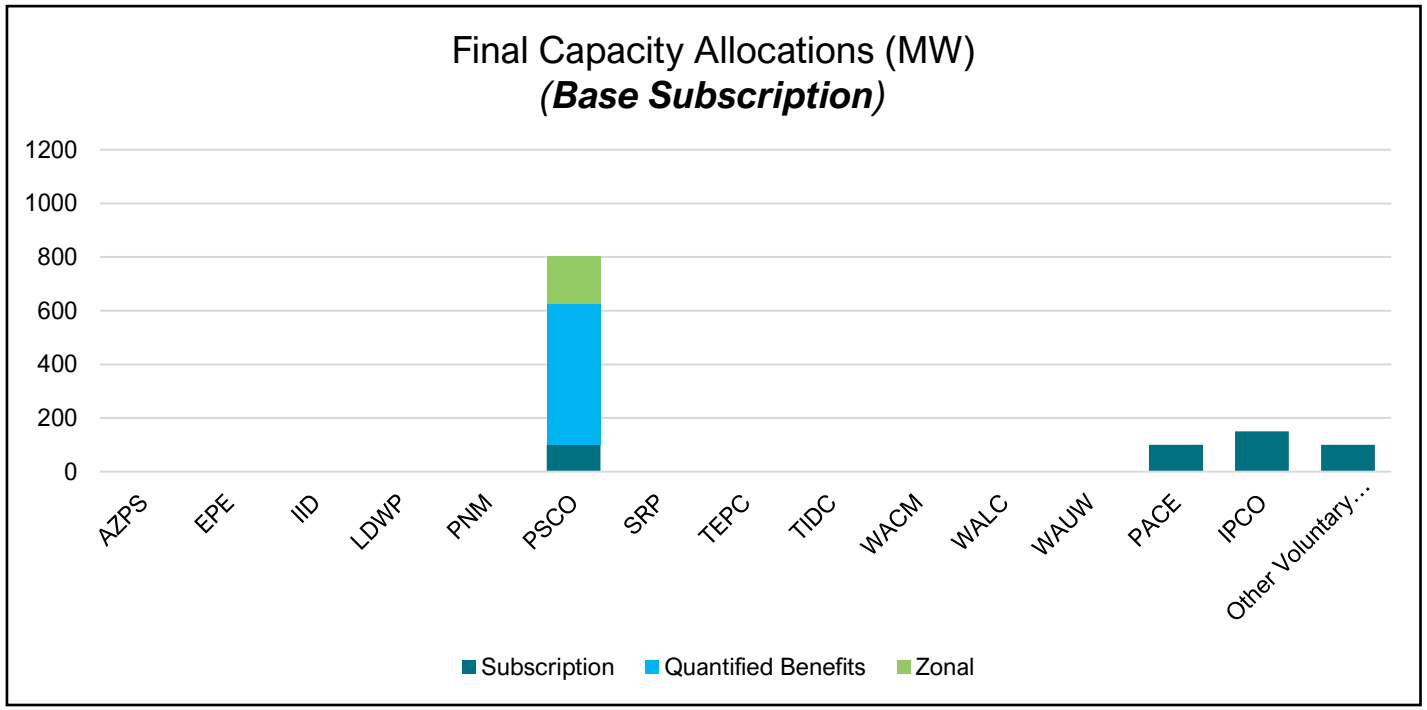
PNM	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	**Y**
PSCo	$2.77	$3.00	$0.00	$0.08	$2.24	**$8.10**	**Y**
TEPC	$0.00	$0.00	$0.00	$0.19	$0.00	**$0.19**	**Y**
WACM	$2.35	$1.85	$0.00	$0.06	$7.44	**$11.70**	**N**

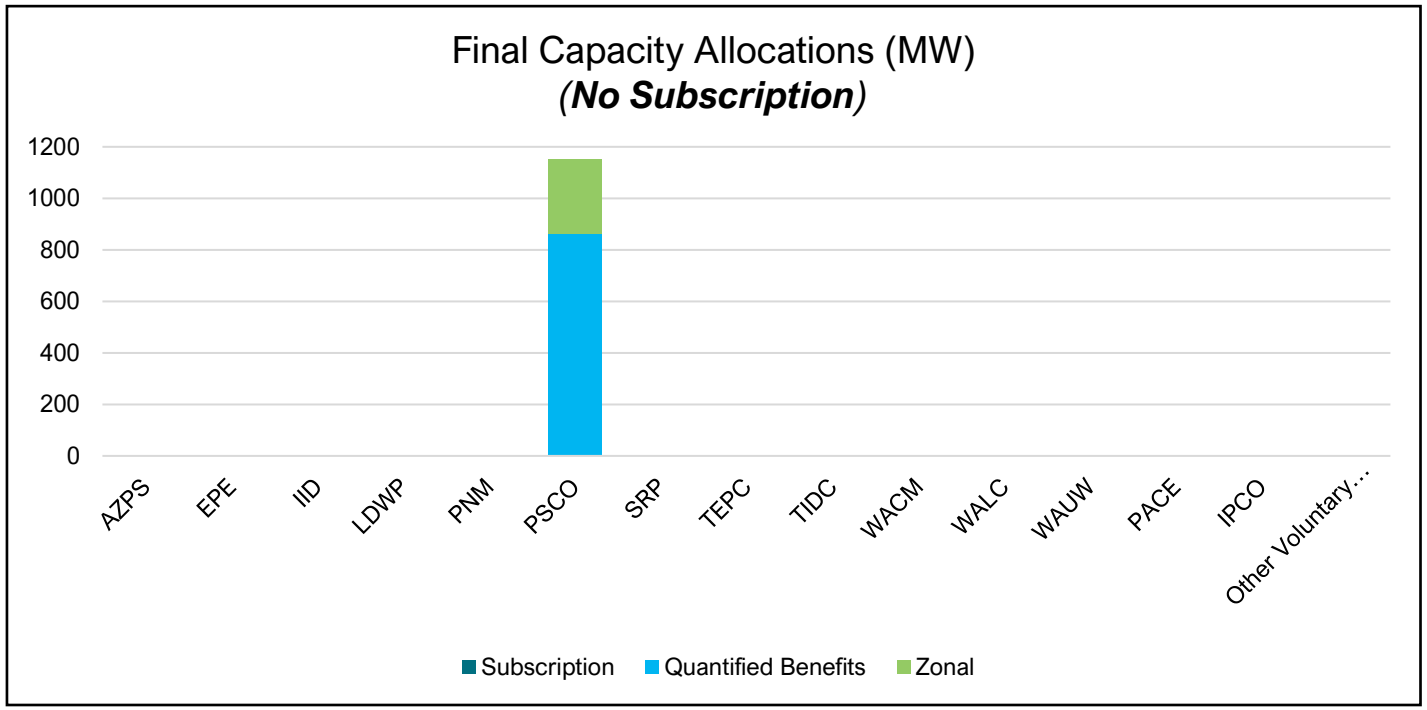
Wyoming-Colorado Project – Results (Base Case)

- Base case assumes that other regional (non-WestConnect) entities voluntarily subscribe to ~25% of the line capacity
- PSCo ends up with all remaining (unsubscribed) capacity and costs
- WAPA Colorado-Missouri, which also received benefits from the project, is not allocated costs because it isn't FERC jurisdictional (and is not an Enrolled Transmission Owner in WestConnect)



Wyoming-Colorado Project – Results (No Subscription)

- Absent some level of subscription, in this case, all costs would be allocated to PSCo
  - And this project probably wouldn't make sense as a regionally allocated project



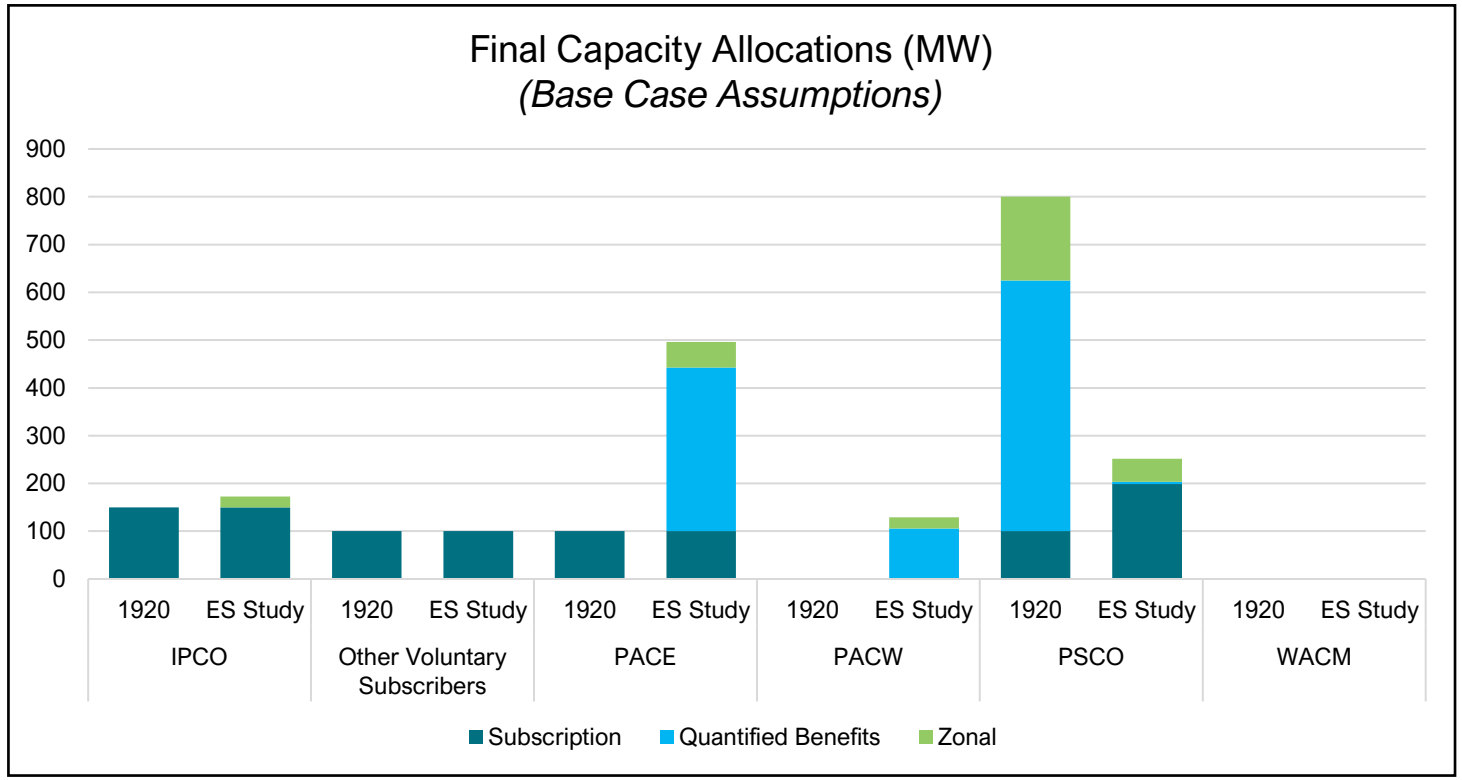
Wyoming-Colorado Project – Comparison of 1920 Approach vs. *State Exploration* Approach

State Exploration (ES Study) Approach

- **IPCo and PacifiCorp were allocated >90% of non-subscription costs** because the study was not bound by FERC planning regions

1920 Approach

- **IPCo and PacifiCorp are <u>excluded</u>** from the quantified benefits and zonal cost allocations because they are not part of WestConnect
  - Note that IPCo and PacifiCorp-East are still assumed to receive 100 MW of capacity each through the *subscription* process
- **PSCo's capacity/cost allocation is significantly <u>higher</u>** because there are fewer eligible entities to allocate costs to based on their quantified benefits

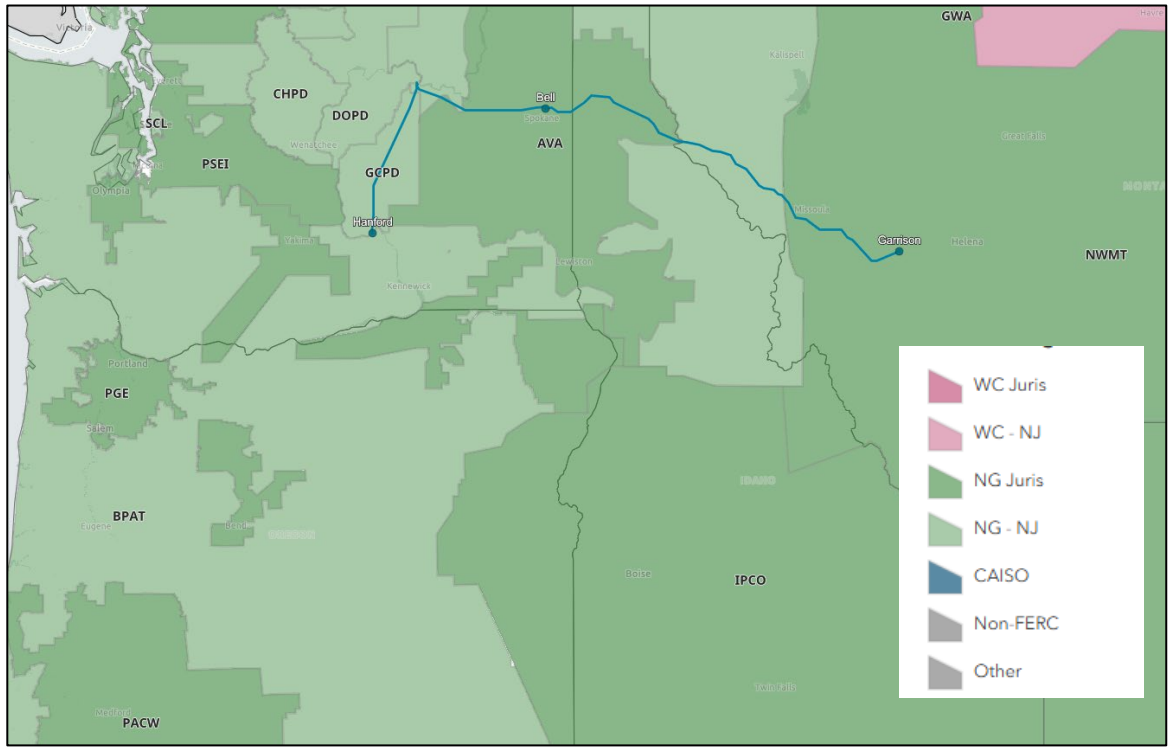


WACM was assumed to "opt-out" of allocations in the State Exploration and would also be excluded under 1920

Montana-Washington Project - Overview

Allocation Under *Ex Ante* Approach		
Subscribed Capacity (MW)	Portland General Electric	400 MW / $415M
	Puget Sound	400 MW / $415M
	Other Subscribers	400 MW / $415M
	Total	**1200 MW / $1,245M**
% of Post-Subscription Cost allocated based on Quantified Benefits	**75%** ($623M)	
% of Post-Subscription Cost allocated to Transmission Owners in adjoining BAs	**25%** ($208M)	

Map of Project Area with Balancing Area Boundaries



Subscribers and subscription amounts are **hypothetical** and intended to be illustrative of a potential subscription. To facilitate comparison, Energy Strategies applied the same subscription levels assumed in the *State Exploration of Western Transmission Cost Allocation Frameworks*

Montana-Washington Project - Benefits

Transmission Zones that are not FERC-jurisdictional and part of the relevant planning region (in this case, NorthernGrid) will not be allocated costs *even if those benefits are substantial*

	Operational & Congestion Benefits	Resource Adequacy Benefits	Avoided Transmission Investments	Resiliency Benefits	Capacity Savings from Reduced Peak Losses	Total Benefits ($M)	ETO in Relevant Planning Region?
AVA	$0.00	$0.00	$0.00	$0.11	$0.66	$0.77	Y
BCHA	$6.68	$0.00	$0.00	$0.22	$0.55	**$7.46**	**N**
BPA	$16.35	$0.00	$8.40	$0.00	$0.83	**$25.58**	**N**
CHPD	$0.62	$0.00	$0.00	$0.00	$0.00	**$0.62**	**N**
GCPD	$0.00	$0.00	$0.00	$0.14	$0.00	**$0.14**	**N**
IPCO	$0.30	$0.00	$0.00	$0.00	$0.25	$0.55	Y
NWMT	$0.00	$1.49	$0.00	$0.00	$1.24	$2.73	Y
NEVP	$1.90	$0.00	$0.00	$0.00	$0.00	$1.90	Y
PACE	$1.10	$0.00	$0.00	$0.00	$0.91	$2.01	Y
PACW	$1.11	$0.00	$0.00	$0.00	$0.13	$1.24	Y
PGE	$0.00	$0.00	$0.00	$0.28	$0.04	$0.32	Y
PSE	$0.00	$0.00	$0.00	$0.55	$0.00	$0.55	Y
SCL	$0.89	$0.00	$0.00	$0.26	$0.00	**$1.16**	**N**
TPWR	$0.00	$0.00	$0.00	$0.11	$0.00	**$0.11**	**N**

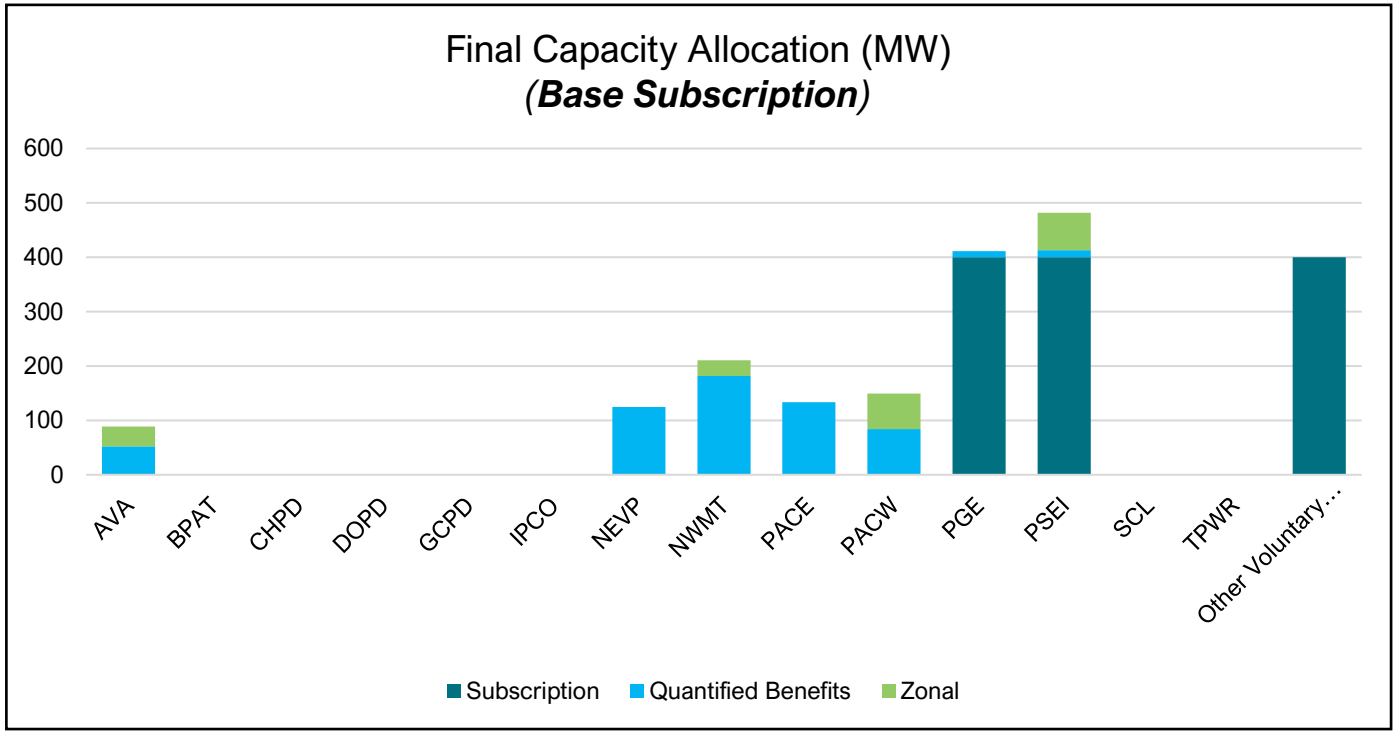
Montana-Washington Project - Benefits

Idaho Power receives minor benefits from the project but is not apportioned costs because its total allocation falls below the *de minimis* threshold

	Operational & Congestion Benefits	Resource Adequacy Benefits	Avoided Transmission Investments	Resiliency Benefits	Capacity Savings from Reduced Peak Losses	Total Benefits ($M)	ETO in Relevant Planning Region?
AVA	$0.00	$0.00	$0.00	$0.11	$0.66	**$0.77**	**Y**
BCHA	$6.68	$0.00	$0.00	$0.22	$0.55	**$7.46**	**N**
BPA	$16.35	$0.00	$8.40	$0.00	$0.83	**$25.58**	**N**
CHPD	$0.62	$0.00	$0.00	$0.00	$0.00	**$0.62**	**N**
GCPD	$0.00	$0.00	$0.00	$0.14	$0.00	**$0.14**	**N**
IPCO	$0.30	$0.00	$0.00	$0.00	$0.25	**$0.55**	**Y**
NWMT	$0.00	$1.49	$0.00	$0.00	$1.24	**$2.73**	**Y**
NEVP	$1.90	$0.00	$0.00	$0.00	$0.00	**$1.90**	**Y**
PACE	$1.10	$0.00	$0.00	$0.00	$0.91	**$2.01**	**Y**
PACW	$1.11	$0.00	$0.00	$0.00	$0.13	**$1.24**	**Y**
PGE	$0.00	$0.00	$0.00	$0.28	$0.04	**$0.32**	**Y**
PSE	$0.00	$0.00	$0.00	$0.55	$0.00	**$0.55**	**Y**
SCL	$0.89	$0.00	$0.00	$0.26	$0.00	**$1.16**	**N**
TPWR	$0.00	$0.00	$0.00	$0.11	$0.00	**$0.11**	**N**

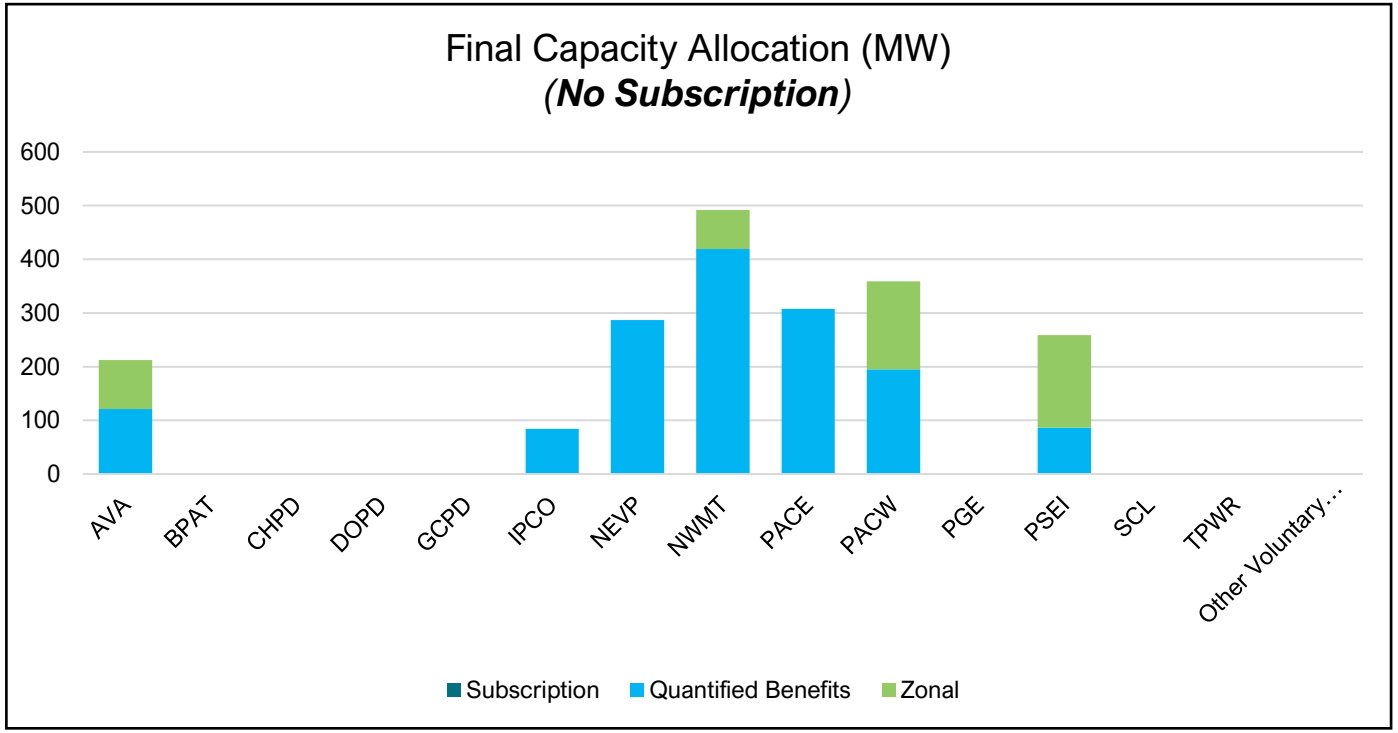
Montana-Washington Project – Results (Base Case)

- Base case assumes that Portland General, Puget Sound, and other **regional entities voluntarily subscribe to ~60% of line capacity**
- **Avista, Northwestern, NVE, and PacifiCorp** each end up with **~10% to 25% of the remaining capacity** and costs
- Despite being adjacent to the project, BPA and the Public Utility Districts are not assigned costs because they are not FERC jurisdictional
- After receiving only *de minimis* shares, IPCo is excluded from cost allocation



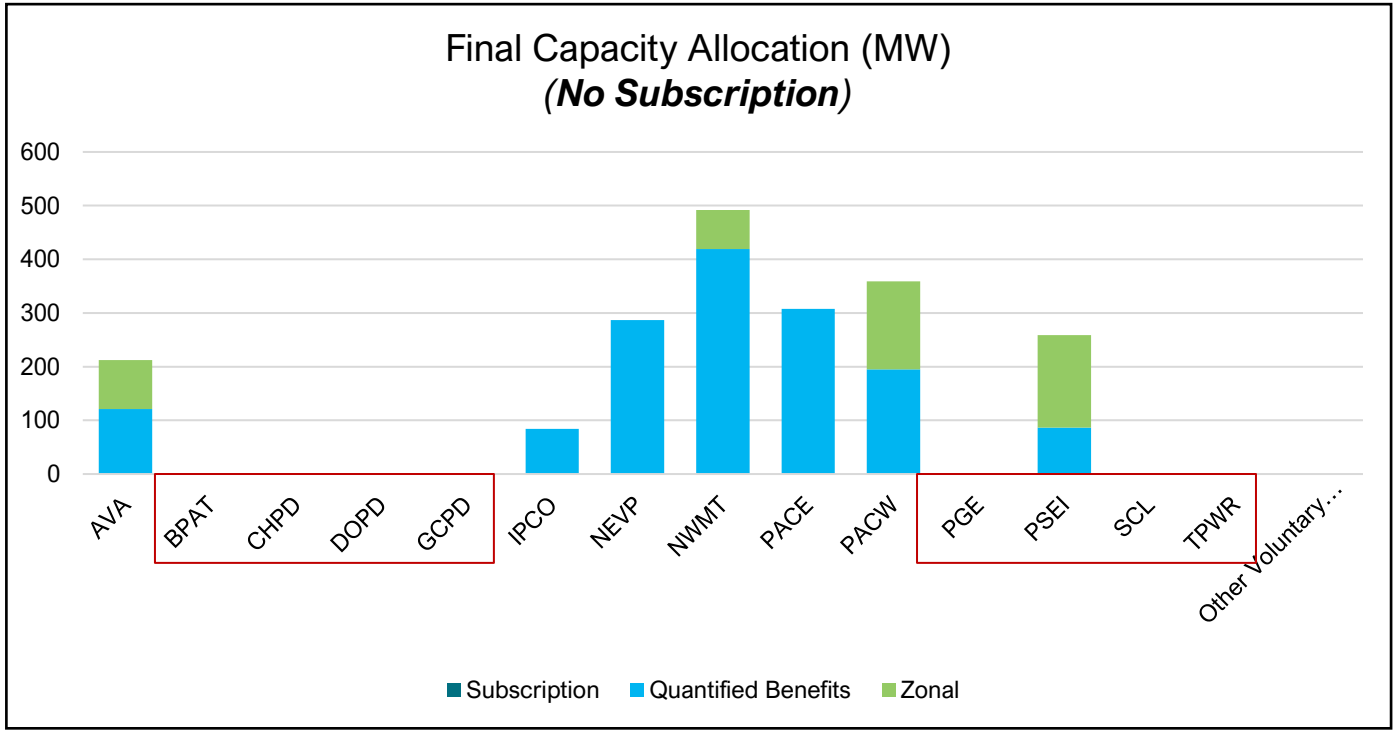
Montana-Washington Project – Results (No Subscription)

- **Puget Sound** receives a significantly <u>smaller allocation</u>
  - And most of its cost allocation is attributable to the zonal allocation
- **Avista, Northwestern, NVE, and PacifiCorp** see their <u>allocations more than double</u>
- **Idaho Power** is now allocated costs where it previously was not



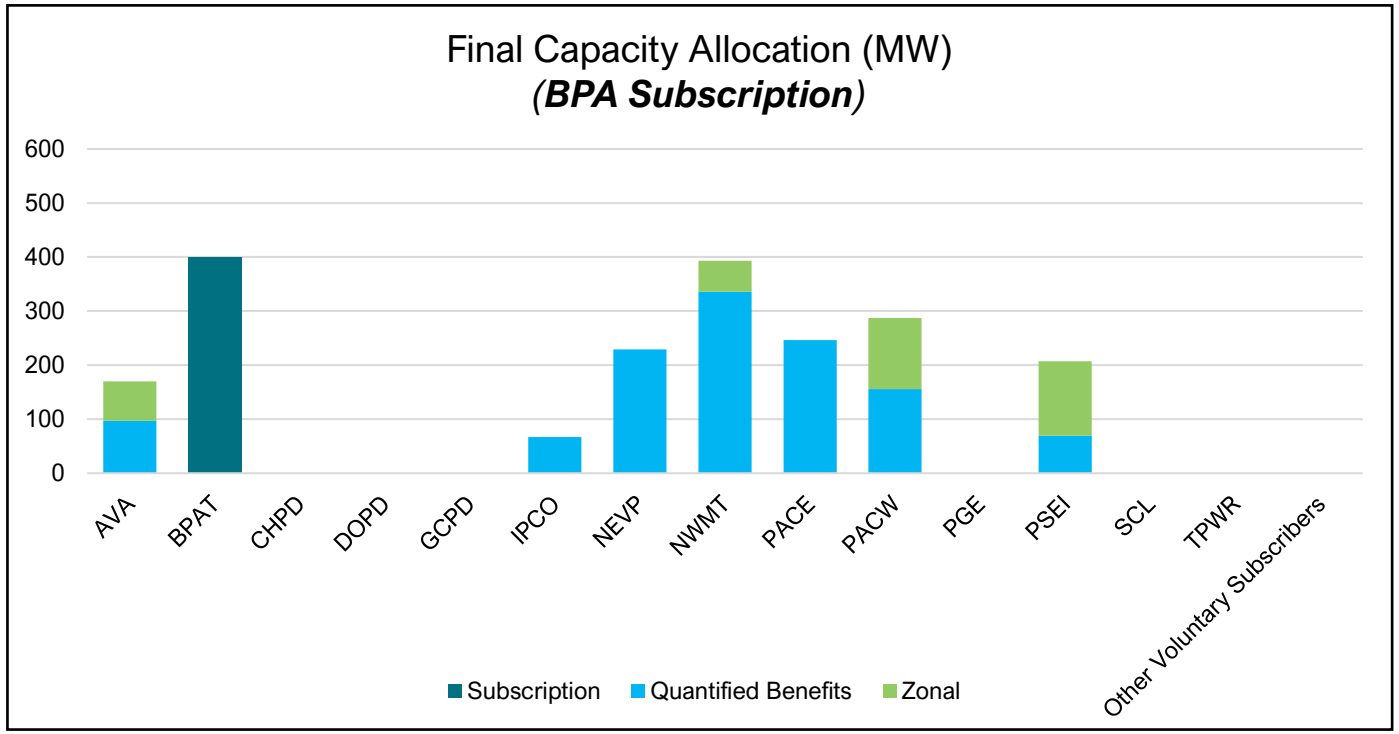
Montana-Washington Project – Results (No Subscription)

- The entities that are most likely to need this project for delivering remote resources and meeting their policy-driven objectives (e.g., **loads on the BPA system and coastal loads**) are largely exempt from capacity/cost allocations based on quantified benefits
  - BPA, the Public Utility Districts, Seattle City Light are all non-jurisdictional entities
  - Recall that the quantified benefits step does not capture policy benefits
- **To realize policy benefits, voluntary subscription is needed**



Montana-Washington Project – Results (BPA Subscribes to 20%)

- In a scenario where BPA subscribes to 20% of line capacity, **overall allocations to the other Transmission Zones decrease**
- However, the ***relative*** **distribution of costs** (among Transmission Zones, and between quantified benefits and zonal steps) **remains similar** to the No Subscription scenario



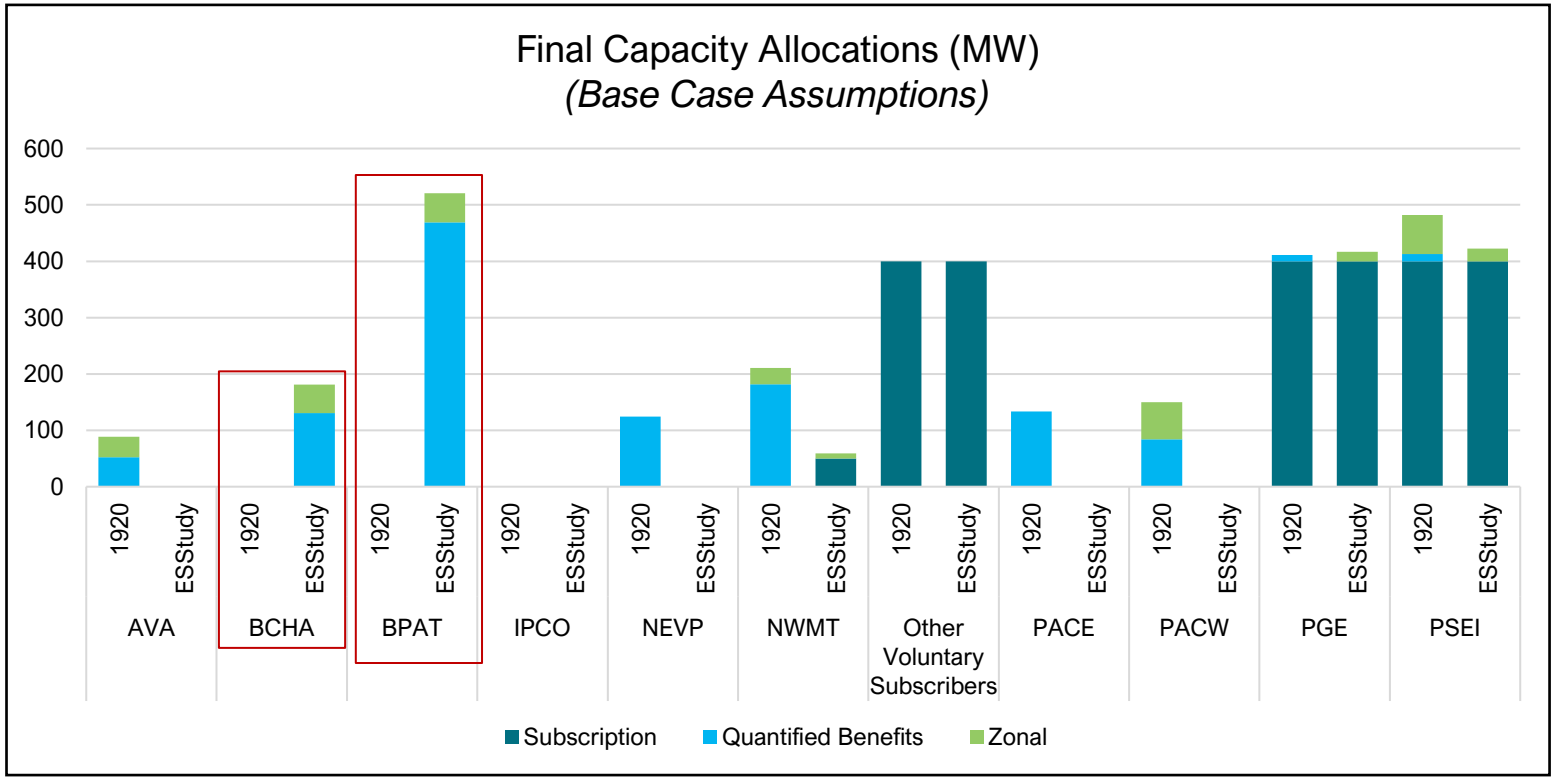
Montana-Washington Project – Comparison of 1920 Approach vs. *State Exploration* Approach

State Exploration (ES Study) Approach

- **BPA and BC Hydro were allocated costs** under the quantified benefits and zonal steps
  - Because that work was not constrained by FERC rules and was hypothetical

1920 Approach

- **BPA and BC Hydro are <u>excluded</u>** from the cost allocation because they are non-jurisdictional



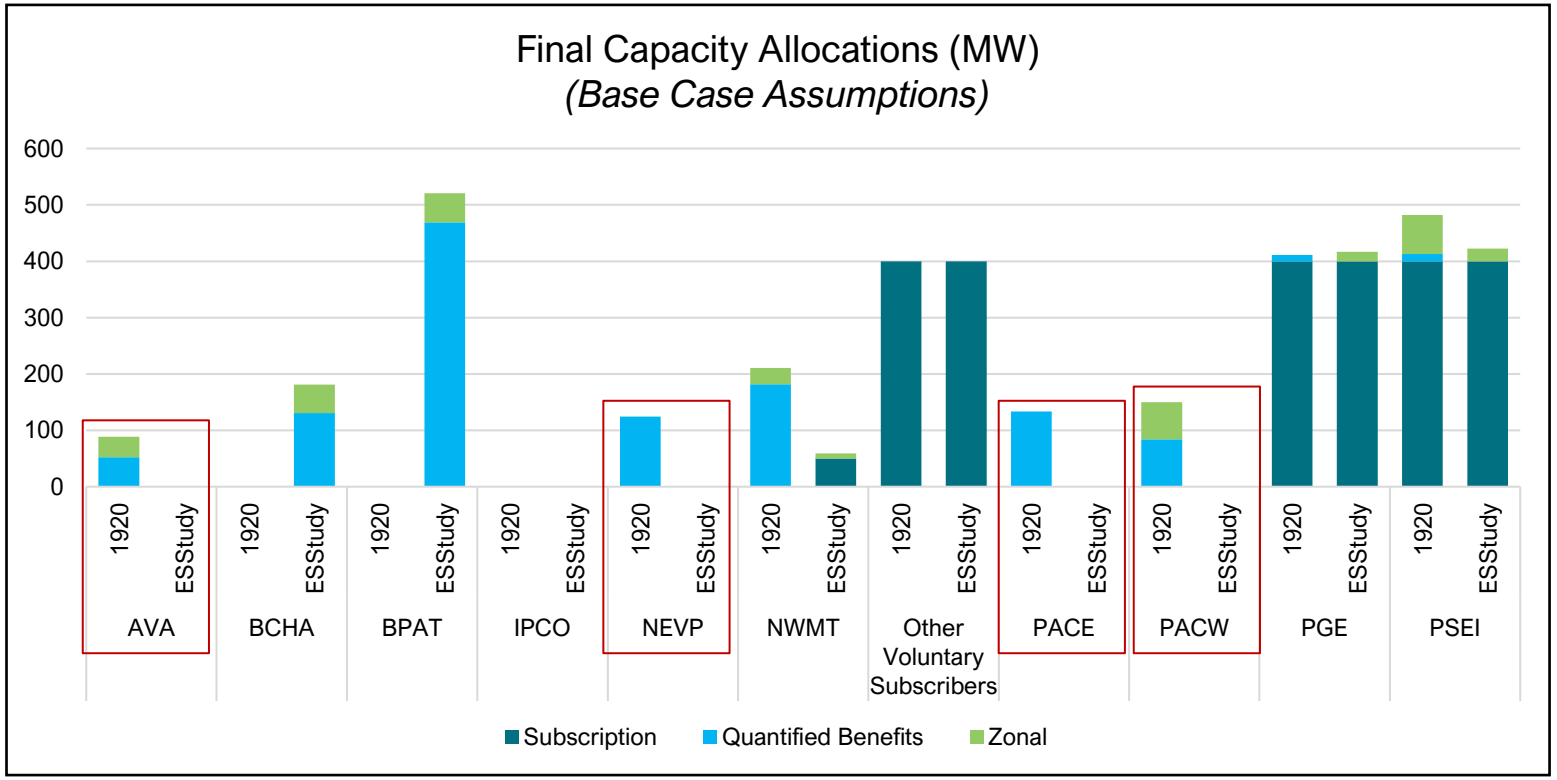
Montana-Washington Project – Comparison of 1920 Approach vs. *State Exploration* Approach

State Exploration (ES Study) Approach

- **Avista and PacifiCorp-West** were both excluded from cost allocation after receiving *de minimis* shares
- To avoid assigning "islanded capacity," **NVE and PacifiCorp-East** were also entirely excluded from cost allocation
  - Goal was to avoid assignment of potentially "unusable" capacity

1920 Approach

- **All four of these entities are allocated costs**
  - In the 1920 Study, BPA and BC Hydro cannot be allocated costs. As a result, Avista and PacifiCorp-West receive larger total allocations (above the *de minimis* threshold)



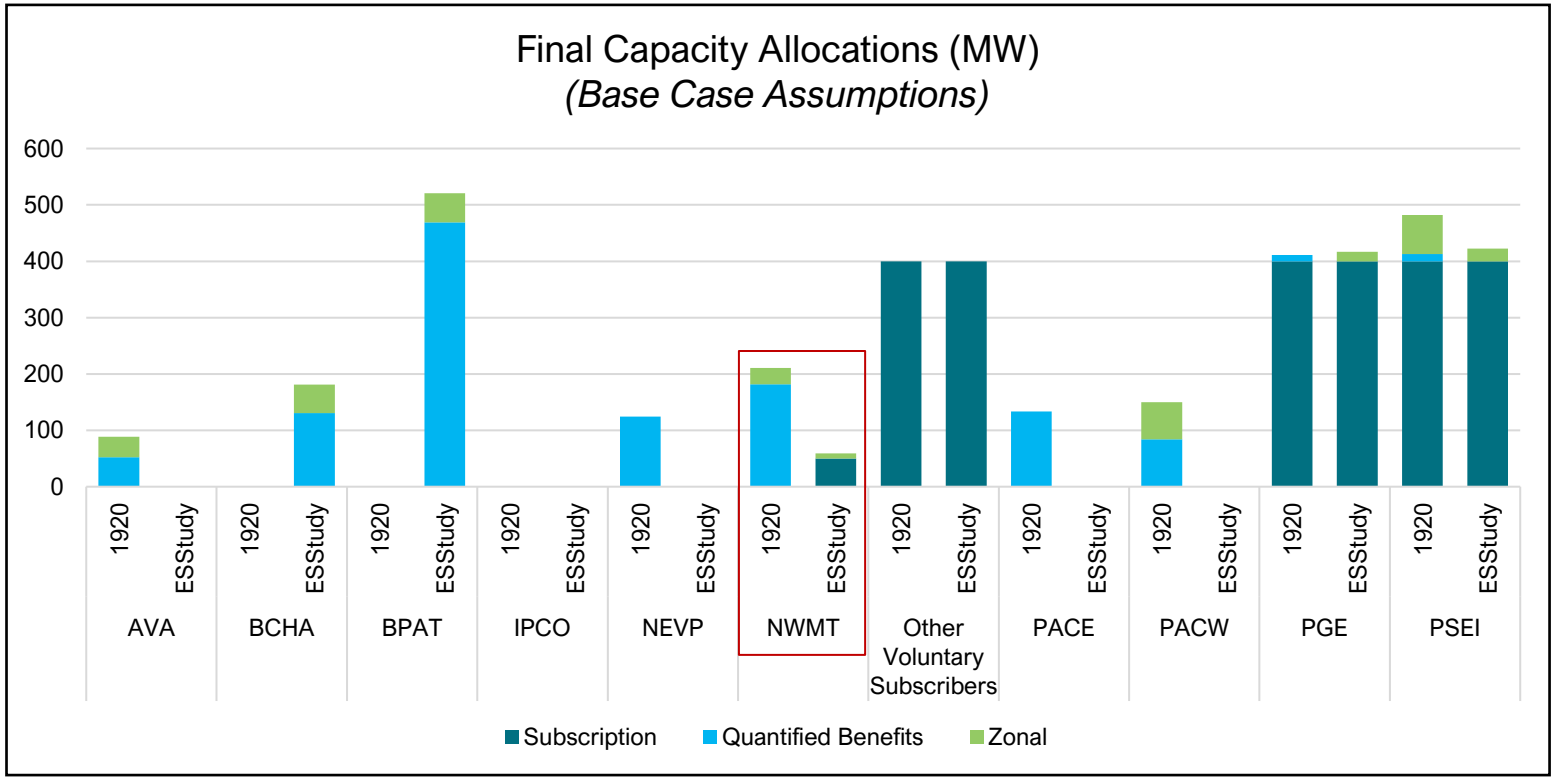
Montana-Washington Project – Comparison of 1920 Approach vs. *State Exploration* Approach

State Exploration (ES Study) Approach

- **Assumed that NorthWestern "opted in"** (i.e., belatedly subscribed) to the capacity other entities had "opted out" of

1920 Approach

- The **opt-in step is unnecessary** because there is no "opt out" option



Key Takeaways

- Cost allocation under Order 1920 will result in cost allocation to a **limited number of parties** (unless they voluntarily subscribe) given that **costs can only be allocated to Enrolled Transmission Owners in the relevant planning region**
  - This is the case *even if* other parties are demonstrated to benefit via benefit quantification
- Voluntary subscription is likely necessary to **align capacity and cost allocations with policy objectives**
- Cost allocating **projects that seem more interregional** in nature (i.e., that create benefits for both NorthernGrid and WestConnect) may create **illogical outcomes**
  - Wyoming-Colorado project generates substantial benefits for both PacifiCorp and IPCo, but only PSCo is allocated costs under this example because the project was assumed to originate in WestConnect
    - In practice, this type of project probably wouldn't pass either region's benefit-cost threshold and would need to proceed outside the FERC 1920 process
- While an appropriate **zonal allocation** approach is important, it **will matter less at high levels of subscription**
  - At high levels of subscription (>40%), less than 15% of total project costs will be allocated zonally
- Under the draft 1920 approach, some **entities may receive "islanded" capacity allocations that may be difficult for them to utilize (**under the current transmission paradigm in the West)
  - For example, NVE would receive capacity in the Montana-Washington line – despite that system being electrically distant
    - This is the case even though NVE is not included in the zonal allocation

Appendix

Summary of Assumptions Used In Case Studies

Subscription	Any party, within or from outside the relevant planning region, may choose to subscribe to a project. For the avoidance of doubt, costs are not allocated to subscribers from outside the planning region or non-jurisdictional transmission providers under any of the other cost allocation steps.
Benefit Apportionment	In cases where modeling identifies benefits for enrolled transmission owners (ETOs) outside of the relevant regional transmission planning organization, benefits are reported for nearby entities, but costs are only assigned based on those benefits to TOs within the relevant RTP.
Zonal Allocation	Per the draft ex ante cost allocations, only ETOs located in the balancing areas (BAs) through which the project traverses and transmission owners in adjoining BAs are assigned costs under the zonal category. For the purposes of this case study, "adjoining BAs" are assumed to include **all BAs within 100 miles of the transmission line** that are **FERC-jurisdictional** and **belong to the relevant planning region**. **For the purposes of this case study, costs were allocated based on the coincident peak loads** of the adjacent BAs. In practice, you might use distribution factor (DFAX) analysis to allocate costs by zones. For example, PJM allocates cost responsibility for its RTEP reliability baseline upgrades, at least in part, using a directionally-weighted solution-based DFAX methodology (see Section A.3.1 of PJM Manual 14B)
No Opt-Outs	ETOs may voluntarily acquire additional transmission rights (i.e., be assigned additional costs) at any time after the subscription process. However, **ETOs may not opt-out of transmission rights/cost allocation**.
Avoidance of Double-Counting	ETOs that subscribe to capacity in a project are **credited for the amount they commit to pay pursuant to the subscription process** but still have to pay an additional amount if their apportioned benefits (i.e., the benefits they would've been assigned absent subscription) exceeds their subscribed capacity. However**, all ETOs "adjacent" to the project** (per the definition above) **are assigned costs under the zonal step – regardless of subscription**. For example, if an ETO would be allocated $300M under the benefits allocation step and $100M under the zonal allocation step absent subscription (for a total allocation of $400M), and later decides to subscribe to $350M, their total allocation would be $400M ($350M + $100M)
De Minimis Allocations	ETOs that receive **less than 2.5%** of the overall capacity/costs of a project through benefits apportionment or zonal allocation are not required to pay any costs associated with the project unless they chose to subscribe to capacity associated with the project.
Treatment of Non-Jurisdictional TOs	Several of the Western TPs (e.g., SRP, WAPA) have been granted Coordinating Transmission Owner status by FERC for purposes of cost allocation. For this case study, it was assumed that **all non-FERC-jurisdictional entities** (e.g., BPA, WAPA, PUDs) **are excluded from mandatory cost assignment**. These entities may still choose to voluntarily subscribe to capacity in the line.

Benefit Quantification Methods

Benefit Methodology: Operational & Congestion Benefits

- **Adjusted production cost (APC) is a widely-used benefit metric used to quantify the operational and congestion relief benefits that accrue to utilities due to a new transmission project**
  - APC represents the net costs for a given area to serve load, accounting for power generation costs, power purchase cost, and revenues from power sales
- **A decrease in APC for an area or region from one scenario to the next represents short-run operational savings**
  - In this study, we would calculate APC hourly for the relevant BAs for each hypothetical project and attribute declines in APC – or savings – to the proposed transmission alternative

APC without Project (Base Case)	−	APC with Project (Base Case + Tx)	=	APC ($M) Savings

  - APC savings represent an annualized benefit of the hypothetical transmission projects
- **Entities that have used APC to estimate transmission benefits include:**

MISO, SPP Southwest Power Pool, ATC Energizing Your Future, U.S. Department of Energy Office of Electricity, ITC A Fortis Company, New York ISO

Adjusted Production Cost =

Region Production Cost
Fuel + VOM + Cycling Costs

+

Market Purchase Cost
energy imported to serve load

−

Market Sale Revenue
Excess energy from the region exported

Benefit Methodology: Resource Adequacy Savings

- **Also known as capacity savings, calculated through avoided cost analysis whereby it is assumed that new transmission capacity can unlock the benefits of load diversity by enabling the sharing of "unused" generation capacity between areas**
  - Load diversity benefits represent the MWs of generation in one area that could be used to meet peak demand in other area based on the nature of the peaks and enabling transmission capacity between areas
  - While transmission doesn't add generation capacity to the grid, it helps to transfer power between areas, accesses capacity to improve reliability, and is essential in ensuring resource adequacy
- **Savings represents the potential to reduce future capacity needs of an area due to transmission enabling access to existing and unused capacity**
- **Methodology assumes that capacity of existing transmission is fully utilized**

FERC Recognizes RA Benefits

"…transmission investments…generally enhance the reliability of the transmission system by increasing transfer capability, which, in turn, reduces the likelihood that a public utility transmission provider will be unable to serve its load due to a shortage of generation over a given period. This enhancement in reliability can be measured as a reduction in loss of load probability, or the likelihood of system demand exceeding generation over a given period"
- FERC, 2022, p. 165

Capacity Benefit Schematic

New transmission capacity enables additional transfer of unused generation from BA1 to BA2, and vice versa, resulting in opportunities for capacity savings so long as the two regions do not have peak loads that occur at the same time

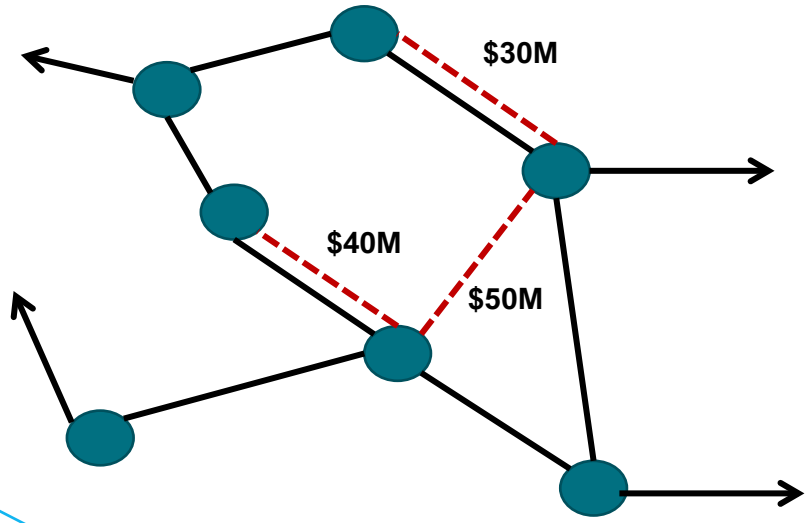
Simplified Analysis Steps

1. Collect hourly or forecasted demand data for study areas
2. Calculate load diversity benefits as the *lesser* of either the new line's capacity or the difference between the combined non-coincident and coincident peaks of the BAs (with savings limited by transmission capacity)
3. Make any required adjustments to estimated benefits
4. Value load diversity savings based on levelized cost of capacity estimates (e.g., net cone or proxy value)

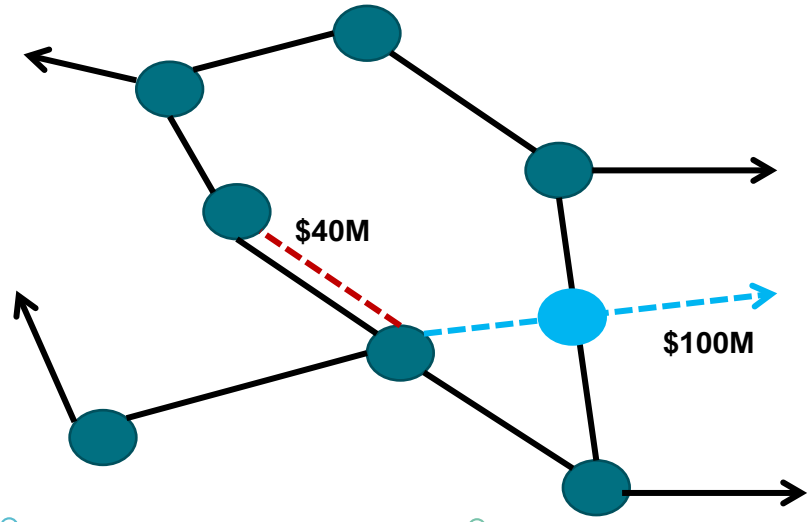
Benefit Methodology: Avoided Transmission Investments

- **If construction of a transmission project avoids the need to build other (often smaller) transmission project(s), the costs associated with the avoided transmission project can be quantified**
  - Requires power system analysis to determine that the local upgrade is no longer needed (or can be deferred) and the needs it was designed to address are met by the larger interstate project
  - The benefit of not building this upgrade is quantified through avoided cost analysis, so an estimated cost of the avoided project must be known as well

Plans for **upgrades** to maintain adequate reliability



A **new interstate project** means certain upgrades can be avoided (e.g., not needed)



The **benefit** of avoiding these projects is the present value of their annual revenue requirement

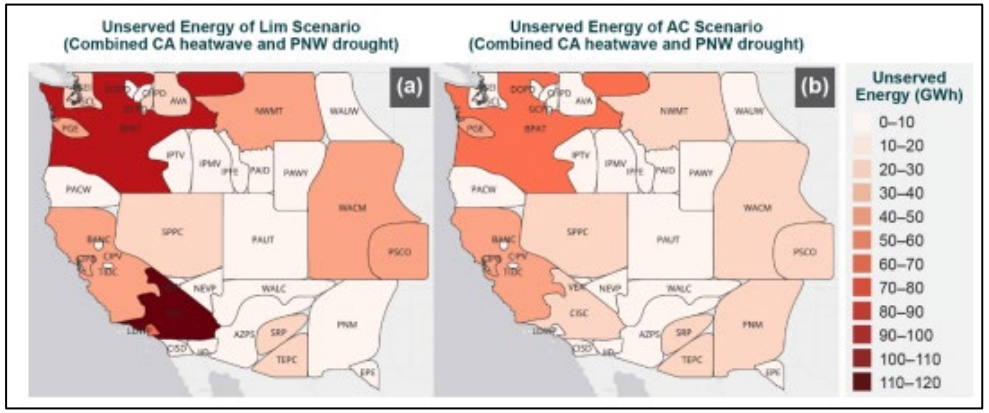
$30M
+
$50M

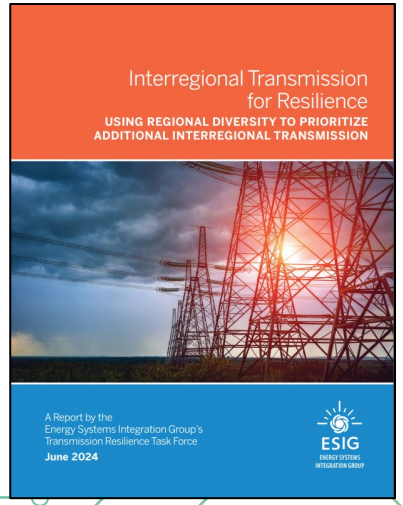
$80M of savings

Benefit Methodology: Resiliency Benefits

- **Study uses historical grid and weather data to help simulate short-term operational conditions under extreme weather events with and without a given transmission project**
- **Benefits of the transmission are calculated as reductions to load payments (area load*LMP) plus the value of any reductions in unserved load**
  - Dispatch model is used to source estimates of unserved load with and without the upgrade
  - Requires a valuation of unserved load, which can vary across jurisdictions
    - National Labs publish tools to support estimating the value of unserved load
    - For this study, Energy Strategies assumed $50,000/MWh
  - Also requires considering probability of the simulated event or similar events
    - 1 event in 10 years is a reasonable starting point, but there are no definitive methods for this
    - For this study, Energy Strategies assumed one summer event and one winter event each occur every five years (i.e., 20% of the total annual benefits occur each year)
- **Modeling features of extreme event studies capture:**
  - ✓ Transmission and/or generator outages consistent with event
  - ✓ Weather-correlated adjustments to loads
  - ✓ Weather-correlated wind and solar output consistent with events
  - ✓ Increased natural gas spot prices consistent with event

National Transmission Study Concludes that AC portfolio reduces unserved load during extreme events





ESIG Recommendation on Resilience

- **Consider transmission as a resilience asset.** Transmission can enable a region's access to resources in other regions that typically experience different weather, fuel supply, or demand patterns. Such exchange of energy can reduce the impact of localized weather events by allowing the region to benefit from geographical diversity. Planners can also consider that transmission can serve as an alternative to local resources by providing access to external resources that are not challenged by the same correlated risks faced by local resources.