State Exploration of Western Transmission Cost Allocation Frameworks

Stakeholder Update

April 2, 2025

Western Interstate Energy Board

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Project Objective: *Develop Comprehensive Cost Allocation "Frameworks" for the West*

- **The frameworks will:**
  - Identify **feasible benefit categories**, considering the possibility of benefit categories beyond those used in Order 1000
  - Illustrate how benefits and costs can **accrue to individual states and utilities**
  - Be designed with the **unique structure of the Western region** in mind

- **Energy Strategies was engaged to:**
  - Perform **background research** on transmission cost allocation approaches
  - Develop several **bespoke cost allocation frameworks** through input from CREPC TC members
  - Conduct **case studies** applying each of these selected frameworks to hypothetical transmission projects

Project Timeline

CREPC TC engages with **stakeholders** by providing project updates

March 2024 — May 2024 — September 2024 — March 2025 — *Tentatively:* May 2025

Conduct Background Research → Develop Cost Allocation Frameworks → Run Case Studies → Compile Results

Presentation of Research

Webinar session with CREPC TC to review findings, receive inputs, and inform next steps

Western Cost Allocation Framework Design

Interim Whitepaper developed in coordination with CREPC TC

Developed key inputs for case studies (e.g., hypothetical test projects)

Case Study Results

Webinar session with CREPC TC representatives to deliver the initial results of the case studies

Final report

Report summarizing the research, designs, and case study results. Materials will be organized and presented to the CREPC TC

Task Status

Complete

In-progress

Future work

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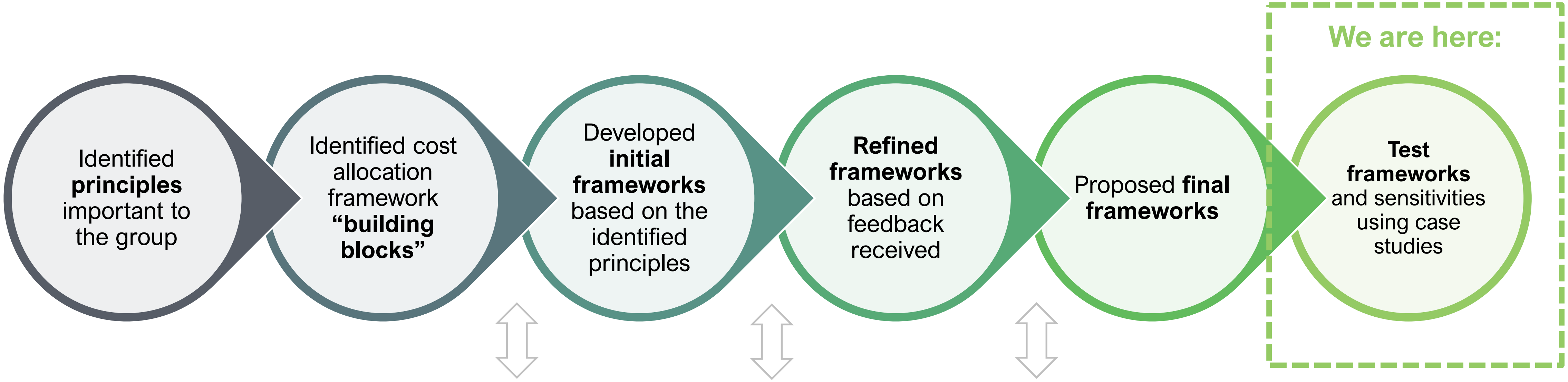
Purpose of Today's Meeting

- **Provide stakeholders with an update on the progress made so far**
- **Highlight preliminary observations from case studies**
- **Outline next steps**

How We Got Here…

Recapping work leading up the case studies and applications of chosen cost allocation frameworks

Process for Developing Cost Allocation Frameworks



Solicited feedback from CREPC TC members on their preferred approaches with periodic updates to stakeholders at CREPC public meetings

Cost Allocation Principles: State Perspectives

Based on survey and outreach performed early on in this project, CREPC TC members identified the following principles as particularly important in developing cost allocation approaches:

- The approach **considers cost causer pays and beneficiary pays principles**, assigning cost in a manner roughly commensurate with costs caused and benefits received
  - Assigns *fewer* costs to all users regardless of benefits
  - Assigns *more* costs to specific project beneficiaries
- The approach provides **opportunities for choice**
- The approach builds in **flexibility**

Cost Allocation Principles: State Perspectives (cont.)

Other elements that are important for developing cost allocation frameworks in the West include:

- **Cost allocation is not actually determined at a state-level**
  - Thus, the goal of this work is to **develop frameworks for allocating costs to Transmission Providers** for high-voltage transmission projects that impact multiple Transmission Providers in multiple states and, which, in turn, **states might generally support** (or at least generally understand) when brought forward for their consideration
- Any cost allocation framework, in the West, should not only outline cost allocation but **also include a framework for the allocation of transmission capacity** to different parties
  - The capacity allocation framework may align (partially or completely) with cost allocation but, nevertheless, should be considered
- **Some transmission benefit categories are better suited to quantification** and other benefit categories are better left as "opt-in" or negotiated
- It **may not be possible to fully achieve all desired principles,** and some approaches that honor one principle may require another to be deemphasized or even not achieved
- **Any costs that are subject to reassessment over time must still have up-front assurances for being recovered** in order for transmission investment to occur in the first place
  - Thus, any costs that are subject to "reassessment" must either be based on pre-agreed to measures and/or must have a default for cost allocation if subject to negotiation

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Cost Allocation “Building Blocks” or Categories

Cost Allocation Category	Description	% or $ Assigned to that Category	Best suited for quantification or negotiation
Capacity sought by Transmission Providers, generators or subscribers (“Subscriber pays”)	Costs allocated to any party that voluntarily agrees to pay for capacity on a transmission line(s)	Costs likely based on $ amounts, proportional to capacity sought, which may be a % of the total cost of the line(s)	**Negotiated** Capacity amounts and % of total costs allocated need to be negotiated between parties
Quantified beneficiary pays	Costs allocated in line with quantification of one or more benefit categories	Costs can be based on $ of benefits, but when used in combination with other benefits, but likely needs to be a defined/agreed to % of total costs	**Quantified** Benefit categories and quantification methods need to be agreed to but total amounts can be quantified using various approaches (**see next slide)**
Zonal cost allocation	Costs allocated to the transmission providers based on the location of the line(s)	Generally, a % of total costs are allocated in this manner	**Negotiated** % of costs allocated this way need to be negotiated in the framework
State/Other Party “Opt-In”	Costs allocated on a voluntary or “opt-in” basis, perhaps for policy needs, which are not in the quantified benefits category	Likely needs to be a % of total costs (not a $ amount)	**Negotiated** % of costs allocated this way need to be negotiated in the framework

Cost Allocation “Building Blocks”

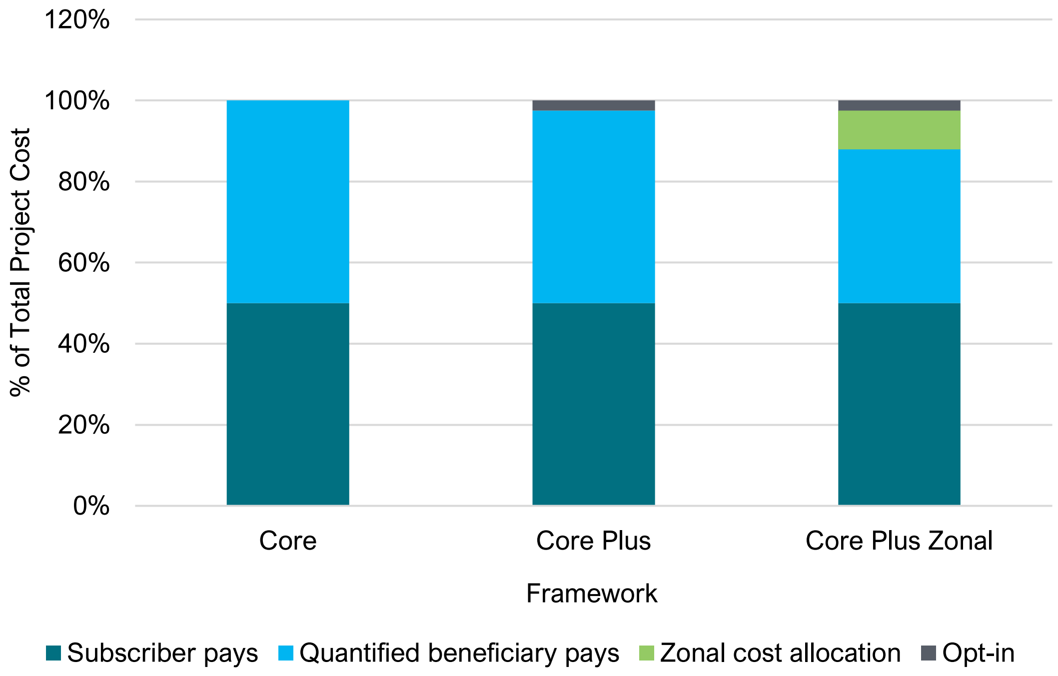
- Subscriber pays
- Quantified beneficiary pays
- Zonal cost allocation
- Opt-in

Generally, % allocated to each category needs to be determined or negotiated up front

Cost Allocation Frameworks Evaluated in Case Studies

- **The CREPC-TC and Energy Strategies developed three (3) frameworks and a series of sensitivities:**

Evaluate These Frameworks…



…Considering These Sensitivities

- Changes in subscription amount
- %'s assigned to categories
- Benefits included in quantified beneficiary pays
- Different levels of opt-in & negotiated outcomes

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Cost Allocation Frameworks Evaluated in Case Studies

Core Approach

Quantified beneficiary pays

100% of *remaining* costs allocated through **quantification of benefits**

Subscriber pays

XX% of project cost allocated via **subscriber pays** on a pro-rata basis

Core Plus Approach

Opt-in

XX% of *remaining* costs allocated to TPs that **opt-in**

Quantified beneficiary pays

XX% of *remaining* costs allocated through **quantification of benefits**

Subscriber pays

XX% of project cost allocated via **subscriber pays** on a pro-rata basis

Core Plus Zonal Approach

Opt-in

XX% of *remaining* costs allocated to TPs that **opt-in**

Zonal cost allocation

XX% of *remaining* costs allocated to **zones** through which the project passes

Quantified beneficiary pays

XX% of *remaining* costs allocated through **quantification of benefits**

Subscriber pays

XX% of project cost allocated via **subscriber pays** on a pro-rata basis

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Cost Allocation Steps

Step 1: Allocate capacity/ costs to subscribers

Step 2: Quantify project benefits

Core and Core Plus approaches take this path

Step 3a: Calculate preliminary capacity allocation for quantified beneficiaries

Step 4a: Adjust capacity allocations to quantified beneficiaries based on subscribed amounts

Core approach ends here

Step 5a: Re-allocate quantified beneficiary share of capacity based on opt-ins

Core Plus approach ends here

Core Plus Zonal approach takes this path

Step 3b: Calculate preliminary capacity allocation for quantified beneficiaries

Step 4b: Adjust capacity allocations to quantified beneficiaries based on subscribed amounts

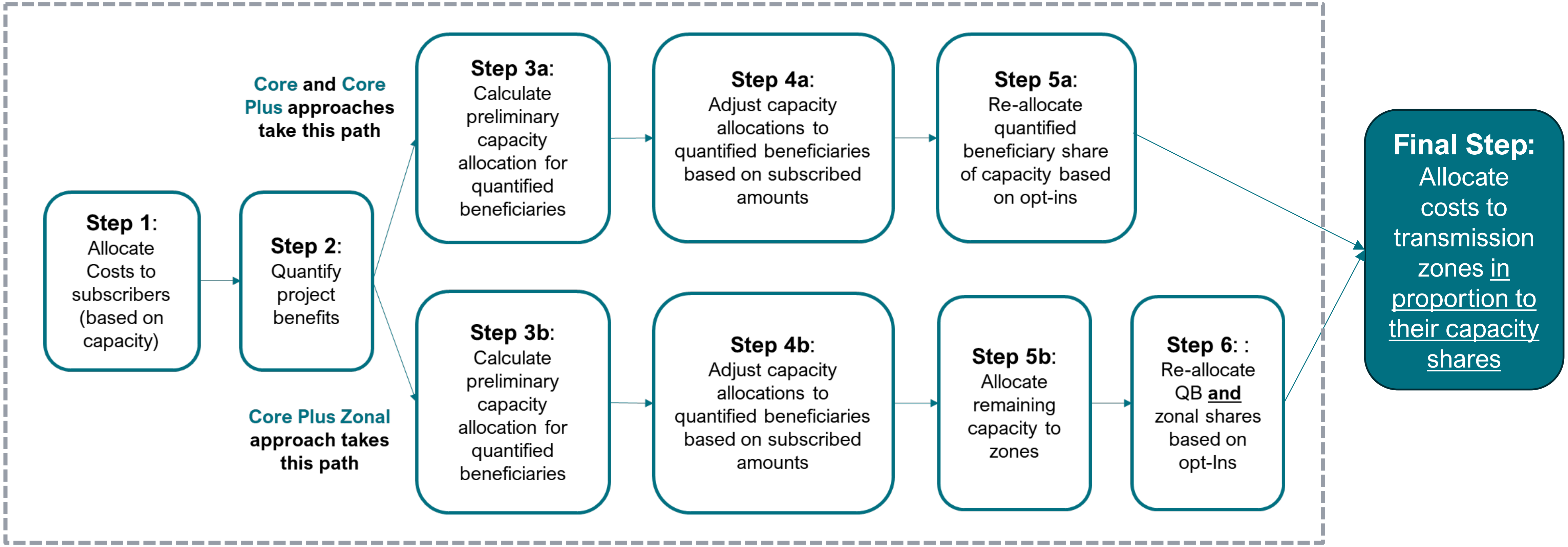
Step 5b: Allocate remaining capacity to zones

Step 6: : Re-allocate QB **and** zonal shares based on opt-Ins

Core Plus Zonal approach ends here

Cost Allocation is Based on Final Capacity Allocation

- **The CAPACITY allocations reached through Steps 1-6 are ultimately used to allocate COSTs**



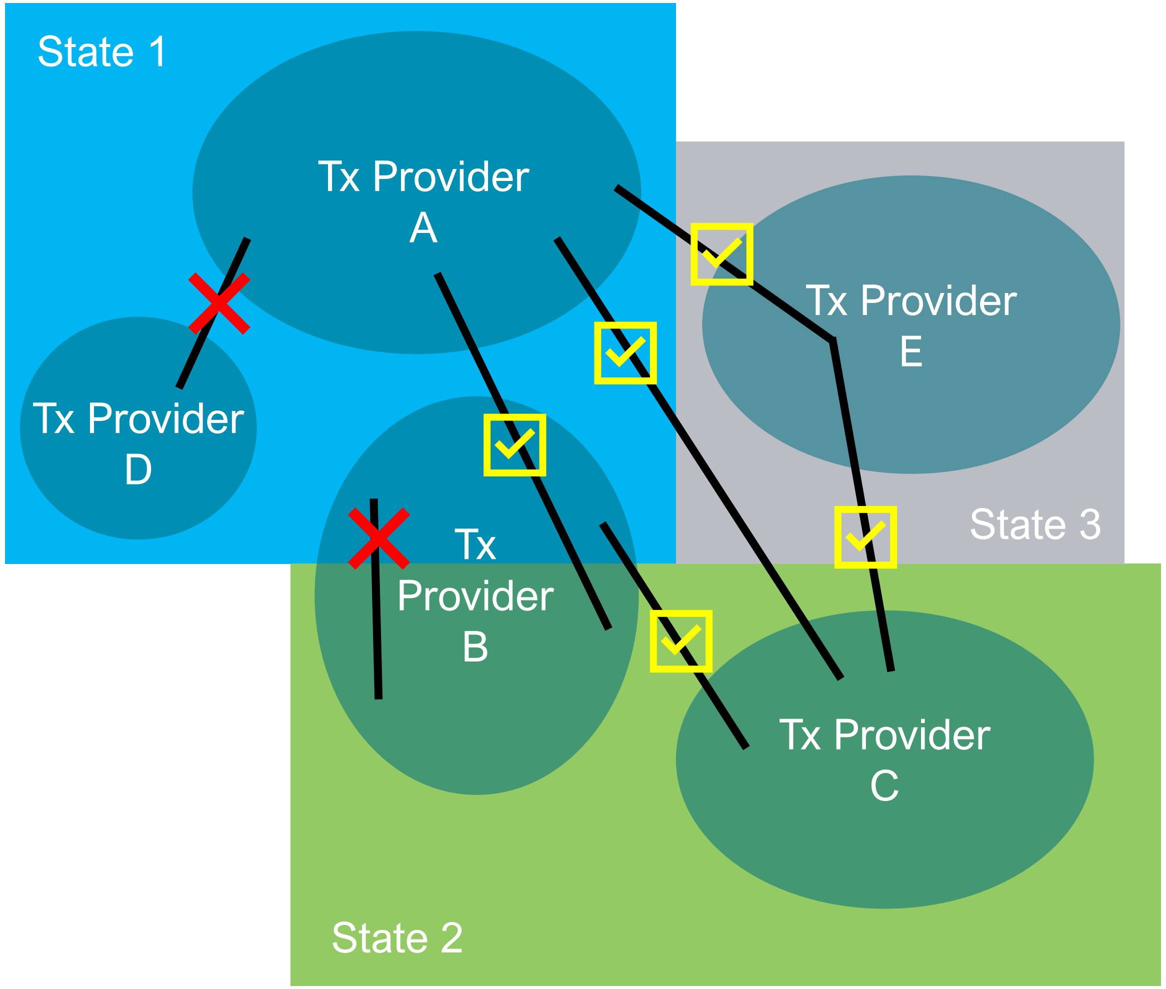
Hypothetical Projects Used in Case Studies

Identified high-voltage, geographically diverse, inter-state conceptual projects to test cost allocation frameworks

Reminder of Transmission Projects Considered in this Study

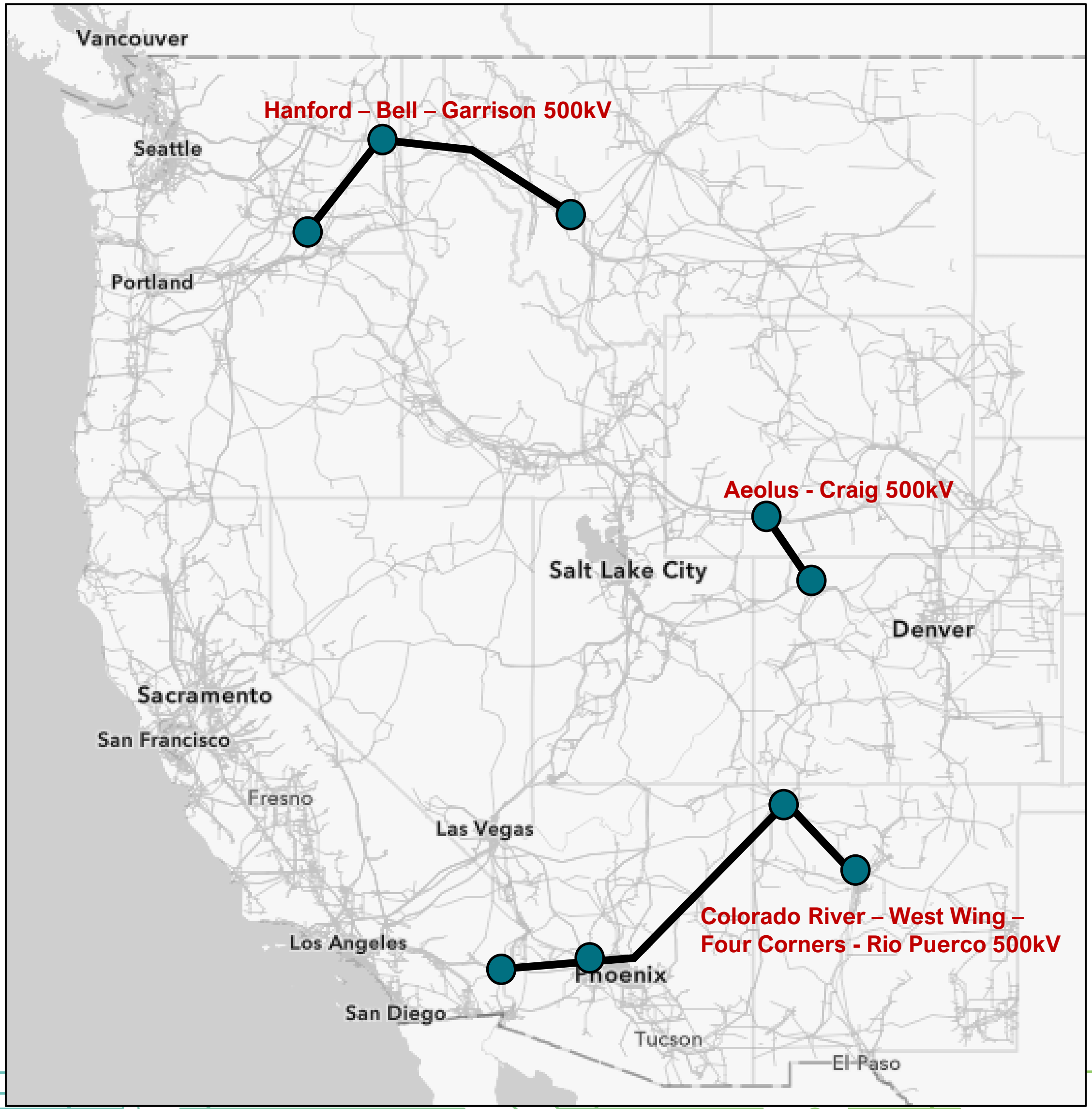
- This study focuses on **high voltage (>200kV or >300kV) transmission projects (or portfolios of projects) that electrically connect more than one transmission provider and directly impact more than one state**
- Our case studies focused on **single-project cost allocation** versus a portfolio of projects
- **Projects selected for study are <u>not</u> actual projects being proposed or in advanced development**

Inter-state & Multi-provider Transmission

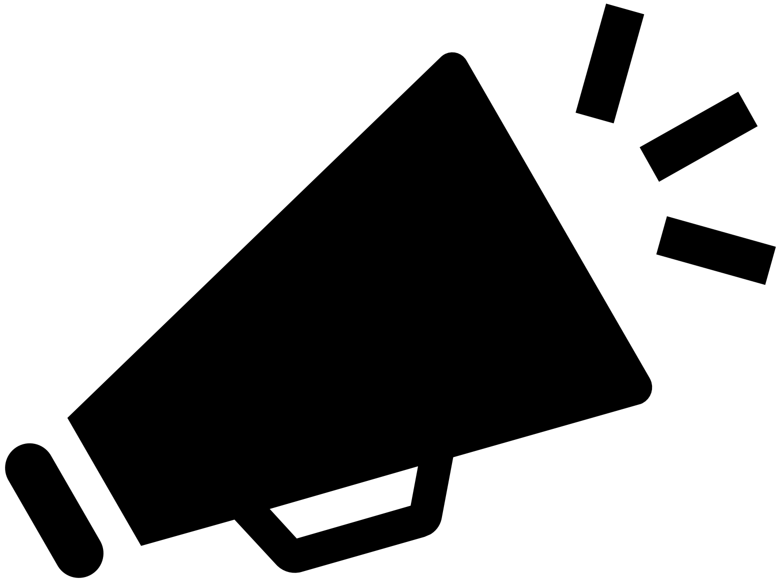


Case Studies Were Performed on Three (3) Projects

- **Montana-Washington project: Hanford – Bell – Garrison 500kV Transmission Line**
  - New ~200-mile Hanford to Bell 500kV transmission line
  - New ~260-mile Bell to Garrison 500kV transmission line
  - 1272 kcmil ACSS Bittern double bundle 3800 MVA
  - Cost Estimate: $2,075M
- **Wyoming-Colorado project: Aeolus – Craig 500kV Transmission Line**
  - New 500kV 4 positions (double-breaker bus) substation and two new 500/345kV 1600 MVA transformers at Craig
  - New ~130-mile Aeolus – Craig 500kV transmission line
  - 795 kcmil ACSS Drake double bundle 2800 MVA
  - Cost Estimate: $650.8M
- **New Mexico-California project: Colorado River – West Wing – Four Corners - Rio Puerco 500kV Transmission Line**
  - New 500kV 4 positions (double-breaker bus) substation and two new 500/345kV 1600 MVA transformers at Rio Puerco 29.8752
  - New ~159-mile Colorado – West Wing 500kV transmission line
  - New ~320-mile West Wing – Four Corners 500kV transmission line
  - New ~136-mile Four Corners – Rio Puerco 500kV transmission line
  - 795 kcmil ACSS Drake double bundle 2800 MVA
  - Cost Estimate: $2,803.5M



Subscriber Amounts & Opt-Ins are All Hypothetical



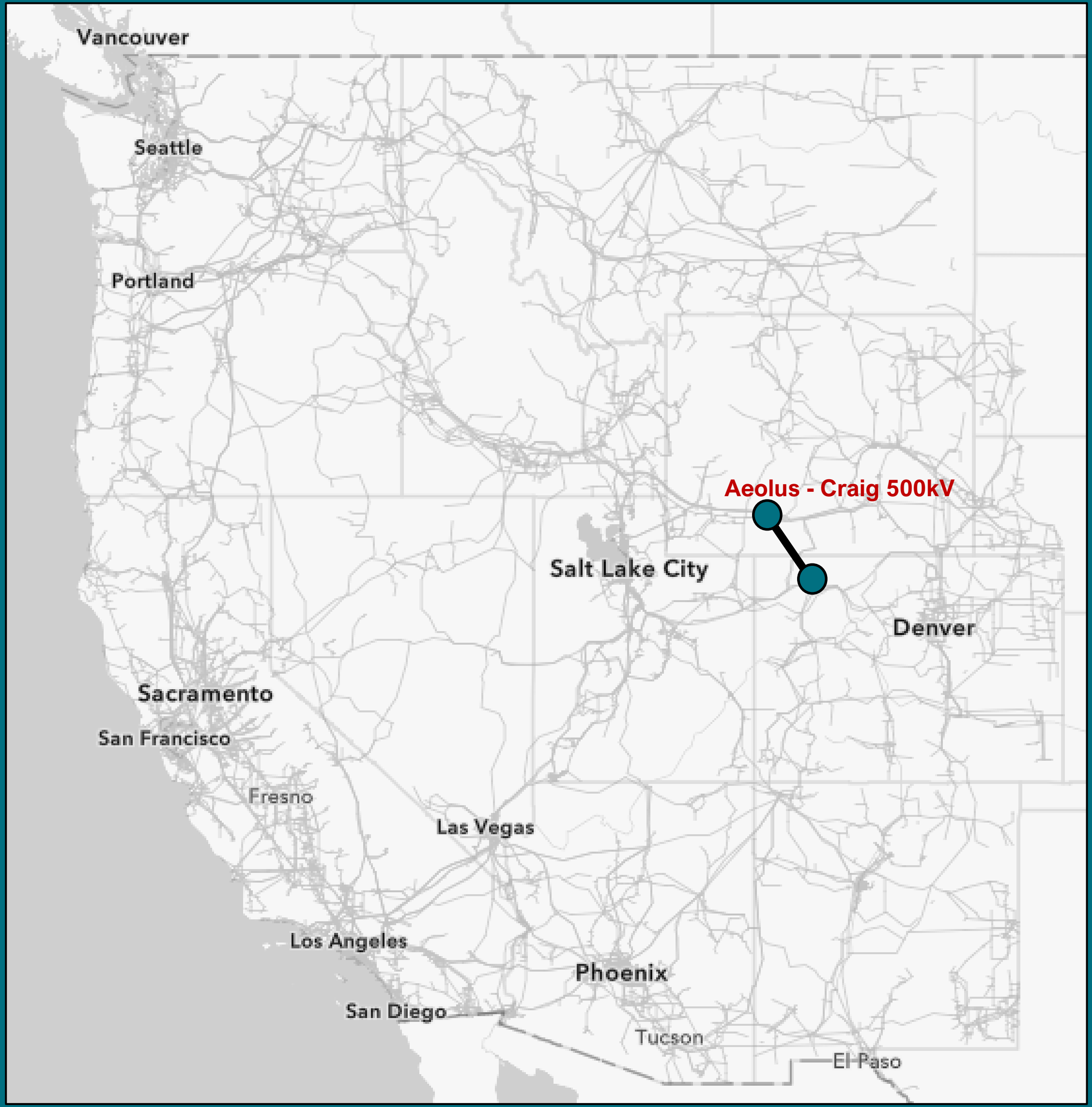
- To apply the cost allocation frameworks to hypothetical projects and produce case study results, Energy Strategies made assumptions regarding capacity subscriptions and how additional opt-in capacity might unfold

- The assumptions around subscription amounts and opt-ins are *hypothetical* and are not intended to reflect actual amounts these parties might voluntarily subscribe to

Case Study Results & Observations

Wyoming-Colorado

Review from Last Session



Review of Quantified Beneficiary Pays Benefit Categories

Benefit	Reasoning for Inclusion
Operational & Congestion Benefits	• Often measured based on changes in Adjusted Production Cost (APC); though there are other metrics that can also be used • APC represents the net short-run operational cost for a given area to serve load, accounting for power generation costs, power purchase cost, and revenues from power sales • Transmission that causes a decrease in APC for a given area reflects operational and congestion benefits for that upgrade
Resource Adequacy (RA) Benefits	• RA benefits from large-scale transmission, often referred to as "capacity savings", can be achieved when transmission capacity enables the sharing of load and resource diversity among multiple regions • These benefits accrue in larger amounts when there is load diversity between the areas that are connected by the transmission project and the regions can share "unused" capacity with one another during the other system's time of peak capacity needs
Avoided Transmission Investments	• In some cases, smaller and more local transmission project(s) could be necessary to integrate new resources and maintain transmission reliability if another (often regional) transmission project is <u>not</u> built • This category captures the savings associated with avoiding or deferring alternative system upgrades that would be otherwise be needed, but are no longer required or can be built at a later date
Resiliency Benefits	• Extreme weather and other system reliability events can cause economic harm in the form of extreme power prices and/or impacts to local communities and business via power outages • Transmission that reduces the frequency or magnitude of such events has a resiliency benefit to the system, with the benefit quantified as avoided economic harm outlined above

Wyoming-Colorado Project: Summary of Quantified Benefits

Quantified Benefits

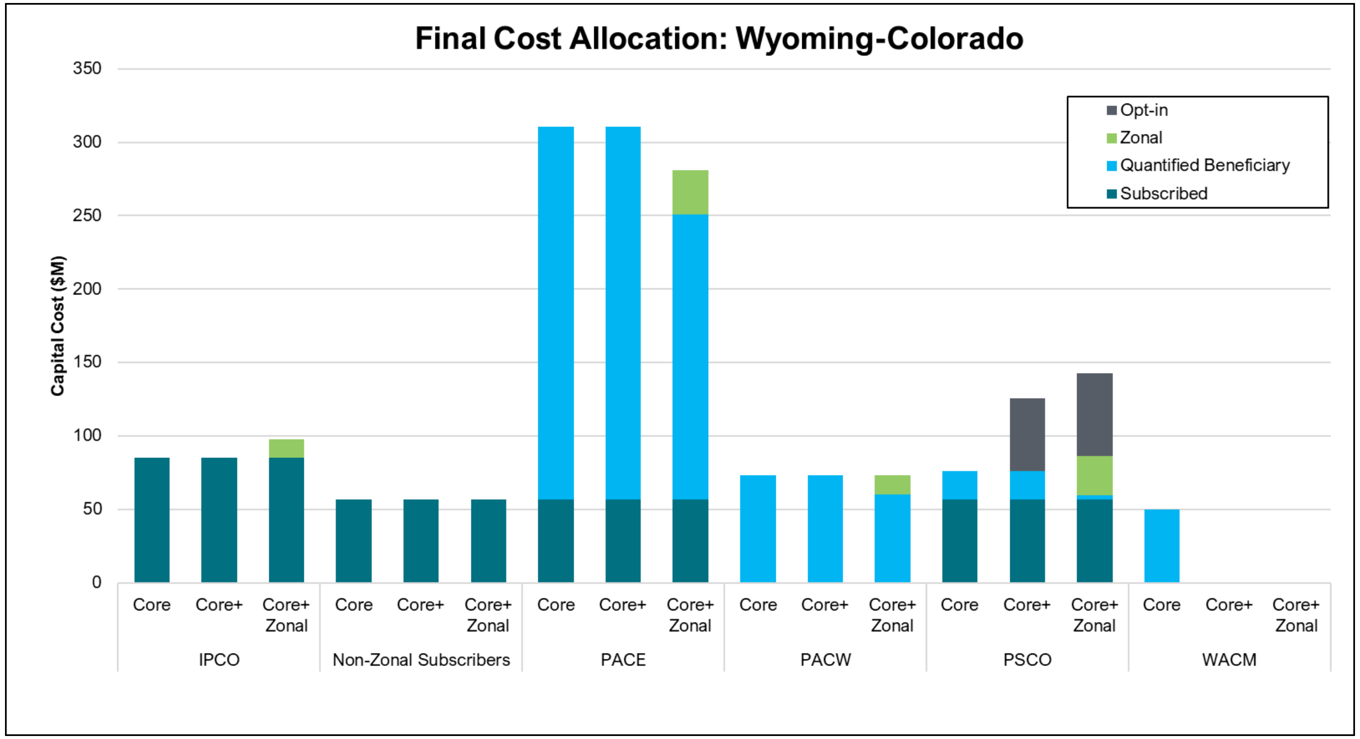
Tx Zone	Operational & Congestion Benefits ($M/year)	Resource Adequacy (RA) Benefits ($M/year)	Avoided Tx Investments ($M/year)	Resiliency Benefits ($M/year)	Total Benefits ($M/year)
IPCO	$0.00	$5.51	$0.00	$0.20	$5.71
PACE	$10.97	$14.82	$0.00	$0.18	$25.96
PACW	$6.25	$0.00	$0.00	$0.05	$6.30
PSCO	$2.77	$3.00	$0.00	$0.08	$5.85
WACM	$2.35	$1.85	$0.00	$0.06	$4.26
Other Subscribers					

Wyoming-Colorado Project: Base Case

Levers	Base Case
Subscriber Share	~40%
% Remaining Assigned to QB vs. Zonal	75% QB / 25% Zonal
Opt-In Share	8-9%

(Hypothetical) Assumptions for Modeling Purposes

Transmission Zone	Capacity Allocated to Subscribers	Opt-In Capacity
PACE	100 MW	
PACW		
PSCO	100 MW	(+) 88-99 MW
WACM		(-) 88-99 MW
IPCO	150 MW	
Other Subscribers	100 MW	



Subscribers and subscription amounts were hypothetical and intended be illustrative of a potential subscription

Opt-in and opt-out amounts were adjusted as necessary in each sensitivity case to zero out WACM's share

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Wyoming-Colorado Project: Case Study Sensitivities

- **The following sensitivities were modeled for the Aeolus-Craig project**

Bolded red text indicates deviation from Base Case

Levers	Base Case	Low Subscription	High Subscription	High Zonal Assignment	No Opt-In/Out	No Subscription & No Opt-In	No RA Benefits
Subscriber Share	**40%**	**10%**	**80%**	40%	40%	**0%**	40%
% Assigned to QB vs. Zonal	**75% QB / 25% Zonal**	75% QB / 25% Zonal	75% QB / 25% Zonal	**25% QB / 75% Zonal**	75% QB / 25% Zonal	75% QB / 25% Zonal	75% QB / 25% Zonal
Opt-In Share	**Varies***	Varies*	Varies*	Varies*	**0%**	**0%**	Varies*

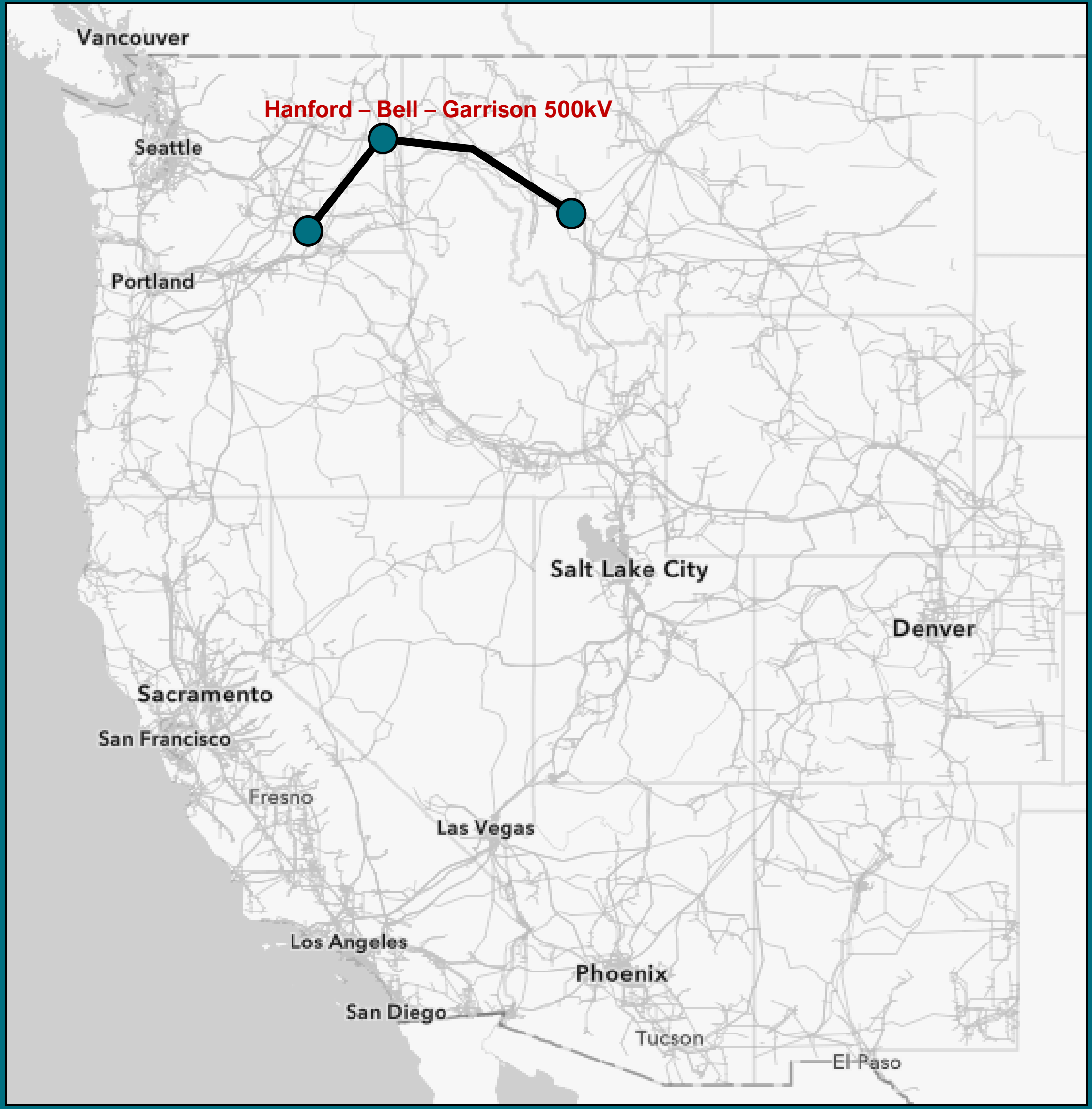
Note: While overall subscriber *shares* change across cases, hypothetical subscribing *entities* remain the same across all cases to allow for comparison

Key questions:

Low Subscription	What if there are fewer voluntary subscriptions?
High Subscription	What if there are increased voluntary subscriptions?
High Zonal Assignment	What if we rely on more zonal cost assignments?
No Opt-In/Out	What if we reduce flexibility by removing the opt-in share?
No Subscription & No Opt-In	What if we eliminate flexibility by removing the subscribers and the opt-in share?
No RA Benefits	What if we exclude certain benefits from the QB calculation?

Montana-Washington

Modeling Results & Sensitivities



Montana-Washington Project: Summary of Quantified Benefits

Quantified Benefits

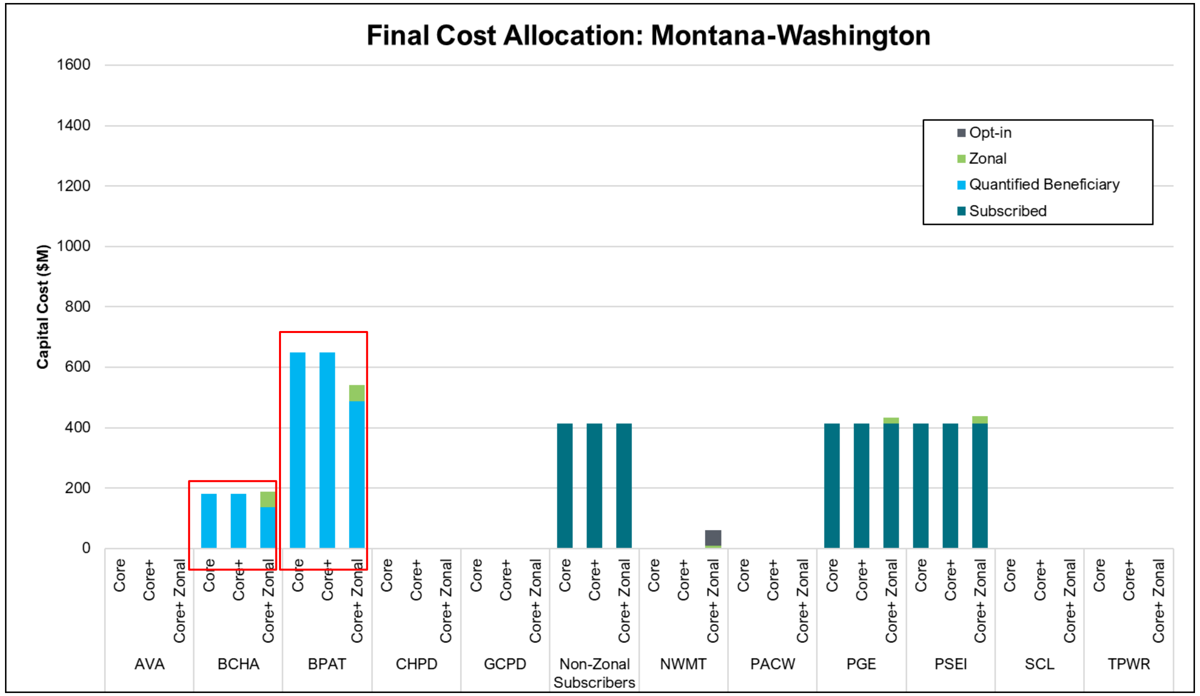
Tx Zone	Operational & Congestion Benefits ($M/year)	Resource Adequacy (RA) Benefits ($M/year)	Avoided Tx Investments ($M/year)	Resiliency Benefits ($M/year)	Total Benefits ($M/year)
AVA	$0.00	$0.00	$0.00	$0.11	$0.11
BCHA	$6.68	$0.00	$0.00	$0.22	$6.90
BPAT	$16.35	$0.00	$8.40	$0.00	$24.75
CHPD	$0.62	$0.00	$0.00	$0.00	$0.62
GCPD	$0.00	$0.00	$0.00	$0.14	$0.14
NWMT	$0.00	$1.49	$0.00	$0.00	$1.49
PACW	$1.11	$0.00	$0.00	$0.00	$1.11
PGE	$0.00	$0.00	$0.00	$0.28	$0.28
PSEI	$0.00	$0.00	$0.00	$0.55	$0.55
SCL	$0.89	$0.00	$0.00	$0.26	$1.16
TPWR	$0.00	$0.00	$0.00	$0.11	$0.11
Other Subscribers					

Montana-Washington Project: No Subscription

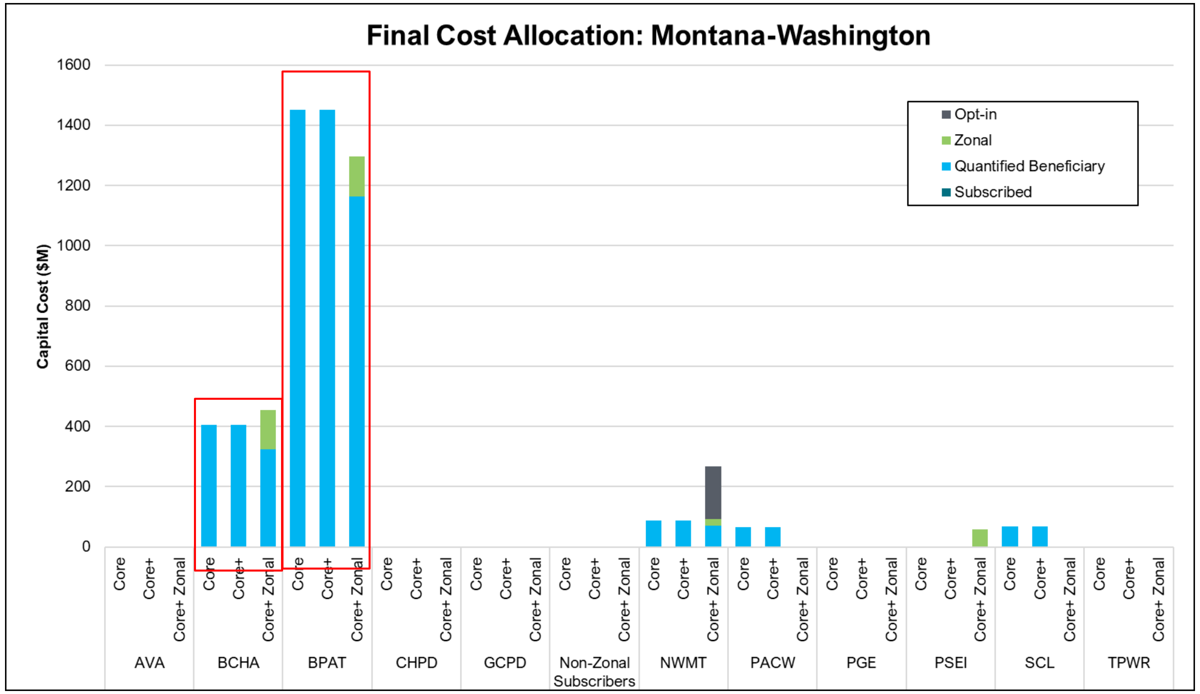
What happens if there are no voluntary subscriptions?

Subscription levels are set to zero (0)

Base Case



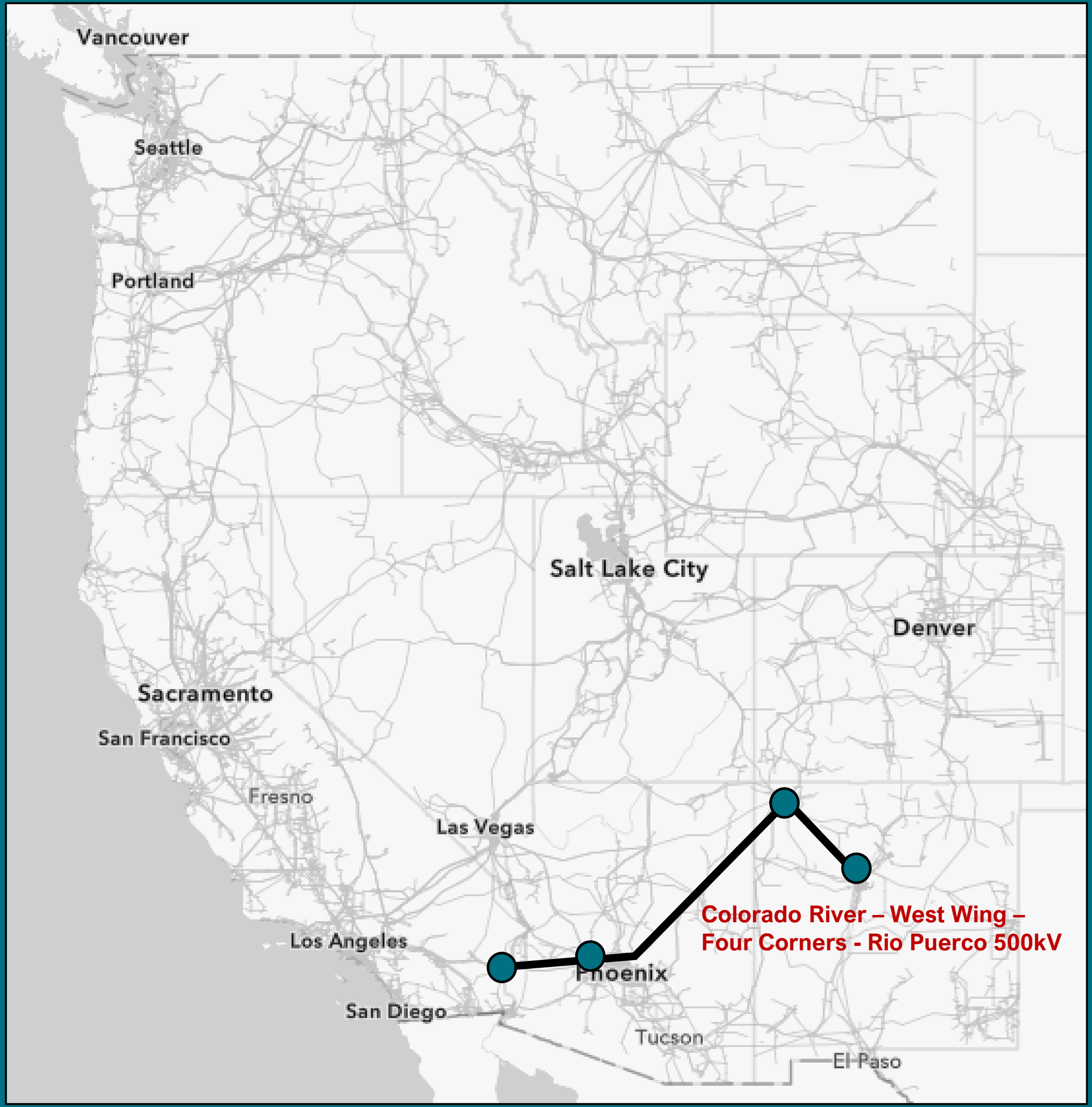
No Subscription Case



- Absent subscription, west-coast utilities in need of regional wind resources (e.g., PSE and PGE) were not allocated sufficient capacity
- At the same time, BPA and BCHA may have experienced too much capacity assignment relative to their actual need

New Mexico-California

Modeling Results & Sensitivities



New Mexico-California Project: Summary of Quantified Benefits

Quantified Benefits

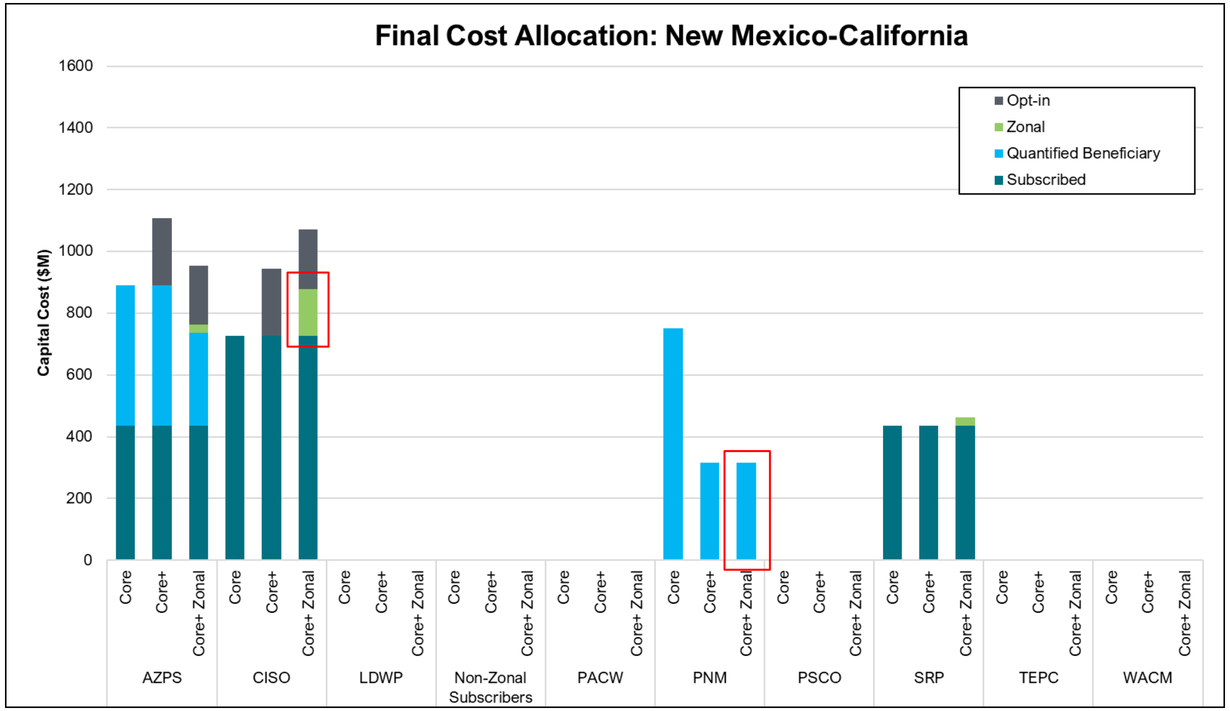
Tx Zone	Operational & Congestion Benefits ($M/year)	Resource Adequacy (RA) Benefits ($M/year)	Avoided Tx Investments ($M/year)	Resiliency Benefits ($M/year)	Total Benefits ($M/year)
AZPS	$0.00	$0.00	$143.00	$0.00	$143.00
CISO	$0.00	$0.00	$0.00	$0.00	$0.00
LDWP	$5.24	$0.00	$0.00	$0.00	$5.24
PACW	$4.47	$0.00	$0.00	$0.00	$4.47
PNM	$135.99	$12.32	$0.00	$5.10	$153.41
PSCO	$5.46	$0.00	$0.00	$0.00	$5.46
SRP	$0.00	$0.00	$0.00	$0.15	$0.15
TEPC	$4.11	$0.00	$0.00	$0.00	$4.11
WACM	$6.75	$0.00	$0.00	$0.00	$6.75
Other Subscribers					

New Mexico-California Project: High Zonal

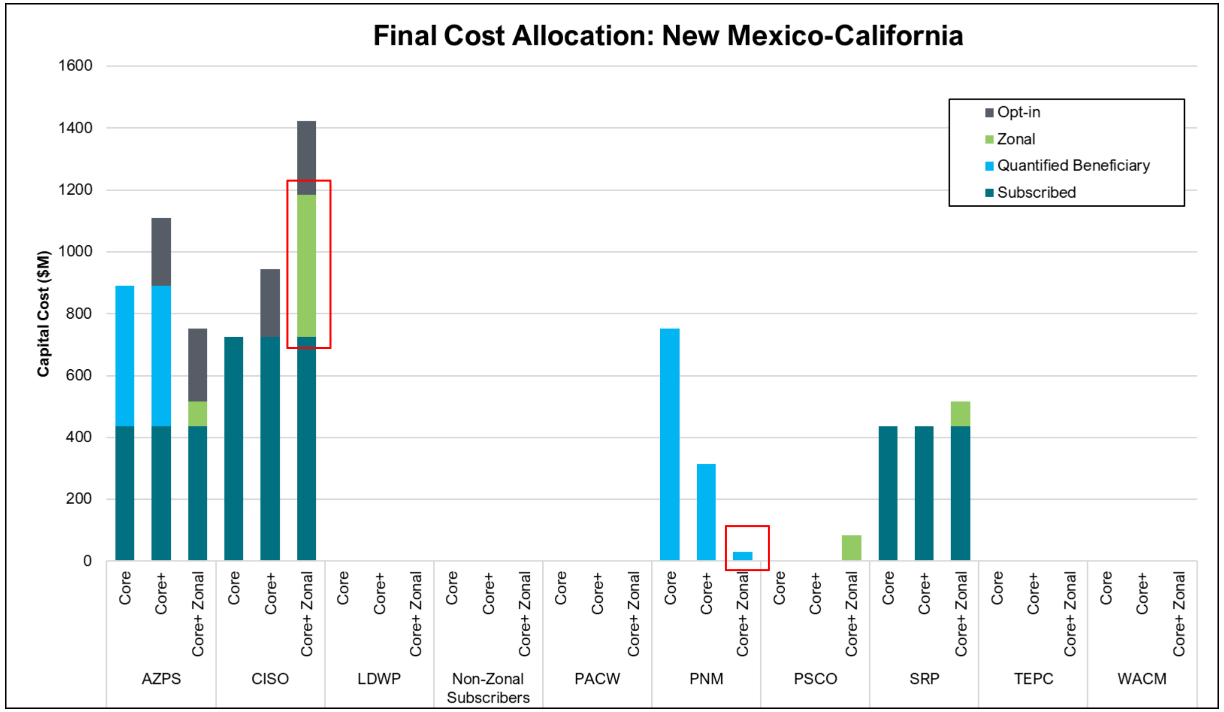
What happens if we rely more on zonal cost assignments?

25% of unsubscribed capacity assigned via QBs and 75% assigned via zonal allocation

Base Case



High Zonal Case



- Some stakeholders have expressed concerns that assigning a greater share of capacity on a zonal basis (rather than a benefits basis) would result in smaller utilities paying for transmission that primarily benefits larger load centers
- Here, assigning more costs on a zonal basis (i.e., based on coincident peak loads) and fewer costs based on quantified benefits, resulted in a *lower* cost assignment for PNM (a smaller utility)

Observations

Energy Strategies' interpretation of study and its outcomes (so far)

Energy Strategies' Observations: Process

1. **Critical role of subscriptions.** The voluntary subscription step is foundational. Without committed subscribers – particularly on projects that primarily support policy or resource access needs – benefit-only frameworks risk irrational and inequitable cost allocations and capacity assignments. The frameworks are predicated on rational actors taking subscriptions; otherwise, resulting allocations are unlikely to be supported by remaining beneficiaries (particularly for resource delivery projects).

2. **Non-binding nature of process is a feature, not a flaw.** The frameworks are designed to be rational, flexible, and non-binding. A fully binding process would likely require broader benefit quantification, which may not be technically feasible. For instance, it may be impossible to accurately quantify every transmission zone's policy benefit from participation on a single project. The approaches adopted here explored balance structure with voluntary (and rational) participation to limit the misallocation of costs that could hinder project acceptance.

3. **Flexibility through opt-in/opt-out.** Allowing transmission providers to decline participation or opt into capacity assignments introduces necessary flexibility. This approach, while susceptible to some free-ridership, preserves progress and avoids "all-or-nothing" scenarios, with an emphasis on negotiating outcomes that keep project feasibility high for those that want capacity and benefit from the upgrade. However, in implementation the approach may require increasingly "firm" contractual or financial commitments for capacity to avoid a "house of cards" effect at the end of the process.

Energy Strategies’ Observations: Benefit Analyses

1. **Significant analytical discretion was required.** The quantified benefit methods and assumptions – particularly production cost savings, RA benefits, and resiliency – were determined using expert judgment and experience. In applying these approaches to real-world projects, these analyses would require months or years of iterative validation and multi-party agreement.

2. **While the benefit categories adopted were reasonable, certain metrics require more research.** Certain metrics (e.g., resiliency and avoided transmission) require future enhancement and subsequent standardization to increase replicability and stability. Other benefit metrics are possible, but controversial and difficult to calculate – CREPC TC landed on a reasonable list (although there is some room for refinement around the edges).

3. **Realistic and pragmatic benefit assignment is critical.** Energy Strategies identified potential beneficiaries of projects based on grid simulation results and our knowledge of system topology and transmission ownership (and regional transmission drivers). This judgement is critical and prevents benefits from being assigned to entities ill-suited to actually use the capacity.

Energy Strategies' Observation: Policy

1. **Reasonable capacity-based allocations are foundational.** Cost allocations must ultimately tie to MW capacity shares, and that capacity must not be de minimis in size or "islanded" from the loads. In a non-flow-based, contract path paradigm like the West, this is essential to ensure that costs result in usable system capacity.

2. **Voluntary cost allocation models require trust and negotiation.** The frameworks require mutual acceptance of uncertainty and a willingness to tolerate modeling imperfections in the interest of advancement. For example, quantified benefits can provide indications of benefits, but isn't all encompassing and may offer a "false sense of precision". For the process to work, parties will need to agree to "live and die by the sword" as much as tolerable.

3. **Could support state-level concerns about top-down allocation risks.** This framework could help address concerns about top-down FERC cost assignments that are not reflective of actual local benefits important to state regulators. By building consensus and transparency from the ground up, the framework reduces the likelihood of cost misallocation.

4. **Tradeoff: Flexibility vs. Project Risk.** While the approach preserves flexibility and autonomy, this comes with a risk: projects may fail if voluntary buy-in & acceptance of allocations are insufficient. The framework offers scaffolding, but not guarantees, for project success. The outstanding question is: do the frameworks offer enough structure to actually make a difference versus the status quo?

Common cost allocation concerns may be addressed through a transparent, well-defined, yet flexible cost allocation process

Common cost allocation concerns	Addressed in study?	Explanation
Overburdening of individual utilities	✅ Yes	Balanced mix of subscribers, narrow beneficiaries, and opt-in/opt-out protections prevent disproportionate costs. Two outcomes are most likely: rational subscription, or project doesn't proceed.
Public power autonomy	✅ Yes	Framework allows full opt-out, accommodating those unwilling or unable to participate.
Free rider risk and cost impact considerations	🟡 Partially	Opt-out invites some free-ridership; mitigations like rate impact tests could help explore cost impacts.
Geographic mismatch of resources and loads	✅ Yes, conditionally	Framework allows remote loads to assume cost if they choose, relying on voluntary rationality.
Different value systems	✅ Yes	Opt-in and subscription structure accommodates diverse definitions of "value." Resolves conflict of what constitutes a "benefit" worth paying for.
Benefit quantification difficulty	🟡 Partially	Reasonable methods used, but long-run uncertainty and complexity remain. In application, more testing and tuning should be done to improve confidence. For those that are too difficult to quantity, we left it to individual entities to determine their benefits and then act rationally in response.
Transmission rights alignment	✅ Yes	Framework encourages alignment between capacity allocation and cost responsibility.
Fairness	✅ Yes, largely	Equal treatment of costs for subscribed or assigned capacity supports fairness principles.
State comfort with cost allocation	???	States might be concerned with federal cost allocation policies that cause costs to be assigned in ways that don't benefit customers. This approach could head that off. As a tradeoff, it does increase the potential for projects to fail given the flexibility and non-binding nature of the process.

Next Steps

Q&A