State Exploration of Western Transmission Cost Allocation Frameworks

Draft Presentation of Case Studies – Part 1

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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

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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 (Remaining case study results forthcoming to CREPC TC at April meeting)

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

Today's Agenda

A Reminder of Cost Allocation Frameworks

B Review of Hypothetical Projects used in Case Studies

C Initial Case Study Results for Aeolus – Craig 500 kV Project

D Aeolus-Craig 500 kV Base Results & Sensitivities

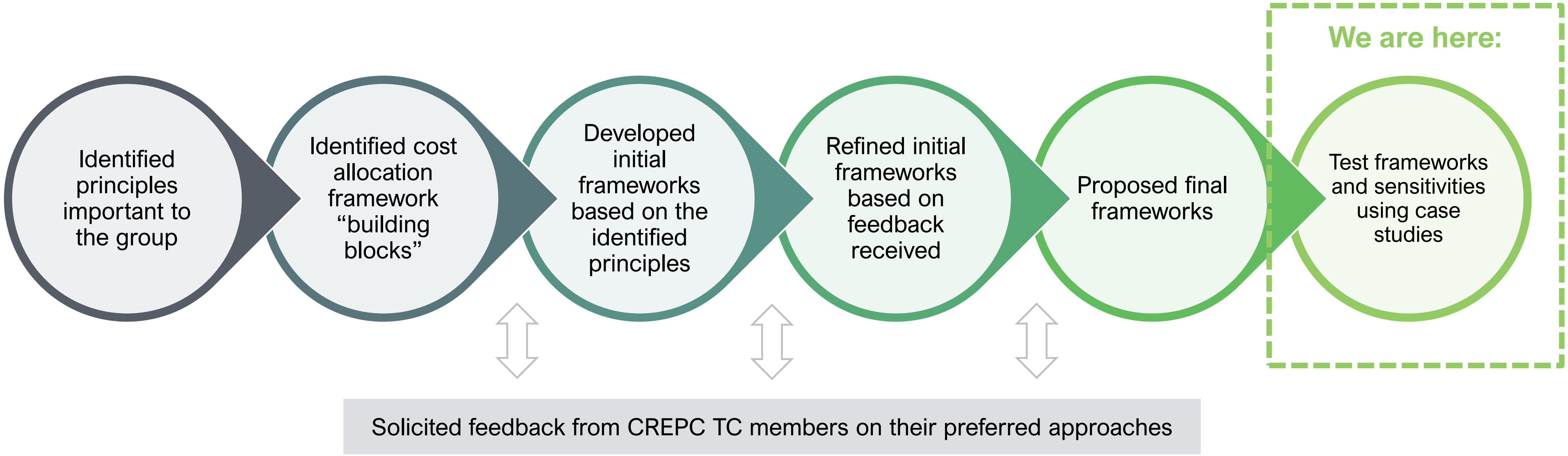
E Questions & Next Steps

Purpose of Meeting & Nature of Results Shared

- **The purpose of today's meeting is to review the cost allocation frameworks and the mechanics of how the cost allocation approaches will work**
  - The goal is for the CREPC TC to become comfortable with **how** the approaches work and the calculations that are made
  - This will allow for a more condensed review of results for the remaining case studies of the other hypothetical projects
- **Results presented today should be considered "draft" in nature**
  - Energy Strategies is still reviewing the modeling results and the benefit quantifications presented today are subject to change based on that ongoing review

Cost Allocation Frameworks Evaluated in Case Studies

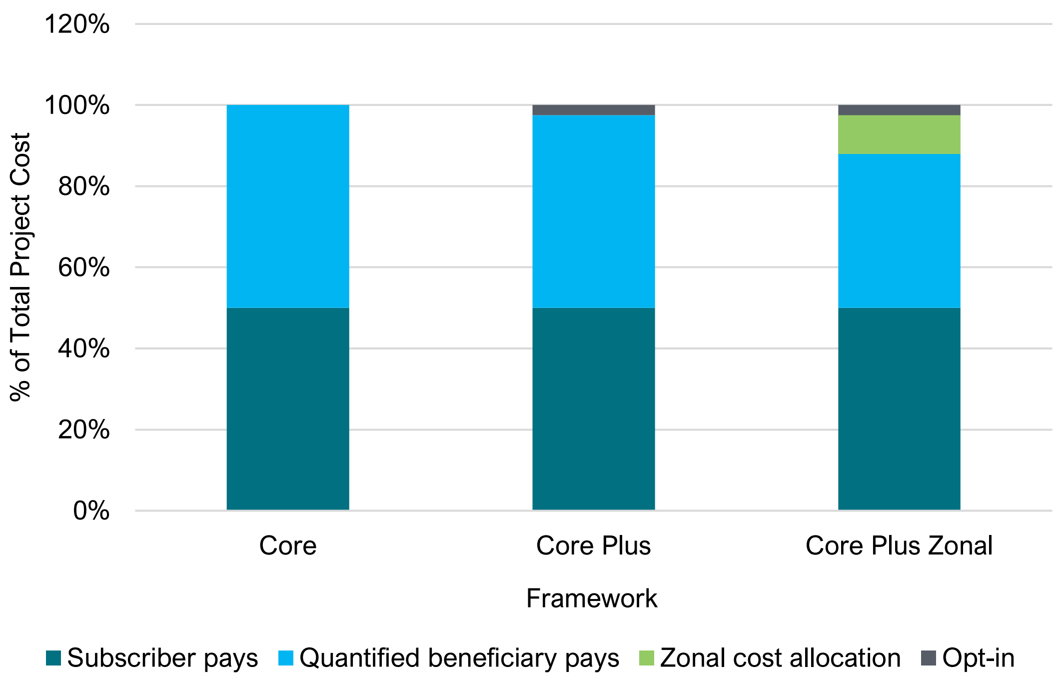
Process for Developing Cost Allocation Frameworks



Cost Allocation Frameworks Evaluated in Case Studies

- **Based on the feedback we received in the initial stages of this project, we moved forward with studying 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

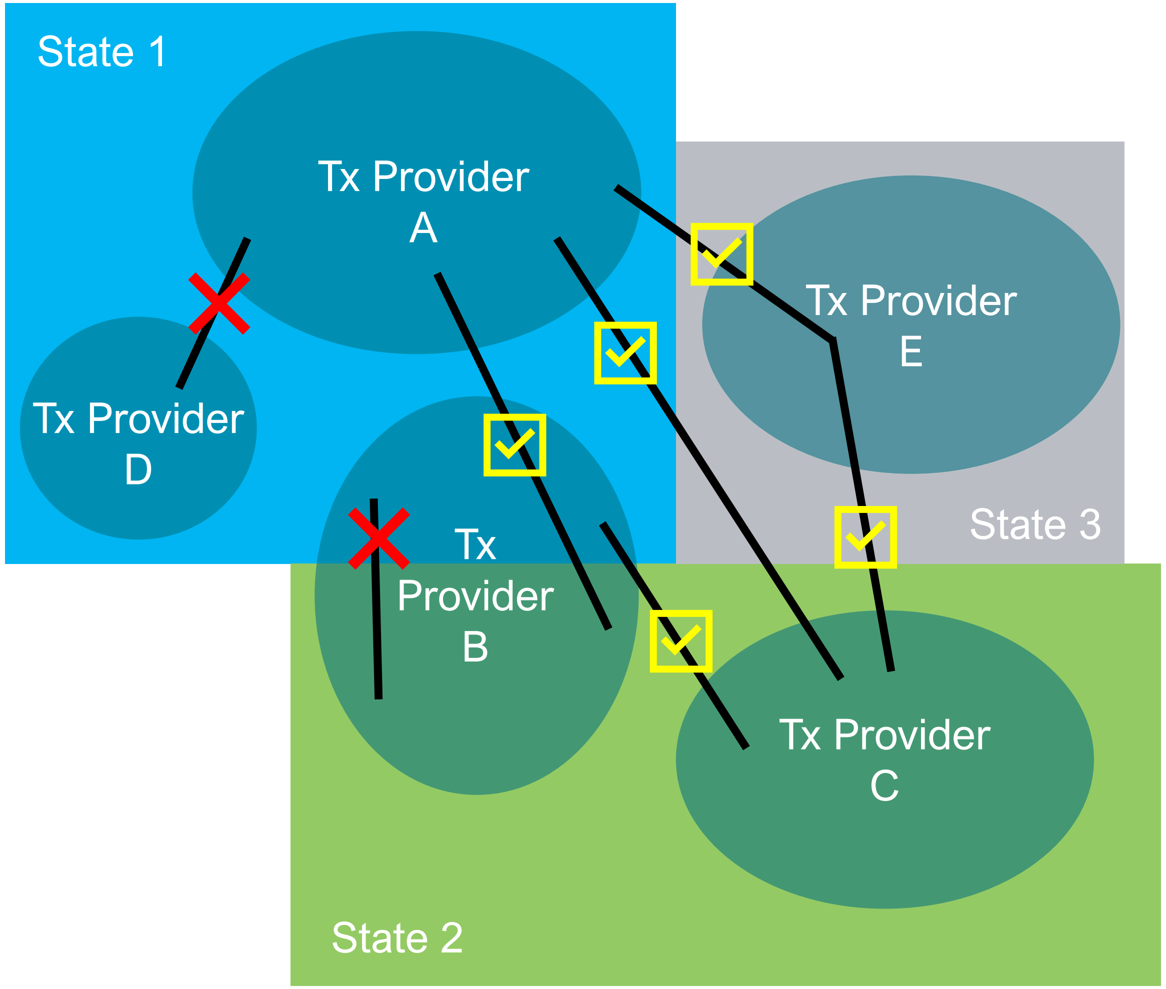
XX% of project cost allocated via **subscriber pays** on a pro-rata basis

Hypothetical Projects Used in Case Studies

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

Inter-state & Multi-provider Transmission



Reminder of Key Criteria for Hypothetical Projects and Groups of Projects

- **The group of projects selected for study were designed to meet the following criteria:**

Meets criteria?	Criteria
☐	Project(s) span two states and two transmission provider systems
☐	Project(s) within a group represent different scales of investment ($)
☐	Project(s) touch states with different policy objectives
☐	Project(s) within a group are likely to impact both FERC-jurisdictional and non-jurisdictional Transmission Providers (utilities)
☐	Project(s) are ***not*** actual projects being proposed/in advanced developed
☐	Project(s) within a group represent regional diversity (i.e., selected projects are not all located within one region)

Overview of Projects Studied

- **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
- **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
- **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

Project for Review Today

- **Hanford – Bell – Garrison 500kV Transmission Line**
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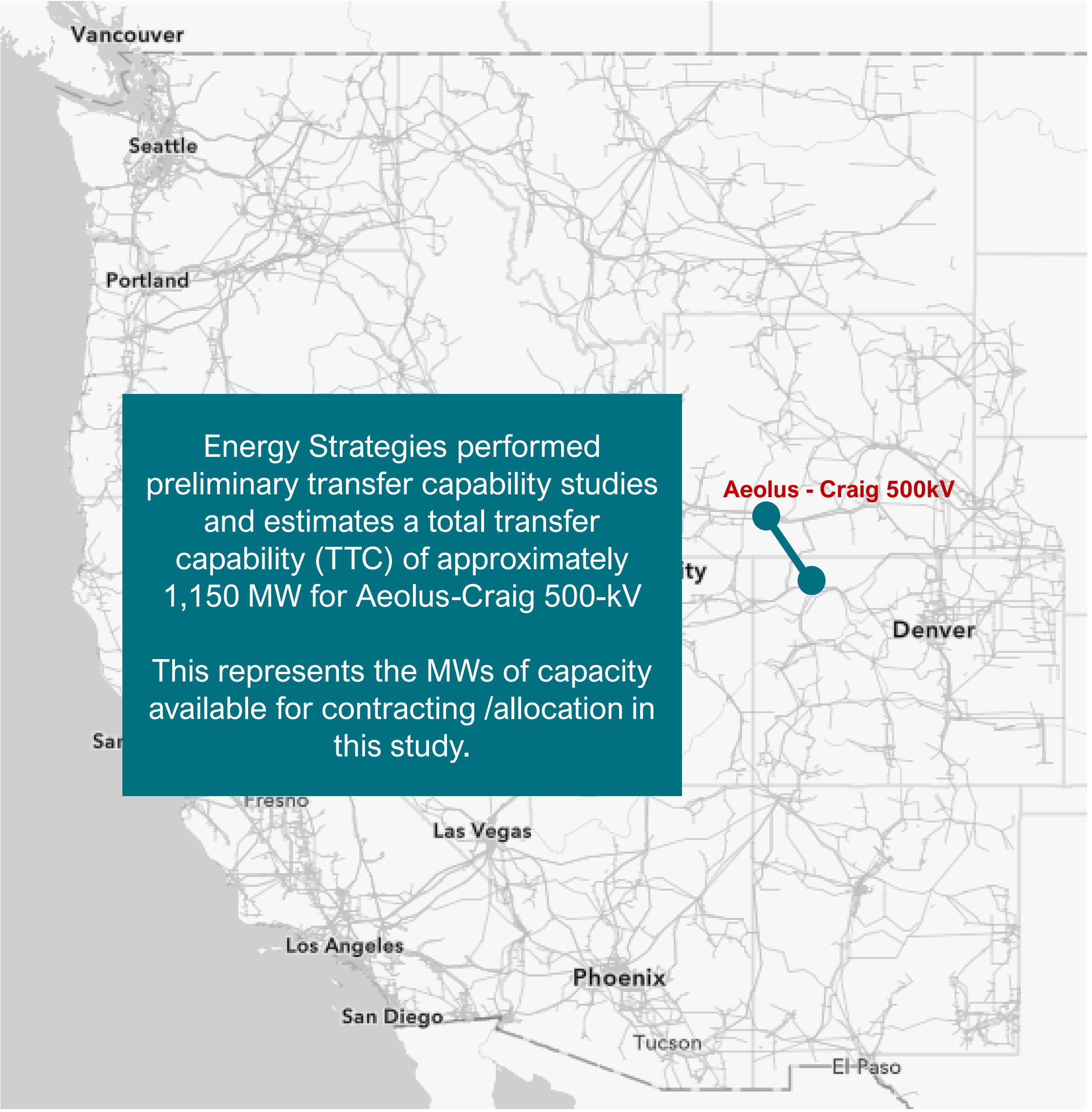


Energy Strategies performed preliminary transfer capability studies and estimates a total transfer capability (TTC) of approximately 1,150 MW for Aeolus-Craig 500-kV

This represents the MWs of capacity available for contracting /allocation in this study.

Initial Case Study Results

Aeolus-Craig Project

Benefit Methodology & Associated Results

Aeolus-Craig 500-kV

Review of Five Quantified Beneficiary Pays Benefit Categories

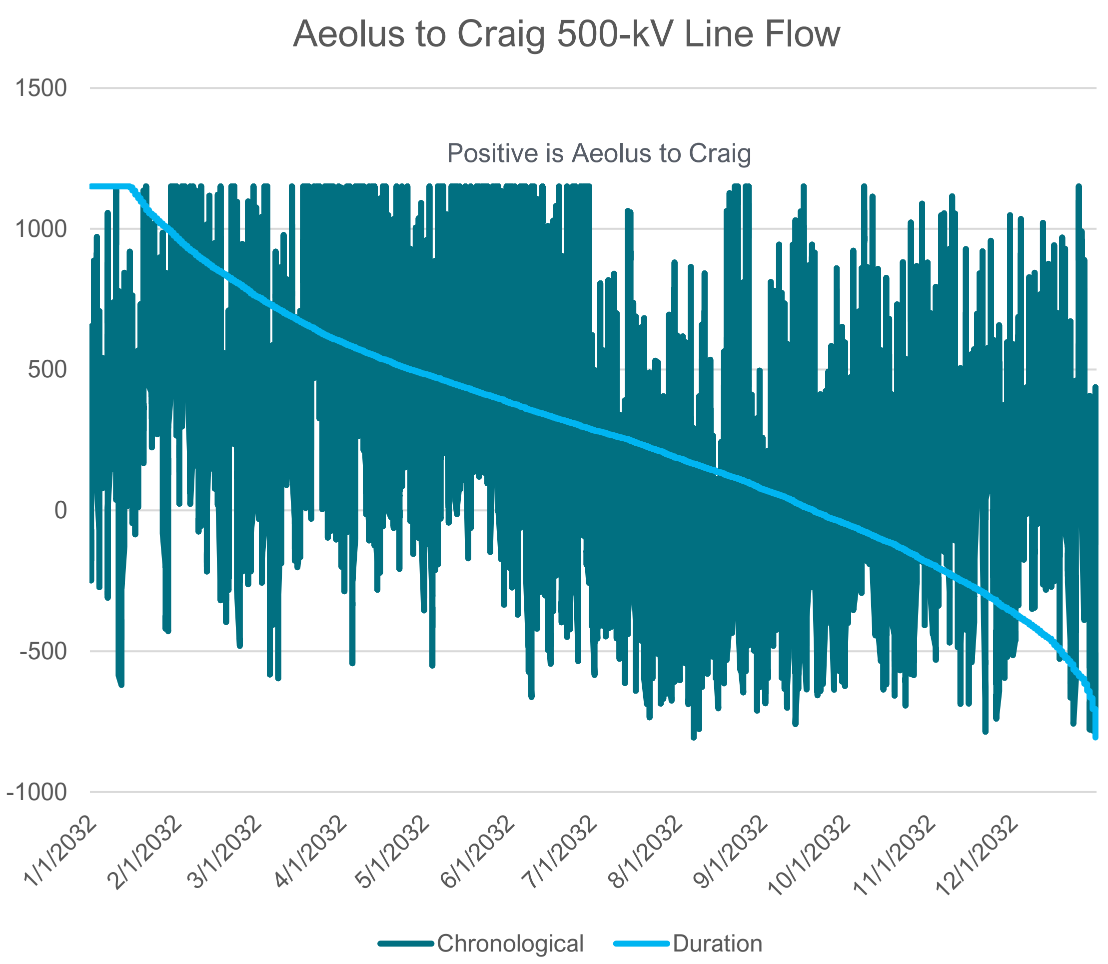
Benefit	Reasoning for Inclusion
Operational & Congestion Benefits	• Often measured based on changes in Adjusted Production Cost (APC); though there are other metrics that can also be used • APC represents the net short-run operational cost for a given area to serve load, accounting for power generation 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
Transmission Revenue	• The addition of incremental transmission projects increases the amount of transmission capacity on the system, which can increase the revenues the owners of that capacity receive from transmission sales to third-parties. • This provides an opportunity for transmission providers to generate additional revenue through sales of firm- and/or non-firm transmission service

Project Utilization and Regional Impact

- While not a planning analysis, we note that the Aoelus-Craig 500-kV project performed well in simulations with strong utilization and ability to demonstrate regional impact

Metric	Aeolus to Craig	Craig to Aeolus
Average Flow (aMW)	500	263
Average Utilization (% of TTC)	44%	23%
% of Hours	72%	28%
# Hours Congested	357 (4% of year)	0

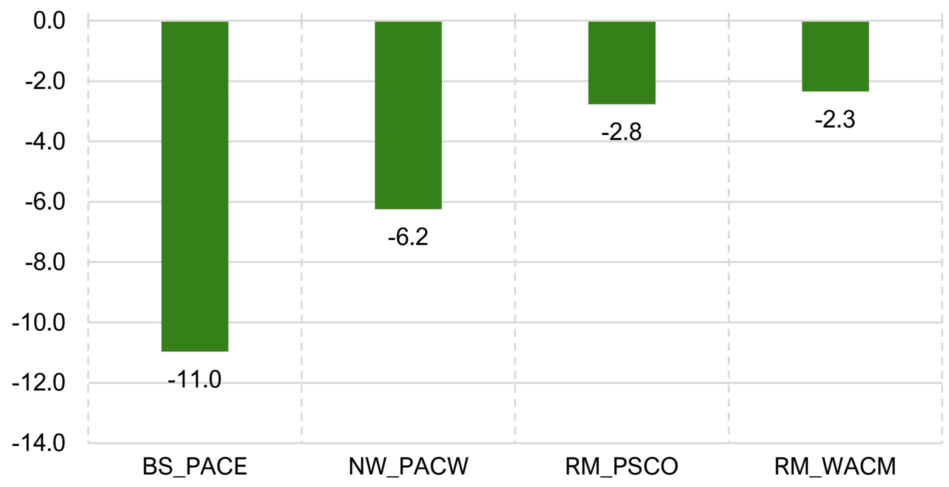
- The project caused WECC-wide annual production cost to fall by ~$8M (roughly 0.1%)
  - Reduced congestion by ~1% ($18M) and annual curtailment by ~4 aMW
- These efficiency improvements generally accrue to the entities we calculated APC savings for (see next slides)



Operational & Congestion Benefits

- Measured based on changes in adjusted production cost (APC), which 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
- Important techno-policy issues:
  - How do we deal with areas that have slightly negative results?
  - How do we deal with areas with very small changes?
- Our approach: limited benefit assignment to those transmission areas with at least a **$500k gross APC savings *and* 0.25% reduction**
  - 22 areas had APC changes of less than $500k – removed from analysis
  - There were 6 areas that had calculated increases in APC, but in all cases but one these increases were less than 0.25% (so they would have been removed anyway)
  - One entity (BPA) had a $7M benefit that represented a 0.54% decrease in APC, but was deemed to be too remote based on our technical judgement

APC Reduction: Wyoming-Colorado Tx Project ($M)



Region	Annual APC (M$) Ref	Annual APC (M$) WY-CO Tx Proj	Change (M$) WY-CO Tx Proj	% Change
AB_AESO	1,869.4	1,869.9	0.6	0.03%
BS_PACE	422.9	411.9	-11.0	-2.59%
CA_CISO	5,276.8	5,273.5	-3.2	-0.06%
CA_LDWP	803.5	805.3	1.8	0.22%
NW_BPAT	-1,420.1	-1,427.8	-7.7	0.54%
NW_CHPD	-109.7	-110.1	-0.5	0.43%
NW_PACW	397.4	391.2	-6.2	-1.57%
NW_PGE	738.0	739.6	1.6	0.22%
NW_PSEI	853.4	855.1	1.7	0.20%
RM_PSCO	895.5	892.7	-2.8	-0.31%
RM_WACM	210.1	207.8	-2.3	-1.12%
SW_PNM	79.0	80.5	1.5	1.92%
SW_SRP	1,078.8	1,080.3	1.5	0.14%

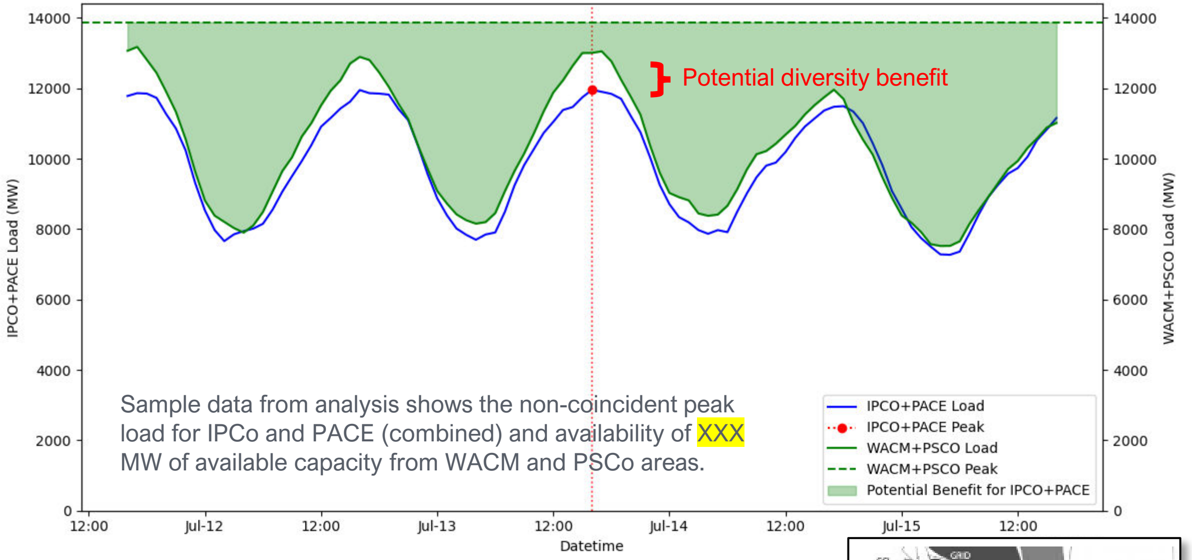
All areas with >$500k change in APC

- Area included in benefit
- Area negative benefit and excluded
- Area small benefit or remote and excluded

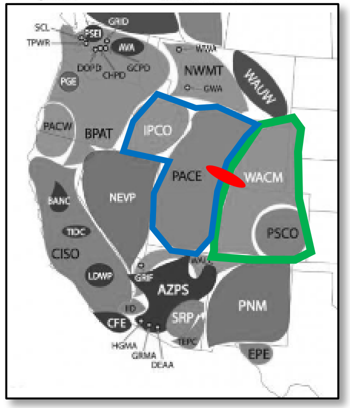
Resource Adequacy Benefits

- Achieved when transmission capacity enables sharing of incremental load and resource diversity among multiple regions
  - Accrues when regions can **share "unused" capacity** with one another during the other system's time of peak capacity needs
- Analyzed **four years of historical hourly load data** for areas adjacent to the project
  - Considers "theoretical" diversity benefit, existing capability of system, and new transfer capability of project
  - Assumed avoided capacity value of $140/kW-year for valuation purposes

Load Diversity Sample Data: Summer 2023 Peak for IPCO and PACE



For this example, identified 2,327 MW of potential diversity savings, reduced to 277 MW of potential after accounting for 2,050 MW of existing transmission capability between areas.

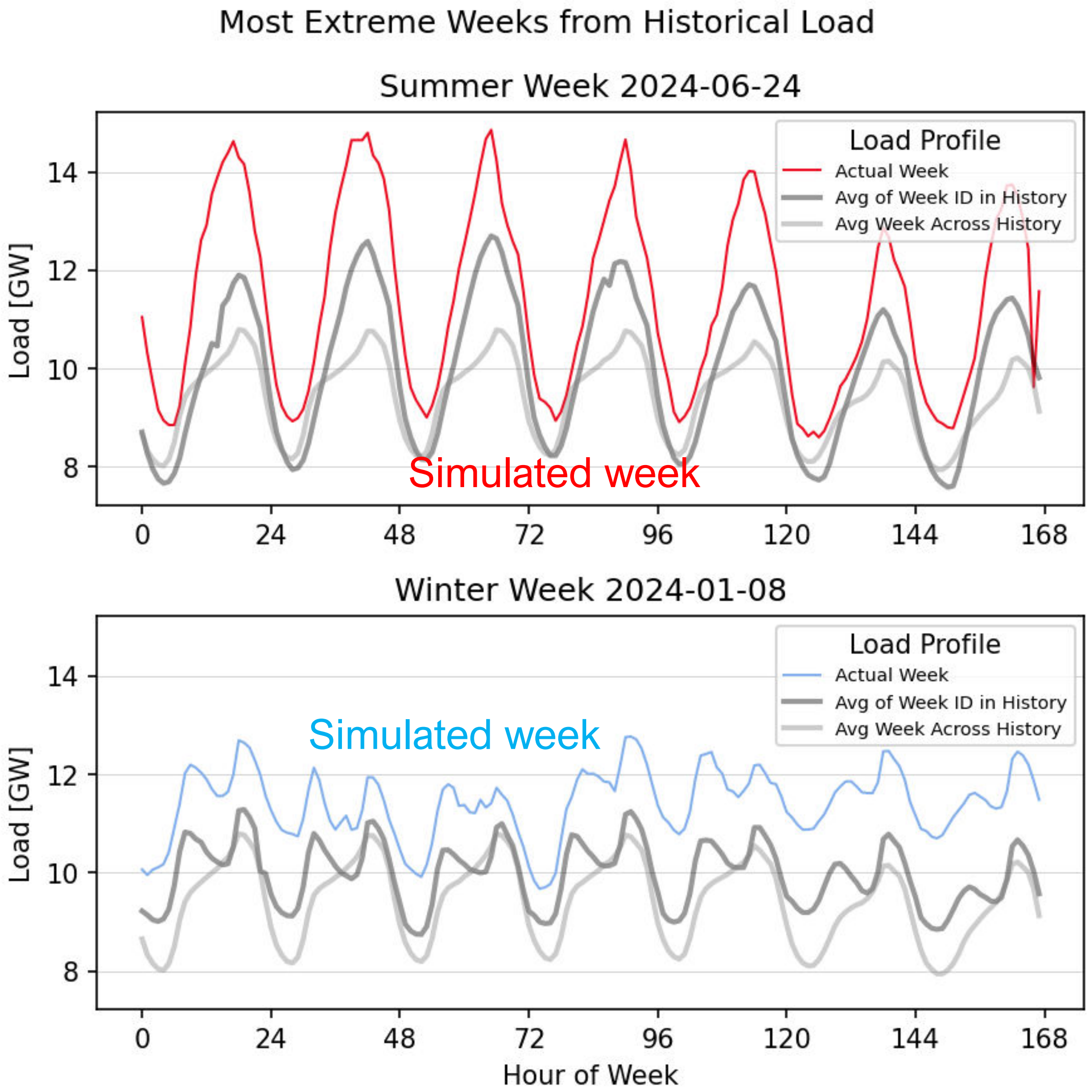


Load Diversity Potential and Project Benefit

Balancing Authority	Potential Saving (MW)	Saving with Current Tx (MW)	Saving with New Tx (MW)	Regional Saving with New Tx ($M/yr)	BA Saving with New Tx ($M/yr)
IPCO	1,563	1,417	145	$20	**$6**
PACE					**$15**
WACM	1,034	999	35	$4.8	**$1.8**
PSCO					**$3.0**

Extreme Event Analysis (Setup)

- Extreme weather or reliability events can cause high power prices or power outages, negatively impacting consumers
  - Transmission that reduces the frequency or magnitude of such events has a resiliency benefit to the system, with the benefit quantified as reduced power prices or avoided lost load
- Energy Strategies identified extreme summer and winter weather events by:
  - (1) Compile historical load 2016 – 2024 for the target footprint, (2) Aggregate, (3) Detrend, (4) Calculate the total load deviation of each week in the record from the corresponding average week, (5) Select weeks with greatest deviation.
- Then, forecast extreme weather informed loads to the study year:
  - 2032 hourly load shapes were adjusted to represent the extreme peak and energy observed in historic events
  - Actual hourly wind and solar from historic extreme events by BA were unitized and used for each wind/solar farm within each BA, replicating historical operational nuances
  - Hydro energy availably used historical low hydro year, 2001
  - System performance evaluated with and without transmission project under these extreme load events
- The goal is to emulate historical event “extremeness” out in time



Extreme Event Analysis (Results)

- Analysis assumes that one summer event and one winter event each occur **once every five years**
  - Therefore, we assume that 20% of the benefits estimated in this annual study occur each year
  - These benefits represent the project's ability to improve grid operation and efficiency during times of system stress
- In addition, the project was able to **reduce unserved load across** the WECC region by 30 MWh during the summer event
  - We valued this lost load at $50,000/MWh, resulting in an additional $1.5M of benefit that would accrue once every five years
  - These benefits were shared across the five entites based on their peak load share ratio

Benefit from Improved Operations

	Winter Event Savings ($M)	Summer Event Savings ($M)	Savings per event ($M)	Savings per year ($M)
PACE	$0.12	$0.3	$0.42	**$0.084**
PACW	$0.05		$0.05	**$0.01**
PSCO			$0	**$0**
WACM	$0.05		$0.05	**$0.01**
IPCO		$0.8	$0.8	**$0.16**
		TOTAL	**$1.32**	**$0.264**

Benefit from Avoided Unserved Load

	% Share of Total Peak	Avoided Lost Load Benefit ($M/year)
PACE	30%	$0.09
PACW	13%	$0.04
PSCO	27%	$0.08
WACM	16%	$0.05
IPCO	13%	$0.04

Total Resiliency Benefit

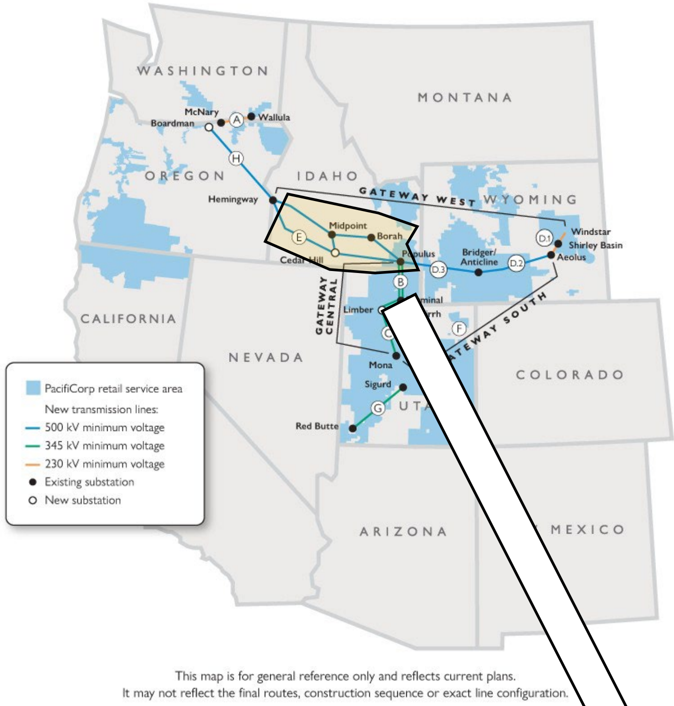
Total Annual Resiliency Benefit ($M)	
PACE	$0.18
PACW	$0.05
PSCO	$0.08
WACM	$0.06
IPCO	$0.20
TOTAL	**$0.57**

Avoided Transmission Benefits

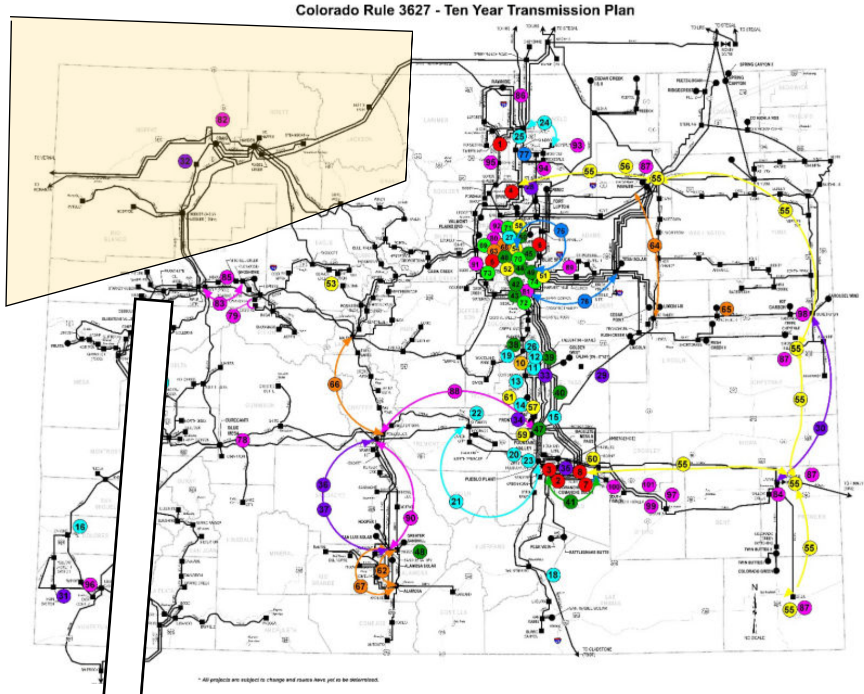
- If construction of a project avoids the need to build other (often smaller) transmission project(s), the **costs associated with the avoided transmission project can be quantified and assigned as a benefit**

- Energy Strategies reviewed utility plans for the areas surrounding the terminus of the Aoelus-Craig project, including:
  - PacifiCorp
  - WAPA
  - Tri-State

Planned components of Gateway West not avoidable or deferrable



No avoidable or deferable upgrades in NW Colorado

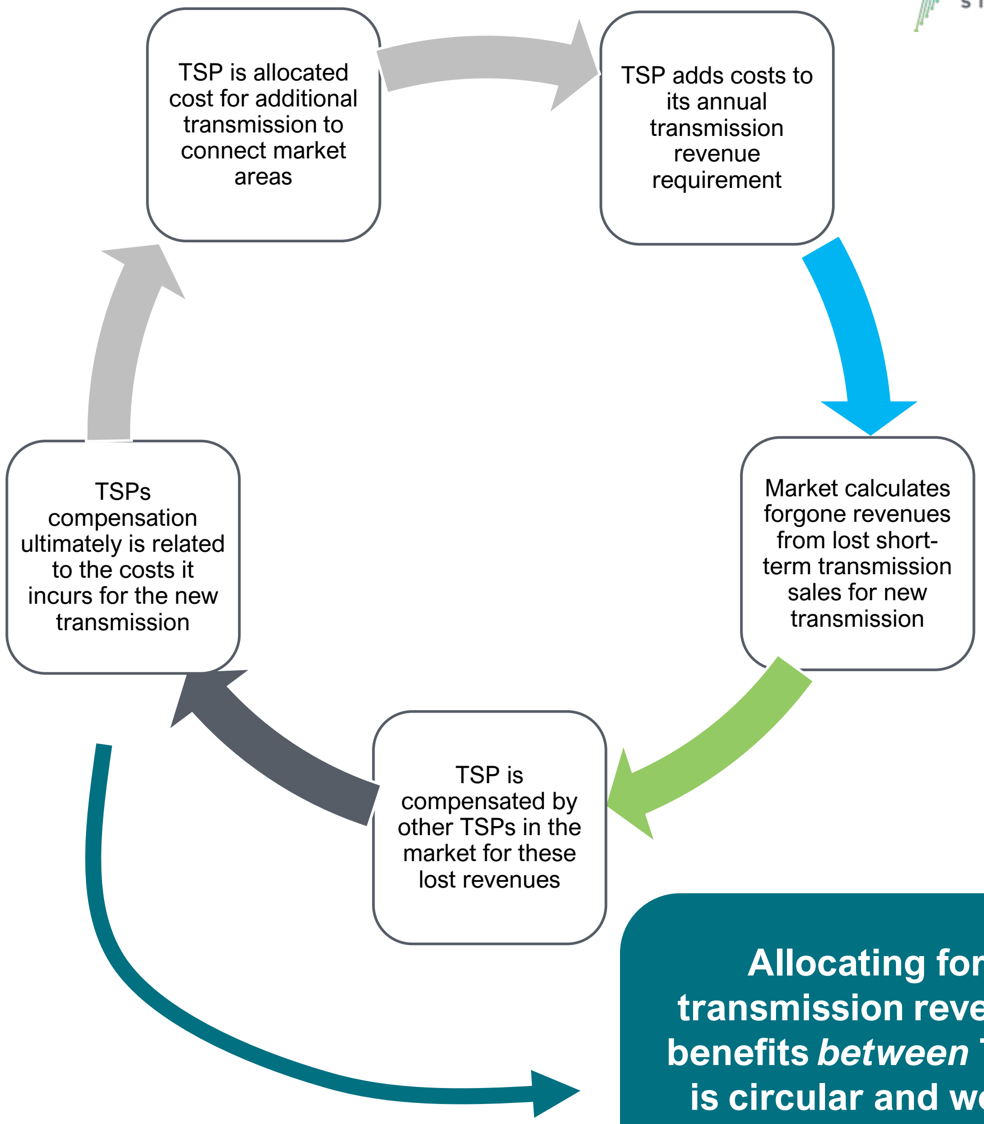


Ma[…]f planned projects in Colorado sourced from Rule 3627 fi[…]

Analysis did not identify any planned projects that could be avoided or deferred due to construction of Aeolus-Craig 500-kV

Transmission Revenue Benefits

- **Included to address the concept that incremental transmission projects might increase the amount of transmission capacity on the system, which in turn could increase revenues the owners of that capacity receive from transmission sales**
- **Needs to be considered in the context of changes to transmission service and market development in the West**
  - Study has generally assumed efficient day-ahead markets in the Western interconnection (without addressing market footprints, effectively assuming a single market)
  - Under efficient markets, it is not clear there will continue to be incentives to purchase short-term transmission capacity for firm/non-firm transmission service
    - In fact, day-ahead markets have been designed to address the likely loss of these revenues
- **Both proposed day-ahead markets provide Transmission Service Providers (TSPs) with compensation for lost/forgone transmission revenues from short term sales, as the expectation is that there will be less (no?) reason for third-parties to purchase short term transmission service once the markets are operations**
  - For new transmission, these compensation mechanisms are generally **based on the additional *costs*** that the TSPs incur
- **Thus, the additional revenues received (which would be a benefit) are proportional to the costs allocated, which ends up being a circular approach**
- **For these reasons, we have included $0 benefits from this category in our baseline cost allocation for these hypothetical projects**

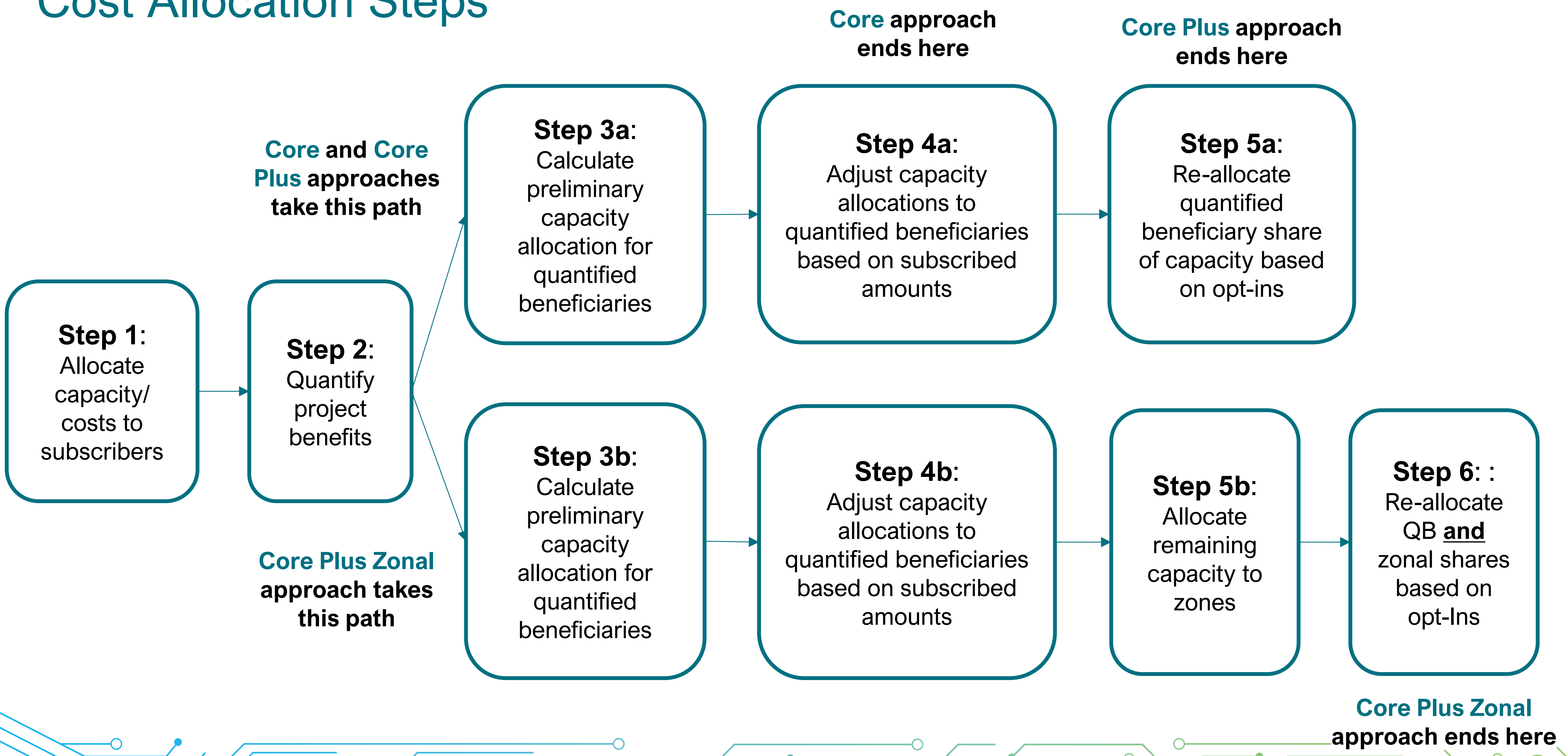


Allocating for transmission revenue benefits *between* TSPs is circular and won't materially impact the cost allocations

Hypothetical Cost Allocation Approach

Aeolus-Craig 500-kV

Cost Allocation Steps

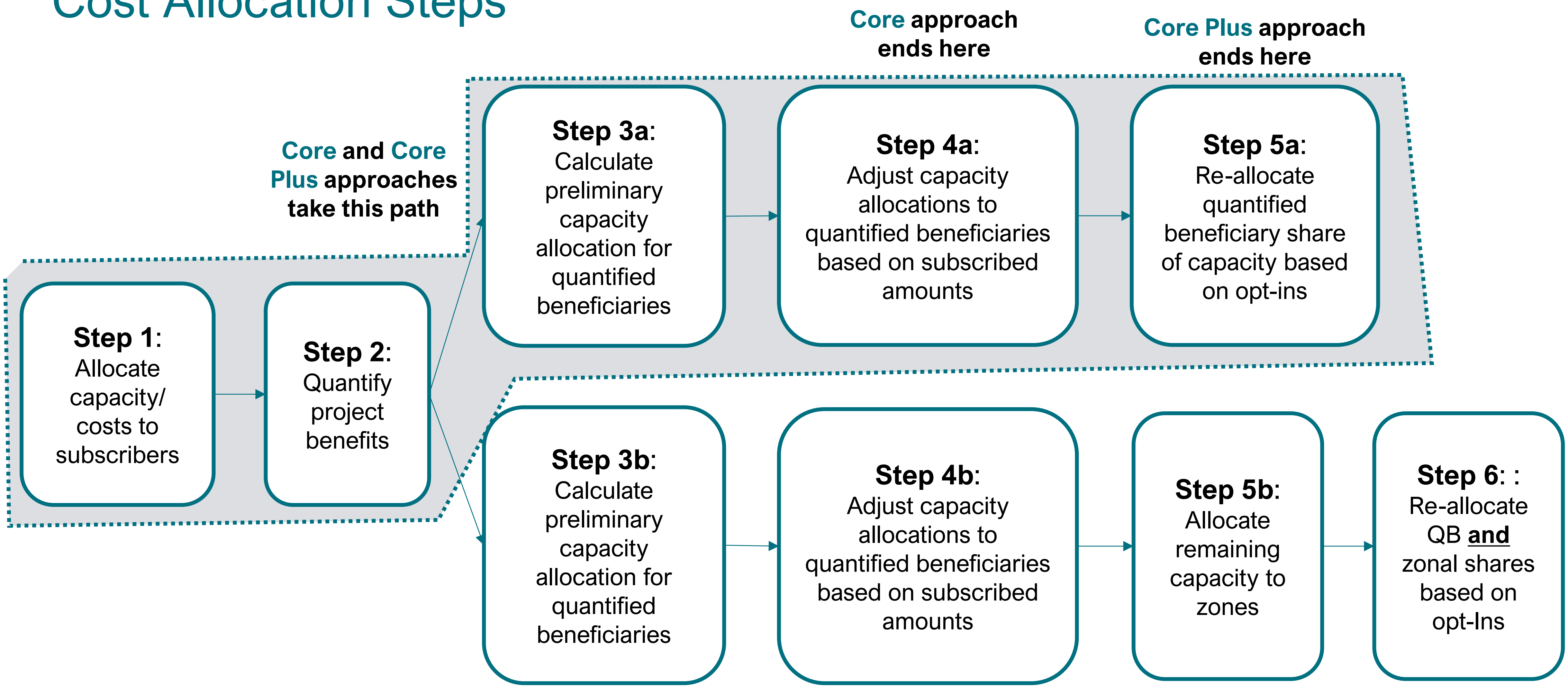


Subscriber Amounts & Opt-Ins are All Hypothetical

- 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 unfold

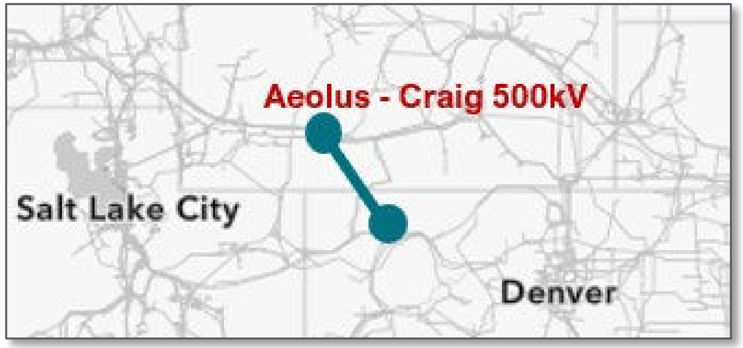
- The assumptions around subscription amounts and opt-ins are *hypothetical* and are not intended to reflect actual amounts these parties might voluntarily subscribe to

Cost Allocation Steps



Step 1: Allocate Capacity to Subscribers

Total capacity	**1150 MW**
Subscriber share	450 MW (39%)
Quantified beneficiary share	
Zonal share	
Opt-in share	



Transmission Zone	Capacity Allocated to Subscribers
PACE	100
PACW	
PSCO	100
WACM	
IPCO	150
Other Subscribers*	100
Total:	**450**

- Assumed that all capacity allocations are bidirectional
- Assumed that ~40% of project capacity (450 MW) was voluntarily subscribed to
    - **These assumptions are illustrative**
- Began with assumption that all *remaining* (unsubscribed) capacity was allocated based on quantified benefits (*see next slide*)

*Other subscribers could include other transmission providers, generators, or marketers that voluntarily seek capacity on the line

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Step 2: Quantify Project Benefits

Draft Benefits

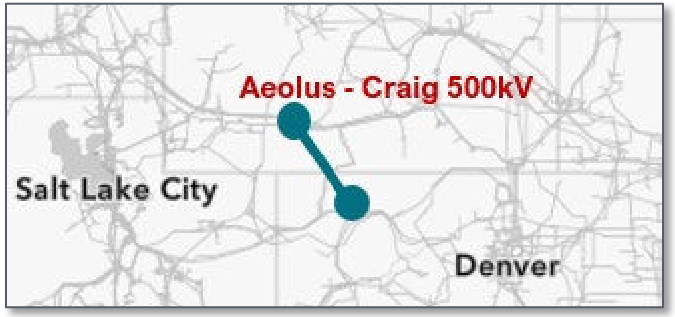
Transmission Zone	Operational & Congestion Benefits	Resource Adequacy (RA) Benefits	Avoided Transmission Benefits	Resiliency Benefits	Transmission Revenue Benefits	*Total Project Benefits*	*Share of Total Benefits*	*Preliminary Capacity (MW) Based on Benefits*
PACE	$11	$14.8	$0	$0.2	$0	$26	54%	**621**
PACW	$6.3	$0	$0	$0.1	$0	$6.3	13%	**151**
PSCO	$2.8	$3	$0	$0.1	$0	$5.9	12%	**140**
WACM	$2.4	$1.9	$0	$0.1	$0	$4.3	9%	**102**
IPCO	$0	$5.5	$0	$0.2	$0	$5.7	12%	**137**
Other Subscribers	-	-	-	-	-	-	-	**-**
					Total:	**$48.1**	**100%**	**1150**

**Due to rounding, columns may not total perfectly*

This column is used as the basis for the quantified beneficiary allocations

Step 3a: Calculate Preliminary Capacity Allocation for Quantified Beneficiaries

Total capacity	**1150 MW**
Subscriber share	450 MW (39%)
Quantified beneficiary share	
Zonal share	
Opt-in share	



Transmission Zone	Capacity Allocated to Subscribers	Preliminary Capacity Allocated to Quantified Beneficiaries
PACE	100	**621**
PACW		151
PSCO	100	**140**
WACM		102
IPCO	150	**137**
Other Subscribers	100	
Total:	**450**	**1150**

***Absent subscribers*, this is how much capacity each transmission zone would receive** based on their share of quantified benefits (QBs)

However, this allocation could result in **"double charging"** subscribers (**once based on subscribed amount and once based on QB amount**)

Step 4a: Adjust Capacity Allocation to Quantified Beneficiaries Based on Subscribed Amounts to Prevent Double Charging

Total capacity	**1150 MW**
Subscriber share	450 MW (39%)
Quantified beneficiary share	700 MW (61%)
Zonal share	
Opt-in share	

IPCo subscribes to *more than* (>) its calculated QB share, it **receives <u>no</u> capacity allocation ($0) via the QB category**

Transmission Zone	Capacity Allocated to Subscribers	Preliminary Capacity Allocated to QBs	Adjust QB Capacity Allocated to Subscribers	QB Capacity Allocated to Non-Subscribers Remains the Same	Calculate Proportion of QB Allocation	Calculate QB Capacity Allocation
PACE	100	621	(621-100) = 521		521/813= 64%	64%*700 = 448
PACW		151		151	151/813= 19%	19%*700 = 130
PSCO	100	140	(140-100) = 40		40/813= 5%	5%*700 = 34
WACM		102		102	102/813= 13%	13%*700 = 88
IPCO	150	137	(137-150) = -13 → 0		0%	0%*700 = 0
Other Subscribers	100	0			0%	0%*700 = 0
Total:	**450**	**1150**	**561**	**252**		**700**

Step 4a: Adjust Capacity Allocation to Quantified Beneficiaries Based on Subscribed Amounts to Prevent Double Charging

Total capacity	**1150 MW**
Subscriber share	450 MW (39%)
Quantified beneficiary share	700 MW (61%)
Zonal share	
Opt-in share	

PACE and **PSCO** both subscribe to *less than* (<) their calculated QB share. To avoid double charging (once based on subscribed amount and once based on QB amount), their **QB allocations are reduced by the difference between their preliminary QB and subscribed amounts**

Transmission Zone	Capacity Allocated to Subscribers	Preliminary Capacity Allocated to QBs	Adjust QB Capacity Allocated to Subscribers	QB Capacity Allocated to Non-Subscribers Remains the Same	Calculate Proportion of QB Allocation	Calculate QB Capacity Allocation
PACE	100	621	(621-100) = **521**		521/813= 64%	64%*700 = 448
PACW		151		151	151/813= 19%	19%*700 = 130
PSCO	100	140	(140-100) = **40**		40/813= 5%	5%*700 = 34
WACM		102		102	102/813= 13%	13%*700 = 88
IPCO	150	137	(137-150) = -13 → 0		0%	0%*700 = 0
Other Subscribers	100	0			0%	0%*700 = 0
Total:	**450**	**1150**	**561**	**252**		**700**

Step 4a: Adjust Capacity Allocation to Quantified Beneficiaries Based on Subscribed Amounts to Prevent Double Charging

Total capacity	**1150 MW**
Subscriber share	450 MW (39%)
Quantified beneficiary share	700 MW (61%)
Zonal share	
Opt-in share	

Finally, the unsubscribed capacity (i.e., 1150-450=700 MW) is allocated to transmission zones proportionately to their share of the QB portion

Transmission Zone	Capacity Allocated to Subscribers	Preliminary Capacity Allocated to QBs	Adjust QB Capacity Allocated to Subscribers	QB Capacity Allocated to Non-Subscribers Remains the Same	Calculate Proportion of QB Allocation	Calculate QB Capacity Allocation
PACE	100	621	(621-100) = 521		521/813= 64%	**64%*700 = 448**
PACW		151		151	151/813= 19%	19%*700 = 130
PSCO	100	140	(140-100) = 40		40/813= 5%	5%*700 = 34
WACM		102		102	102/813= 13%	13%*700 = 88
IPCO	150	137	(137-150) = -13 → 0		0%	0%*700 = 0
Other Subscribers	100	0			0%	0%*700 = 0
Total:	**450**	**1150**	**561**	**252**		**700**

ENERGY STRATEGIES

Step 4a: Adjust Capacity Allocation to Quantified Beneficiaries Based on Subscribed Amounts to Prevent Double Charging

Total capacity	**1150 MW**
Subscriber share	450 MW (39%)
Quantified beneficiary share	700 MW (61%)
Zonal share	
Opt-in share	

Transmission Zone	Capacity Allocated to Subscribers	Capacity Allocated to Quantified Beneficiaries	Total Capacity Allocation
PACE	100	448	**548**
PACW		130	**130**
PSCO	100	34	**134**
WACM		88	**88**
IPCO	150	0	**150**
Other Subscribers	100	0	**100**
Total:	**450**	**700**	**1150**

Final Allocation for Core Approach

Step 5a: Re-allocate Quantified Beneficiary Share of Capacity Based on Opt-Ins

Total capacity	**1150 MW**
Subscriber share	450 MW (39%)
Quantified beneficiary share	612 MW (53%)
Zonal share	0 MW
Opt-in share	88 MW (8%)

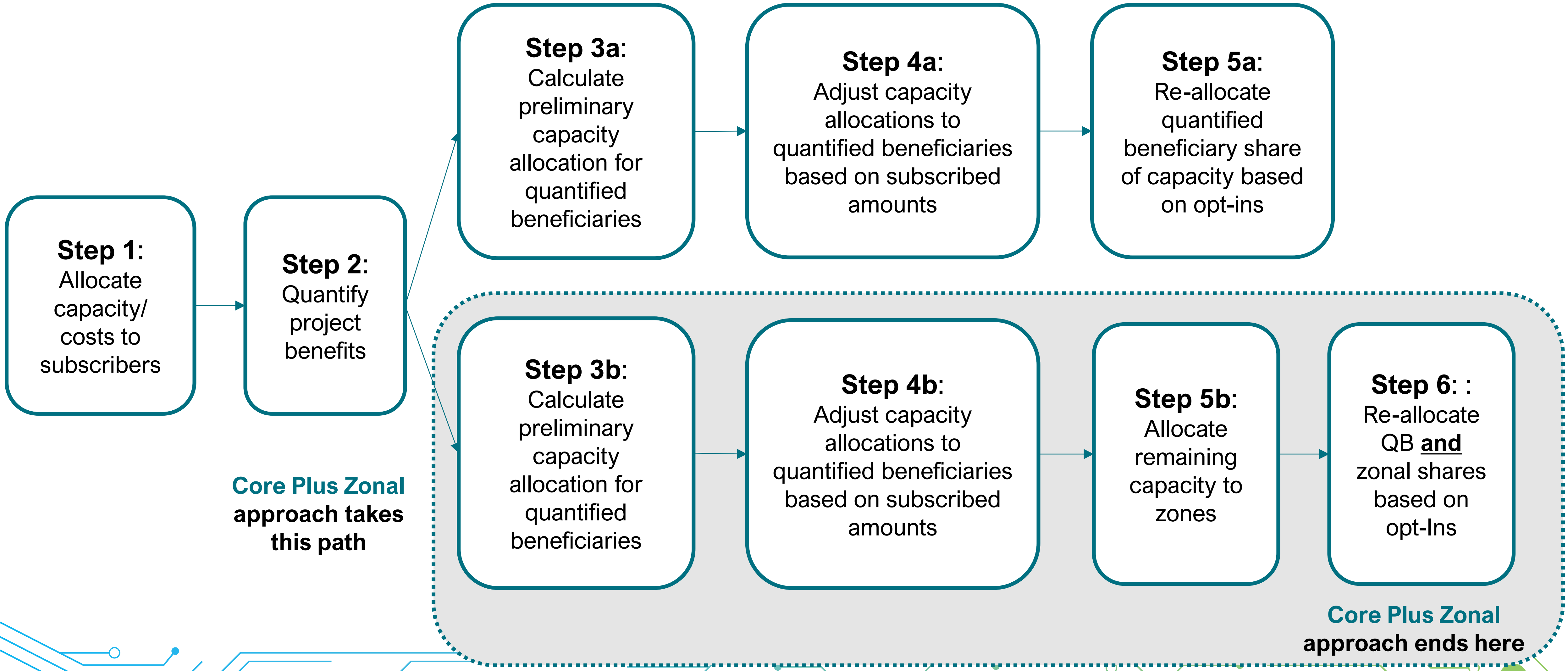
PSCo opts into an additional 88 MW

WACM opt out of 88 MW, which is subtracted from its QB allocation

Final Allocation for Core Plus Approach

Transmission Zone	Capacity Allocated to Quantified Subscribers	Capacity Allocated to Quantified Beneficiaries	Opt-In Capacity	Total Capacity Allocation
PACE	100	448		**548**
PACW		130		**130**
PSCO	100	34	**88**	**222**
WACM		88-88=0	**(-88)**	**0**
IPCO	150	0		**150**
Non-Zonal Subscribers	100	0		**100**
Total:	**450**	**700**	**88**	**1150**

When using the Core Plus Zonal approach there is additional complexity



ENERGY STRATEGIES

Step 3b: Calculate Preliminary Capacity Allocation for Quantified Beneficiaries to Prevent Double Charging

- Assumed that 25% of unsubscribed capacity is allocated using zonal approach, with remaining 75% assigned to QBs

Total capacity	**1150 MW**
Subscriber share	450 MW (39%)
Quantified beneficiary share	
Zonal share	
Opt-in share	

If using the Core+ Zonal approach, the initial "preliminary" QB allocation will be adjusted to reflect the share (%) of unsubscribed costs being allocated via QB vs. Zonal

Transmission Zone	**Capacity Allocated to Subscribers**	**Preliminary Capacity Allocated to Quantified Beneficiaries** assuming 100% of unsubscribed share allocated via QB	**Preliminary Capacity Allocated to Quantified Beneficiaries** assuming 75% of unsubscribed share allocated via QB
PACE	100	621	**621*75% = 466**
PACW		151	= 113
PSCO	100	140	= 105
WACM		102	= 76
IPCO	150	137	= 102
Other Subscribers	100	0	0
Total:	**450**	**1150**	**863**

ENERGY STRATEGIES

Step 4b: Adjust Capacity Allocation to Quantified Beneficiaries Based on Subscribed Amounts to Prevent Double Charging

Total capacity	**1150 MW**
Subscriber share	450 MW (39%)
Quantified beneficiary share	525 MW *(75% of unsubscribed capacity)*
Zonal share	
Opt-in share	

The preliminary QB allocation from the previous step is the starting point from which QB allocations are adjusted to avoid double charging

Transmission Zone	Capacity Allocated to Subscribers	Preliminary Capacity Allocated to QBs assuming 75% QB share	Adjust QB Capacity Allocated to Subscribers	QB Capacity Allocated to Non-Subscribers Remains the Same	Calculate Proportion of QB Allocation	Calculate QB Capacity Allocation
PACE	100	**466**	(466-100) = 366		366/560= 65%	65%*525= 343
PACW		**113**		113	113/560= 20%	20%*525= 106
PSCO	100	**105**	(105-100) = 5		5/560= 1%	1%*525= 5
WACM		**76**		76	76/560= 14%	14%*525= 72
IPCO	150	**102**	(102-150) = -48 → 0		0%	0%*525 = 0
Other Subscribers	100	**0**			0%	0%*525 = 0
Total:	**450**	**863**	**371**	**189**	**100%**	**525**

Step 4b: Adjust Capacity Allocation to Quantified Beneficiaries Based on Subscribed Amounts to Prevent Double Charging

Total capacity	**1150 MW**
Subscriber share	450 MW (39%)
Quantified beneficiary share	525 MW *(75% of unsubscribed capacity)*
Zonal share	
Opt-in share	

Transmission Zone	**Capacity Allocated to Subscribers**	**Adjusted Capacity Allocated to Quantified Beneficiaries** assuming 75% QB share
PACE	100	343
PACW		106
PSCO	100	5
WACM		72
IPCO	150	0
Other Subscribers	100	0
Total:	**450**	**525**

Step 5b: Allocate Remaining Capacity to Zones in Accordance with Zonal Share

Total capacity	**1150 MW**
Subscriber share	450 MW (39%)
Quantified beneficiary share	525 MW *(75% of unsubscribed capacity)*
Zonal share	175 MW *(25% of unsubscribed capacity)*
Opt-in share	

The remaining 25% of unsubscribed capacity is **allocated to transmission zones proportionately to their coincident peak loads**

Transmission Zone	**Capacity Allocated to Subscribers**	**Capacity Allocated to Quantified Beneficiaries** assuming 75% QB share	**Capacity Allocated to Zones** assuming 25% zonal share	**Total Allocation** (Pre-Opt-in)
PACE	100	343	**53**	496
PACW		106	**23**	129
PSCO	100	5	**48**	153
WACM		72	**27**	99
IPCO	150	0	**23**	173
Non-Zonal Subscribers	100	0	**0**	100
Total:	**450**	**525**	**175**	1150

ENERGY STRATEGIES

Step 6: Re-allocate Quantified Beneficiary and Zonal Shares of Capacity Based on Opt-Ins

Total capacity	**1150 MW**
Subscriber share	450 MW (39%)
Quantified beneficiary share	453 MW
Zonal share	148 MW
Opt-in share	99 MW (8%)

WACM opts-out of its remaining 99 MW share

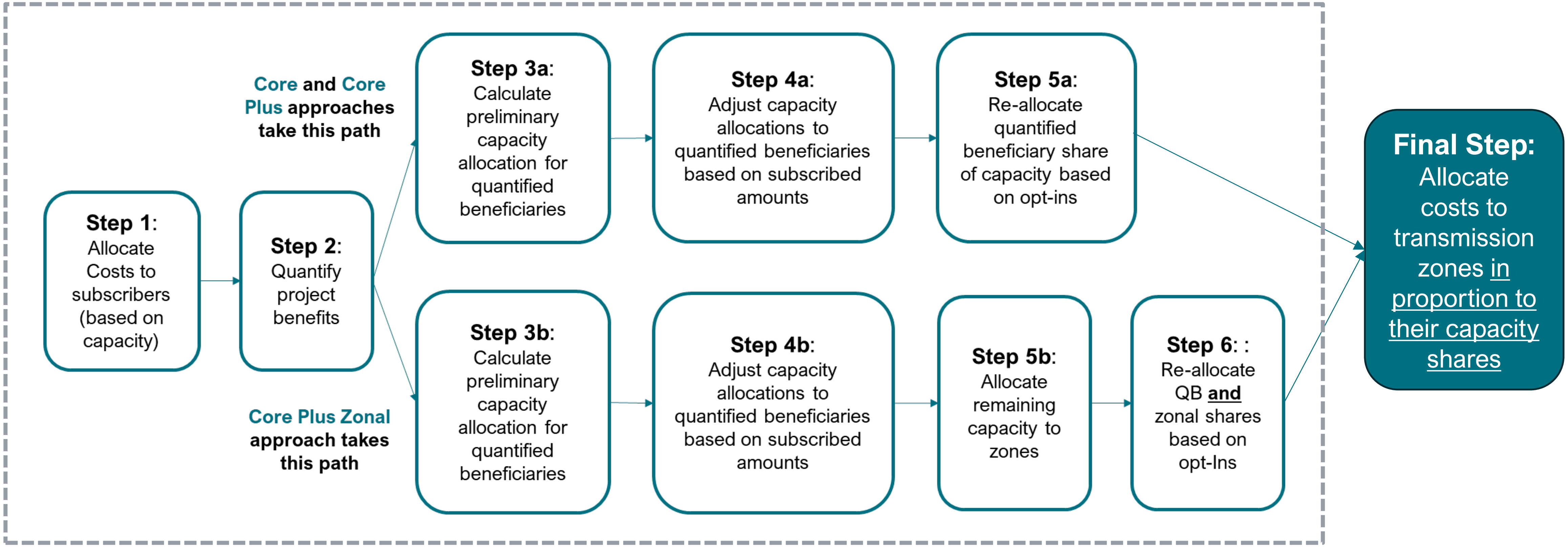
Opted-*out* capacity is subtracted first from zonal allocation and then (if there is a remainder) from QB allocation

Final Allocation for Core Plus Zonal Approach

Transmission Zone	Capacity Allocated to Subscribers	Capacity Allocated to Quantified Beneficiaries assuming 75% QB share	Capacity Allocated to Zones assuming 25% zonal share	Opt-In Capacity	Total Capacity Allocation
PACE	100	343	53		**496**
PACW		106	23		**129**
PSCO	100	5	48	**99**	**252**
WACM		**72-72=0**	**27-99=0**	**(-99)**	**0**
IPCO	150	0	23		**173**
Other Subscribers	100	0	0		**100**
Total:	450	**453**	**148**	**99**	**1150**

Cost Allocation is Based on Final Capacity Allocation

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



Comparison of Final Capacity and Cost Allocations

- **The CAPACITY allocations reached through Steps 1-6 are ultimately used to allocate COSTs**
  - I.e., cost allocations are directly proportionate to capacity allocations

Transmission Zone	Core		Core Plus		Core Plus Zonal	
	MW	Capital Cost in $M	MW	Capital Cost in $M	MW	Capital Cost in $M
PACE	548	**$310**	548	**$310**	496	**$281**
PACW	130	**$73**	130	**$73**	129	**$73**
PSCO	134	**$76**	222	**$126**	252	**$142**
WACM	88	**$50**	0	**$0**	0	**$98**
IPCO	150	**$85**	150	**$85**	173	**$57**
Other Subscribers	100	**$57**	100	**$57**	100	**$57**

Modeling Results & Sensitivities

Aeolus-Craig 500-kV

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:

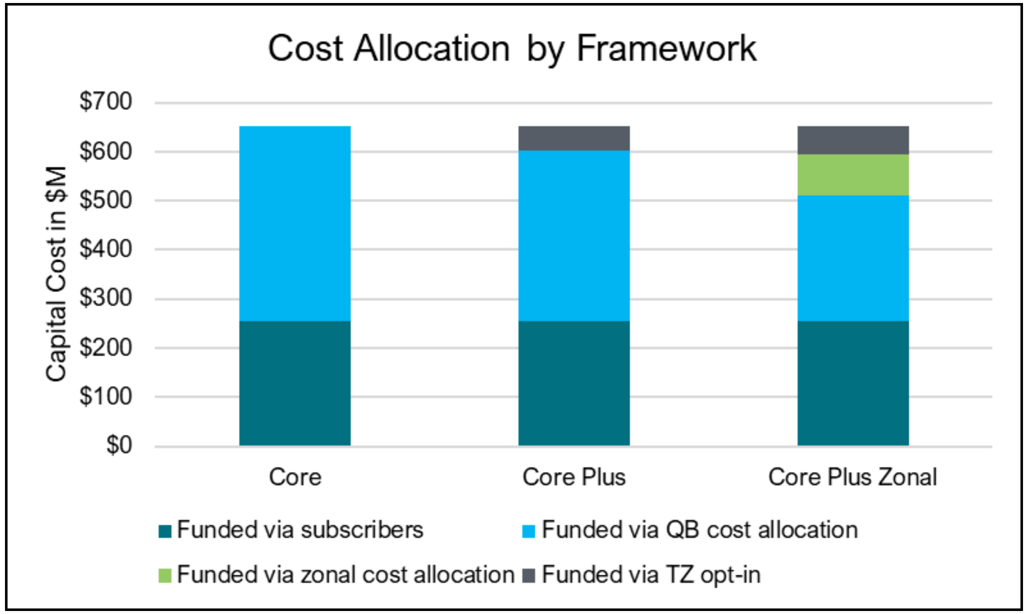
Low Subscription	High Subscription	High Zonal Assignment	No Opt-In/Out	No Subscription & No Opt-In	No RA Benefits
What if there are fewer voluntary subscriptions?	What if there are increased voluntary subscriptions?	What if we rely on more zonal cost assignments?	What if we reduce flexibility by removing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

Aeolus-Craig: 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	

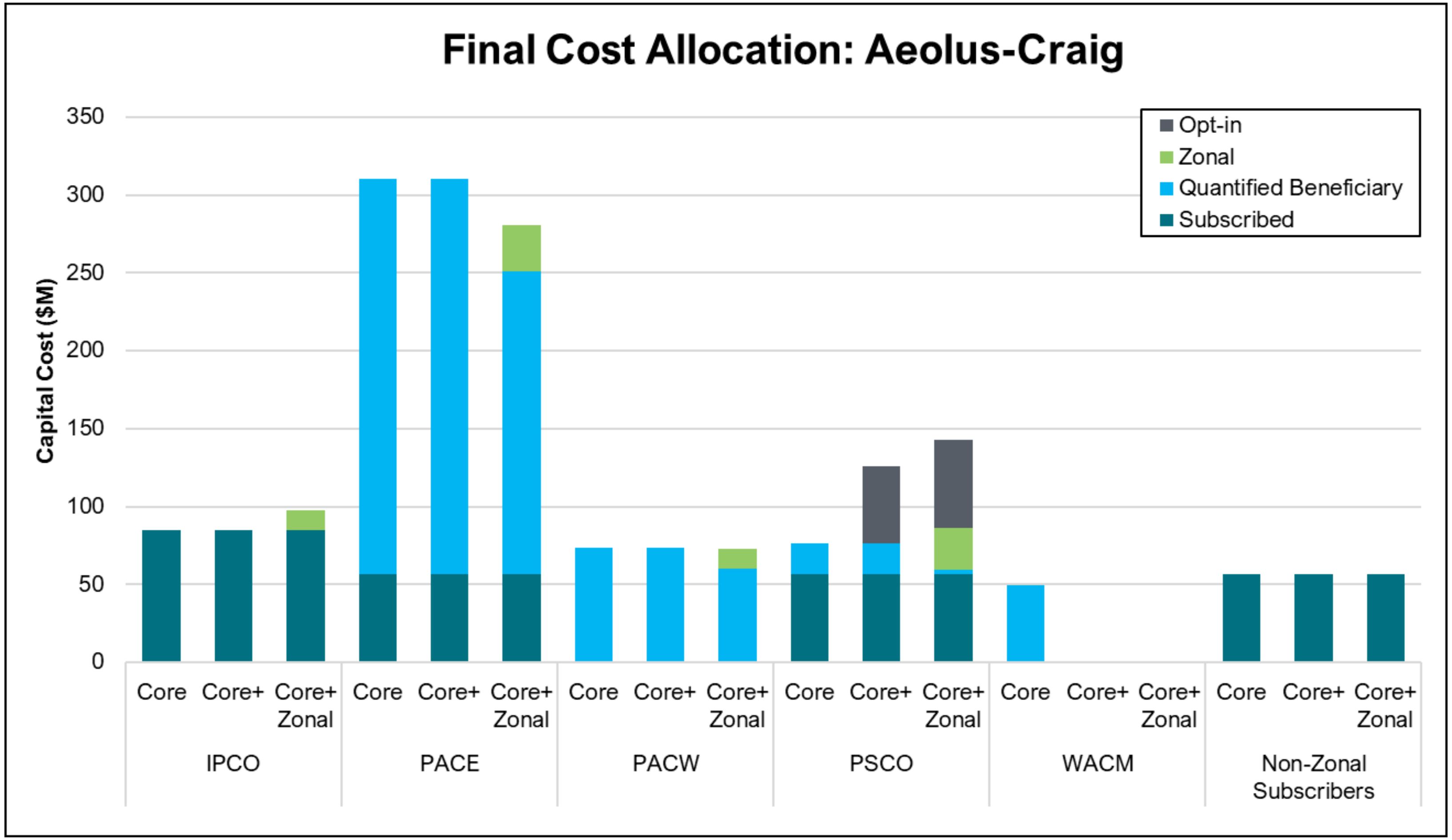


Subscribers and subscription amounts are hypothetical and intended be illustrative of a potential subscription

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

Aeolus Craig: Base Case

- **PACE is allocated by far the largest share of costs, regardless of the framework used**
  - There is a slight decrease in total costs assigned when a zonal category is included
- **IPCo and PACW both see their total allocations increase slightly with the inclusion of the zonal category**
- **Transmission zones with high coincident peak loads and low quantified benefits can expect to see relative cost increase under the Core+ Zonal framework**



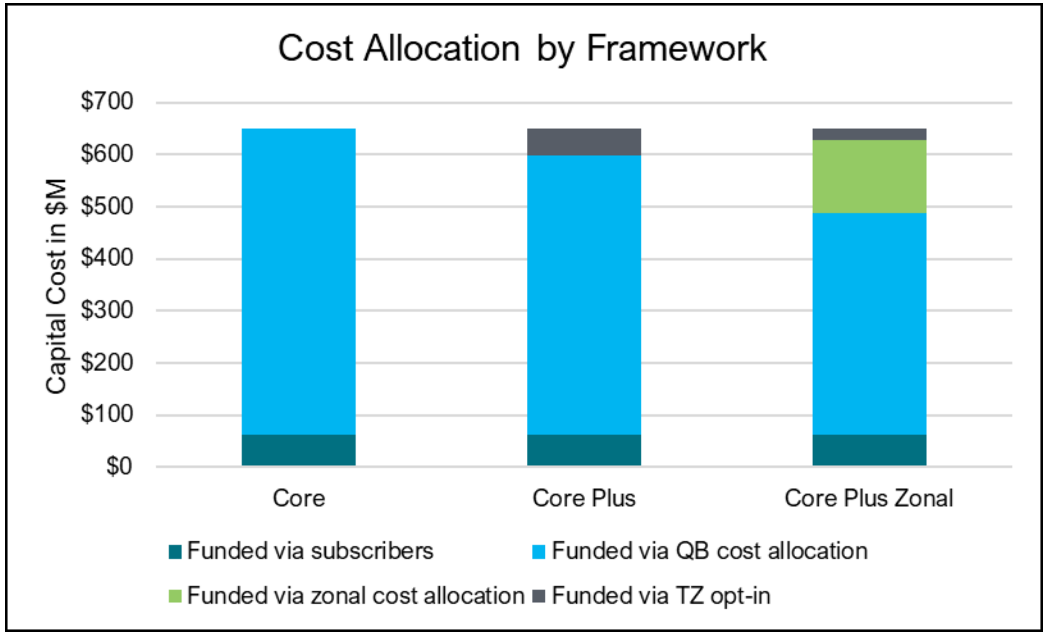
ENERGY STRATEGIES

Aeolus-Craig: Low Subscription Case

Levers	Low Subscription Case
Subscriber Share	**~10%**
% Remaining Assigned to QB vs. Zonal	**75% QB / 25% Zonal**
Opt-In Share	**8-10%**

(Hypothetical) Assumptions for Modeling Purposes

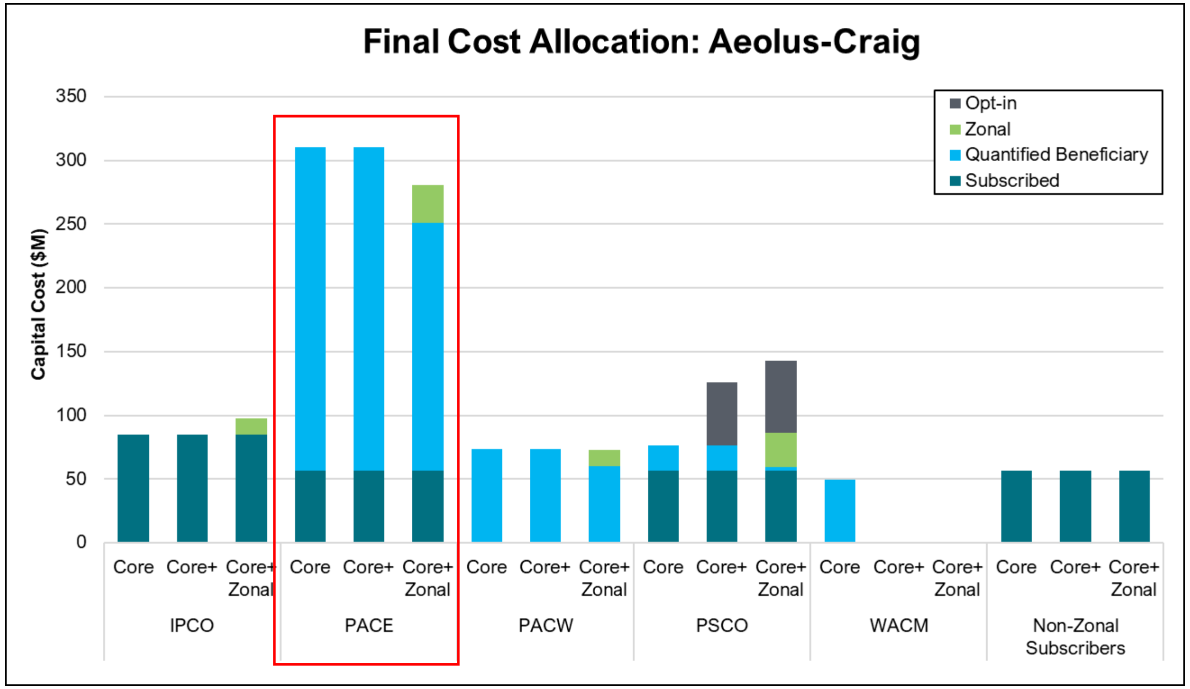
Transmission Zone	Capacity Allocated to Subscribers	Opt-In Capacity
PACE	25	
PACW		
PSCO	25	(+) 99-117 MW
WACM		(-) 99-117 MW
IPCO	37.5	
Other Subscribers	25	



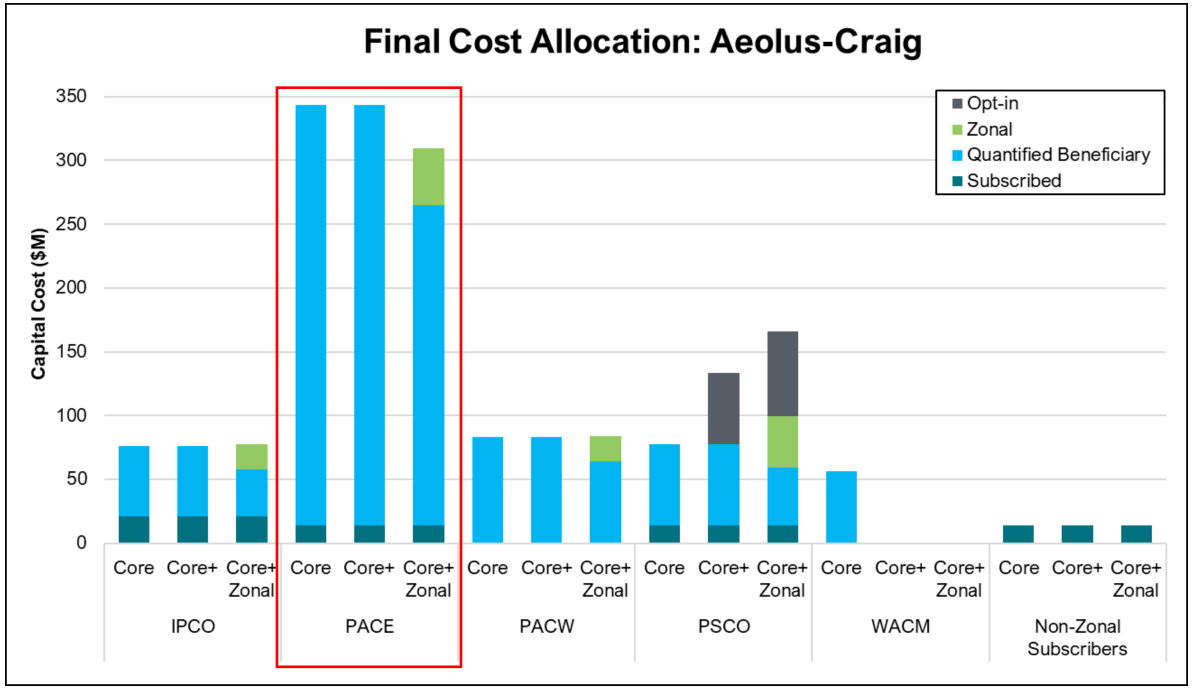
Q: What if there are fewer voluntary subscriptions?

Base Case vs. Low Subscription Case

Base Case



Low Subscription Case



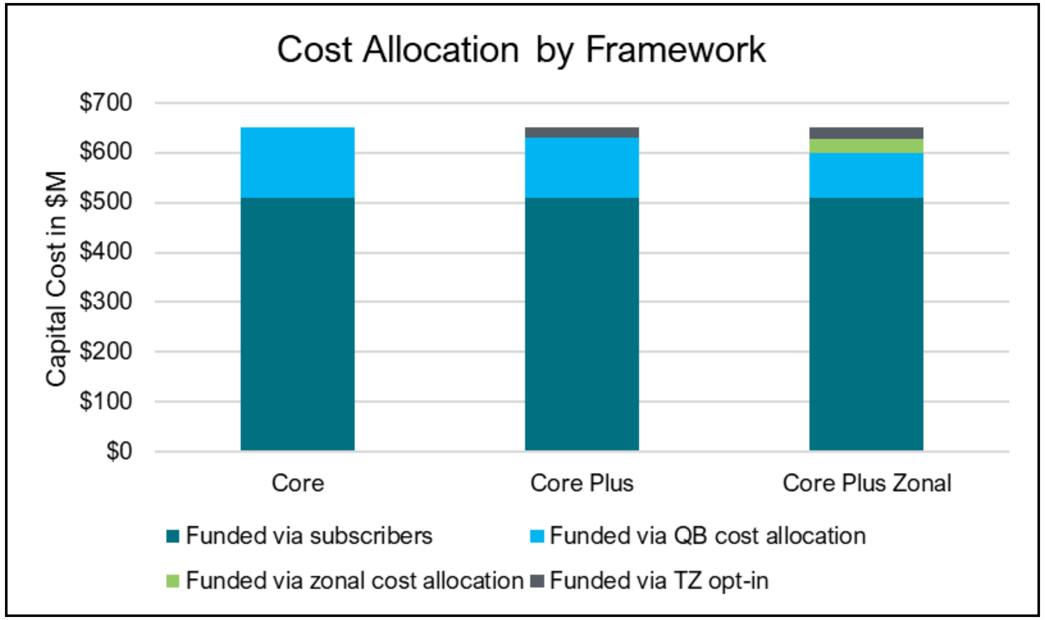
- **PACE, which receives a large share of quantified benefits, sees its overall cost allocation increase when subscription is low**
- **Overall trends persist across all three cost allocations frameworks: adjusting subscription levels does not materially impact how costs are proportionally spread**

Aeolus-Craig: High Subscription Case

Levers	High Subscription Case
Subscriber Share	**~80%**
% Remaining Assigned to QB vs. Zonal	**75% QB / 25% Zonal**
Opt-In Share	**3-4%**

(Hypothetical) Assumptions for Modeling Purposes

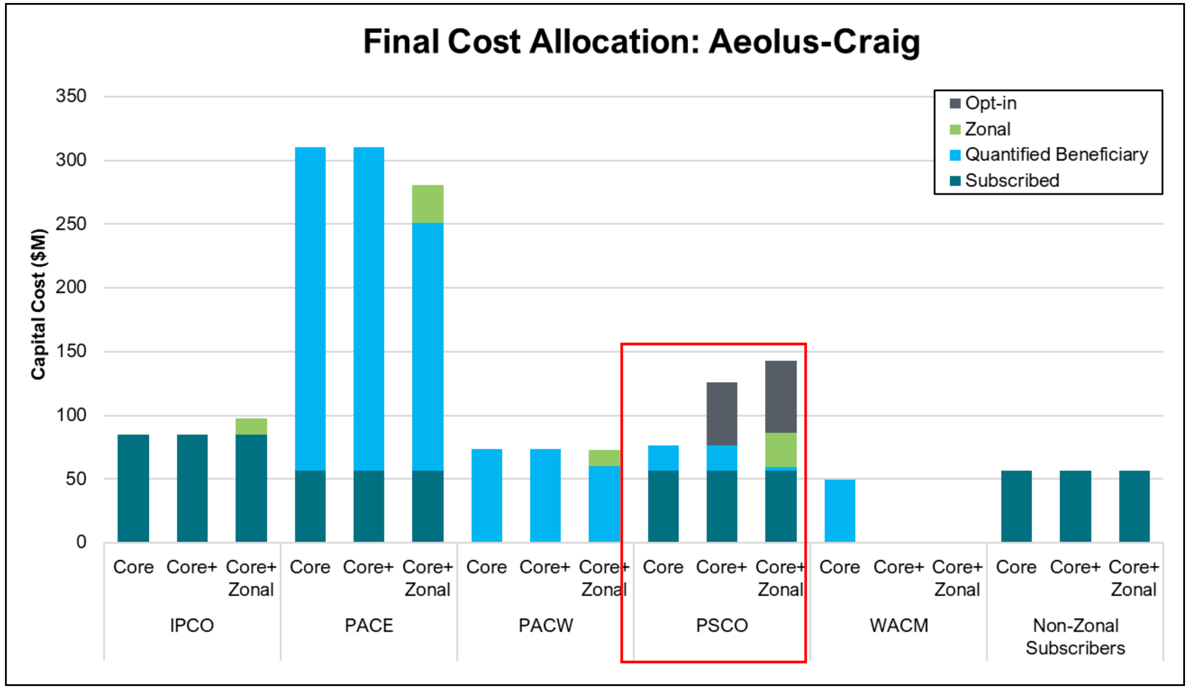
Transmission Zone	Capacity Allocated to Subscribers	Opt-In Capacity
PACE	200	
PACW		
PSCO	200	(+) 38-41 MW
WACM		(-) 38-41 MW
IPCO	300	
Other Subscribers	200	



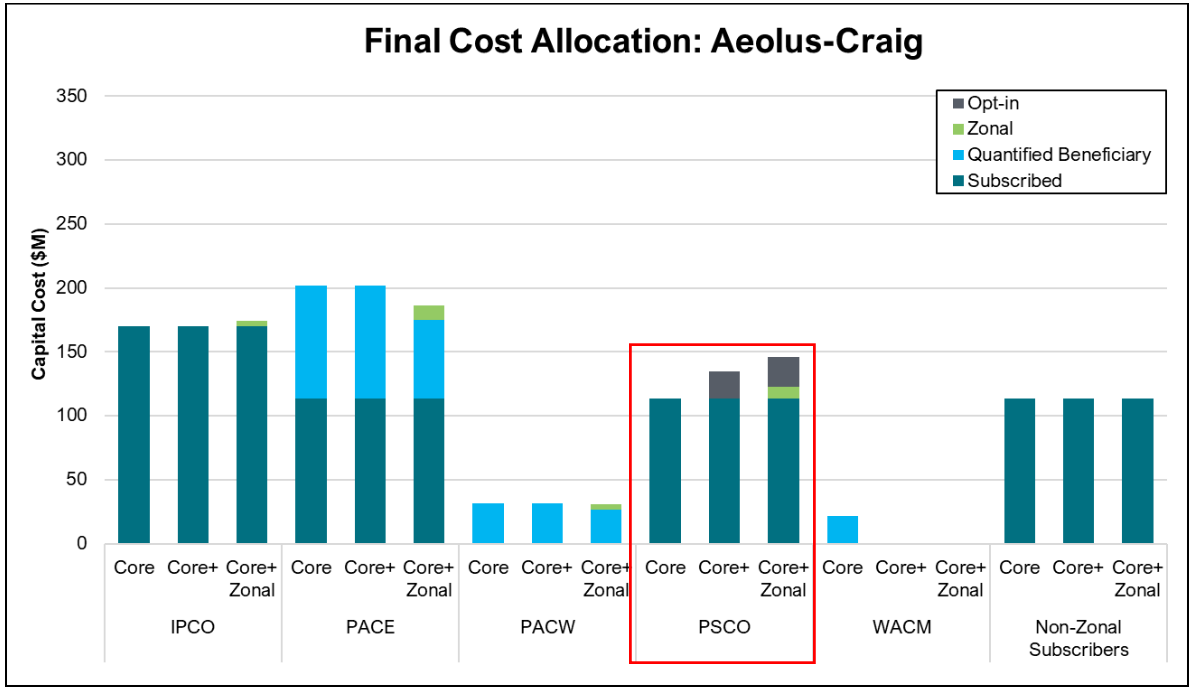
Q: What if there are increased voluntary subscriptions?

Base Case vs. High Subscription Case

Base Case



High Subscription Case



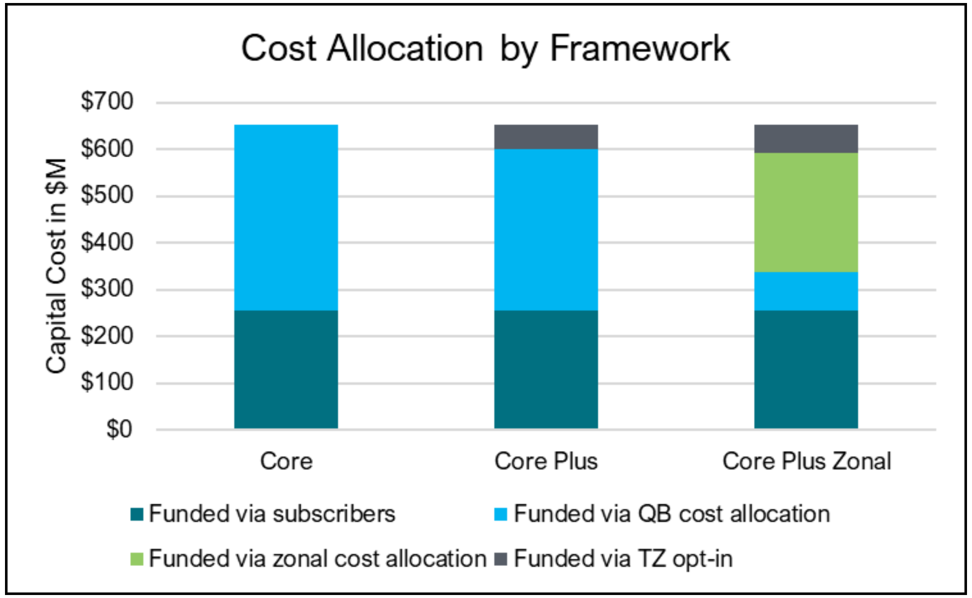
- **When subscription rates are high, transmission zones with large shares of quantified benefits see their overall cost allocations decrease (unless they are the ones increasing subscription levels)**
  - In the case of PSCo, an increased subscription level results in roughly the same costs that would ultimately have been assigned

Aeolus-Craig: High Zonal Case

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

(Hypothetical) Assumptions for Modeling Purposes

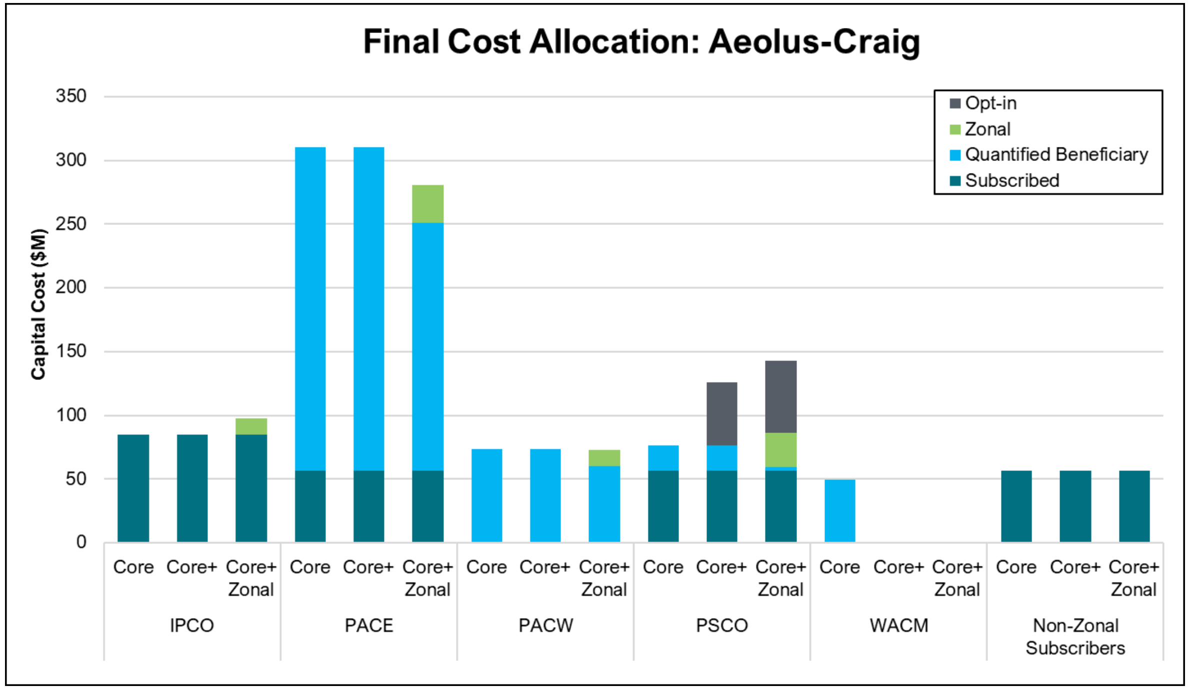
Transmission Zone	Capacity Allocated to Subscribers	Opt-In Capacity
PACE	100 MW	
PACW		
PSCO	100 MW	(+) 88-106 MW
WACM		(-) 88-106 MW
IPCO	150 MW	
Other Subscribers	100 MW	



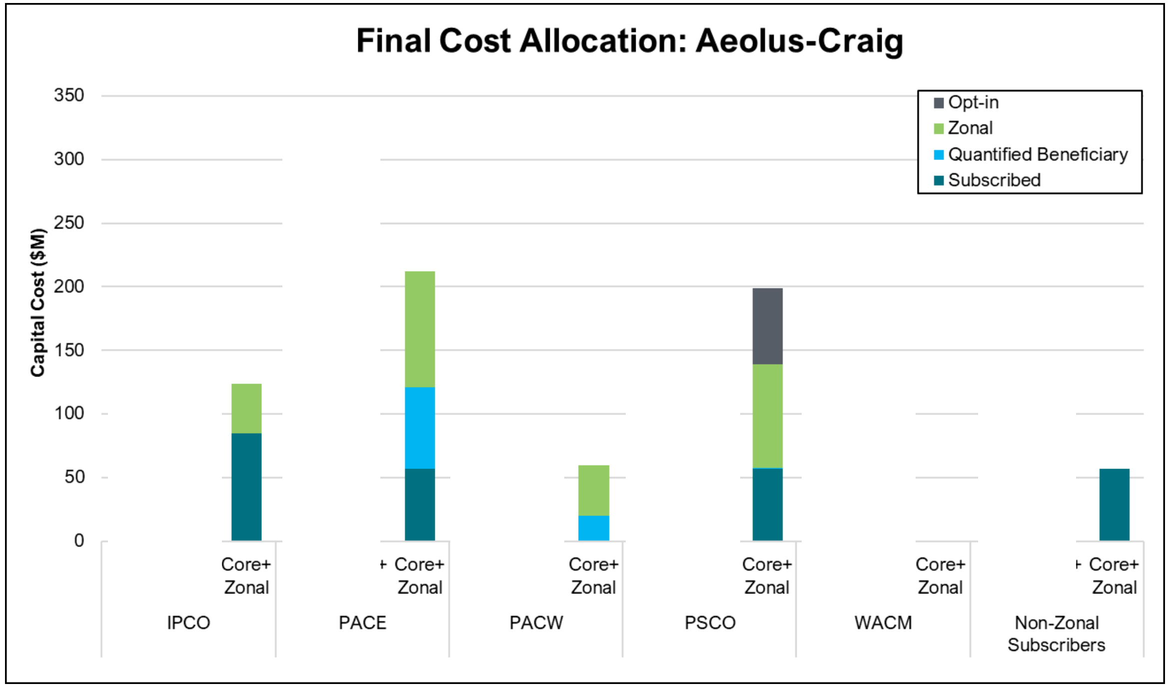
Q: What if we rely on more zonal cost assignments?

Base Case vs. High Zonal Case

Base Case



High Zonal Case



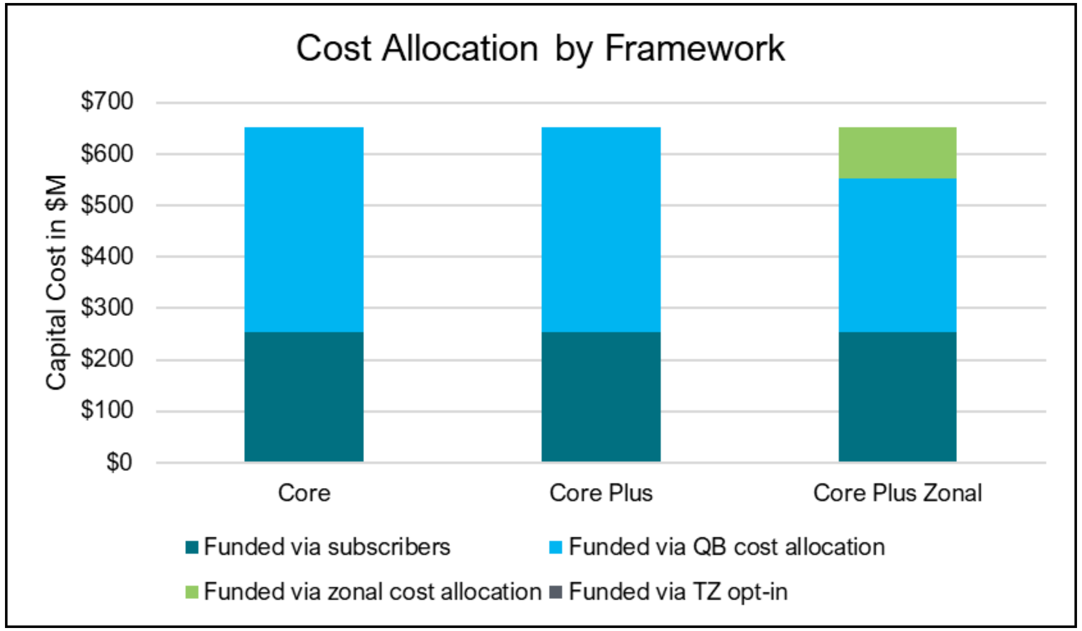
- **At a 40% subscription level, increasing the amount of benefits assigned via the zonal approach can materially impact areas that have relatively fewer quantified benefits but are larger load areas (like PSCo in this example, who sees costs and allocation increase by ~$50M)**

Aeolus-Craig: No Opt-in Case

Levers	No Opt-In Case
Subscriber Share	~40%
% Remaining Assigned to QB vs. Zonal	75% QB / 25% Zonal
Opt-In Share	0%

(Hypothetical) Assumptions for Modeling Purposes

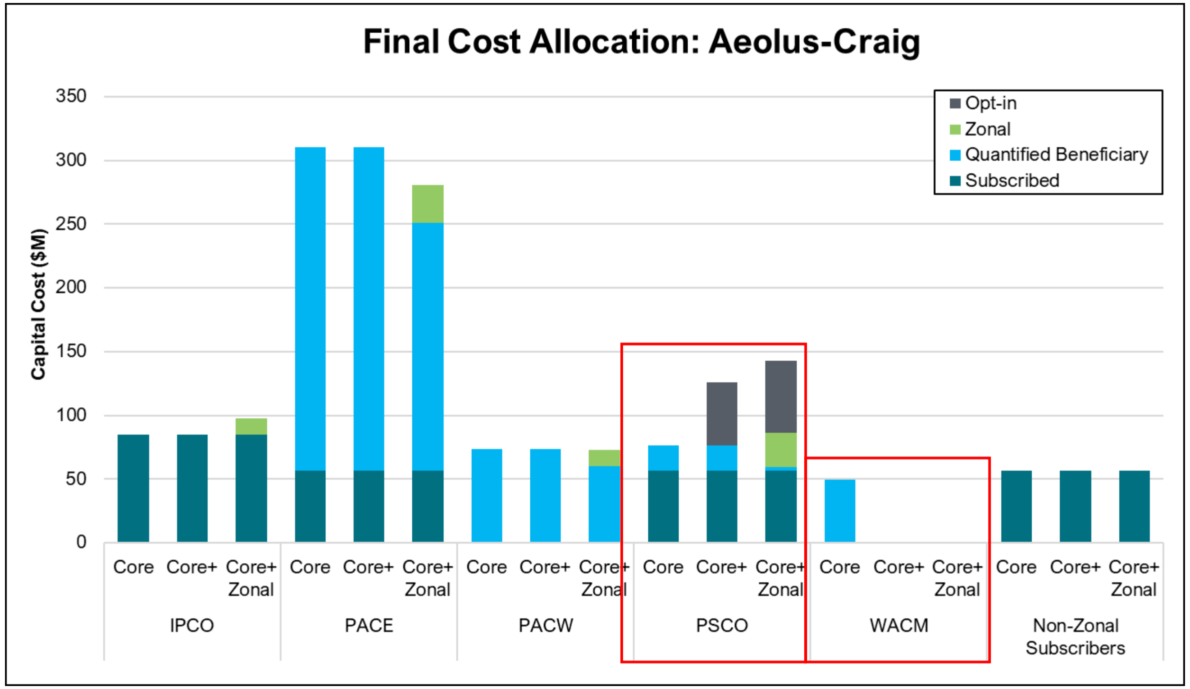
Transmission Zone	Capacity Allocated to Subscribers	Opt-In Capacity
PACE	100 MW	
PACW		
PSCO	100 MW	
WACM		
IPCO	150 MW	
Other Subscribers	100 MW	



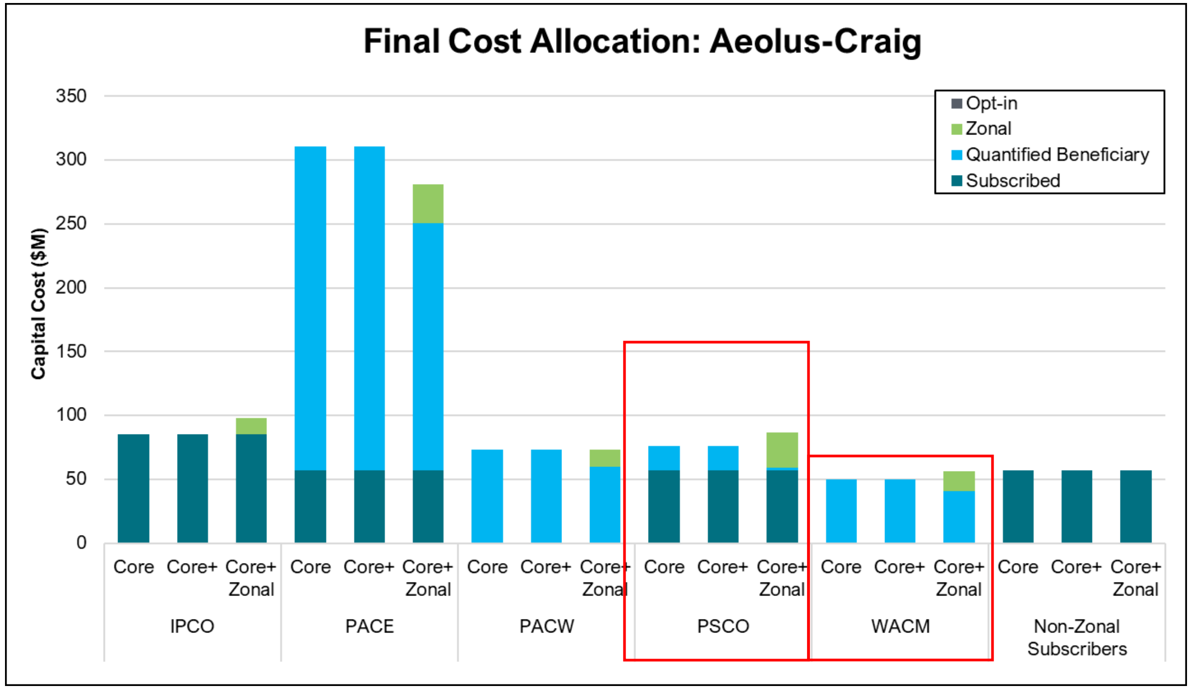
Q: What if we reduce flexibility by removing the opt-in share?

Base Case vs. No Opt-in Case

Base Case



No Opt-In Case



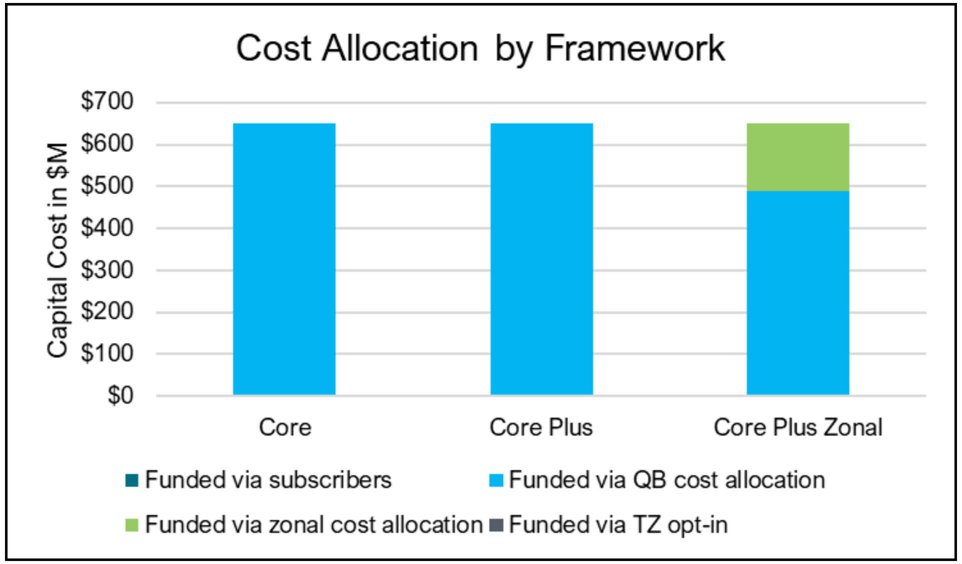
- **While costs assignments do not change substantively for most areas, in this example we see that WAPA no longer has tools to opt-out of project participation and is assigned ~$50M of upfront costs**
- **Similarly, absent the opt-in policy an entity like PSCo does not get as much capacity (and cost) as they may ultimately want)**

Aeolus-Craig: No Subscription & No Opt-In Case

Levers	No Sub & No Opt-In Case
Subscriber Share	~0%
% Remaining Assigned to QB vs. Zonal	25% QB / 75% Zonal
Opt-In Share	0%

(Hypothetical) Assumptions for Modeling Purposes

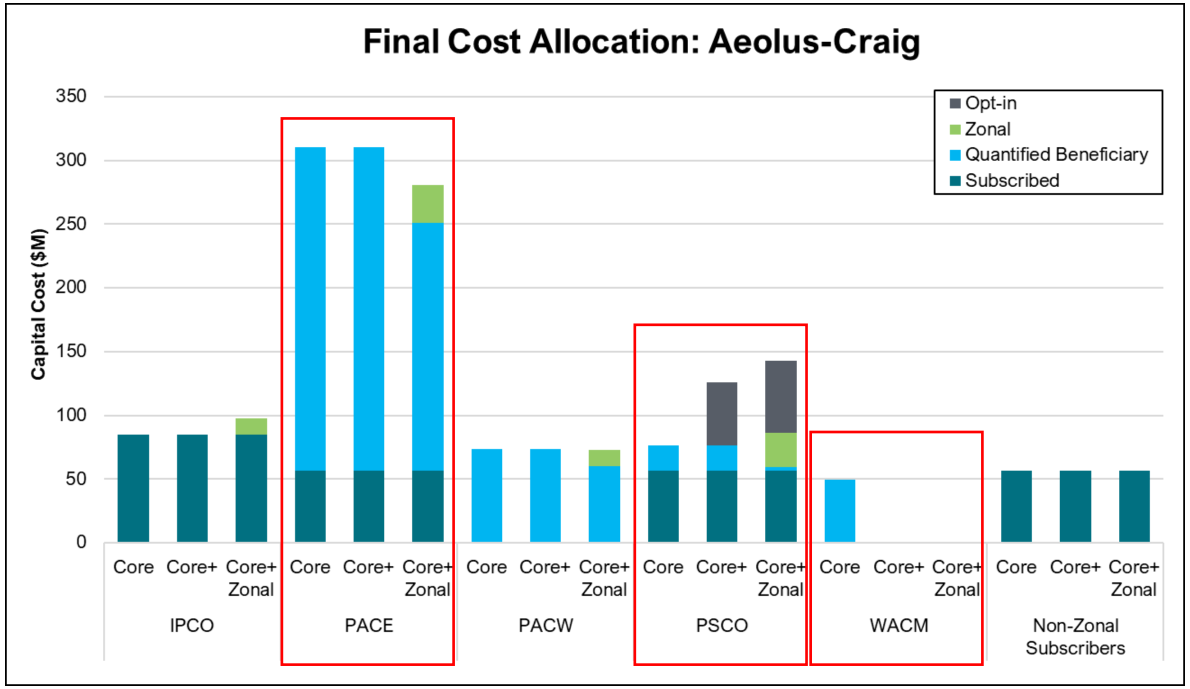
Transmission Zone	Capacity Allocated to Subscribers	Opt-In Capacity
PACE		
PACW		
PSCO		
WACM		
IPCO		
Other Subscribers		



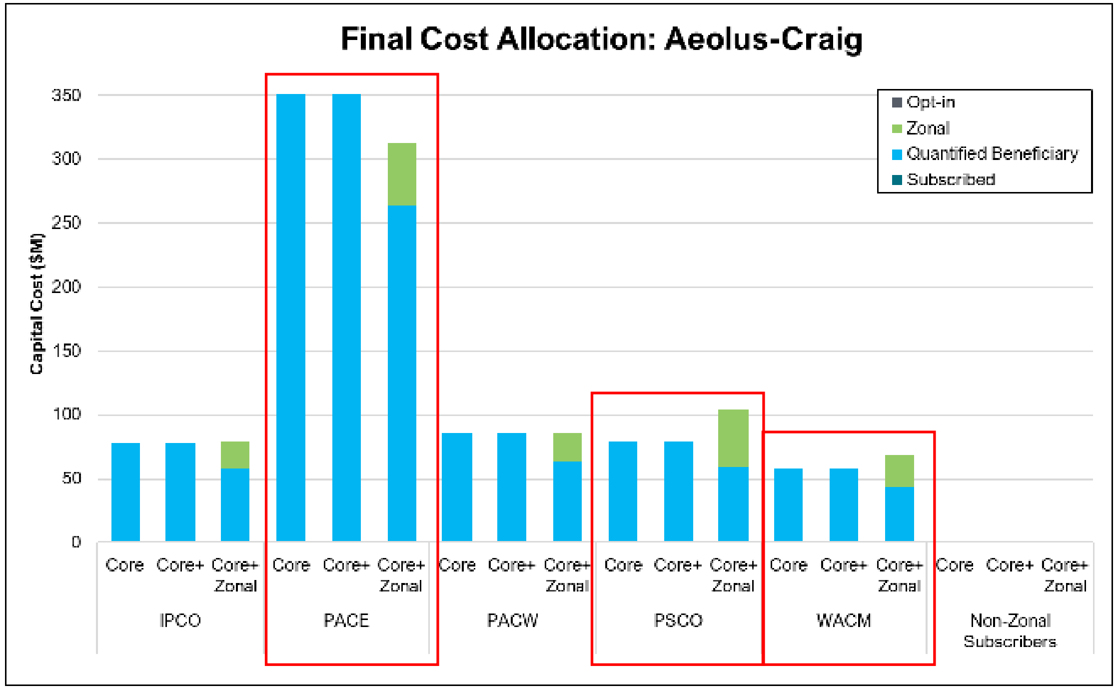
Q: What if we eliminate flexibility by removing the subscribers and the opt-in share?

Base Case vs. No Subscription & No Opt-In Case

Base Case



No Subscription & No Opt-In Case



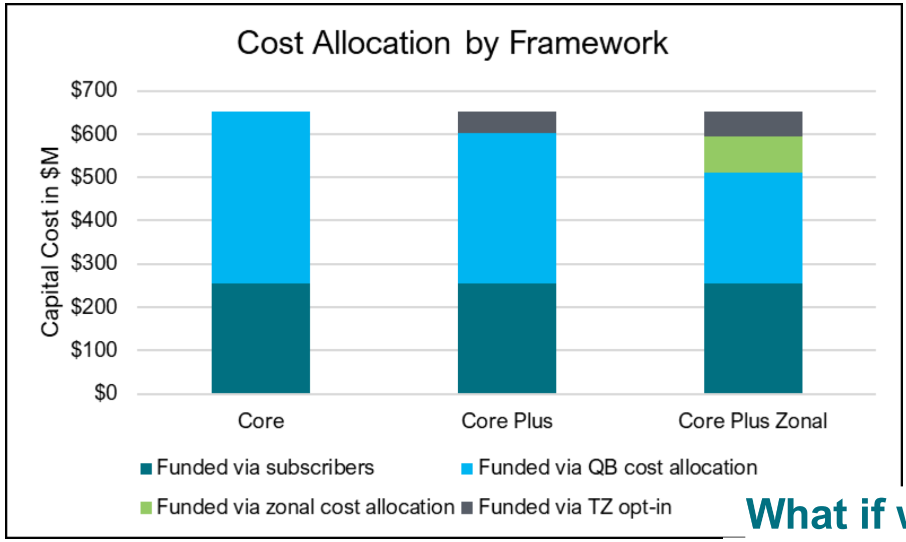
- **Overall trends among the different areas hold, suggesting that (1) overall cost allocation closely aligns with share of quantified benefits and (2) zonal share is primarily impactful at the margins (i.e., for areas that have either a proportionately large or small coincident peak)**

Aeolus-Craig: No Resource Adequacy Benefits Case

Levers	No RA Benefits Case
Subscriber Share	~40%
% Remaining Assigned to QB vs. Zonal	25% QB / 75% 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	(+) 90-100 MW
WACM		(-) 90-100 MW
IPCO	150 MW	
Other Subscribers	100 MW	



What if we exclude certain benefits from the QB calculation?

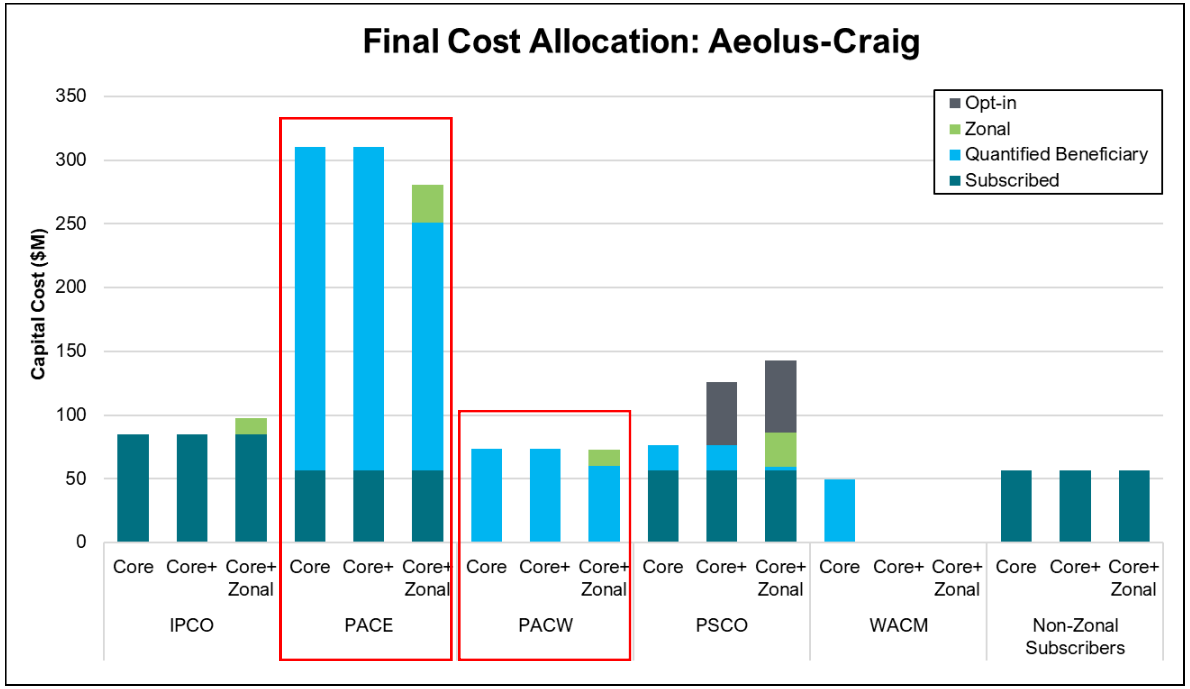
Quantified beneficiary pays (benefits in $M)

Transmission Zone	Operational & Congestion Benefits ($M/year)	Resource Adequacy (RA) Benefits ($M/year)	Avoided Transmission Investments ($M/year)	Resiliency Benefits ($M/year)	Total Benefits ($M/year)
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
IPCO	$0.00	$5.51	$0.00	$0.20	$5.71
Non-Zonal Subscribers					
Total					$48.08

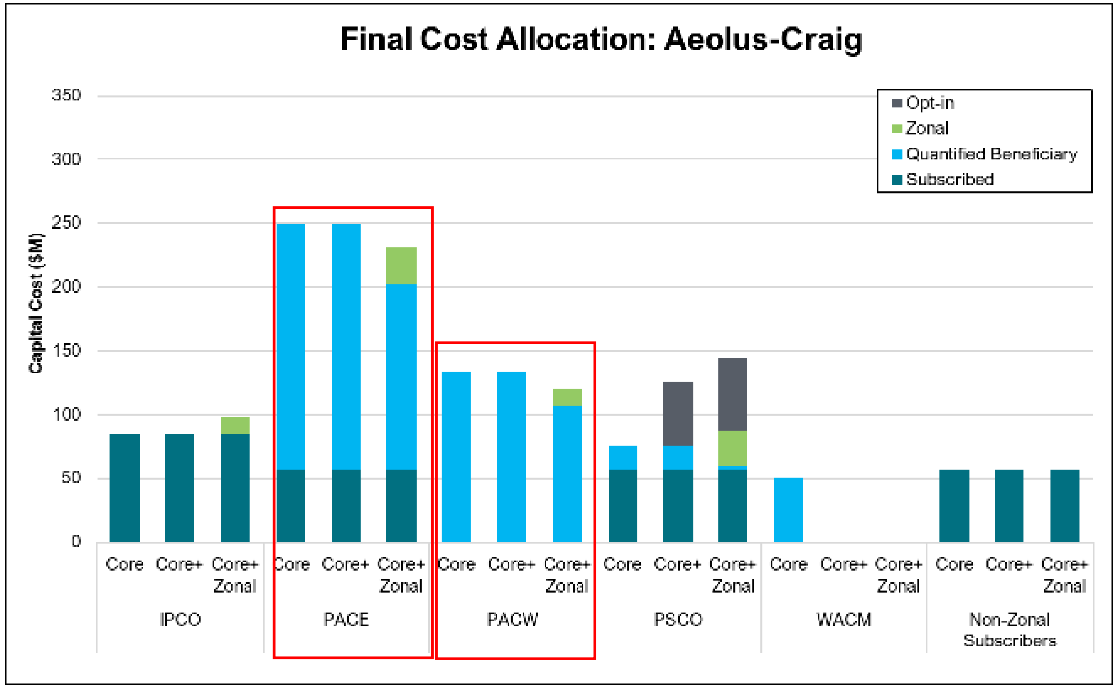
In this sensitivity, these RA Benefits are all set to $0

Base Case vs. No Resource Adequacy Benefits Case

Base Case



No Resource Adequacy Benefits Case



- **Costs decrease substantially for areas (e.g., PACE) with the highest share of resource adequacy benefits, and increase for areas (e.g., PACW) with the lowest share of resource adequacy benefits, but don't change much for other areas**

Comparison of Sensitivities

- **For the most part, Transmission Zones see similar overall cost impacts across all three (3) cost allocation frameworks for each sensitivity**
  - For example, in the Low Subscription Case, PACE sees increases in its overall cost assignment under the Core, Core+, *and* Core+ Zonal frameworks
  - But there are exceptions. For example, in the No Opt-In case, overall cost assignments for PACE, PACW, and IPCO do not change under the Core or Core+ frameworks compared to the Base Case. However, they do change under the Core+ Zonal case
- **Suggests that Transmission Zone differences in overall cost assignments may be primarily driven by differences in model inputs (i.e., subscriber amounts, quantified benefits, and opt-in/-out amounts) rather than differences in cost allocation frameworks**

Changes in Total Cost Allocation Relative to Base Case, by Sensitivity & Cost Allocation Framework

	Base Case			High Subscription			Low Subscription			High Zonal			No Opt-in			No Subscription/No Opt-In Case			No RA Benefits		
	Core	Core+	Core+ Zonal	Core	Core+	Core+ Zonal	Core	Core+	Core+ Zonal	Core	Core+	Core+ Zonal	Core	Core+	Core+ Zonal	Core	Core+	Core+ Zonal	Core	Core+	Core+ Zonal
PACE	$310	$310	$281	-35%	-35%	-34%	11%	11%	10%	0%	0%	-25%	0%	0%	21%	13%	-19%	-17%	-19%	-19%	-17%
PACW	$73	$73	$73	-57%	-57%	-58%	13%	13%	15%	0%	0%	-19%	0%	0%	36%	16%	82%	65%	82%	82%	65%
PSCO	$76	$126	$142	49%	7%	3%	2%	7%	17%	0%	0%	40%	0%	-39%	-1%	4%	0%	1%	-2%	0%	1%
WACM	$50	$0	$0	-57%	0%	0%	13%	0%	0%	0%	0%	0%	0%	0%	0%	16%	0%	0%	3%	0%	0%
IPCO	$85	$85	$98	100%	100%	78%	-11%	-11%	-21%	0%	0%	27%	0%	0%	27%	-9%	0%	0%	0%	0%	0%
Non-Zonal Subscribers	$57	$57	$57	100%	100%	100%	-75%	-75%	-75%	0%	0%	0%	0%	0%	0%	-100%	0%	0%	0%	0%	0%

Next Steps

Next Steps

- **April 2025: Likely share remaining hypothetical project results with CREPC TC at CREPC-WIRAB meeting**
  - All three case studies are expected to be complete or nearly complete before CREPC-WIRAB meeting
- **Late April/May 2025: Final report and presentation to CREPC TC summarizing the research, designs, and case study results**

Appendix

Development of Hypothetical Projects

Project Cost Estimates

- **Cost estimates were developed using MISO's Transmission Cost Estimation Guide (2024), which is a combination of stakeholder-submitted cost estimates for potential projects within MISO**
- **The exploratory cost estimates have an expected accuracy range of -15%-50% which are intended to provide a feasibility desktop analysis.**
- **The exploratory cost estimate includes:**
  - Project management, administrative and general overhead, engineering, environmental studies, testing, commissioning, right-of-way land acquisition, regulatory, permitting, structures, material, and contingency percent.

Table 4.2-2: Exploratory cost estimate – new substation

Scope of work	69 kV	115 kV	138 kV	161 kV	230 kV	345 kV	500 kV	765 kV
4 positions (ring bus)	$7.5M	$8.3M	$9.1M	$9.8M	$11.1M	$15.8M	$22.9M	$47.5M
4 positions (breaker-and-a-half bus)	$8.9M	$10.0M	$11.0M	$11.9M	$13.6M	$19.8M	$28.7M	$58.8M
4 positions (double-breaker bus)	$10.3M	$11.5M	$12.7M	$13.9M	$15.9M	$23.7M	$34.6M	$71.3M
6 positions (ring bus)	$9.4M	$10.6M	$11.6M	$12.6M	$14.5M	$21.1M	$30.8M	$63.0M
6 positions (breaker-and-a-half bus)	$11.4M	$12.9M	$14.2M	$15.5M	$18.0M	$26.9M	$39.3M	$80.8M
6 positions (double-breaker bus)	$13.4M	$15.2M	$16.8M	$18.4M	$21.3M	$32.3M	$47.4M	$97.3M

Includes contingency (30%) and AFUDC (7.5%)

Table 4.1-1: Exploratory cost estimate – AC transmission new single circuit transmission line $/mile

Location	69 kV	115 kV	138 kV	161 kV	230 kV	345 kV	500 kV	765 kV
Arkansas	$1.7M	$1.9M	$2.0M	$2.1M	$2.2M	$3.5M	$4.4M	$5.5M
Illinois	$1.8M	$2.0M	$2.0M	$2.1M	$2.2M	$3.6M	$4.5M	$5.6M
Indiana	$1.7M	$1.9M	$2.0M	$2.0M	$2.1M	$3.4M	$4.3M	$5.4M
Iowa	$1.7M	$1.9M	$2.0M	$2.1M	$2.2M	$3.5M	$4.4M	$5.6M
Kentucky	$1.8M	$2.0M	$2.1M	$2.2M	$2.3M	$3.7M	$4.6M	$5.8M
Louisiana	$2.0M	$2.2M	$2.3M	$2.4M	$2.6M	$4.1M	$5.1M	$6.3M
Michigan	$1.8M	$2.0M	$2.1M	$2.2M	$2.3M	$3.7M	$4.6M	$5.8M
Minnesota	$1.8M	$2.0M	$2.1M	$2.1M	$2.3M	$3.6M	$4.5M	$5.7M
Mississippi	$2.0M	$2.2M	$2.3M	$2.4M	$2.6M	$4.1M	$5.0M	$6.3M
Missouri	$1.7M	$1.9M	$2.0M	$2.0M	$2.2M	$3.5M	$4.4M	$5.5M
Montana	$1.6M	$1.8M	$1.9M	$1.9M	$2.0M	$3.2M	$4.1M	$5.2M
North Dakota	$1.6M	$1.8M	$1.9M	$1.9M	$2.0M	$3.3M	$4.1M	$5.2M
South Dakota	$1.6M	$1.8M	$1.9M	$1.9M	$2.0M	$3.3M	$4.1M	$5.2M
Texas	$1.9M	$2.2M	$2.3M	$2.3M	$2.5M	$4.0M	$4.9M	$6.1M
Wisconsin	$1.8M	$2.0M	$2.1M	$2.2M	$2.3M	$3.7M	$4.6M	$5.8M

Includes contingency (30%) and AFUDC (7.5%)

Table 2.3-7: Power transformer ($/MVA)

Voltage class	69 kV	115 kV	138 kV	161 kV	230 kV	345 kV	500 kV	765 kV
69 kV	$5,606	$4,564	$5,050	$5,317	$5,896	$7,239	$9,336	$13,135
115 kV	$4,564	$6,209	$5,050	$5,317	$5,896	$6,880	$8,444	$10,807
138 kV	$5,050	$5,050	$6,880	$5,606	$5,896	$6,880	$8,444	$10,807
161 kV	$5,317	$5,317	$5,606	$7,622	$6,209	$7,239	$8,884	$10,807
230 kV	$5,896	$5,896	$5,896	$6,209	$8,444	$7,239	$8,884	$10,807
345 kV	$7,239	$6,880	$6,880	$7,239	$7,239	$10,286	$9,336	$11,340
500 kV	$9,336	$8,444	$8,444	$8,884	$8,884	$9,336	$13,784	$12,510
765 kV	$13,135	$10,807	$10,807	$10,807	$10,807	$11,340	$12,510	$18,475

Quantification of Project Benefits

Benefits Captured Via Each Cost Allocation Category

- **Each of the cost allocation categories in the proposed framework captures different types of benefits**
  - The table to the right represents our initial assumptions and is subject to change
- **Today, we will discuss each category in greater depth, reviewing the strengths/weaknesses of each of the five (5) benefits included in the *quantified beneficiary pays* building block**
  - For a range of reasons, we are not currently considering the following benefits for *quantification*:
    - Resource access benefits
    - Public policy benefits
    - Avoided emissions
    - Economic development benefits

Category	Benefits Captured (Directly or Indirectly)
Subscriber pays	• Benefits determined by the subscribing entity (not necessarily quantified through the cost allocation framework)
Quantified beneficiary pays	• Operational & congestion benefits • Resource adequacy benefits (capacity savings) • Avoided transmission investments • Resiliency benefits • Transmission revenue
Zonal allocation	• Other non-quantifiable or difficult-to-quantify benefits (economic development, general reliability, etc.)
Opt-in	• Resource access • Public policy benefits

We recognize that preferences for including/excluding a zonal allocation category may depend on which benefits are ultimately captured in the quantified beneficiary pays category

Overview of Five 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
Transmission Revenue	• The addition of incremental transmission projects increases the amount of transmission capacity on the system, which can increase the revenues the owners of that capacity receive from transmission sales to third-parties. • This provides an opportunity for transmission providers to generate additional revenue through sales of firm- and/or non-firm transmission service

Methodologies for Quantifying Benefits

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 projects**
  - 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 and 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 visa versa, resulting in opportunities for capacity savings so long as the two regions do not have peak loads that occur at the same time

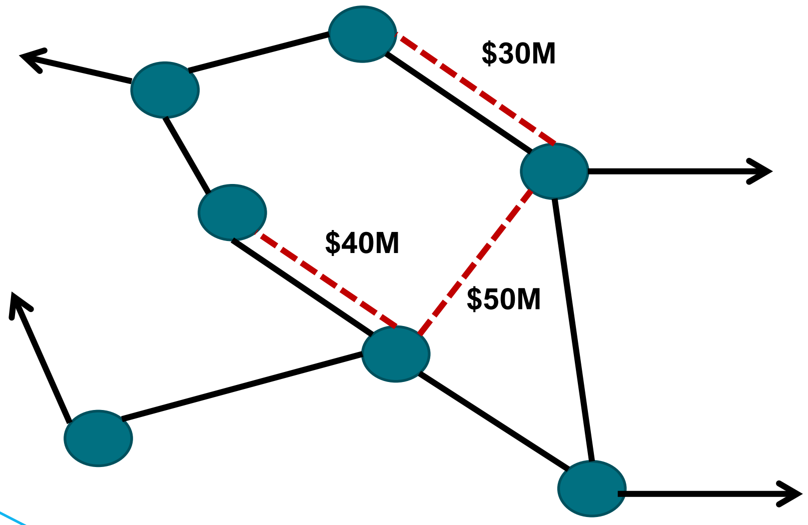
Simplified Analysis Steps

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)

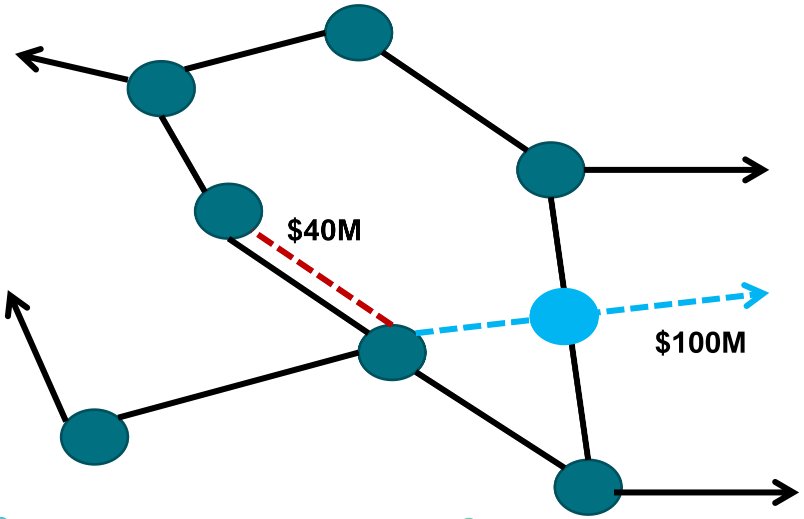
Benefit Methodology: Avoided Transmission Investments

- **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

\+

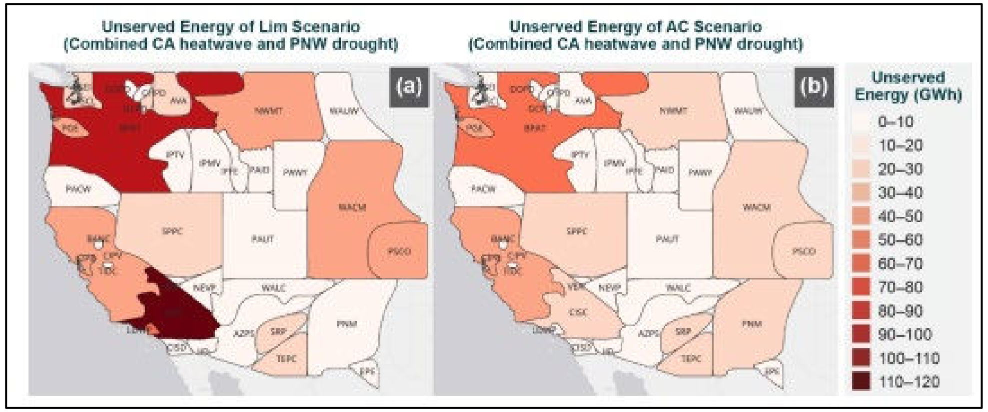
$50M

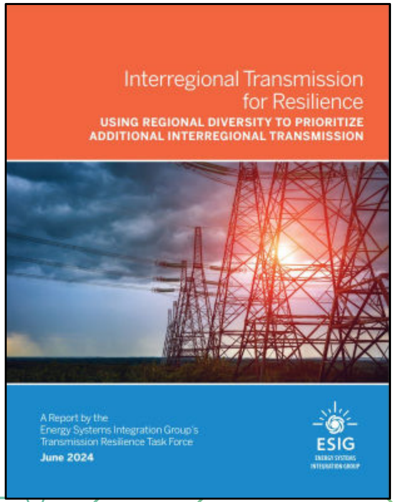
$80M of savings

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
    - May be assumed to cost up to $80,000/MWh, although other data points suggest something in the $40,000/MWh range is also reasonable
    - National Labs publish tools to support estimating
  - 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
- **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.

Benefit Methodology: Transmission Revenue

- **The addition of transmission capacity to the system may result in an opportunity for the owners of that capacity to sell it for use by third parties**
    - In other words, the inclusion of new transmission projects may increase interest from transmission customers in obtaining firm or non-firm point-to-point transmission service, which will result in payments to the owner of the capacity
- **This benefit can be quantified by multiplying the incremental transmission capacity used by third-parties multiplied by (x) the applicable transmission service rate**
- **Approach requires assumptions regarding:**
    - Amount of capacity purchased by third-parties and how frequently (or what duration) purchase would be
        - Informed by past experience/data on third-party transmission sales for jurisdiction
        - Also informed by the nature of the line in question
    - Transmission rate of provider over time
        - Informed by current rate and assumptions regarding rate escalation

ENERGY STRATEGIES

Comparison of Benefit Categories

Benefit	Strengths	Weakness	Energy Strategies Recommendation
Operational & Congestion Benefits	• Reasonably captures congestion relief and resulting dispatch efficiency improvements, which represent cost reductions that are "real" (versus hypothetical) • Nodal dispatch modeling is reliable at estimating these savings when a relatively efficient day-ahead market is in place – ISOs/RTOs have been using these tools to quantify such savings for decades	• Absent a relatively efficient day-ahead market in the West, dispatch modeling needs substantial adjustment and tuning to represent realities of contract path approach to transmission rights in the West, so the accuracy of this benefit metric goes down when no day-ahead market is assumed to be in place	Include in initial quantified beneficiary category
Resource Adequacy Benefits	• Widely recognized that inter-area transmission capacity enables the sharing of resources during peak load events • Reasonable to assume the new transmission capacity could open up bilateral capacity transactions that would be more efficient than building new generation • Aligns with WRAP, which enables a region-wide approach to assessing and addressing RA	• Since we can not know for certain which capacity transactions will take place, the benefits are in some way academic or theoretical • For calculating the Planning Reserve Margins and several other metrics, WRAP currently does not consider transmission limitations between "Zones", only "subregions" (which are relatively broad), but as the program evolves this weakness may dissipate (and it is also mitigated by the WRAP requirement for 75% of resources to be delivered to load on firm transmission)	Include in initial quantified beneficiary category

Comparison of Benefit Categories (cont.)

Benefit	Strengths	Weakness	Energy Strategies Recommendation
Avoided Transmission Investments	• Relatively definitive and defensive benefit as there are NERC mandated transmission planning standards that dictate required levels of reliability that can be measured via powerflow simulations with and without the transmission upgrade • The value of the avoided investment is clear – it is either the avoided capital cost or the time value of money associated with deferring an upgrade (keeping rates lower for longer)	• Could impact investment plans of utilities, which may complicate planning processes • Requires complex modeling – not possible to do via spreadsheet	Include in initial quantified beneficiary category
Resiliency Benefits	• Likely one of the more important and widely agreed upon benefits of transmission • Value of lost load (VOLL) is not a new concept and there are many examples of the economic damage that can occur as a result of prolonged power outages	• Complex to model – there are fewer standards for these types of studies and weather/grid data needed requires substantial effort to prepare • Requires “starting point” dispatch model • Results of modeling often are not intuitive – a transmission line can help mitigate reliability event hundreds of miles away • Potential for debate on VOLL estimate	Include in initial quantified beneficiary category
Transmission Revenue	• Simple to model – can be done in days, not weeks • Represents a “real” benefit to utilities, as they typically do experience increased transmission revenue from transmission sales after expanding their systems	• Effectively a forecast, as there are not real contracts to “backup” anticipated revenues from transmission capacity sales	Include in initial quantified beneficiary category