WestConnect Regional Transmission Planning

2016-17 Planning Cycle

Regional Opportunity Study Summary For San Luis Valley Congestion

December 27th, 2017

Contents

STUDY DISCLAIMER

This study report summarizes results from an exploratory exercise performed by Energy Strategies, LLC at the request of the WestConnect PMC. It does not represent a regional transmission need, and references to transmission project costs, project alternatives and project benefits are conceptual and have not be validated or endorsed by the WestConnect PMC. Additionally, a number of the assumptions used in the assessments were made by Energy Strategies, LLC independently. The assessment has not been evaluated by the Transmission Owners with Load Service Obligation (TOLSO) members of WestConnect for compliance with their Order No. 1000 implementing tariffs, and may not depict the process and analyses required under the FERC tariffs.

1.0 Background

The WestConnect 2016-17 Study Plan ("Study Plan") included several Scenario studies that complement the Base Case assessments by evaluating alternate, but plausible, futures. Scenarios represent futures with resource, load, and public policy assumptions that are different in one or more ways than what is assumed in the Base Cases, which are considered "business as usual". As detailed in the Study Plan and the 2016-17 Regional Transmission Plan, Base Cases are used to identify FERC Order 1000 regional transmission needs within the Planning Process, while Scenarios can, at the PMC's discretion, lead to "opportunities".[1] Opportunities are economic congestion or reliability issues identified in Scenario studies that warrant additional consideration by WestConnect and can be investigated on an informational basis. Opportunities do not constitute regional transmission needs, and the subsequent requirement to address a regional need, under the WestConnect process.[2]

During the first two quarters of 2017 the WestConnect Planning Subcommittee reviewed the results of the scenarios assessments. The goal of the scenario assessments was to test the capabilities of the base transmission plan under futures different than the Base Case "expected" future. WestConnect performed the scenario assessments and found that, generally, the WestConnect regional system performed well under the scenarios as judged by the reliability and economic criteria within the scope of the studies. The scenario studies did not reveal any major regional reliability issues (steady-state or transient stability) and there were two significantly congested regional elements identified in the economic studies – both the result of resource siting decisions made during the development of the scenarios.

In the 2016-17 Planning Process, the PMC decided to evaluate one regional opportunity: congestion in the San Luis Valley in Colorado identified in a Scenario study. The PMC viewed the regional opportunity evaluation as a way to test and explore certain elements of the planning process, which in turn would give WestConnect information to improve the process, create data for planning policy decisions in the future, and prepare for future cycles.

2.0 Study Purpose and Scope

The purpose of this report is to summarize the information-only investigation into the San Luis Valley regional opportunity identified by the WestConnect Planning Management Committee (PMC) during the 2016-2017 Regional Transmission Planning Process ("Planning Process"). The materials seek to capture the purpose, methodologies, results, and observations pertaining to the regional opportunity and alternative evaluation process.

---

[1] If regional transmission needs are identified, WestConnect solicits solutions and seeks to identify the more efficient or cost effective of those solutions. These steps are required when regional needs are identified in WestConnect's Order 1000 planning process.

[2] For example, it would be impossible to have an "opportunity" lead to binding cost allocation or competitive solicitations

At the May 17, 2017 meeting the PMC decided to evaluate the San Luis Valley ("SLV") economic opportunity, which consisted of studying solutions to the congestion on the San Luis Valley – Poncha 230 kV line in the Regional Renewables scenario study.[3] The purpose of the opportunity evaluation was to test and explore certain aspects of the planning process. The evaluation scope was focused on:

1. **Technical Performance –** WestConnect studied the ability of three project alternatives to mitigate the regional congestion without causing additional regional issues. This required a comparison of congestion results from the "no-project" scenario to each "post-project" alternative case. The scope only included the economic performance of the alternatives and did not consider local/regional reliability or resource deliverability, two factors that, among others, would be important if the evaluation of projects were being performed to meet a regional need.
2. **Economic Assessment –** An evaluation of the cost effectiveness of alternatives was accomplished by ranking them according to benefit-cost ratios with benefits represented by the present value of the sum of individual WestConnect Transmission Owner with Load Serving Obligations (TOLSO) total adjusted product cost (APC) savings, and costs represented by the present value of the annual revenue requirement of the capital cost of the alternative. Project feasibility and additional costs of network upgrades identified in interconnection system impact studies were not considered, nor where the potential benefits of an alternative resource portfolio. No effort was made to assess the "most efficient" alternative, though if alternatives were being compared to meet a regional need, WestConnect would need to select the more cost-effective or efficient solution.
3. **Cost Allocation -** Test cost allocation for the most cost-effective alternative, making a number of assumptions pertaining to eligibility criteria and benefit determinations.

3.0 Assumptions and Modeling Techniques

The evaluation of project alternatives required numerous assumptions and modeling techniques pertaining to not only the economic studies but also financial analysis used to derive benefit and costs estimates. Some of these assumptions have been established and approved by the PMC, while others are still being developed or will be decided on when a regional need is identified.[4] This analysis also required the identification of project alternatives. The project alternatives, financial assumptions, and other input parameters relevant to the economic assessment are detailed below.

3.1 Project Alternatives and Capital Cost

WestConnect chose to evaluate three project alternatives as part of the SLV Regional Opportunity study. The project alternatives were:

---

[3] *The Regional Renewables Scenario considered renewable resource expansion at levels 50% higher than enacted state requirements across the WestConnect footprint*

[4] *The assumptions used in the SLV Regional Opportunity study are not intended to pre-define any decisions the PMC may make at a later date.*

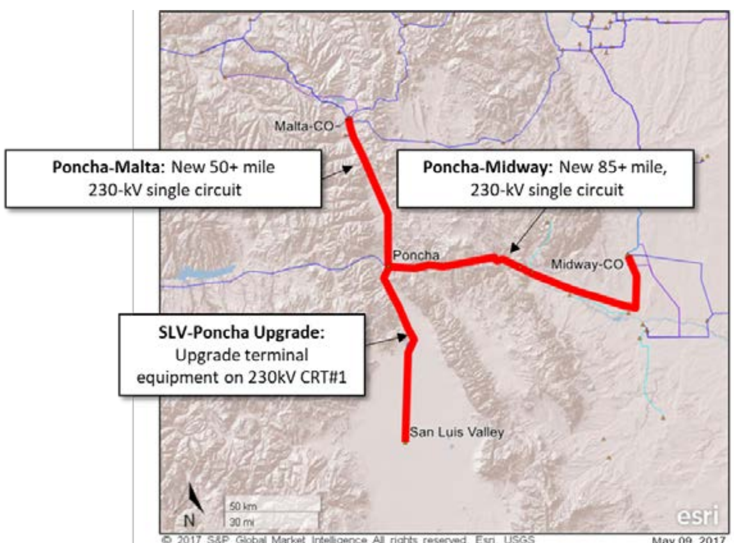
- **Alternative 1:** SLV-Poncha 230-kV Upgrade + Poncha-Midway 230-kV
- **Alternative 2:** SLV-Poncha 230-kV Upgrade + Poncha-Malta 230-kV
- **Alternative 3:** SLV-Poncha 230-kV Upgrade + Energy Storage at Poncha

The line segments making up these alternatives had been previously identified by work performed by the Colorado Coordinated Planning Group (CCPG).[5] WestConnect decided to leverage this prior work since the alternatives were relevant and saved WestConnect from having to identify new transmission projects for the assessment. The energy storage alternative was included to gain experience at evaluating non-transmission alternatives.

Notably, the SLV-Poncha upgrade is included in all three alternatives. The CCPG's prior study work concluded that increased export capability from the SLV substation to Poncha would be required but, alone, would not be sufficient to resolve a long-term congestion issue since there is no long-term transfer capability available beyond Poncha. For this reason, the SLV-Poncha Upgrade, which consists of terminal upgrades to one of the existing San Luis Valley to Poncha circuits to increase the line rating from 180 MVA to 570 MVA (increasing the total export capability by 780 MVA), was combined with the three other additions individually to create three alternatives.

The line segments that make up the alternatives are shown in the map in **Figure 1**.

Figure 1: Line Segments for Alternatives



The capital cost estimate of the individual segments is presented in **Figure 2**, and the alternatives' total cost and NPV revenue requirement is provided below in **Figure 3**. The present value of the annual revenue requirement for each alternative was calculated using financial assumptions presented in Section 3.2.

---

[5]*Phase 1 Report: https://doc.westconnect.com/Documents.aspx?NID=17247&dl=1;*

Phase 2 Report: https://doc.westconnect.com/Documents.aspx?NID=17715

Figure 2: Alternative Segment Cost Assumptions

Project Segment	Capital Cost (2016 $)	Basis
SLV-Poncha 230-kV Upgrade	$3 M	Upgrade of terminal substation equipment at SLV and Poncha. *Source: PSCO estimate for study purposes*
Poncha-Midway 230-kV	$175 M	Construct approximately 88 miles of new single circuit 230kV transmission line. Will require new easements/right-of-way (ROW). New line terminations and associated equipment at Poncha and West Cannon and Midway Substations. *Source:* CCPG SLV Phase 2 Report
Poncha-Malta 230-kV	$100 M	Construct approximately 52 miles of new single circuit 230kV transmission line. Will require new easements/ROW. New line terminations and associated equipment at Poncha and Malta. *Source:* CCPG SLV Phase 2 Report
Battery Storage	$750 M	New 250 MW / 4-hour storage Li-Ion battery assuming $3000/kW. *Source: TEPPC Capital Cost Calculator 2017 Update (E3 presentation to TAS) and TSGT Study, "San Luis Valley: Non-Transmission Alternatives"* (Presentation to CCPG)

Figure 3: Alternative Total Cost and Present Value of Revenue Requirement

Project Alternative	Total Cost (2016$)	Present Value of Annual Revenue Requirement (2016$)
Alternative 1	$178M transmission	$157 M
Alternative 2	$103M transmission	$91 M
Alternative 3	$3 M transmission and $750M battery	$665 M

3.2 Financial Assumptions

The financial analysis required for benefit-cost ratio derivation and cost allocation was conducted using the following financial assumptions:

- 2026 project in-service date;
- 2016 real dollars;
- Project costs assumed:
  - 20-year valuation timeframe (i.e. 20 years of the revenue requirement were included in the calculation of the NPV that makes up the project costs);

- Costs equal to the NPV of the project revenue requirement, assuming 7% discount rate;
  - Project annual revenue requirements were calculated using the Western Electricity Coordinating Council (WECC) Transmission Expansion Planning and Policy Committee (TEPPC) 2014 Generation Capital Cost Calculator, using and number of input assumptions reviewed by the Cost Allocation Subcommittee in 2016-17;
- 40-year economic life and debt period;
- 50/50 debt-equity financing with debt interest rate of 6% and 11% cost of equity totaling 7.31% weighted-average cost of capital

- Alternative project benefits assumed:
  - 20-year valuation timeframe (i.e. 20 years of the project benefits were included in the calculation of the NPV that makes up the total project benefits);,
  - Benefits equal to the NPV of annual APC savings assuming 7% discount rate;
    - TOLSOs that had increases in APC as a result of the addition of an alternative were excluded from the calculation of benefits for each alternative evaluated
  - Benefits were held constant in real terms and were not escalated beyond the rate of inflation (which was assumed to be 2%);

3.3 Project Modeling and APC Calculation

The projects were evaluated against their ability to reduce congestion along the lines of interest. The economic study was performed by adding the alternative (individually) to the pre-project scenario case and then reviewing the congestion and economic changes between the two production cost model studies. WestConnect leveraged the APC methodology developed by the Cost Allocation Subcommittee (and documented in the CAS Procedures Document) to identify the benefits offered by each alternative. Details on the APC calculation are available in the Cost Allocation Procedures Document. However, some additional assumptions, on items that have not yet been finalized in the Cost Allocation Procedures were required to complete the analysis and are described later in the document.

4.0 Study Results

The study scope included a review of the technical performance of each project, in terms of congestion relief, as well as a comparative ranking of the projects based on their relative economics through benefit-cost ratios. It also included an illustrative testing of the cost allocation methodology for economic projects. All three of these analyses are summarized below.

4.1 Technical Performance

All three of the alternatives eliminated congestion on the SLV-Poncha 230-kV circuits, thereby meeting the technical requirements of this evaluations limited scope. The lines were congested for 26% of the year (2,311 hours, $18M congestion cost) in the Regional Renewables scenario case and in the project alternative studies the congested hours and congestion cost were zero. The three alternatives did not cause any new regional elements to become congested, although there were minor changes in congestion to previously congested regional elements, which was expected with changes to system dispatch that result from adding the alternatives.

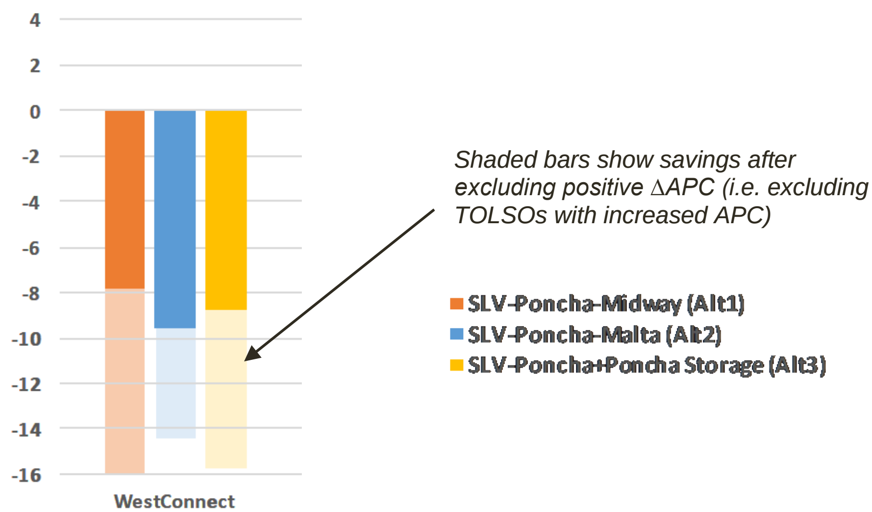
All alternatives were also effective at eliminating curtailment from resources located at and near the SLV substation. In the scenario, new renewable resources were added to meet a hypothetical public policy goal representing an increase to WestConnect-state Renewable Portfolio Standards by 50%. As a result, approximately 672 MW of additional solar PV was added near the SLV substation on top of the already existing 164 MW of generation in the area. Nearly 30% of the new solar PV energy was curtailed in the scenario study because of the transmission constraint out of the SLV. In the alternative cases, including the battery storage case, effectively all of the new renewable energy was delivered to load and curtailments were eliminated. [6]

4.2 Economic Assessment

APC savings, or reductions in APC from the scenario case to the project case, were calculated for each of the alternatives. This value was derived by summing the APC for each WestConnect TOLSO consistent with the methodology established by the CAS (but in this instance, was applied not for cost allocation but for benefit identification). In this assessment, only the decreases in APC for TOLSOs (i.e., benefits) were including in the summation. Because WestConnect has not established a policy on how to treat increases in APC for determining project cost-allocation eligibility and cost-allocation, the decision to exclude increases in APC for the SLV Regional Opportunity study was made to illustrate one approach to determining economic benefits and cost-allocation eligibility and should not be viewed as predisposing which approach WestConnect will ultimately use. **Figure 4** shows the change in APC for each of the alternatives and the impact of the assumption to exclude increases in APC from the summation.

[6] WestConnect members were concerned with how degradation of new solar could impact the analysis. There was not an assumed installation date for the new generation in this analysis and as a result degradation impacts where not considered.

Figure 4: Change in APC (2016 $M)



Depending on the project, there were additional benefits accrued to a category of beneficiaries called "others in WestConnect", which were loads or generators in the regional footprint but not assigned to any particular TO for purposes of APC derivation. These entities accounted for about 4% of the load and roughly 25% of the generation and they accrued between $1M and $4M of annual benefits not attributed to WestConnect entities. This result is not necessarily incorrect, but it is important to review these results going forward to ensure that loads and generation are properly assigned to the TOLSOs to ensure accurate benefit calculation. WestConnect has since updated its APC datasets and this new information should help to ensure that benefits held by "others in WestConnect" will be accurate.

All three alternatives had single-year 2026 benefits between $14M and $16M. The 2026 single-year benefit was inflated at the rate of inflation, 2% annually, to maintain the value of the benefit, in real terms, throughout the evaluation period. The evaluation period was assumed to be 20-years. The present value of this 20-year string of benefits was calculated using a 7% nominal discount rate. The multi-year savings for each project alternative are provided in the charts below in **Figure 5.**

Figure 5: Multi-year Savings and Total NPV (Nominal $)

Alternative 1

APC Multi-Year Savings			
Date	Savings by Year	PV of Savings	Year
1/1/2026	$19,392,676	$9,858,253	1
1/1/2027	$19,780,530	$9,397,587	2
1/1/2028	$20,176,140	$8,958,447	3
1/1/2029	$20,579,663	$8,539,828	4
1/1/2030	$20,991,256	$8,140,771	5
1/1/2031	$21,411,081	$7,760,361	6
1/1/2032	$21,839,303	$7,397,727	7
1/1/2033	$22,276,089	$7,052,039	8
1/1/2034	$22,721,611	$6,722,505	9
1/1/2035	$23,176,043	$6,408,369	10
1/1/2036	$23,639,564	$6,108,913	11
1/1/2037	$24,112,355	$5,823,449	12
1/1/2038	$24,594,602	$5,551,326	13
1/1/2039	$25,086,494	$5,291,918	14
1/1/2040	$25,588,224	$5,044,632	15
1/1/2041	$26,099,989	$4,808,901	16
1/1/2042	$26,621,988	$4,584,186	17
1/1/2043	$27,154,428	$4,369,972	18
1/1/2044	$27,697,517	$4,165,768	19
1/1/2045	$28,251,467	$3,971,106	20
Total	$471,191,020	$129,956,059	

Alternative 2

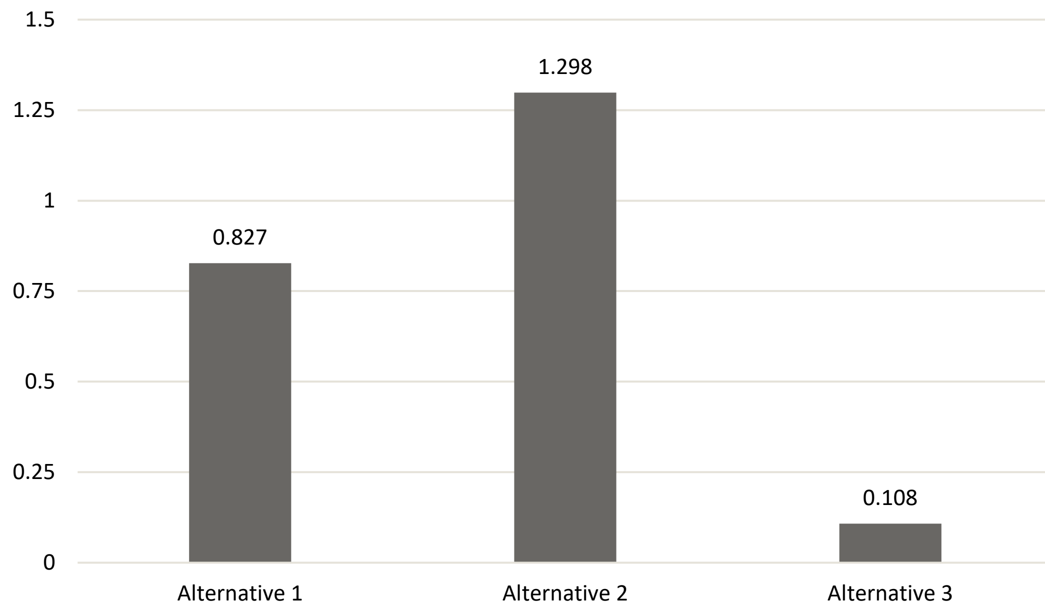
APC Multi-Year Savings			
Date	Savings by Year	PV of Savings	Year
1/1/2026	$17,611,953	$8,953,024	1
1/1/2027	$17,964,192	$8,534,658	2
1/1/2028	$18,323,476	$8,135,842	3
1/1/2029	$18,689,946	$7,755,663	4
1/1/2030	$19,063,744	$7,393,249	5
1/1/2031	$19,445,019	$7,047,770	6
1/1/2032	$19,833,920	$6,718,435	7
1/1/2033	$20,230,598	$6,404,489	8
1/1/2034	$20,635,210	$6,105,214	9
1/1/2035	$21,047,914	$5,819,924	10
1/1/2036	$21,468,873	$5,547,965	11
1/1/2037	$21,898,250	$5,288,714	12
1/1/2038	$22,336,215	$5,041,578	13
1/1/2039	$22,782,939	$4,805,990	14
1/1/2040	$23,238,598	$4,581,411	15
1/1/2041	$23,703,370	$4,367,326	16
1/1/2042	$24,177,437	$4,163,246	17
1/1/2043	$24,660,986	$3,968,702	18
1/1/2044	$25,154,206	$3,783,248	19
1/1/2045	$25,657,290	$3,606,461	20
Total	$427,924,137	$118,022,908	

Alternative 3

APC Multi-Year Savings			
Date	Savings by Year	PV of Savings	Year
1/1/2026	$10,690,581	$5,434,549	1
1/1/2027	$10,904,393	$5,180,598	2
1/1/2028	$11,122,481	$4,938,514	3
1/1/2029	$11,344,930	$4,707,743	4
1/1/2030	$11,571,829	$4,487,755	5
1/1/2031	$11,803,265	$4,278,047	6
1/1/2032	$12,039,331	$4,078,138	7
1/1/2033	$12,280,117	$3,887,571	8
1/1/2034	$12,525,720	$3,705,908	9
1/1/2035	$12,776,234	$3,532,735	10
1/1/2036	$13,031,759	$3,367,654	11
1/1/2037	$13,292,394	$3,210,287	12
1/1/2038	$13,558,242	$3,060,274	13
1/1/2039	$13,829,407	$2,917,270	14
1/1/2040	$14,105,995	$2,780,949	15
1/1/2041	$14,388,115	$2,650,998	16
1/1/2042	$14,675,877	$2,527,120	17
1/1/2043	$14,969,394	$2,409,030	18
1/1/2044	$15,268,782	$2,296,459	19
1/1/2045	$15,574,158	$2,189,147	20
Total	$259,753,001	$71,640,747	

The present value of the economic benefits offered by the alternatives were $72M for Alternative 3 and $130M and $118M for Alternative 1 and 2, respectively. These benefit values were then compared with the cost (present value of annual revenue requirement) of each alternative to derive the benefit-cost ratios presented in **Figure 6**.

Figure 6: Benefit-Cost Ratio Comparison of Alternatives



The scope of the evaluation did not include any detailed analysis around project selection as the goal was not to identify a specific alternative. WestConnect does not have specific criteria for selection of economic projects, but it would be reasonable to conclude that based on the assumptions used in this analysis, Alternative 2 appears to be the most cost-effective solution since it is has the highest-ranking benefit-cost ratio and has benefits that exceed its costs, providing the region with net benefits. Importantly, as discussed elsewhere in this document, we did not consider other important considerations like reliability and the fact that the project should be economically robust under a variety of sensitivities (e.g., higher or lower loads). We also did not include any costs beyond those associated with the alternatives, like network upgrades required for wire-to-wire interconnections. These factors, once considered, could have a significant impact on the selection of project to meet a regional need.

4.3 Cost Allocation

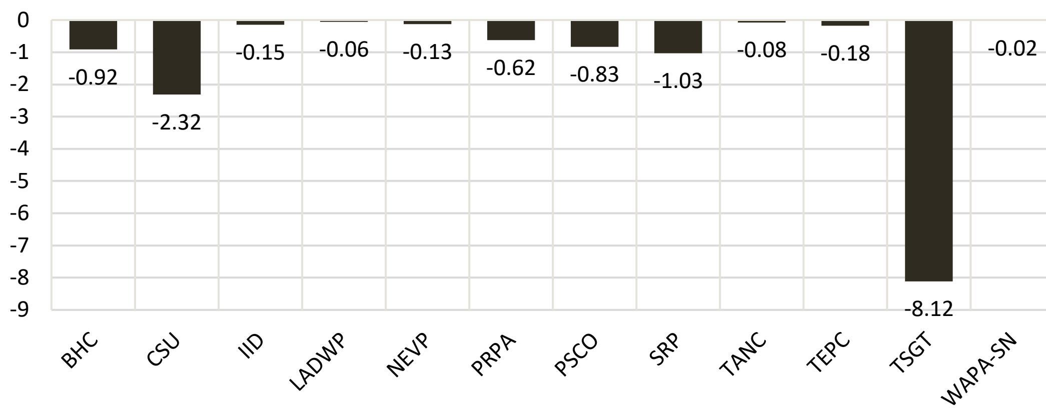
The hypothetical cost allocation evaluation was conducted for only Alternative 2 as a proxy for the most cost effective solution. Assuming that the alternatives considered above were to meet only an economic need (or "opportunity" in this example), in order for projects to be eligible for cost allocation the project must:

- Have a benefit-cost ratio ≥1.25 (on average, under all reasonable sensitivities evaluated); and
- Have a benefit-cost ratio >1.0 under each reasonable sensitivity evaluated.

Given the limited scope of this analysis, only one case was studied. If we assume the "average" benefit-cost ratio was equal to the single case, then Alternative 2 would be cost allocation eligible (subject to additional approvals/review) since its benefit-cost ratio is 1.298, which is greater than or equal to 1.25 (and, as discussed below, each entity also has a benefit cost ratio of greater than or equal to 1.25).

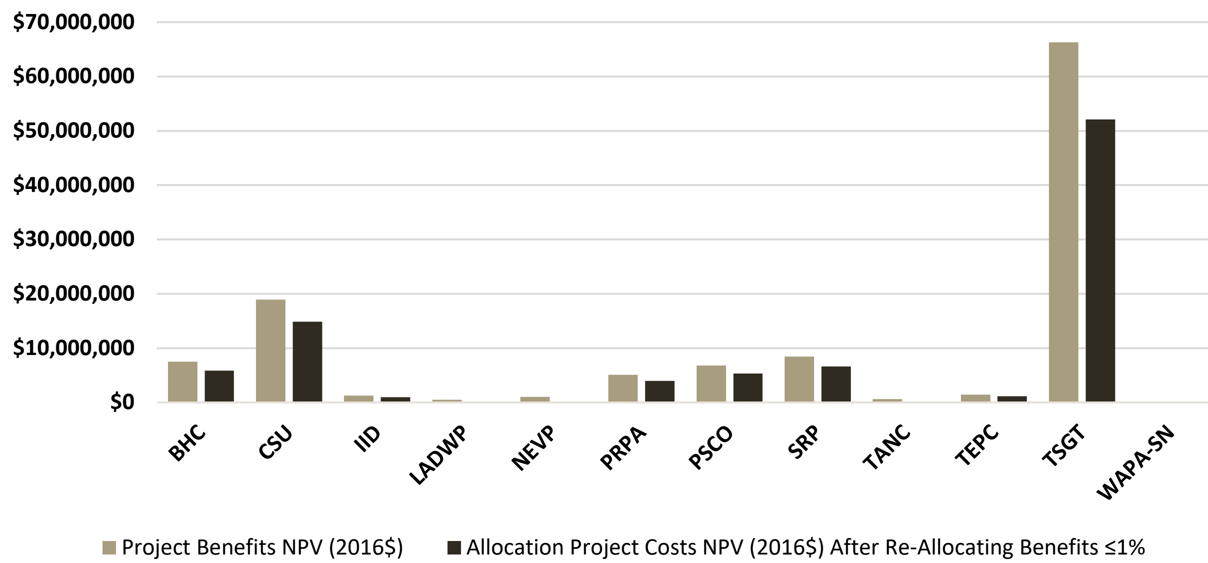
The beneficiaries of Alternative 2 and their annual change in APC, excluding APC increases, are shown in **Figure 7**. The WestConnect cost allocation process assigns the cost of the project to the entities benefiting, in proportion to their respective benefits. In this example, each TOLSO's benefit-cost ratio is the same as the overall project benefit-cost ratio (1.298) since decreases in APC were excluded. Note that recently updated data on TOLSO generation assignment and load responsibility will change these APC results, so they are more indicative of the format in which results would be presented in versus representative benefits of the project. Also note that beneficiary identification for a regional need would be subject to additional vetting and the sensitivity studies mentioned above – such work was not conducted in this analysis.

Figure 7: WestConnect TOLSO Annual Change in APC (2016 M$), excluding APC increases



The WestConnect cost allocation process assigns the cost of the project to the entities benefiting (as shown in the chart above), with the exception of the entities that were calculated to have less than or equal to 1% of the total alternative benefits. According to the WestConnect cost allocation process, when benefits less than or equal to one percent of total project benefits accrue to identified transmission owner(s), those benefits will be re-allocated to the other identified beneficiaries on a pro-rata basis. **Figure 8** shows each TOLSOs project benefits and their cost allocation for this illustrative example, after this re-allocation of benefits less than or equal to one percent. Note that, in this illustrative example, certain entities would not be subject to cost allocation because their share to total project benefits was less than or equal to one percent

Figure 8: Illustrative Example of Cost Allocation and Benefits for Alternative 2 (2016$)



The process described above required a number of assumptions that may or may not be employed by WestConnect for a future regional need. For example, the example excludes TOLSOs that were calculated to have an increase in APC and if those increases were included, the project would not have been eligible for cost allocation since its benefit-cost ratio would have been less than 1.25. Furthermore, the example used "D8 APC assumptions" to assign generation output and responsibility for serving load to each TOLSO. The "D8 APC assumptions" are outdated at the time this document will be reviewed by the PMC.[7] Re-studying the alternatives with new data would likely shift benefits to other entities. Lastly, the analysis did not specifically consider the impact of reserve sharing (beyond what may be reflected in the APC calculation), a benefit metric that the Cost Allocation subcommittee continues to review and consider.

5.0 Observations

Since this evaluation of the SLV regional opportunity was conducted to explore and enhance the economic assessment portion of the WestConnect planning and cost allocation processes this report does not offer project-specific conclusions pertaining to the SLV congestion issue subject to study. There were, however, a number of observations made during open PMC and Planning Subcommittee meetings that may help improve future project evaluations, including:

[7] *In the fall of 2017, entities such as TANC explained that the APC tool should be corrected to exclude loads/resources/generation that the TOLSO does not own and is not responsible for planning in WestConnect, and committed to work with the PMC Membership to ensure accurate representation of load and generator assignment going forward.*

- It is critical to make accurate assignment of generation ownership/contract data and load responsibility data to individual TOLSOs to support the calculation of APC for the determination of aggregate and individual beneficiaries;
- There can be a significant impact associated with including or excluding negative benefits (or increases in APC) when calculating benefit cost ratios for purposes of determining cost allocation eligibility;
- It may help to establish reasonable sensitivities ahead of time, since sensitivities are critical to project review process and can impact the outcome of project selection and of project cost allocation eligibility;
- More consideration dedicated to understanding how regional planning process interacts with local process might help with future analyses – e.g. when and how should any local network upgrades and their costs be reflected and tied to regional project evaluations and when should that planning occur and who should be responsible for the studies?;
- Scenarios that have deliverability issues present a unique challenge and planning using economic models alone could result in undersized transmission as the economic assessment may not require transmission expansion sufficient to fully deliver the incremental resources and thus, care must be taken when sequencing releated power flow and production cost modeling studies;
- When storage systems are evaluated as non-transmission alternatives, they may need to be optimized for size and performance.