Stakeholder Comments Template

Review TAC Structure Straw Proposal

This template has been created for submission of stakeholder comments on the Review Transmission Access Charge (TAC) Structure Straw Proposal that was published on January 11, 2018. The Straw Proposal, Stakeholder Meeting presentation, and other information related to this initiative may be found on the initiative webpage at: http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx

Upon completion of this template, please submit it to initiativecomments@caiso.com.

Submitted by	Organization	Date Submitted
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Submissions are requested by close of business on **February 15, 2018.**

Please provide your organization's comments on the following issues and question.

EIM Classification

1. Please indicate if your organization supports or opposes the ISO's initial EIM classification for the Review TAC Structure initiative. Please note, this aspect of the initiative is described in Section 4 of the Straw Proposal. If your organization opposes the ISO initial classification, please explain your position.

   BAMx/CCSF support the CAISO's initial classification.

Ratemaking Approaches

2. Please provide your organization's feedback on the three ratemaking approaches the ISO presented for discussion in Section 7.1 of the Straw Proposal. Does your organization support or oppose the ISO relying on any one specific approach, or any or all of these ratemaking approaches for the future development of the ISO's proposals? Please explain your position.

   BAMx/CCSF see value in incorporating elements of cost causation and in providing the right price signals as incentives to modify future behavior. A fundamental tenet of rate design and cost allocation is that costs should be assigned proportional to benefits received. This avoids cross-subsidization and provides proper incentives at the transmission level and should assist longer-term transmission planning.

[1] BAMx consists of City of Palo Alto Utilities and City of Santa Clara, Silicon Valley Power.

Hybrid Approach for Measurement of Usage Proposal

3. Does your organization support the concept and principles supporting the development of a two-part hybrid approach for measurement of customer usage, including part volumetric and part peak-demand measurements, which has been proposed by the ISO as a potential TAC billing determinant modification under the current Straw Proposal? Please provide any additional feedback on the ISO's proposed modification to the TAC structure to utilize a two-part hybrid approach for measurement of customer usage. If your organization has additional suggestions or recommendations on this aspect of the Straw Proposal, please explain your position.

   Yes - BAMx/CCSF support adopting a methodology where a significant portion of the HV TRR is recovered based upon peak demands on the system because this reflects cost causation and sends appropriate price signals for maximizing usage of existing transmission.

Split of HV-TRR under Proposed Hybrid Approach for Measurement of Usage

4. The ISO proposed two initial concepts for splitting the HV-TRR under two-part hybrid approach for measurement of customer use for stakeholder consideration in Section 7.2.1.2 of the Straw Proposal. Please provide your organization's feedback on these initial concepts for determining how to split the HV-TRR to allocate the embedded system costs through a proposed two-part hybrid billing determinant. Please explain your suggestions and recommendations.

   a. Please provide any additional feedback or suggestions on potential alternative solutions to splitting the HV-TRR costs for a two-part hybrid approach.

   b. Please indicate if your organization believes additional cost data or other relevant data could be useful in developing the approach and ultimate determination utilized for splitting the HV-TRR under the proposed two-part hybrid approach. Please explain what data your organization believes would be useful to consider and why.

   BAMx/CCSF recognize that a numbers-driven assessment is important, even if ultimately an administratively set split is used. The Straw Proposal discusses transmission capital approval through the CAISO's Transmission Planning Process (TPP) as a potential allocator of the annual HV TRR between energy and demand. While Table 3 in the Straw Proposal makes an initial attempt at such a numbers-based approach, BAMx/CCSF is concerned that it understates the reliability driven portion of the approved transmission projects in several ways.

   a) Table 3 in the Straw Proposal asymmetrically includes Policy/Renewable Access projects approved prior to the 2010-11 transmission planning cycle, while excluding Reliability projects from the same timeframe. While Policy/Renewable Access projects from as far back as August 2006[2] have been included in the table, Reliability projects have been truncated at the 2010-11 Transmission Plan. For a balanced assessment, the CAISO should update the table with actual project cost data for all CAISO-approved projects, preferably as far back as 1999, the first year after the formation of the CAISO.

[2] Date of the CAISO Board Approval of the Sunrise Powerlink Project

b) Some of the Policy/Renewable Access project approvals also were based, in part, on reliability, for example

i. Sunrise Powerlink Project: the CPUC made an explicit calculation quantifying the expected benefits in three categories: i. access to low cost out-of-state resources (energy benefits generated by energy cost savings), ii. enhanced reliability associated with reduced LCR benefits, and iii. access to low cost renewable resources.[3] Of these benefits, the enhanced reliability component made up approximately 44% of the total project benefits.[4]

ii. Tehachapi Renewable Transmission Project (TRTP): Segments 1-3 were identified by SCE as needed to address inadequacy of the local transmission system to reliably serve the growing Antelope Valley load.[5] These segments were proposed to minimize voltage problems, increase transmission capability and improve system performance in the Tehachapi area. Therefore, the majority of the TRTP Segments 1-3 transmission investment cost should be attributed to the *reliability* category.

iii. TRTP Segments 4-11, while primarily a renewable generation interconnection driven project, also was justified on the basis of meeting the load growth transmission reliability needs for the South of Lugo and Los Angeles Basin areas.[6] Therefore, a portion of TRTP Segments 4-11 transmission investment cost should be assigned to the *reliability* category.

c) Significant elements of the Policy/Renewable Access projects resulted from decisions to allow interconnecting generation to receive full capacity deliverability status (FCDS) for Resource Adequacy counting. Transmission system deliverability assessments are linked to meeting summer peak demands even during multiple overlapping contingencies, and the associated transmission upgrades are not needed for congestion relief except under extreme conditions. The costs associated with deliverability upgrades represented majority of the total project costs for several of the Policy projects included in Table 3 such as, Colorado River - Valley 500kV project. Ideally, project costs allocated to *energy* should be based on only the amount of transmission, if any,

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[3] Decision Granting a Certificate of Public Convenience and Necessity for The Sunrise Powerlink Transmission Project, Decision 08-12-058, December 18, 2008, p. 104, 154, 283, 284,

[4] Total projected reliability benefits of Sunrise were estimated to be $214 million per year out of the overall benefit of $482 million per year.

[5] The CAISO South Regional Transmission Plan (CSRTP) for 2006 stated the following. "The 2006 summer peak load was about 700 MW and is projected to increase to 1,100 MW by 2016. SCE has identified reliability concerns in meeting the Antelope area load from the sub-transmission system by 2008 and on the bulk transmission system by year 2011."

[6] "Increase transmission capability from SCE's Lugo Substation located in Hesperia) to the Mira Loma area (South of Lugo), which is an existing transmission "bottleneck" that has been an ongoing source of reliability concern for the Los Angeles Basin and that will worsen with the inclusion of additional generation resources in the Tehachapi area." Source: SCE's AB970 submittal (April 2013).

that would have been needed to provide interconnection service on an "energy-only" basis. Practically, this expectedly small component is conceptually addressed by the proposed energy component already within the hybrid transmission rate.

A more accurate estimate of Table 3 should be developed for all CAISO-approved transmission projects after 2006. Such an evaluation likely would result in a much greater allocation to demand than estimated in the Straw Proposal Table 3.

5. The ISO seeks feedback from stakeholders regarding if a combination of coincident and non-coincident peak demand charge approaches should potentially be used as part of the two-part hybrid approach proposed in Section 7.2.1.2. Does your organization believe it would be appropriate to utilize some combination of coincident and non-coincident peak demand methods to help mitigate the potential disadvantages of only use of coincident peak demand charges? Please provide any feedback your organization may have on the potential use of coincident versus non-coincident peak demand measurements, or some combination of both under the proposed two-part hybrid measurement of usage approach.

BAMx/CCSF believe that within each TAC area, each entity's contribution to that TAC area's coincident peak (CP) demand should be used, and that something closer to a yearly (1 CP) methodology would more closely align with the CAISO transmission planning methodology.

The CAISO cites FERC Order No. 888 in its description of the options for demand-based billing determinants. An important element in FERC consideration of an appropriate allocation method is the linkage to how the utility plans its electric transmission system.[7] Annually, the CAISO produces a Transmission Planning Process Unified Planning Assumptions and Study Plan that describes the planning method for the CAISO controlled grid. For example, for the 2017-2018 Study Plan, two peak periods are studied, Summer Peak and Winter Peak, but an insignificant portion of the projects are needed to address Winter Peak issues.[8] (See the attached Study Plan Table 4.11-1.) While a breakout has not been developed, the large majority of the identified reliability projects in the PG&E area are driven by summer peak load conditions.[9] Additionally, as an indication that the reliability projects are driven by summer peak load conditions, winter base cases are not even developed for the southern California TAC areas. Therefore, a demand-based billing determinant that focuses on the summer peak loading condition best follows the way the transmission system is planned and is the best method to appropriately allocate cost.

While the California Energy Commission IEPR load forecasting process and California Public Utilities Commission resource adequacy program are both based on monthly peaks as cited in the Straw Proposal, this rationale for adopting a monthly (12 CP) method is flawed. The use of monthly data by the CEC and the CPUC does not mean that the CAISO

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[7] CAISO "Review Transmission Access Charge Structure Straw Proposal" January 11, 2018, p. 27

[8] While spring condition base cases are also studied as part of the CAISO reliability assessment, they are for light load or off-peak conditions where the lack of demand, rather than excessive demand, is the issue.

[9] The winter peak simulations also use higher line ratings due to lower ambient temperature, so the system is less likely to be overloaded.

transmission planning process is itself a monthly process. The CEC IEPR forecast has many uses, only one of which is to support the CAISO Transmission Planning process. For example, the CEC forecast is also used for resource planning, resource adequacy requirements, RPS compliance and other purposes. Additionally, the draft 2017 IEPR forecast has been expanded to include hourly data, but it does not follow that every hour in the hourly dataset drives transmission planning. Similarly, it does not follow that every month included in the CEC forecast is a driver of transmission reliability needs. The CAISO uses that portion of the CEC demand forecast that supports the development of the scenario base cases identified in Table 4.11-1 below. Similarly, the CPUC's monthly Resource Adequacy program assessment approach does not directly impact the CAISO transmission planning base case scenarios. In fact, resource deliverability, which is the nexus between the transmission planning process and the CPUC's RA program, only includes studies of the summer peak season.[10] Thus, the CPUC's and CEC's programs do not support the selection of a 12 CP methodology, and in some cases (such as the CPUC's RA calculation based on a summer peak) actually support use of the 1 CP methodology. Any adopted methodology for allocating transmission costs should be more aligned with the CAISO transmission planning methodology that is focused on the summer peak load condition.

While BAMx/CCSF believe a 1 CP methodology is appropriate, if considering more data points around the summer peak is more desirable, the CAISO could consider using a 3 CP methodology to capture the three highest monthly peaks.

See discussion below regarding the use of coincident vs. non-coincident peak demand methodology.

a. What related issues and data should the ISO consider exploring and providing in future proposal iterations related to the potential utilization of part coincident peak demand charge and part non-coincident peak demand charge? Please explain your position.

   The CAISO transmission planning process uses TAC area coincident peak, rather than the coincident peak for the entire CAISO area. If something other than a system-wide coincident peak were to be used, the four TAC area non-coincident peaks would be good candidates, with each entity's contribution to its TAC area's coincident peak as the allocator.

Treatment of Non-PTO Municipal and Metered Sub Systems (MSS) Measurement of Usage

6. Under Section 7.2.1.2 of the Straw Proposal the ISO indicated there may be a need to revisit the approach for measuring the use of the system by Non-PTO Municipal and Metered Sub Systems (MSS) to align the TAC billing determinant approaches for these entities with the other TAC structure modifications under any hybrid billing determinant measurement approach. Because the Straw Proposal includes modifications for utilization of a two-part

[10] http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf

hybrid measurement approach for measurement of customer usage the ISO believes that it may also be logical and necessary to modify the measurement used to recover transmission costs from Non-PTO Municipal and Metered Sub Systems (MSS) entities. The ISO has not made a specific proposal for modifications to this aspect of the TAC structure for these entities in the Straw Proposal, however, the ISO seeks feedback from stakeholders on this issue. Please indicate if your organization believes the ISO should pursue modification to the treatment of the measurement of usage approach for Non-PTO Municipal and Metered Sub Systems to align treatment with the proposed hybrid approach in the development of future proposals. Please explain your position.

BAMx/CCSF[11] support applying the hybrid billing approach to the Non-PTO Municipal and Metered Sub Systems (MSS) entities. In contrast to Exports to entities external to the CAISO, the billing methodology for deliveries to Non-PTO Municipal and MSS loads embedded within the CAISO BAA should be consistent with the methodology used for other CAISO embedded loads. These loads are included in the CAISO transmission planning process, unlike the loads external to the CAISO BAA.

Point of Measurement Proposal

7. Does your organization support the concepts and supporting justification for the ISO's current proposal to maintain the current point of measurement for TAC billing at end use customer meters as described in Section 7.2.3.2 of the Straw Proposal? Please explain your position.

   Yes – BAMx/CCSF support not changing the Point of Measurement.

8. The ISO has indicated that the recovery of the embedded costs is of paramount concern when considering the potential needs and impacts related to modification of the TAC point of measurement. The ISO seeks additional feedback on the potential for different treatment for point of measurement for the existing system's embedded costs versus future transmission costs. Does your organization believe it is appropriate to consider possible modification to the point of measurement only for all future HV-TRR costs, or additionally, only for future ISO approved TPP transmission investment costs? Please provide supporting justification for any recommendations on this issue of point of measurement that may need to be further considered to be utilized for embedded versus future transmission system costs. Please be as specific as possible in your response related to the specific types of future costs that your response may refer to.

   BAMx/CCSF do not support establishing a different POM for embedded versus future HV TRR costs. As noted above, BAMx/CCSF do not support a change in the POM.

9. The ISO seeks additional stakeholder feedback on the proposal to maintain the status quo for the point of measurement. Please provide your organizations recommendations related to any potential interactions of the point of measurement proposal with the proposed hybrid billing determinant that should be considered for the development of future proposals. Please indicate if your organization has any feedback on this issue and provide explanations for your positions.

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11 Unlike the BAMx members, CCSF is not a CAISO Metered Sub-System (MSS) customer, but is a Non-PTO Municipal customer.

Additional Comments

10. Please offer any other comments your organization would like to provide on the Review TAC Structure Straw Proposal, or any other aspect of this initiative.

Table 4.11-1: Summary of Base Scenario Studies in the ISO Reliability Assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2019	2022	2027
Northern California (PG&E) Bulk System	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak Summer Partial Peak Spring Off-Peak
Humboldt	Summer Peak Winter Peak Spring Light Load	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Spring Light Load	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter peak
North Valley	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Spring Light Load	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Kern	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Spring Light Load	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
Southern California Bulk transmission system	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE Metro Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE Northern Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE North of Lugo Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE East of Lugo Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak

SCE Eastern Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SDG&E main transmission	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SDG&E sub-transmission	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Valley Electric Association	Summer/Winter Peak Spring Light Load	Summer/Winter Peak Spring Off-Peak	Summer/Winter Peak

Note:

- Peak load conditions are the peak load in the area of study. Peak load time - hours between 16:00 and 18:00.
- Off-peak load conditions are approximately 50-65 per cent of peak loading conditions. Off-peak load time – weekend morning.
- Light load conditions are the system minimum load condition. Light load time - hours between 02:00 and 04:00.
- Partial peak load condition represents a critical system condition in the region based upon loading, dispatch and facilities rating conditions. Partial peak load time - hours between 20:00 and 21:00.