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
Kanya Dorland *(415) 703-1374*	*Office of Ratepayer Advocates*	*February 15, 2018*

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

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

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.

The California Independent System Operator (CAISO) states that this initiative falls outside the scope of the Energy Imbalance Market (EIM) Governing Body's advisory role because it does not propose changes to CAISO's real-time market rules or the rules that govern CAISO markets. Specifically, the initiative will not change the Transmission Access Charge (TAC) structure for participants outside of the CAISO's balancing authority area (BAA).[1]

The CAISO's initial proposed Hybrid Transmission Access Charge (Hybrid TAC) approach for measurement of energy usage would modify the existing volumetric TAC billing determinant to include both volumetric and peak demand charges for transmission usage.[2] If the proposed Hybrid TAC structure would not impact transmission rates paid outside of the CAISO's BAA, ORA agrees that the CAISO should seek CAISO Board approval, but not EIM Board approval.

[1] The CAISO's determination that this TAC initiative falls out of the scope of the EIM.

[2] *Review TAC Structure Straw Proposal Stakeholder Meeting Presentation*, January 18, 2018, CAISO, slide 9.

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.

ORA prefers the existing volumetric TAC structure and does not recommend considering a peak demand or time of use approach for the TAC structure at this time.

Background

The CAISO's initial Hybrid TAC cost recovery proposal would modify the existing volumetric TAC structure to include a peak demand component. The cost recovery ratio for volumetric and peak demand usage could be based on past transmission project expenditures on reliability projects, which represent peak demand, and policy and economic project expenditures, which represent energy. Based on the CAISO's transmission investment data, reliability/peak demand projects represent 42% of the total transmission investments, and policy and economic/energy projects represent 58% of the total transmission investments. Therefore, the CAISO could split the TAC cost recovery with 42% of the TAC cost recovered through a peak demand charge and 58% recovered through a volumetric rate, or implement a "straight forward"[3] 50/50 split between a volumetric rate and a peak demand charge. The demand charge would be based on the system coincident peak. The CAISO is currently studying if some portion of this demand charge should be based on non-coincident system peaks as well as system coincident peaks to mitigate possible drawbacks from a solely coincident system peak approach. The CAISO states that non-coincident peaks "may better capture some of the usage and benefits provided to specific customers that peak frequently different from the overall coincident system peak."[4]

The CAISO's proposal is in response to stakeholders' requests to take a broader look at the existing TAC structure and consider revisions to reflect current grid uses and resources since there have been significant changes in both grid uses and resources in the last 10 years.

ORA's Response

ORA supports the CAISO's review of existing grid charges to determine if they remain consistent with regulatory requirements and two of the core principles of utility and regulatory ratemaking that concern ratepayers, which are: (1) cost causation and (2) equitable treatment based on usage and benefits received.[5] ORA does not support the proposed Hybrid TAC billing determinant approach because this approach as proposed would

[3] *Review Transmission Charge Structure Straw Proposal*, January 11, 2018, CAISO, (TAC Straw Proposal), p. 35.

[4] TAC Straw Proposal, p. 28.

[5] *See e.g., Review Transmission Access Charge Structure Issue Paper,* June 30, 2017, CAISO, pp. 8-12.

not more accurately reflect cost causation and would not result in equitable treatment of ratepayers because some ratepayers would likely pay more than their fair share of transmission costs. For these reasons, ORA recommends retaining the existing TAC structure. In addition, ORA raises the following issues regarding the proposal to collect any portion of the existing and new transmission costs through a demand charge.

A. Using a demand charge at the CAISO grid level would not be as easily understood or implemented as the existing volumetric charge, and may not reflect customer contributions to the system peak.

- Peak demand charges are based on the previous month's or the previous year' information.
- The coincident peak periods for each Utility Distribution Company (UDC) may not be the same as the coincident CAISO system peak period, and thus using a system coincident peak may not fairly attribute cost causation.
- A price signal based on non-coincident peak will consider the different peaks for different customers, but it will not incentivize customers to reduce their circuit coincident peak just their non-coincident peak.
- Concepts such as coincident and non-coincident peak demand may also be difficult for customers to understand.

The CAISO has commissioned the Brattle Group to develop a spreadsheet model to analyze alternative approaches to the existing TAC structure.[6] This analysis should also demonstrate whether or not the proposed Hybrid TAC would result in cost shifting among UDCs.[7] The Brattle Group's analysis should also determine the coincident peak period for the CAISO system. This analysis has not been released. Without this information, ORA cannot determine if this proposal will shift costs unfairly among UDCs as described in this section.

B. The Hybrid TAC proposal could also result in cost shifting among Load Serving Entities (LSEs). This cost shifting might not be consistent with cost causation. Silicon Valley Power (SVP) provided a preliminary impact analysis of the changing the TAC billing determinant to include a demand component using the California Energy Commission's load factor data[8] from 2014 in its August 2017 presentation to the TAC stakeholders.[9] SVP's analysis demonstrated that the implementation of a 50/50

---

[6] *Review TAC Structure Straw Proposal Stakeholder Meeting Presentation*, January 18, 2018, CAISO, slide 28.

[7] TAC Straw Proposal, p. 37.

[8] Load factor is defined as the average load divided by the peak load in a specified time period. *Resources: An Encyclopedia of Energy Utility Terms*, 1992, PG&E, p. 266.

[9] *Silicon Valley Power TAC presentation Overview*, August 28, 2017, Silicon Valley Power (SVP 2017 Presentation), slides 17-19.

volumetric/peak demand approach would result in cost shifting among LSEs. In particular, SVP's analysis demonstrated that using a 50/50 volumetric and peak approach for TAC cost recovery would result in lower costs for LSEs with high load factors and higher costs for LSEs with low load factors.[10] Specifically, the analysis demonstrated that a demand charge based on an average system peak may shift higher peak costs to LSEs with low load factors[11] that may not be contributing as much to the system peak.

C. The proposed 42-50% peak demand charge for TAC cost recovery may not be consistent with cost causation. The CAISO acknowledges that "all investments in the transmission system many provide some benefits for both energy and capacity functions..."[12] Thus, isolating the transmission investments that are exclusively to serve peak may not be feasible. It is also unclear that transmission investments to meet peak demand are significant drivers of new transmission costs. The Northern California Power Agency observes that

> "roughly 80% of [Pacific Gas & Electric Company] PG&E's capital transmission projects, accounting for 60% of PG&E's capital transmission expenditures in 2016, were for upgrade and replacement projects not developed through the TPP or any other stakeholder process. Likewise, the numbers for [Southern California Edison Company] SCE and [San Diego Gas & Electric Company] SDG&E indicate that at least 64% and 30% of their respective capital transmission expenditures last year were for similar transmission projects not vetted through the CAISO [Transmission Planning Process] TPP or any other type of stakeholder process."[13]

The past CAISO TPPs and IOUs' transmission expenditures also provide evidence that new transmission projects are not needed to meet peak demand. Recent transmission costs appear to have two primary drivers, which are: (1) capital, operation and maintenance expenditures to maintain the existing infrastructure; and (2) new transmission lines and transmission line enhancement expenditures to integrate renewable resources to meet the state Renewable Portfolio Standard (RPS) targets and to respond to these new RPS resources.[14] Thus a peak demand charge does not appear to reflect cost causation principles.

---

[10] SVP 2017 Presentation, slides 22-24.

[11] SVP 2017 Presentation, slides 17 and 22-23.

[12] TAC Straw Proposal, p. 35.

[13] *Northern California Power Agency Comments on Review Transmission Access Charge Structure Issue paper*, July 25, 2017, (NCPA TAC Comments), p. 5.

[14] NCPA TAC Comments, p.5; *CAISO 2016-2017 Transmission Plan*, March 17, 2017, CAISO, pp. 10 and 379; *CAISO 2016-2017 Transmission Planning Process (TPP) - Draft Transmission Plan*, February 17, 2017, Customized Energy Solutions Market IQ, p. 1.

Currently, the CAISO grid is experiencing a shift in evening peak demand,[15] and consequently new steep evening peak ramping needs. This change in grid operations appears to be due to new renewable resources on the grid, specifically solar power, to meet state's RPS targets[16] and not due to customer behavior. This shift in peak demand is more significant in the summer months, but is experienced throughout the year. It has moved the evening peak from 4 p.m. to 5 p.m. to 5 p.m. to 6 p.m. or 7 p.m.[17] Responding to this peak shift and energy ramping needs requires the CAISO to utilize generation resources with high levels of flexibility that charge a premium for their energy.

Going forward, it may be the case as PG&E predicts that "Peak and capacity changes will have minimal impact on cost; and RPS targets may no longer drive significant new transmission investment."[18]

Since it is not clear that customer peak demand is a significant or sole cost driver for new transmission, ORA does not support the proposed Hybrid TAC approach. The implementation of the Hybrid TAC proposal could also have inequitable outcomes for certain customer classes and or services areas with low load factors that do may not contribute significantly to peak demand.

D. The proposed TAC structure change appears unlikely to achieve a change in customer behavior that would impact transmission costs going forward since serving customer peak load does not appear to be a significant or sole cost driver. The TAC does not represent a significant portion of customer bills to impact customer behavior.[19] The

---

[15] *2016-2017 Transmission Planning Process Unified Planning Assumptions and Study Plan*, March 31, 2016, CAISO, p.11, citing. *CEC California Energy Demand 2016-2026, Revised Electricity Forecast Volume1: Statewide Electricity Demand and Energy Efficiency*, January 2016, ("'At some point, continued growth in PV adoption will likely reduce demand for utility-generated power at traditional peak hours to the point where the hour of peak utility demand is pushed back to later in the day. This means that future PV peak impacts could decline significantly as system performance drops in the later hours*.'");* 2016-*2017 Transmission Planning Process Stakeholder Meeting* slide presentation, November 16, 2016, CAISO, (2016-2017 TPP Presentation) slides 74 and 117. ("Due to assumptions of significant penetration of the behind-the-meter photovoltaic distributed generation (BTM PVDG) for the ten-year horizon, the ISO also evaluated a sensitivity scenario in which the utilities' peak loads are shifted to early evening hours (i.e., 6 p.m.) when solar generation contribution is not available.").

[16] *California Wholesale Electricity Prices Are Higher at the Beginning and End of the Day*, July 24, 2017, US Energy Information Administration ("Recently, the addition of both utility-scale and small-scale solar generators has contributed to steeper morning ramp-down and evening ramp-up periods.").

[17] 2016-2017 TPP Presentation, slides 74 and 117.

[18] *PG&E Comments on Review Transmission Access Charge Structure Working Group Meetings August 29 and September 25, 2017*, November 1, 2017, p. 3.

[19] TAC Straw Proposal, p. 25 ("[A}mong the three major California IOUs, the entire cost for the full transmission system (HV and LV TRRs) only accounts for approximately 9% of the overall SCE annual revenue requirement, 11% of the overall PG&E annual revenue requirement, and 16% of the overall

proposed rate design change would also be "muted" by the UDC and LSE retail energy rates as the CAISO states.[20]

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.

ORA does not support the proposed modifications to the existing TAC structure as explained in our response to question 2.

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.

The CAISO proposed two initial concepts for the Hybrid TAC approach. The first initial concept is to base the TAC cost recovery on investments in reliability, economic and policy projects. The CAISO used data on transmission investments for these specific project types to determine the investment cost ratio for reliability, policy and energy projects, but has limited data on project investments beyond the past seven years. Using this data, the first Hybrid TAC approach would charge approximately 42% of the TAC costs to reliability/peak usage and charge approximately 58% of the TAC costs to economic and policy projects/energy usage. This concept does not consider the operating and maintenance (O&M) costs for these transmission projects since their construction. These O&M costs represent a significant portion of transmission investments as explained in response to question 2 under item C. The O&M costs for transmission are not allocated to specific reliability, economic or policy projects for two reasons. First, once a transmission project becomes part of the transmission system, it can serve multiple purposes in addition to its intended function. Second, O&M costs for existing infrastructure are not tracked or identified in rate cases specifically to operate and maintain reliability, economic and policy projects. Thus, ORA recommends that

SDG&E revenue requirement. The vast majority of the overall costs that must be recovered by ratepayers annually are comprised of generation and distribution costs.") (footnote omitted).)

[20] TAC Straw Proposal, p. 25.

the reported transmission investments for the past 10 years for both capital and O&M expenses for reliability, policy and economic projects be separately identified.

The second initial TAC hybrid approach is a 50/50 split between a volumetric rate and a demand charge. As mentioned in response to question 2 under section B, a 50% peak demand charge for TAC cost recovery would likely result in transmission cost shifts without cost causation. Additionally, as discussed in the response to question 2 under section C, since customers' peak demand does not appear to be driving new transmission costs, a 50% demand charge for it does not seem justified.

ORA does not support revising the TAC, but if the CAISO moves forward with allocating a portion of the HV TRR to a demand component, it should conduct further analysis to separately identify transmission investments (both capital and O&M) for reliability, policy and economic projects. This approach will help to properly identify relevant costs by transmission project types and to design an appropriate cost-based demand charge.

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

While ORA supports maintaining the existing TAC structure, it requests that the CAISO provide additional information on the cost drivers for recent transmission projects to assist future TAC initiative discussions. As stated, new transmission costs appear to be driven by two main cost drivers, which are: (1) operation and maintenance of the existing transmission system; and (2) integration of new RPS resources. Both capital and O&M costs should be tracked separately.

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.

ORA recommends that the CAISO provide information on transmission costs over the past 10 years that were incurred to maintain the existing grid, comply with RPS targets, and to respond to the new evening demand peak that has moved from 4 p.m. to 5 p.m. to later in the evening.[21] This information will help to inform future TAC initiative discussions on the appropriate cost recovery methodology for new transmission costs.

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

[21] California Energy Commission Draft Staff Report, 2017-2027 California Energy Demand Updated Forecast pp. 7-8; *Draft 2016-2017 Transmission Plan,* February 17, 2017, Presentation from Shucheng Liu, Ph.D. Principal Potential Impact on system level requirements, slide 165.

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.

As explained in our response to question 2, ORA does not support the Hybrid TAC approach and cannot respond to this Hybrid TAC proposal in its entirety because analysis has not been provided to identify the proposed CAISO grid coincident peak period. In advance of reviewing this information, if the Hybrid TAC proposal is pursued, ORA recommends that a peak demand charge should include a broader time period than 15 minutes and that the coincident peak demand measurement be based on monthly peaks since the CAISO "plans the system to meet the system's coincident peaks each month."[22]

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.

Please refer to section A in the response provided to question 2 in this document.

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 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.

ORA does not recommend modifying the existing TAC structure. If the CAISO moves forward with a Hybrid TAC billing determinant measurement approach, ORA recommends using the same TAC structure approach for Non-PTO Municipal and MSS entities.

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

[22] TAC Straw Proposal, p. 28.

customer meters as described in Section 7.2.3.2 of the Straw Proposal? Please explain your position.

ORA supports the proposal to maintain the point of measurement for the TAC billing determinant at the end use customer meter for three reasons, which are:

(1) The existing bulk transmission system was built to serve load, some of which is now served by distributed generation (DG).[23] The costs incurred to build, operate and maintain existing transmission facilities were to serve the load regardless of whether that load is now served by DG. These are sunk costs and should continue to be recovered from all customers;

(2) DG has the capacity to serve load, but needs additional services from the CAISO controlled grid to serve load effectively at all times; and

(3) There are costs incurred to enable DG to serve load. These costs have not yet been sufficiently tracked or examined. More analysis is needed to determine the benefits that DG provides and the costs incurred, as well as DG's impact on the grid. More analysis also is required to determine the amount of DG benefits that are distributed to all ratepayers.[24]

As outlined in ORA's July 2017 comments in this initiative, the services that DG receives from transmission system include:

1) Voltage Support, which maintains local voltages within customer limits;
2) Frequency Control, which balances load with demand;
3) Fault Control, which ensures safety when there is an outage;
4) Access to Black Start, which provides start-up energy when there is an outage;
5) Access to Ramping, which provides energy to meet extreme changes in demand; and
6) Access to Back-up resources, which provides energy in the event of a loss of local generation."[25]

[23] Distributed Generation is primarily behind the meter solar. It includes wholesale and retail behind the meter solar, and some non-renewable resources. DG primarily reduces the load of the customer that it is directly connected to and it also has the capacity to produce surplus power that could be injected into the grid.

[24] The California Energy Commission removes the estimated output from Behind the Meter Solar from the forecasted gross load for California. The output from Behind the Meter Solar is an estimate and there is currently no tracking mechanism to determine that customers with Behind the Meter Solar use the expected portion of output from their solar installations or that the Behind the Meter Solar output exported to the grid is used. The existing distribution facilities were not designed to support bi-directional power flow for greater distribution, so the grid must be enhanced to allow the transfer of net metered distributed generation power to the grid.

[25] *ORA Review Transmission Access Charge Structure Comments,* July 31, 2017, p. 2.

These services are provided by the transmission system as needed on a 24/7 basis. Currently, DG alone cannot provide these necessary services when needed.

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.

ORA supports the CAISO's consideration of different TAC approaches for existing versus new transmission system costs. In regards to new transmission costs, future discussion should consider the following

- New transmission projects, as stated in ORA's response to question 2 under section C, may be to primarily support maintenance of the existing system and the integration of RPS renewables. ORA recommends that the majority of costs incurred due to these activities be shared.
- The degree to which DG is responsible for recently avoided or deferred transmission projects is unclear. There is evidence that energy efficiency and changing customer behavior has also played a role in the need for fewer approved and constructed transmission projects.[26]
- Finally, it is not clear that the costs to support DG resources equal the benefits.

For these reasons, ORA does not recommend that DG be treated differently for existing or future transmission costs. Further study is needed to determine if DG should be charged a different TAC rate based on its transmission costs and benefits, and the services it receives from the transmission system.

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

[26] *Putting the Potential Rate Impacts of Distributed Solar into Context,* Galen Barbose Lawrence Berkeley National Laboratory, January 2017, p. 4 **(**"Utility energy efficiency programs and federal appliance efficiency standards together reduced U.S. retail electricity sales in 2015 by an amount 35-times larger than that of distributed solar.").

proposals. Please indicate if your organization has any feedback on this issue and provide explanations for your positions.

ORA recommends considering different cost measurements and allocation approaches for new transmission costs only if it can be demonstrated that certain system users are driving TAC costs or that certain system users' contributions to the transmission costs recovery does not equal the range of benefits they receive from the transmission system. As stated in these comments, it may be the case that a significant future transmission cost driver is the integration of RPS renewables, which includes DG.

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.

ORA recommends that the CAISO hold the next stakeholder meeting after it makes available to stakeholders the results of the Brattle Group analysis of potential cost shifts under alternative TAC structure approaches. In addition, the CAISO should hold a stakeholder meeting after it has isolated and provided transmission costs related to system maintenance, and integration of RPS resources for the past 10 years.