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

Submitted by	Organization	Date Submitted
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Upon completion of this template, please submit it to initiativecomments@caiso.com.

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.

   SVP supports the CAISO's belief that the examination of TAC billing determinants under this Review TAC Structure initiative falls outside of the scope of the EIM Governing Body's advisory role.

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.

   The three ratemaking approaches the ISO presents for consideration are:

1. Charge TAC according to cost causation and cost drivers when decisions to invest in transmission infrastructure were made. i.e., load for whom the facilities were built should continue to pay for transmission built to serve them, regardless if their usage patterns have changed.

   SVP agrees with this ratemaking principle but believes that adhering closely to this principle would require tracking historical usage patterns. Creating billing determinants that measure historic usage patterns that change over time will bring in undesirable complexity. However, identifying billing determinants that get closer to maintaining cost causation principles, but are still simplistic enough to administer, should be the desired outcome.

2. Charge TAC according to current usage (and benefits), which may be different than the previous usage. If the ISO took this approach, then it needs to decide how to best characterize and measure current usage and benefits.

   SVP believes this ratemaking approach may result in the billing determinants that are the easiest to administer, but it also may be able to incorporate elements of ratemaking principles 1 and 3. While the current volumetric rate has worked to collect the PTO's TRR, it also has a level of unfairness that requires higher load factor UDCs to pay for more of the HV transmission system than lower load factor UDCs, which may not align with benefits received. This is because a high load factor UDC can serve the same megawatts of demand using fewer megawatts of transmission capacity, but that is not reflected in volumetric rates. Additionally, transmission usage rates charged to a UDC are ultimately paid by retail load within its system, so retail rate design should align with how transmission costs are incurred by the UDC. Under the current volumetric only design, retail customer demand response is undervalued from the perspective of avoiding the need to build future transmission. Transitioning to a hybrid billing determinant approach, with demand and volumetric components to the rate, will better align benefits of the transmission system and also allow UDCs to send price signals to end use customers to modify their behavior in a way that reduces future costs. Overall, this ratemaking principle best aligns with retail rate designs, and will likely result in achieving aspects of the other principles.

   Charge TAC to send price signals as incentives to modify future behavior. This principle can potentially reduce future cost drivers and incent behavior that will support public policy goals or mandates. This approach is complicated by the multifaceted ratemaking layers regarding transmission cost recovery currently present in California.

   The current TRR is almost entirely made up of fixed costs associated with transmission already built, including the original investment, operations and maintenance, and capital projects to replace existing infrastructure. Those costs must be collected from present end use customers. While changing behavior may reduce the need for future transmission expansion, it doesn't change the level of the existing TRR. TAC pricing should not create incentives to modify behavior in a way that shifts already incurred transmission costs to other UDCs, absent offsetting benefits to the existing grid. Sending price signals to modify certain behavior and usage patterns can be desirable, but cost shifts need to be accounted for and avoided, as such cost shifts might not be consistent with cost causation principles.

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.

   SVP strongly supports moving from a single volumetric billing determinant to a hybrid approach that incorporates both volumetric and demand components. While SVP believes this is the correct direction to move, SVP understands this will have economic impacts on various UDCs. The change to a hybrid approach better aligns cost allocation with benefits received from the transmission system, and how the transmission system is planned.

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.

      In its straw proposal the CAISO presented two possible ways of splitting the HV TAC into demand and volumetric components: (a) an administrative allocation (50/50 percentage split) approach, or (b) via Reliability/Policy buckets. SVP considers either option to be better than the status quo of a single volumetric rate, but feels both of these options have potential problems.

      Of the two options provided, SVP would prefer the simplicity of the administrative allocation approach, yet would prefer to explore means of splitting that are tied to some form of system or usage metrics. In order for the administrative allocation proposal to move forward, SVP believes it should be evaluated in comparison with approaches based on various metrics to justify the proposed split.

      The Reliability/Policy split is much more complicated when you consider the thorough debate that is likely to occur as the CAISO attempts to classify the existing transmission system into these categories, as well as continuing onward with new projects. As an example, one could surmise that it would be a policy decision to close the once through cooling facilities, but their closure also brings about reliability issues. Many of these same reliability issues were impacted by the closure of SONGs. How would the CAISO propose splitting costs associated with transmission projects needed from these closures that deal with reliability issues, yet are downstream issues resulting from furthering policy goals? SVP believes this is an area that is best avoided on a going forward basis if at all possible, even though this concept may provide a reasoned basis for splitting the TRR as an alternative to the administrative allocation approach.

SVP proposes the following as a third possible mechanism for splitting the TRR between demand and volumetric charges. SVP stresses that the proposal is intended to illustrate concepts for further discussion, examination and study by the CAISO and market participants – and that SVP is not wed to any particular "split" calculation at this time and is open to considering other suggestions that would better reflect aligning costs with benefits, and meet the ratemaking principles outlined in Section 7.1 of the straw proposal.

Proposal:

Step 1.
Start with the current filed and approved TRR found on the CAISO website, (assume $2,195,146,895 from the HV Access Charge Rates effective Jan 1, 2016, and divide this amount by the year's annual system peak multiplied by 8760 hours in a year (assume 2016 peak of 45,666.19 MW * 8760 hours = 400,035,824.4 MWh). This becomes your volumetric rate of $5.49/MWh and reflects the cost of the transmission system if all UDCs were 100% load factor utilities.

Step 2.
Using the PTO filed annual Gross Load (211,289,953 MWh), multiply this value by the rate determined in Step 1. ($5.49/MWh * 211,289,953 MWh = $1,159,427,371). This is the amount of revenue expected to be collected by the volumetric component.

Step 3.
Subtract the revenue determined in Step 2 from the total TRR ($2,195,146,895 - $1,159,427,371 = $1,035,719,523) which is the revenue that would remain to be collected through a demand based billing determinant.

Step 4.
With the revenue that will be collected through a demand based billing determinant, the next step is to decide whether this should be a daily, monthly, quarterly, or annual Coincident Peak (CP) or non CP demand, or some other measurement of system use, and then dividing this remaining revenue requirement to get the applicable rate.

Some of the more common industry options (for determining the appropriate method and interval(s) of measuring demand) include 1 CP, 3 CP (one CP for each of the summer months), 4 CP (one CP for each of four months), 12 CP (monthly), or 1, 3, 4, and 12 non-CP, or potentially even other methods. Keeping in mind that the higher number of intervals used - the further you get from the primary determinant used in transmission system planning criteria - which is the forecasted system peak. California and the CAISO Balancing Authority Area (BAA) is clearly a summer peaking system, and the peak set during winter or shoulder months has little to no bearing on the CAISO's planning to meet its system's summer peak demand. This leads to focusing on a smaller subset of billing determinant intervals which would determine the demand component. One issue with using a small number of billing determinant intervals is the incredibly high per MW rate that would ultimately be developed, and the economic incentive it would create for some abnormal behavior from customers that could avoid the full effects of the rate - where such behavior does not provide a comparable benefit to the transmission system. Example: If the $1,035,719,523 amount to be collected through the demand component (determined in Step 3 above) utilized a single hourly interval at time of system peak, the rate would be $22,680 / MW and would provide considerable incentive to simply reduce load during that peak hour – if it could be anticipated. Such a rate would likely cause the actual peak to shift to another hour, but ultimately would incent load response during most hours where the peak load could be set. A concept to possibly address some of these concerns is to split the $1,035,719,523 TRR demand component developed above into additional buckets. For illustrative purposes, we chose an example which uses three equal buckets, but using more or less buckets – and/or or unequal dollar amount buckets – should also be studied with the goal being achieving a result that better reflects cost causation and also limits the potential for excessive shifting of costs amongst UDCs.

This example splits $1,035,719,523 into three equal buckets of $345,239,814 each. These individual buckets could then be collected from the demand billing determinant in the following manner:

Bucket 1 is collected based on the CP during any hour where the peak demand was within 5% of the annual system peak in the year (.95 * 45,666.19 = 43,382.88 MW). So any hour during the year in which the peak demand fell within 43,382.88 MW - 45,666.19 MW would be used in a determinant for allocating bucket 1's portion of the demand based TRR. Using 2016 data, the cumulative peak demands during the top 5% of hours amounted to 1,022,136 MW that occurred on seven separate days during June, July and August and over 23 hours. This results in a rate of $345,239,814 / 1,022,136 MW = $337.76/MW

OPR_DT	OPR_HR	TAC_ZONE_NAME	SCHEDULE	MW
7/27/2016	17	Caiso_Totals	Load	45666.19
7/28/2016	17	Caiso_Totals	Load	45658
7/27/2016	16	Caiso_Totals	Load	45483.28
7/29/2016	17	Caiso_Totals	Load	45383.86
7/28/2016	16	Caiso_Totals	Load	45113.81
7/29/2016	16	Caiso_Totals	Load	45067
7/27/2016	18	Caiso_Totals	Load	44877.34
6/28/2016	17	Caiso_Totals	Load	44776.02
7/28/2016	18	Caiso_Totals	Load	44770.82
7/29/2016	18	Caiso_Totals	Load	44557.12
7/26/2016	17	Caiso_Totals	Load	44466.78
6/28/2016	16	Caiso_Totals	Load	44410.16
6/27/2016	17	Caiso_Totals	Load	44194.17
7/29/2016	15	Caiso_Totals	Load	44119.76
7/27/2016	15	Caiso_Totals	Load	44115.35
7/28/2016	15	Caiso_Totals	Load	43949.62
7/26/2016	16	Caiso_Totals	Load	43867.33
6/28/2016	18	Caiso_Totals	Load	43705.62
7/26/2016	18	Caiso_Totals	Load	43682.67
6/27/2016	16	Caiso_Totals	Load	43601.08
7/27/2016	19	Caiso_Totals	Load	43579.96
6/28/2016	15	Caiso_Totals	Load	43548.65
8/15/2016	17	Caiso_Totals	Load	43541.5

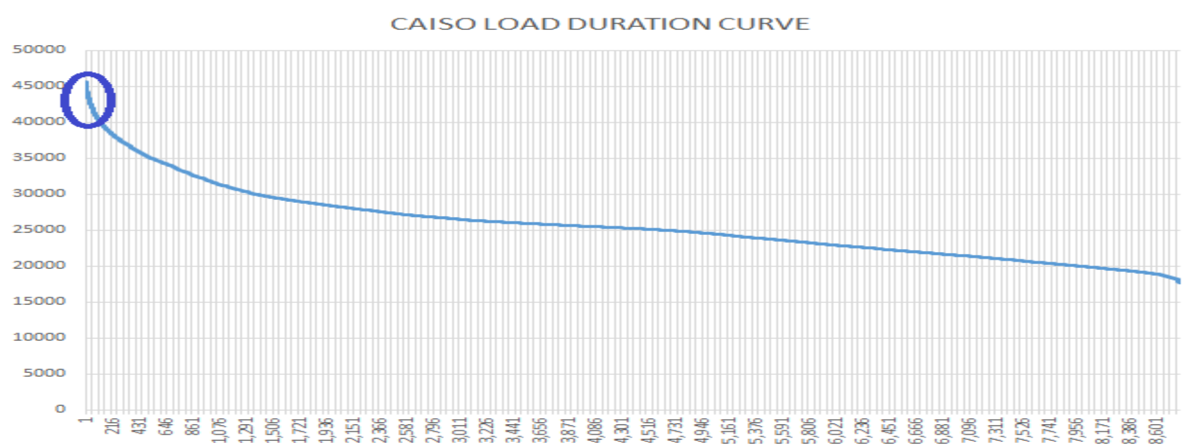
Utilizing this same logic for bucket 2 (Peak hours between 90% - 95% of annual system peak) and bucket 3 (Peak hours between 85% - 90% of annual system peak) results in the following table and rates (NOTE – these peak hours all fall within the June 20th through September 27th timeperiod of 2016:

TRR	$ 2,195,146,895.00	
Demand	211289953	
recorded peak	45666.19	
100% lf energy	400035824.4	
Vol Rate	$ 5.49	
Vol Revenue	$ 1,159,427,371.21	
demand rev	$ 1,035,719,523.79	
1/3 top 5% CP	$ 345,239,841.26	
1/3 top 10% CP	$ 345,239,841.26	
1/3 top 15% CP	$ 345,239,841.26	
5% CP Cumulative Demand	1022136.09	MWh
10% CP Cumulative Demand	2275917.63	MWh
15% CP Cumulative Demand	4305195.01	MWh
5% CP Cumulative Demand rate	$ 337.76	$/MW
10% CP Cumulative Demand rate	$ 151.69	$/MW
15% CP Cumulative Demand rate	$ 80.19	$/MW

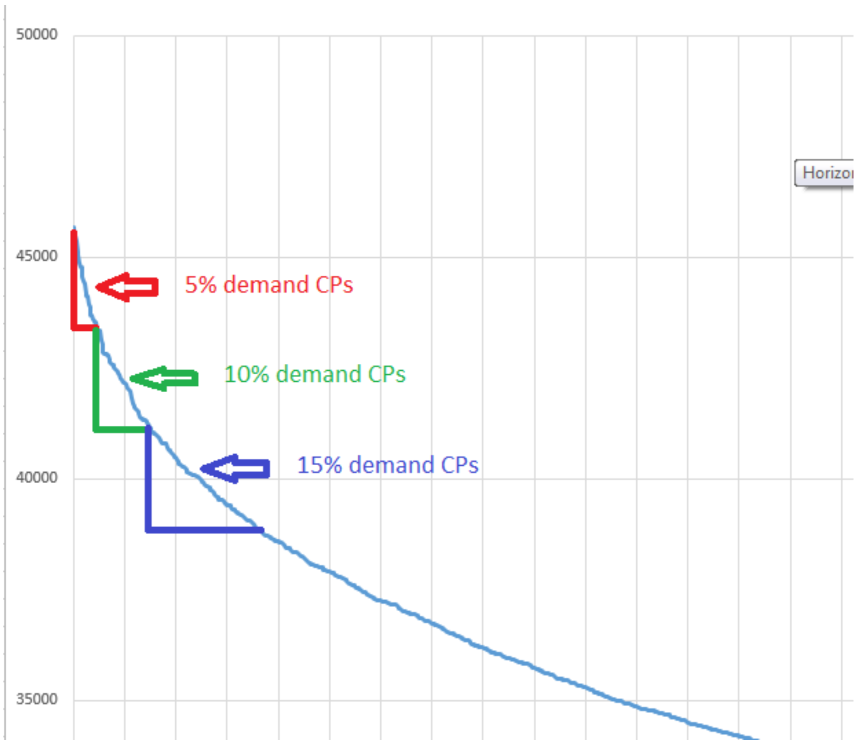
The advantage of this method is that it recognizes demand reduction during the highest load hours as being more valuable than it is in the lower bucket tiers - and it produces rates that are relatively reasonable. This method also captures multiple hours on a single day if the identified system peak hours were in the top 5%, 10%, 15% of the year and takes into account that customer-sited behind the meter energy storage or demand response may have been able to respond during a portion of the hours in the period, but not during all hours in the period. Thus the UDC would still be allocated some of the demand based charges that would likely otherwise be shifted to other UDC's if a single time interval was used on a single day, month or season.

The incurring of demand based costs in this manner enables UDC's to design retail rate programs that closer match the way the CAISO would allocate costs, and would incent desired behavior potentially resulting in the reduction of future transmission system needs.

Additionally, in looking at the 2016 load duration curve below, the demand component, in this example, is basically being allocated during the blue circled portion of hours in the year.



And within this circle exists the hours in the three different buckets that have different resulting rates.



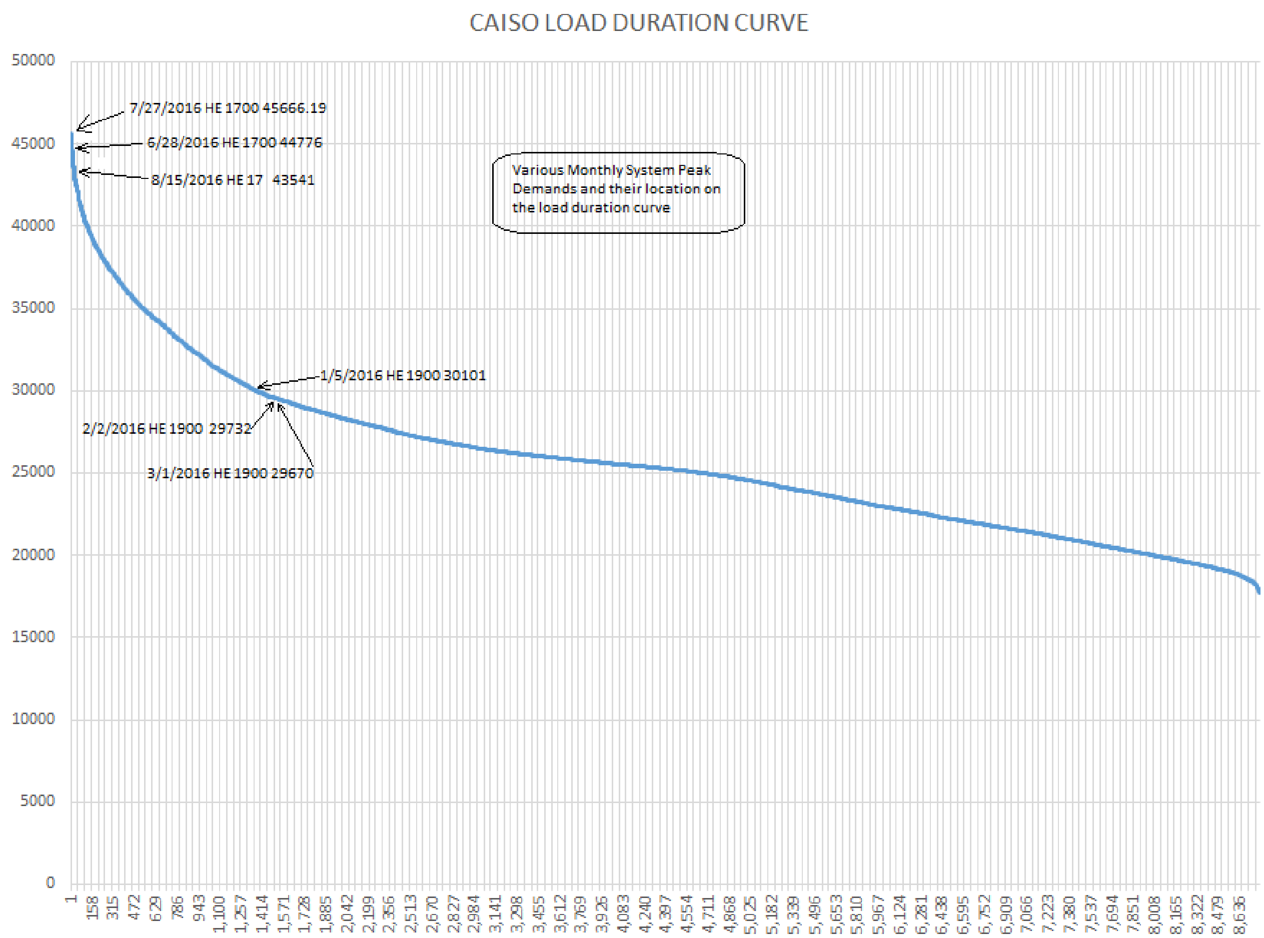
We also suggest that sensitivities could be looked at utilizing this type of structure:

1. The split of the demand based TRR component doesn't have to be equal for each bucket (1/3, 1/3, 1/3 or instead something like 50%, 30%, 20%, etc.). The example utilized an equal split since the number of hours in each of the proposed buckets (based on historical 2016 data) resulted in a reasonable rate reduction when looking at what ultimately will drive demand response and electric storage and their value to the system during different peak conditions.

2. The involved percentage and number of buckets can be varied during the investigative process. A figure of 5% was used to capture around 20 hourly intervals in the first bucket. Using a smaller percentage would allocate this cost over fewer intervals driving the rate higher - if that is the desired outcome. Based on the 2016 historical data a 1% bucket would equate to 4 hourly intervals, a 2% bucket would equate to 9 hourly intervals, and a 3% bucket would equate to 12 hourly intervals.

This sort of a demand-based allocation also would be consistent with Federal Energy Regulatory Commission (Commission) precedent on coincident peak pricing of transmission network service. A review of Commission orders leads to a resulting conclusion that the Commission does not have a preference in the calculation of coincident annual peak, as it reviews proposals on a case-by-case basis – yet it seeks to ensure that such proposals are consistent with the area's transmission planning approach as well as the specific facts of the area's transmission system. Since the CAISO does not have a relatively flat load profile throughout the year (it peaks in the summer), the expectation would be that demand-based costs would be allocated during a smaller number of months (as opposed to on a 12 CP basis). Further, the majority of scheduled system maintenance occurring in non-summer months also supports a summer peaking system. It is also worthy to note that the CAISO's PTOs plan their systems to meet an annual coincident system peak over a small amount of months.

The alternative concept of using a 12 CP approach to demand charges has been briefly discussed since it has been used by other RTOs and TPs. SVP provides the figure below simply to demonstrate where the CAISO BAA monthly system peaks (from 2016) in the winter are located on the Load Duration Curve vs. where the summer monthly system peaks fall on that same curve. It is apparent that the design of the system to meet peak demand will not be significantly influenced by the winter peak, which is approximately two-thirds of the system peak. This supports use of a methodology that allocates demand based on the buckets described above, or another method to reflect the summer peaking characteristics of the CAISO Grid.



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.

Assuming the CAISO moves forward with a hybrid approach that explores utilizing concepts SVP has suggested above (that focuses on a UDC's CP during CAISO annual system peak hours), it makes sense to consider how billing would work as the CAISO goes through the calendar year. If the new billing determinants were put in place January 1, 2019, how would the CAISO or stakeholders propose the demand component would apply for a month like January - when the subject month historically hasn't had a peak load in the top 5%, 10%, or 15% of the annual peak? Would waiting for the summer season to collect the demand portion of the TRR create cash flow issues for stakeholders and PTOs, or would it be more reasonable to collect some amount each month and then true that value up after the year is complete?

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.

    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.

SVP believes using CP best matches the criteria for transmission planning of the CAISO's system at the high voltage level. That said, SVP would be interested in reviewing any analysis that might be done stemming from the examination of any positions or justifications that non-coincident peak usage has affected the planning of the CAISO's high voltage system.

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.

SVP believes Non-PTO Municipal and Metered Sub Systems (MSS) entities are different than PTO UDC's and Exports from the CAISO BAA. The main distinction is that that Non-PTO entities own transmission assets which only their customers pay for, and load-following MSS entities are required to balance their own load and resources. These same Non-PTO entities are also different than typical BAA export transactions that pays the WAC since the load of the Non-PTO entities are incorporated into CAISO transmission studies. It seems justified that the Non-PTO entities pay both the volumetric rate and demand rate charged under the hybrid approach, but also retain the current point of measurement used today for both billing determinants. SVP also suggests that seventeen years of experience with MSS operation in the CAISO BAA demonstrate that the mechanisms function well and there is no reason presented to change the existing point of measurement.

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. SVP supports the CAISO's decision to maintain the end-use meter as the determinant for determining wholesale transmission costs. SVP also agrees with the numerous concerns and issues (such as its inappropriate cost shifts) stakeholders have raised in opposition to the suggested use of the T-D interface. In that regard SVP incorporates by reference its prior comments in the Review TAC Structure stakeholder process.

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.

   SVP supports the proposal that existing HV-TRR costs should be collected based on the existing point of measurement, but is also aware that future transmission development may be caused by increasing peak load demand. Energy storage, distributed generation, demand response, and other technologies may play a future role in curbing the need for future transmission expansion. With that in mind it may be worthwhile exploring a concept where the 1st bucket (or a smaller subset of the 1st bucket) of demand charges in SVP's above proposal used a different point of measurement that recognizes new technology devices that reduced demand on HV facilities during hours of extreme transmission loading. Limiting this change in the point of measurement to only a small subset of the HV – TRR costs may produce the desired outcome of avoiding some future transmission costs that all affected stakeholders wish to avoid. Additionally, limiting the amount of TRR in this bucket would prevent cost shifting amongst UDCs during hours when such technologies are not providing a reduction to peak demand at critical times. Before supporting or advocating for such a change SVP would need to see exactly how such a measurement would be accomplished and be assured that measurement devices are available at all needed locations. SVP also believes moving to the collection of the HV – TRR through a hybrid approach, using both a volumetric charge and demand charge, should not be delayed if this concept (in this Section 8 of the comments template) takes longer to explore. Assuming that all stakeholders agreed that this potential change has merit it could eventually be implemented any time after the hybrid approach goes into effect.

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.

   As stated above, SVP supports maintaining the status quo for the point of measurement. That said, SVP also supports the response to this particular question that is being provided by the Transmission Agency of Northern California (TANC) in its comments.

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.

   SVP suggests that the CAISO should further consider, in this initiative, whether any billing determinant changes should be made to the transmission rate that Exports from the CAISO BAA currently pay. Currently Exports from the CAISO BAA are exposed to a “hurdle rate” that results in lower amounts of exports during times of CAISO BAA over generation or negative LMP (at supply node) conditions. One potential result from such further consideration could be that BAA Exports should only be charged the volumetric portion of the new hybrid measurement approach. Such a hypothetical result would then need to lead to a new Tariff term to be used for Exports from the CAISO BAA – to differentiate them from “wheeling out” transactions for internal CAISO BAA UDCs.