Stakeholder Comments Template

Submitted by	Company	Date Submitted
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Please use this template to provide your written comments on the stakeholder initiative:

"Review Transmission Access Charge Structure"

Submit comments to InitiativeComments@CAISO.com

Comments are due July 26, 2017 by 5:00pm

The Issue Paper posted on June 30, 2017 and the presentations discussed during the July 12, 2017 stakeholder meeting can be found on http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx.

Please use this template to provide your written comments on the issue paper topics listed below and any additional comments that you wish to provide.

These initial comments offered by SVP are preliminary in nature, mainly intending to raise ideas for discussion and consideration, realizing that more technical analysis must yet be conducted.

1. Suggested modifications or additions to proposed scope of initiative.

The issue paper proposed two main topics for the scope of this initiative. If you want to suggest modifications or additions to the proposed scope, please explain how your proposed changes would fit with and be supportive of the two main topics.

Comments:

Scope Main Topic 1.

1. Whether/how to modify the TAC billing determinant to reduce TAC charges in PTO service areas for load offset by “DG output”

   –“DG Output” includes energy injections from (1) distribution-grid connected resources, and (2) behind-the-meter resource output that exceeds consumption at the same site during the same hour

   –For each settlement hour the difference [TED –Gross Load] reflects DG Output for the same hour

There are a number of drivers that effect the existing Transmission Revenue Requirements (TRRs) of the various Participating Transmission Owners (PTOs), and SVP is not convinced that the scope listed above is sufficient to look holistically at transmission cost allocation and how it should apply to load offset by Distributed Generation (DG) output. A large share of these TRR-related costs are not necessarily the costs associated with new transmission development, but with the ongoing debt service and Operation and Maintenance (O&M) associated with existing facilities. As we have seen the ongoing build out of behind the meter DG, (roof top solar), the gross load which the current TAC is applied to is shrinking. This calls for some questions to be answered: Is this causing a shift from any one market participant group to another, and is it appropriate for this shift to take place? Is it appropriate to pay for Transmission Access Charges (TAC) on a volumetric basis if you are able to offset much of this usage, but yet don’t reduce peak usage by a similar amount? If a large share of the TRR is for covering the costs of existing transmission, should DG be able to avoid this sunk cost? With these questions in mind SVP suggests expanding Major TAC structure topic 1.

The existing, specific wording of the topic 1 scope is limited to whether/how to modify the TAC billing determinant to “reduce” TAC charges in PTO service areas for load offset by “DG Output”. SVP suggests the topic should be broader, and proposes the following:

Explore whether/how the TAC billing determinant (used to allocate costs from TRRs of PTOs, where such TRRs utilize established TRR accounting principles) could be modified to more accurately allocate costs associated with, and necessary to meet, all facets of Transmission Planning, (Reliability, Policy, and Economic), such that the costs of existing and future transmission built and maintained to serve existing and planned demand, is paid for by those who receive a benefit from the existing and future transmission system. To the extent that resources such as DG, energy storage, demand response, or others are able to provide a verifiable reduction in transmission costs (either the costs of the existing grid or the costs of the future grid) - explore whether there is a modified billing determinant that allows for such resources to monetize this benefit. Alternatively consider whether the benefits of DG are better captured through such resources contracting directly with the LSE particular to the area of the resource(s).

TAC structure topic 2.

Whether to modify the current volumetric TAC structure to incorporate other approaches such as demand-based or time-of-use structure.

SVP suggests considering the modifying of topic 2 to read as follows:

Identify issues associated with the current volumetric rate collection of TAC that causes market inefficiencies, does not send a market price signal that generates the desirable response, or potentially shifts costs from one market participant to another – where such shifts are not justified by cost causation principles. Once a list of potential issues are identified with the existing volumetric rate design, determine if other billing determinants, such as demand-based rates or time-of-use rates, would result in an improved outcome (SVP notes that a combination of volumetric and demand-based rates could also be considered) – while also being workable within the CAISO market structure and supporting efficient least-cost dispatch of generation resources.

SVP questions whether the scope should be even further expanded to encompass a review of how TAC could be modified to help resolve existing seams issues. During the CAISO's market participant meeting on July 12, 2017, the CAISO presented a slide (Slide 11) which included FERC guiding principles for transmission rate development, of which one such principle is "provide economic efficiency". SVP questions if the existing treatment of how TAC is applied to intertie/Balancing Authority Area (BAA) exports accomplishes this goal. If the present CAISO market initiative is looking to resolve internal TAC issues, should the process also try to ensure the outcome is compatible with future BAA expansion and existing seams issues? SVP suggests that the review of potential TAC billing determinant changes should keep in mind how neighboring BAAs view the CAISO and its markets and how those BAAs may mesh with the CAISO under BAA expansion. That is, separate and apart from trying to develop a regional TAC mechanism, for any changes to the TAC mechanisms being considered in this initiative CAISO should consider: (1) Whether the modified TAC billing determinants would make potential BAA expansion more likely, or less likely, to succeed?; (2) How would the use of a demand-based charge in combination with, or instead of, a volumetric charge potentially affect market awards at interties?; and (3) How would the CAISO market handle scheduling limit congestion under such a rate structure? Bids at interties could be noticeably different based on the related marginal costs of generation. It would seem to be more efficient to structure the application of any potential demand-based component to avoid the situation where a 16000 heat rate unit ends-up running instead of a 7000 heat rate unit.

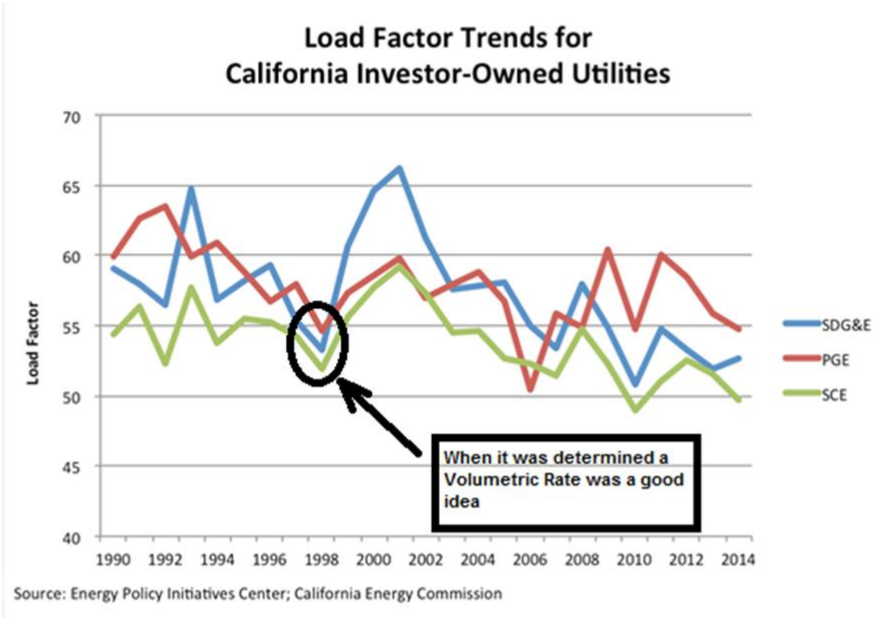
SVP could foresee a modified TAC structure based in part on demand charges as potentially providing an economic incentive to LSE's outside of the CAISO BAA to pay for transmission to access generation resources within the CAISO that have a lower marginal cost than resources external to the CAISO, whereas that transmission would go unused under the existing TAC mechanism because the volumetric rate creates a hurdle that eliminates the generation resource cost advantage. Would such an adjusted TAC structure help to eliminate negative pricing during periods of high renewable output? Would such an amended structure provide a benefit to the ramping energy needs of the CAISO by potentially keeping more efficient baseload generation on during the middle of the day, or by increasing the number of hours in which the evening ramp occurs? [Solar projects further East drop offline earlier than those located in the West. As solar projects in the East go offline, California exports could meet this incremental need causing the overall ramp in the CAISO to be slightly less steep.] Do these type of potential operational and economic benefits justify the exploration of different billing determinants for the TAC?

2. <u>Structure of transmission cost recovery in other ISOs/RTOs.</u>

Please comment on any lessons learned or observations from the other ISO/RTO approaches that you think will be useful to the present initiative.

Comments:

SVP believes it is important to understand that when the CAISO and Stakeholders developed the current TAC structure, the focus was on the large Investor Owned Utilities (IOUs) who have their entire service territories in California. These IOUs (PG&E, SDG&E, and SCE) have similar load factors and load profiles, and the TAC structure - whether it was volumetric based, demand based, or a combination of the two - would not have substantially shifted costs from one IOU to another. Additionally the TAC structure was created in an era where the generation mix in the BAA was substantially different than that of today, and the generation mix will continue to change going forward. During this same time period, other ISO/RTO regions chose approaches for their allocations of transmission cost that more appropriately allocated costs in line with benefits and burdens particular to the customer types and generation mix within their regions. SVP agrees with other market participants who have observed that the systems established by other ISO/RTOs are complex results of numerous trade-offs, and thus focusing on one or two specific elements of transmission cost recovery structures in these other ISO/RTOs as just and reasonable – without considering the entirety and history of these cost recovery structures – is not productive.



For a high load factor utility such as SVP, a purely volumetric-based allocation of TAC results in a considerably higher contribution to the various PTO's TRRs than would be assessed to SVP in other ISO/RTO regions that use a demand-based allocator. When the CAISO's Metered SubSystem (MSS) operational paradigm was negotiated, a compromise was reached for a number of reasons that allows a non-PTO MSS to pay TAC/WAC on net load as opposed to gross load basis, and SVP believes it is very just, reasonable and appropriate to maintain this netting treatment should the CAISO go forward utilizing only a volumetric TAC structure. It is SVP's strong belief that the desire for simplicity in transmission recovery cost structure must be balanced with adherence to cost causations principles - such that the benefits and burdens of the transmission system are allocated in a just and reasonable manner. It is also very important to consider the economic and operational benefits that may be captured by transitioning to a different rate structure, but keeping in mind that any change to the existing rate structure will potentially result in rate shock for various market participants who planned their operations based on the existing volumetric-only methodology. Therefore, SVP strongly suggests that if examination of appropriate transmission cost recovery structure results in a change from existing billing determinants, a phased-in approach should be utilized, similar to the 10-year CAISO transition to a system-wide high voltage TAC rate. This would require that the CAISO's Transmission Planning Process (TPP) recognize investments made under the existing TAC structure while being cognizant of potentially stranded value of such investments.

3. Today’s volumetric TAC rate structure.

Do you think it is appropriate to retain today’s volumetric TAC rate structure ($ per MWh of internal load or exports) going forward? If so, please explain why. If not, please indicate what type of change you think is preferable and why that change would be appropriate.

Comments:

SVP believes that it may be necessary to consider several possible TAC recovery structures for further study, in order to ensure that any updated TAC allocation that uses different billing determinates produces desired market outcomes, and does not unjustly shift costs from one customer, or customer class, to another. Assuming all Load Serving Entities (LSEs) within the CAISO were nearly identical, it would make little sense to change from a volumetric rate, but since the CAISO’s volumetric rate was adopted there have been significant changes within the CAISO footprint (additional traditional PTOs, MSSs, Non Load serving PTO’s, LSEs – including customer choice aggregations, significant additions of DG, and large amounts of intermittent generation), all which impact the cost associated with the TAC, and who pays for it. SVP does not think it is appropriate to automatically assume that the facts and circumstances upon which a volumetric-only TAC structure was determined - in the 1996 to 1998 time frame – are still an appropriate basis for developing a TAC mechanism going forward, unless significant studies are performed that determine this is in fact still a valid basis to build upon.

SVP understands that a particular concern for many market participants is how CAISO intertie export transactions are treated with respect to transmission cost allocations – an item that SVP touched on in Section 1 above. Under the current CAISO volumetric rate structure, intertie exports – at high voltage - pay $11.67/MWh for use of the CAISO grid. This causes a significant distortion in the economic market outcomes that could be mitigated if transmission costs were allocated in a different manner. Looking back to as recently as April and May of this year, there were significant hours during the mid-day time period when the LMPs in the CAISO day ahead market would have suggested that substantial intertie exports could have taken place - considering that the energy price was lower than the cost of even the most efficient thermal generation outside of the CAISO BAA footprint. The use of a volumetric rate and applying this to exports results in a “hurdle rate” - a marginal cost that must be overcome to enable transactions - that distorts the market. Market participants, depending on their situation, may view the prospect of re-examining TAC application to intertie exports differently – depending on how changing to a different billing determinant may impact their bottom line. SVP understands that a hurdle rate creates a net benefit for an LSE that takes a “short” market position and purchases a significant amount of power (used to serve its customers) at the PTO DLAP - and doesn’t have a corresponding supply portfolio that settles at these same depressed supply LMPs. Conversely, for an LSE that has a "long" market position with additional supply, this hurdle rate would provide a net cost, where an LSE that is relatively balanced would in theory be somewhat indifferent. The CAISO should desire that its resulting TAC billing determinant produces market signals that create efficient market outcomes. For these reasons the CAISO should consider treating export transactions at intertie scheduling points differently than how it allocates TAC to load within the CAISO. In that regard, would transitioning to a demand-based billing determinant at the interties, (limiting export bids to an SC's purchased transmission at a demand based rate), reduce the currently-experienced market inefficiencies? This would seem to be related to the issue Bonneville Power Authority (BPA) has at its Southern Intertie with respect to Long Term Transmission rights and Short Term Non-Firm transmission sales. Allowing Scheduling Coordinators (SCs) who expect to export from the CAISO to pay a demand based rate may generate significantly more TAC revenue than the existing volumetric-only rate design - while also allowing the market to operate more efficiently. SVP suggests that one option for further study/analysis by the CAISO include SCs who plan to submit bids to export power at interties having the option to sign up for the demand-based rate. Energy awards up to the amount of contracted-for transmission would not be exposed to the volumetric rate, and energy quantity awards above the contracted-for quantity would pay the volumetric rate. This may be a change that could be implemented relatively quickly to determine the effect a different TAC billing determinant has on market behavior.

SVP believes that it is appropriate for the CAISO, in this TAC options review initiative, to consider studying a scenario where a portion of the various PTO's TRR would be collected through a demand-based component determined by a LSE's Coincident Peak (CP) forecasted demand. This method would more closely align how some transmission costs are incurred and allocated with how planning and developing transmission investment is done in practice. Moving from a purely volumetric-based rate structure to one that has both a volumetric and demand-based allocation will have both advantages and disadvantages.

Potential Advantages:

1. As explained above, the export hurdle rate could be reduced or eliminated. Today's high hurdle rate greatly reduces the margins that can be earned by generation projects and distorts the efficiencies that could be gained if the hurdle rate was lower.
2. More closely aligns transmission costs with benefits and burdens such that low load factor LSEs pay a fair share of the transmission system costs, and high load factor LSEs are not overly burdened.
3. Allocating a demand-based component of the TAC on forecasted CP demand could provide a mechanism for an LSE to avoid future cost allocations through incentives

for energy efficiency, DG, and energy storage that reduces peak load which lessens the need for future transmission development.

4. More closely aligns the TPP and the need for transmission investment with cost allocation than the current volumetric-only rate.
5. May make regionalization more acceptable to neighboring BAA's with lower transmission costs (than experienced by the CAISO BAA).
6. May result in lower West wide GHG emissions.
7. May help with the ramping needs being experienced within the CAISO.

Potential Disadvantages:

1. More complex rate structure than the current volumetric rate.
2. May not provide the same level of monetary incentive to DG proposed by the Clean Coalition in their TED proposal unless the DG is able to reduce CP demand.
3. If the demand component is based on forecast demand it may provide an opportunity to game the market by supplying low forecasts.
4. Simply transitioning to, or including, a demand based allocation does not prevent cost shifting of the existing transmission system from LSE's who have declining load and a declining coincident peak. This may be addressed by basing the demand based component on the highest CP or forecasted CP during a specified historical period (3 years, 5 years, 10 years?)

Other Issues:

1. How should DG, Energy Storage, DR, or other programs and resources be factored into CP forecasts?
2. Are there issues with PTO TRR's that use stated rates vs. formula rates?

4. <u>Impact of distributed generation (DG) output on costs associated with the existing transmission system.</u>

Do you think DG energy production reduces costs associated with the existing transmission system? Please explain the nature of any such cost reduction and suggest how the impact could be measured. Do the MWh and MVAR output of DG provide good measures of transmission costs avoided or reduced by DG output? Please explain your logic.

Comments:

The transmission system must be designed to meet the load serving obligation of the various LSE's within the CAISO, and with that in mind the existing transmission system has been developed with certain assumptions regarding future load growth and energy efficiency. We are not aware of any reduction in LSEs' forecasted CP attributed to perceived future expansion of DG. The costs of the "existing" transmission system with regards to debt and ongoing O&M are relatively fixed, and are not likely to change with the deployment of additional DG, or the output of existing DG. To provide a reduction in transmission development and associated costs a DG must/should be treated similarly as other generation projects that are incorporated into transmission planning studies. This would appear to point towards a transition to a two-tier transmission cost recovery structure – one for the costs of the existing grid and the other for future grid expansion/investment, with the latter being the one that can be affected by the growth of DG.

5. Potential shifting of costs for existing transmission infrastructure.

If the TAC rules are revised so that TAC charges are reduced or eliminated for load offset by DG output, and there is no reduction in the regional transmission revenue requirements that must be recovered for the existing transmission infrastructure, there will be an increase in the overall regional TAC rate that presumably will be paid by other load. How should this initiative take into account this or other potential cost shifts in considering changes to TAC structure?

Comments:

SVP is in a unique position as a load following MSS because it receives the netting treatment the Clean Coalition is advocating should be granted to DGs in a PTO service area. It bears noting that there were a number of reasons this netting treatment was allowed for certain (non-PTO) MSSs.

1. SVP is not a PTO, and has considerable transmission assets that are only paid for by SVP customers, and not socialized through the collection of a regional and/or local TAC.
2. SVP has a significantly higher load factor than any of the IOU's, and without this netting treatment a purely volumetric rate would unjustly allocate extreme transmission costs to SVP.
3. SVP's electric system is extensively networked with, and supports, the CAISO grid.
4. Even with the netting treatment SVP pays for CAISO grid transmission in amounts equivalent to that of a PTO with a similar peak load and 50% load factor.
5. SVP purchased transmission from PG&E for many years prior to the establishment of the CAISO and contributed to the ongoing O&M and capital costs of past transmission projects.
6. Unlike a DG project, SVP's MSS is a separate and distinct utility that balances its loads and resources, and which predated the establishment of the CAISO Grid.

From a cost causation principle, the netting treatment for a non-PTO MSS corrects some of the unjust allocations that would result if a purely volumetric rate were applied to a Publicly Owned Utility (POU) such as SVP. SVP questions (1) whether DGs should get similar netting treatment when they have not endured the same circumstances, and also (2) if the Clean Coalition's proposal recognizes FERCs general guiding principles for transmission pricing - as they were articulated in the CAISO's July 12, 2017 presentation. SVP fully understands that should the CAISO decide to transition to different TAC billing determinants that FERC's general guiding principles will need to continue to be adhered to – to ensure that TAC costs are not unjustly allocated for the sake of simplicity of method.

SVP suggests that, in applying the cost causation principle to DG located in a PTO service area, the load offset by the DG should receive a netting benefit on the volumetric rate associated with DG output if it met a two-factor test, where: (1) there is load growth within the load pocket, and (2) the DG offsets that load growth and provides a reduction to peak demand at that transmission interface. Assuming forecasts for demand and energy exist at transmission/distribution interfaces, it would be possible to allocate costs on the higher of either forecasted, or actual, demand and energy. By allocating cost on the higher of either forecasted or actual demand, a mechanism will be created that could well circumvent the potential cost shifts mentioned above. To the degree there is significant load growth within the distribution system that can be offset by DG - that eliminates or reduces the need to develop new or expand existing transmission - then a DG should be able to capture that value. Whether it is appropriate to do this through DG contracting directly with the PTO - or through a CAISO TAC billing determinant - needs further consideration and discussion. For transmission/distribution interfaces that have stable or declining demand, a DG's output would appear to simply provide a reduction in the denominator in the equation whereby the TAC is developed, but does not provide an offsetting reduction in transmission costs (peak demand), and as such should not receive a TAC allocation benefit associated with its output. This type of structure would appear to require tracking of past load forecasts as well as consideration for basing the benefit that could be provided by DG on the highest forecast used in previous TPP cycles.

This sort of transmission cost recovery structure would also eliminate some of the cost shifting experienced today that is caused by the build-out of roof top solar, and would appear to prevent such costs from shifting to those customers with a lesser degree of solar development.

6. Potential for DG and other DER to avoid future transmission costs.

The issue paper and the July 12 presentation identified a number of considerations that the transmission planning process examines in determining the need for transmission upgrades or additions. Recognizing that we are still at an early stage in this initiative, please provide your initial thoughts on the value of DG and other DER in reducing future transmission needs.

Comments:

The transmission system must be designed to meet the load serving obligation of the various LSE's within the CAISO. To the degree that DG output is available during system peaks and this availability decreases the flow on the transmission system then there should be some reduced cost associated with a lessening of future grid expansion. To the extent that DG energy is available during "all" defined hours where the coincident peak could occur, then it is justifiable that a DG should be compensated for the benefit provided. If a DG is available 10%, 50%, or 99% of the time it cannot reasonably claim it automatically provides for a reduction of future transmission costs. To the degree that a DG can attest and be verified to being available during hours when a CP demand could be set, then the DG should be allowed to be compensated through a contract with the LSE for the avoided allocation of a demand-based component of the TAC (if one is decided to be developed going forward). Example: If an LSE is forecasting an increase to its CP in the future, but is able to avoid this increase by deploying some amount of DG, then the LSE should be willing to contract directly with DG developers that would aid in avoiding this future CP increase. SVP does not support a structure where existing transmission costs would be able to be avoided simply by reducing volumetric energy flow below historical or current levels.

7. Benefits of DERs to the transmission system.

The issue paper and the July 12 discussion identified potential benefits DERs could provide to the transmission system. What are your initial thoughts about which DER benefits are most valuable and how to quantify their value?

Comments:

SVP supports the CAISO's determining of whether or not DER benefits depend on the location and output profile of the individual DERs (and thus not necessarily a global benefit from the existence/presence of all DERs).

8. Other Comments

Please provide any additional comments not covered in the topics listed above.

Comments:

SVP has no additional comments at this time.