Stakeholder Comments Template

Review TAC Structure
Stakeholder Working Groups

This template has been created for submission of stakeholder comments on the Review Transmission Access Charge (TAC) Structure Working Group Meetings that were held on August 29 and September 25, 2017. The working group presentations 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 **October 13, 2017.**

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

NOTE: See last page for definitions of some key acronyms and terms.

The Turlock Irrigation District (TID) appreciates this opportunity to provide comments regarding the California Independent System Operator's (CAISO) Review of TAC Structures. The comments below are meant to provide input into the process and reflect the current thinking at the TID.

We attempted to be responsive to the questions posed. However, TID reserves the right to update our comments as this process continues. Our position may evolve as this topic is further discussed and we understand better the position of other stakeholders and both the intended and unintended consequences of various alternatives.

1. One concept for allocating the costs of the existing transmission infrastructure is to charge each user of the grid in accordance with their usage of or benefits received from the grid. What do you believe is the most appropriate way to measure each end-use customer's or load-serving entity's (LSE) benefits or usage of the grid? What specific benefits should be considered? Please explain you answer.
    a. The very short answer is a combination of a capacity charge reflecting a customer's reliance on the transmission system and the ancillary services provided in conjunction with an energy charge.
    b. Let me offer a further explanation:

I would hesitate at this point to say what the "most" appropriate way is. However, I would like to propose options and criteria that should be considered.

Under the belief that all users benefit from the sturdiness (electrically speaking) of the transmission system, I believe some type of demand charge would be appropriate. The stiffness of the electric system provides a stability factor for each customer that results is stable frequency and voltage. All customers ultimately receive all the ancillary services as delineated in the pro-forma OATT as well as factors not yet included such as frequency responsive reserves. Any rate structure must recognize all customers receive these benefits.

Determining the capacity billing determinant may be difficult as it would depend on the configuration of the customer. If a customer had a single 100 MW unit to supply a 100 MW load, I would argue that the customer depends on the transmission for its full load because a single contingency would require the transmission system to meet the full load of the customer. Moreover, even if it is unlikely to occur, the transmission system would need to be built to supply the full load of the customer just in case. If the customer had ten 10MW generators to supply a 100MW load, I would argue that it would not depend on the transmission system for the full 100 MW load. It is not clear in my mind whether that should be a 10 MW requirement or something different. I suggest that such a determination could be resolved through reasoned discussions among the stakeholders.

Adding an energy charge for energy delivered to each customer would be reasonable (even if they do not impose a capacity burden on the system) to defray the fixed cost of the transmission system (that more often than not was built for reliability/capacity reasons rather than energy delivery). Such a charge could be set to reflect some percent of the benefit of being able to take delivery of economical energy in lieu of generating internally with a peaking type power plant. (By way of example, a customer with numerous generators, all running on oil, should not be able to avoid *all* transmission costs by virtue of the fact it *does not need* the transmission capacity.)

The existing transmission system was built based on an existing paradigm. Customers should not be able to avoid transmission costs simply by adding self-generation capability. Accordingly, there should be some mechanism for customers to pay for the existing transmission system based on the current paradigm and if a new transmission rate mechanism is decided upon, those rates should be applied to new transmission costs.

In establishing criteria transmission rates, I suggest the following:

c. Recognize that transmission costs are basically fixed and are not affected by use. Accordingly, the transmission rates should be established such that they have de minimis effect on the real time economic dispatch of the electrical system. By doing so, we will tend toward minimizing real time costs and minimize the adverse effects of using less efficient fossil generation.

d. Allocate costs to both generation and load so that both have an incentive to recognize transmission costs in their decisions.

e. Transmission costs should *mostly* be allocated to those that cause the increased investment (as opposed to those who are perceived to receive a benefit from the new transmission).

f. The existing paradigm should be recognized as a sunk investment and those currently responsible for paying for the existing transmission system should (for the most part) not be able to shift those costs to other existing transmission customers.

2. The example the ISO presented at the August 29 working group meeting (slides 21-22 of the ISO presentation) illustrated how using transmission energy downflow (TED) as the high-voltage TAC billing determinant (instead of end-use metered load) affects all ratepayers of each utility distribution company (UDC) irrespective of which LSE serves that load. If the ISO were to adopt TED as the billing determinant for the high-voltage TAC, what further procedures would be needed to ensure that the benefits of reduced TAC payments go to the correct LSEs that make the decisions to procure DG? Please explain your answer.

    a. This issue is illustrative of the shell game that might be created by moving to a TED based system. System A may build a resource on the distribution or low voltage system of System B. System B may build a resource on the distribution or low voltage System C. In addition, Marketer Q may have resources on multiple low voltage systems. One can argue that the choice to build resources on other's systems is enabled by the high voltage transmission interconnecting the systems. And yet, if the right conditions exist, use of the high voltage may not increase as a result of all these remotely located generation because of the economic penalty associated with importing energy from the high voltage system. And note that no costs associated with the high voltage system were saved.

    b. Not addressed during the discussions were how the CAISO market would function. Each LSE would much prefer to use the generation on its low voltage transmission system in order to reduce the HV TAC. Would that be accomplished by making such units a must run? Does that not defeat the purpose of having an organized market? And yet if the one does not establish the hourly dispatch based on the same principles used in evaluating resources, there is an inconsistency that would not lead to the lowest cost decision. When the economics dictate, each generator on the low voltage system might arrange with the LSE to self-schedule the unit so the LSE could avoid transmission charges.

3. The ISO could (a) continue to use the end-use metered load (EUML) or customer energy downflow (CED) as the basis for assessing high-voltage TAC, or (b) propose a change to assess HV TAC based on downflow at the transmission-distribution interface (T-D TED), or (c) assess HV TAC based on downflow at the interface between the high-voltage and low-voltage transmission systems (HV-LV TED). Does your organization prefer one of these approaches at this time? Please explain the reasons for your preference.

    a. As explained in earlier responses, the HV-LV TED results in uneconomic generation dispatch and should not be considered without significant modification.

    b. The T-D TED would be less disruptive but still has the same basic problems.

    c. The EUML seems the most practical but even in the case of EUML one must consider how behind the meter generation is addressed.

   d. As more eloquently expressed in the comments of the IEP on September 19, if there is an issue regarding the evaluation of alternate generation resources, examining the GIDAP could be more appropriate than changing the transmission access rates.

4. Does your organization believe that any of the options in the previous question present any potential problems or issues that have not been identified or explained during the stakeholder process thus far? If so, please explain. Also, please indicate what other analyses could be done to help understand the impacts of changing the point of measurement?

   a. As discussed at the meeting, the down flow does not reflect the reliability benefits that the high voltage system provides to the low voltage system. Those benefits in part are related to the capacity that is available and that can be called upon if necessary. The high voltage system also provides voltage support and frequency support to all customers connected to it (directly or indirectly).

   b. The concept as presented does not account for flows through a system. It is possible for energy to flow from the HV system at one location and flow back up to the HV system at the same time. One also needs to consider that flows from the HV system to "LSE A" may ultimately be caused by "LSE B" that is connected to LSE A at a lower voltage. The metering, contracts and billing may be much more complicated than assumed by the presenters.

   c. By applying the high voltage TAC only to the energy that is delivered from the high voltage system, all generators on the low voltage system would have a competitive advantage of $10-15+/MWh (the HV TAC). Some may argue that this provides an incentive for distributed renewable resources. In fact, it favors all generators connected to the low voltage transmission system. So a less efficient, more polluting generator might be dispatched prior to a more efficient, less polluting generator connected to the high voltage system. Note, the additional costs attributed to the generator connected to the HV transmission have nothing to do with the incremental cost of generating and delivering the energy to the ultimate customer in the short-term market.

5. Does your organization believe that the ISO should change *only* the point of measurement utilized for assessing TAC apart from considering other changes to the TAC structure? Alternatively, should the ISO change the point of measurement in conjunction with other changes to the TAC structure? Please explain your position.

   a. TID is concerned that changing the point of measurement of energy conflicts with operating the electrical system as efficiently as possible.

   b. If the point of measurement is changed at all, the entire TAC structure should be examined to be sure it leads to the least cost transmission system and the least cost operation.

6. Does your organization believe that changing the point of measurement for assessing TAC to use TED instead of metered customer demand will result in increased procurement of DG by LSEs? Please explain your position.
    a. It may. However, more DG should not be the goal of transmission pricing. Other regulations will require renewable generation. It should be the goal of all pricing and transmission planning decisions to lead to the least cost electric system that meets the reliability requirements and RPS requirements of the state.
    b. TED inappropriately provides DG a competitive advantage over generation connected at a high voltage. It is very possible, or even likely, that additional generation could be connected to the high voltage system without additional transmission reinforcements. If that is the case, why should DG be provided with such a competitive advantage? Pricing for central solar generation is now as low as $35/MWh. High Voltage TAC will be on the order of $15MWh representing a 40+ percent increase in cost. As an example, a generator could be located on the site of a retired power plant without requiring any additional high voltage transmission investment and yet it would still incur the 40+% economic penalty.

7. Does your organization believe that increased procurement of DG by LSEs will reduce the need for future investment in transmission infrastructure? Please explain your position.
    a. It is conceivable that DG may ultimately result in less transmission investment. However, transmission investment will be effected by many factors, not just the location of DG. Much of the recent transmission cost increases were due to changes being made to meet NERC and WECC standards and improve reliability and security.
    b. Transmission investment is very lumpy. DG is more likely to postpone transmission investment rather than eliminate it. Of course, the ultimate effect of DG will depend on where on the system it is placed and when and how much control there will be over the output.

8. The Clean Coalition provided a spreadsheet and documentation (available at the ISO's TAC initiative web page link on page 1) showing their approach for estimating the savings from avoided future transmission investment that could result from increased DG procurement in response to the ISO adopting TED as the point of measurement for assessing TAC. Does your organization believe that Clean Coalition's analysis provides a reasonable projection of transmission cost savings as a result of DG growth? Please explain your position.
    a. No detailed comments at this time but I do not believe it takes into account the effects of uneconomically dispatching generation connected to the low voltage system.

9. If you do not agree with Clean Coalition's projections of transmission cost savings, what approach would you suggest for estimating savings from reduced need for future investment in transmission that could result from increased DG development?

   a. The economics of DG will be site specific as will the economics of generation connected to the high voltage system. The CAISO should consider a process that imposes any increased costs of transmission caused by generator additions on those generators causing the transmission costs. The existing rules may not be sending the correct signals. It is my understanding that transmission costs incurred by the generators are payed back in 5 years. Although that might cause a bit of a cash flow issue, the transmission costs are not really reflected in the ultimate cost of power from the facility.

10. The ISO must decide what types of analyses to perform to evaluate alternative TAC approaches, and how to prioritize them. Please provide your organization's view on what analyses would be most useful, and indicate the relative importance of each analysis you recommend to assist the ISO in determining which analyses should take precedence.
    a. As a start, the CAISO should set forth criteria to use to judge any pricing paradigm. The response to question 1 provides some input to that process.
    b. Minimizing transmission costs is NOT the objective! Rather, it should be the intent to minimize the total cost of supplying clean reliable energy to the customer. Because of economies of scale and solar characteristics, it may be more cost effective to build a utility scale solar farm than attempt to install DR on the roofs of customers. From the CAISO perspective, the sum of the following costs should be minimized
        i. Transmission
        ii. Generation (Capital and Fuel and O&M)
        iii. Environmental consequences

11. How can the ISO evaluate the downstream financial impacts of potential changes to the TAC structure? What data would best inform the ISO and stakeholders of the potential impacts to various entities? Does your organization believe the ISO should focus on this question now, or wait until potential TAC structure options are better defined (e.g., after the ISO issues a straw proposal)? Please explain your position.
    a. See response to 10

12. How are transmission needs and costs driven by the delivery of energy versus the provision of capacity necessary to meet peak load conditions? Please explain your position.
    a. As discussed in other stakeholder processes, transmission is built for a number of reasons. Often the reason is to meet capacity needs but not always. For example, some facilities are built to enable the transmission system to function reliably at low load (not peak load). Some facilities are built to deliver lower cost energy (and or capacity).

13. In considering potential changes to the TAC structure, what kinds of changes would best align with the impacts of energy delivery, peak load and other drivers of new transmission investment? Please explain your answer.
    a. Having generators share the burden of transmission costs may assure sure that interests are aligned between generator and ultimate customers. It would force the generator, or its customer, to consider the incremental transmission costs in its decision regarding where to locate a new resource.
    b. Imposing an energy charge for transmission use interferes with the economic operation of the electric system. (Inserts a hurdle rate that must be overcome to enter into transactions.) The CAISO should consider how transmission charges might affect the dispatch of resources on its system. Uneconomic dispatch could lead to increased fuel costs and increased carbon emissions. Such a result would not align with state energy policy

14. What are the cost drivers of operating and maintaining the existing transmission system and what, if anything, could materially affect these cost drivers? In particular, does your organization believe that increasing the share of load served by DG can reduce any costs associated with the existing transmission system? Please explain your position.
    a. Whether or not DG reduces transmission and distribution costs is application specific. It is possible that DG could increase costs because of the added complexity causes by adding numerous sources of fault current on a distribution system designed with a particular system resources in mind. Similarly, DG could eliminate or postpone the need to upgrade transmission by eliminating overloads.

15. Please offer any other comments your organization would like to provide on the material discussed in the two Review TAC Structure Working Group meetings (August 29 and September 25), or any other aspect of this initiative.
    a. No additional comments at this time.

Related Acronym Definitions:

- **Community Choice Aggregator (CCA):** One type of non-utility Load Serving Entity that can operate in an investor-owned utility service area.

- **Customer Energy Downflow (CED):** Metered energy delivered from the grid to an end-use customer measured at a customer meter, also referred to as end-use metered load (EUML). Customer energy consumption that is met by output of DG located behind the same customer meter is not included in CED. Also, CED does not include any production of DG behind the customer meter in excess of consumption behind the same meter during the same interval.

- **Distributed Energy Resources (DER):** Energy resources connected at distribution level, either on the utility side or the customer side of the customer meter, without regard to technology type or size. DERs include distributed generation (DG), energy storage of various types, EV charging stations, as well as demand response and energy efficiency.

- **Distributed Generation (DG):** Generating resources deployed at the distribution system level, either on the utility side or the customer side of the customer meter; DG is one type of DER.

- **Electric Service Provider (ESP):** One type of non-utility Load Serving Entity that can operate in an investor-owned utility service area.

- **End Use Metered Load (EUML):** Another term for customer energy downflow (CED).

- **High Voltage (HV):** Transmission system 200kV and above.

- **Low Voltage (LV):** Transmission system below 200kV.

- **Transmission Energy Downflow (TED):** Gross metered energy flow measured at specified transmission system interfaces, either (a) from high-voltage to low-voltage transmission **(HV-LV TED)**, or (b) from transmission to distribution **(T-D TED)**. TED measurements do not reflect energy flows in the opposite direction from LV to HV transmission or from distribution to transmission.