Stakeholder Comments Template

Submitted by	Company	Date Submitted
Please fill in the name, e-mail address and contact number of a specific person who can respond to any questions about these comments.	California Public Utilities Commission	July 26, 2017

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.

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:

The ISO is considering whether to modify the current volumetric structure of the TAC to consider, for example, using a demand-based charge, either instead of or in addition to a volumetric charge, or a time-of-use pricing structure.[1] Presumably, the intention is to better align the costs charged to transmission users with cost causation. While retail transmission rate design may not be central to the current ISO initiative, CPUC staff believes it is relevant and the CAISO should include within the scope of this initiative an inquiry into whether similar modifications should be made to retail transmission rates as well as wholesale rates. Therefore these comments support adding additional language to the TAC rate design issue to include:

- **Whether the ISO should recommend to FERC that the California IOUs' retail transmission rates be restructured to include either peak-related (coincident) demand charges or time-of-use volumetric rates (or both).**

As discussed in the July 12, 2017 stakeholder meeting and the ISO's April 12, 2017 Background Paper:

> "FERC ruling determines the TRR amount each PTO may collect in rates. The rate cases and the FERC rulings for the load-serving PTOs also address the forecasted Gross Load quantities from which the TRRs will be recovered. For the IOU PTOs, FERC also approves each PTO's retail transmission rate structure for the various customer classes and the exact amounts of its retail transmission rates."

For California IOU customers, end-use transmission charges are determined in a 3-step process:

Stage 1: TAC is allocated among PTOs based on total volumetric usage (at the customers' meters)

Stage 2: The IOUs allocate their TRR to customer classes using FERC's 12 Coincident Peak (12-CP) methodology.

Stage 3: The IOUs set rates to collect the class-allocated TRRs from retail customers. Residential and small commercial customers pay non-TOU volumetric rates; Medium & Large Commercial customers pay non-TOU demand charges.

Currently, only Stage 2 accounts for the contribution of customer demands to the peak load on the transmission system. If the ISO does in fact institute a demand-based charge or a time-of-use pricing structure (as recommended below), both Stage 1 and Stage 2 would account for the contribution of customer demands to the peak load on the transmission system. **However, the resulting pricing signals will not be effectively passed through to IOU retail customers without a reform of IOU retail transmission rates (Stage 3). California IOU retail transmission rates are not currently time dependent.**

The ISO's Background Paper states: "… the IOUs generally align the retail transmission rate structures they file at FERC with the CPUC's overall retail rate policies prior to making their FERC filings." However, CPUC staff believes that the IOUs have NOT aligned the retail transmission rate structures they file at FERC with the CPUC's overall retail rate policies. Specifically, the CPUC has been steadily moving toward time-varying rates; while the IOUs have adhered to retail transmission rates which have no time differentiation.

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[1] June 30, 2017 Issue Paper, p. 4.

According to the ISO's "Issue Paper" (p.9): "Traditionally, the courts and FERC have required that approved rates reflect to some degree the costs actually caused by a customer who must pay for them. Stated differently, 'cost responsibility should track cost causation.' "

In 2015 the ISO identified the hours of 4-9 pm as peak (or super-peak) hours in which load reduction would be especially beneficial.[2] Singling out these hours implied that loads occurring between 4 and 9 pm cause more costs than loads at other times. Yet, for both the TAC and for the IOU's retail transmission rates, loads during those hours are not charged more, and customers cannot benefit by shifting load out of those hours.

The ISO presentation at the July 12, 2017 Stakeholder Meeting states:

•Through its Transmission Pricing Policy Statement, FERC has recognized general guiding principles for transmission pricing:

–Must meet traditional revenue requirements
–Must reflect comparability
–Should promote economic efficiency
–Should promote fairness
–Should be practical

CPUC staff believes that the current non-time-differentiated IOU retail transmission rates fail to meet comparability, economic efficiency, and fairness goals:

- Current transmission rates unfairly overcharge off-peak transmission users based on cost causation
- The cost-causation principle is closely tied to economic efficiency
- Under the FERC's 12-CP methodology used by the IOUs to allocate the TRR among rate classes, each wholesale customer is its own rate class and is billed based on its contribution to each of 12 monthly coincident peak demands; a wholesale customer can therefore reduce its bill if it can shift load off peak. In contrast, the IOUs bill individual retail customers based on non-coincident demand; a retail customer cannot generally reduce its bill by shifting demand out of the peak hours. This appears to raise a comparability issue between similarly situated retail and wholesale customers.

For the reasons stated above, the ISO should add to the scope consideration whether the ISO should recommend to FERC that the California IOUs' retail transmission rates be restructured to include either peak-related (coincident) demand charges or time-of-use volumetric rates (or both).

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

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

[2] Study filed by CAISO in the CPUC Rulemaking R.15-12-012 (TOU OIR).

Comments:

The CPUC staff have no comments at this time.

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:

CPUC Staff believes that either a demand-based charge or a time-of-use pricing structure would be preferable to the current volumetric TAC charge. Presumably, the ISO's intention in raising this issue is to consider TAC rate design structures that would better align the costs charged to transmission users with costs they cause. As stated in detail in answer to Question 1 above, CPUC staff believes that the current non-time-differentiated volumetric TAC rates fail to meet economic efficiency, and fairness goals:

- Current TAC rates do not promote economic efficiency because they do not align with cost causation; they do not charge peak users in accordance with the costs they cause.
- Current TAC rates unfairly overcharge off-peak transmission users based on their reduced role in cost causation.

Therefore CPUC Staff believes that the ISO should restructure its TAC rates to account for a PTO's contribution to peak loads on the transmission system, either via demand-based pricing or time-of-use pricing. CPUC staff notes that the FERC has found that basing transmission charges on 12-Coincident Peak methodology has been found elsewhere to meet its general guiding principles for transmission pricing.

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

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:

CPUC staff have no comments at this time.

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:

The initiative should examine cost causation among loads and ensure that cost causation is transparently identified, studied, and quantified.

The Transmission Access Charge is essentially a cost recovery mechanism for the FERC approved costs of present and past transmission investments. The CPUC staff support cost of service ratemaking principles for TAC rate design. Any consideration of an exemption from TAC charges should be based on cost of service principles. The exemption of a select group of ratepayers from TAC charges is a policy decision which has implications on other ratepayers' charges and must be justified based on cost causation principles. CPUC Staff sees the need for more intensive study to determine the extent to which DER/DG resources do not need transmission facilities or need significantly less transmission facilities and therefore should be exempt from the costs of transmission. A rigorous and fact-based analysis, using cost of service principles, is needed to determine whether load served by existing and new DER/DG resources eliminates the need for, or reduces the cost of, existing transmission investment. This analysis should include further study of whether existing DER/DG resources are currently paying for more (or less) transmission facilities than they use. .

CPUC Staff does not favor the potential shifting of costs between ratepayer groups without justification or causal relationship based on a thorough analysis to determine cost causation. If the initiative prevails in establishing an additional billing determinant which changes the existing TAC structure, the result could be a shift in: 1) who pays for the existing transmission system, and 2) who will pay for the going-forward costs of the transmission system.

CPUC Staff notes that a very limited analysis of the possible consequences of adopting the Transmission Energy Downflow (TED) proposal was attempted by CAISO in the now closed energy Storage and Distributed Energy Resources Phase 2 (ESDER 2) Initiative[3]. It is recommended that the CAISO undertake a more extensive review of the effects of this billing determinant mechanism on IOUs, ESPs, and CCA settlement charges for TAC.

Any consideration of the TED proposal should estimate the costs of new metering at the proposed substation locations (presumably using high voltage meters of billing accuracy), transmission/distribution losses, and other associated costs; as well as clarify who would pay for these costs.

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[3] Review Transmission Access Charge Wholesale Billing Determinant – Issue Paper (June 2, 2016), pp. 7-11

At this time CPUC Staff believes the initiative needs more detailed data collection and in-depth analysis to provide an informed analytical foundation for deciding the reasonableness of any exemption proposal, as viewed from the perspective of solid adherence to cost causation principles.

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:

CPUC staff have no comments at this time.

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:

CPUC staff have no comments at this time.

8. Other Comments

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

Comments:

CPUC staff have no additional comments.