Stakeholder Comments Template

Review Transmission Access Charge Wholesale Billing Determinant

June 2, 2016 Issue Paper

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The ISO provides this template for submission of stakeholder comments on the June 2, 2016 issue paper. The issue paper, presentations and other information related to this initiative may be found at: http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeWholesaleBillingDeterminant.aspx

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Issue Paper

Currently the ISO assesses transmission access charge (TAC) to each MWh of internal load and exports. Internal load is measured as the sum of end-use metered customer load (EUML) in the service area of each participating transmission owner (PTO) in the ISO balancing authority area. Clean Coalition proposes that the ISO change how it measures internal load for TAC purposes, to measure it based on the hourly energy flow from the transmission system to the distribution system across each transmission-distribution substation; a quantity called "transmission energy downflow" (TED). The main difference between using TED or EUML as billing determinant is that TED excludes load that is offset by distributed generation (DG). Please see the ISO's June 2 straw proposal for additional details.

Both the Clean Coalition proposal and the Staff Issue Paper are seriously problematic; they are based on flawed premises and a misunderstanding of the process of recovering transmission costs. A more accurate statement of how the TAC process actually works is below, and some, but not all, of the mistakes are addressed.

Description of Transmission Costs Recovery and Errors in Proposals

TAC costs represent the costs of transmission under the control of the CAISO grid, the Transmission Revenue Requirement (TRR). The TAC rate is charged to each load-serving participating transmission owner (PTO), each of which is also a scheduling coordinator and a utility distribution company, for each unit of measured Gross Load. CAISO staff describes measured Gross Load as "end-use metered load" (EUML). Thus the TAC rate is the TRR divided by the sum of all PTO-served Gross Load, effectively a postage stamp rate. The TAC revenues are ultimately returned to the respective PTOs in proportion to their respective transmission revenue requirements.

The issue paper wrongly states that the denominator for the TAC rate is EUML plus exports.[1] Metered Subsystems (MSSs, discussed later) and exports pay Wheeling Access Charges. Wheeling Access Charge revenue is credited against the TRR recovery through the Transmission Revenue Balancing Account Adjustment (TRBAA). The balance in the TRBAA is returned to the PTOs in proportion to their respective revenue requirements.

The description of the roles of FERC and the CPUC (or other Local Regulatory Authority) in recovery of the TRR is also incorrect in the issue paper. FERC approves each CAISO PTO's revenue requirement, even if the PTO is a publicly owned utility (POU) not otherwise subject to FERC jurisdiction. For the investor-owned utilities (IOUs), the FERC transmission rate cases set not just the TRR, but also set retail and wholesale transmission rates. The IOUs pass these FERC-approved transmission rates on to their retail customers by filing an advice letter with the CPUC saying that FERC has approved changed rates. The CPUC does nothing to change these FERC-set rates, which vary by customer class and represent an allocation made by FERC among the customer classes. For small customers these charges are volumetric but for medium and large customers they include volumetric and demand charges. Therefore, it is incorrect to state that "the CPUC sets the retail transmission charge as a component of the rate structure of each investor-owned utility (IOU)".[2]

Indeed, the CPUC has made it clear that FERC sets these rates. In D. 99-10-057, the Commission stated as a policy:

> The Commission defers to FERC's authority with regard to costs, cost allocation, and rate design for transmission and RMR costs and revenues.[3]

Furthermore, Finding of Fact 9 in that decision states:

> PG&E, SCE and SDG&E propose that the Commission adopt allocation of and ratemaking for transmission and RMR costs. The Commission should make no

1 Issue Paper at 3.
2 Issue Paper at 5.
3 D. 99-10-057 at 33.

> findings here regarding how RMR costs should be allocated and defer to the FERC on all related issues.[4]

Conclusion of Law 11 in that decision states:

> The Commission should reject utility proposals that would establish rate design or other ratemaking or accounting mechanisms for transmission or RMR costs.[5]

The IOU transmission rates are passed on through delivery charges to retail delivery customers, which include bundled, DA and CCA customers. The transmission charge includes the TRBAA and the TACBAA, to be discussed below. The CPUC does not adjust these charges.

Indeed, more recently, in Resolution E-3930, the CPUC issued the following findings of fact:

> The new Process approved in this Resolution has the following elements:
>
> 5. The Commission recognizes that under the filed rate doctrine, the Commission should allow a pass through of these [IOU] transmission rates that are filed with and become effective at the FERC.
>
> 6. It is just and reasonable for the utilities to charge their customers rate increases that have been filed with, and become effective, at the FERC; provided that those rate increases are subject to refund to the same extent as they are at the FERC.[6]

Since retail customers of an IOU PTO are already paying FERC rates for transmission owned by their UDC who is a PTO, the CAISO addresses in settlement *the difference between* the TAC TRR and the UDC PTO's TRR. This can be a charge or a credit. Non-UDC LSEs do not engage in settlement with the CAISO on the TAC. It is not correct to state: ""[i]f however, the ISO changes its billing determinant and the CPUC does not change the retail rate structure to be consistent, then the LSE could have a surplus or shortfall"."[7]

CAISO Tariff Appendix F, Schedule 3, Section 10.2, states:

> **10.2** If the same entity is both a Participating TO and a UDC or MSS Operator, then the monthly Regional Access Charge[8] amount billed by the CAISO will be

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4 Id, at 35.
5 Id., at 38.
6 Resolution E-3930, at 11.
7 Issue Paper at 6.
8 The Regional Access Charge is the TAC less the Local Access Charge. We have not addressed the differences between the High Voltage and Low Voltage Access Charges in these comments, since that would add quite a bit more complexity.

> the charges payable by the UDC or MSS Operator in accordance with Section 26.1.2 of the CAISO Tariff *less the* disbursement determined in accordance with Section 10.1(d) of this Schedule 3. If this difference is negative, that amount will be paid by the CAISO to the Participating TO. (emphasis added)

This difference is included in the TACBAA (TAC Balancing Account Adjustment) which is added to (or subtracted from) the FERC transmission rates passed along to retail IOU delivery customers. Thus it is not correct to say that "changing the ISO's TAC billing determinant will not directly affect what end-use customers in the IOU service areas pay for transmission service, absent action by the CPUC to modify the retail rate structure."[9]

There are various balancing accounts associated with recovery of transmission costs from retail delivery customers of UDC PTOs, of which the TACBAA is only one. For example, SCE's tariffs include the following footnote:

> Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00036) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00005 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $(0.00012) per kWh.[10]

Correction of Some Clean Coalition Errors

The Clean Coalition proposal makes many flawed assertions as to how this process works. The paper is sufficiently problematic that it does not provide a proper basis for a stakeholder process. A few quotes below illustrate the significant concerns about the inaccuracies incorporated in the Clean Coalition proposal, but these are by no means exhaustive. The concerns are real and should be shared by other stakeholders and the CAISO. For example, the Clean Coalition states:

> TAC are per kWh fees for transmission usage assessed by the California Independent System Operator (CAISO) on Load Serving Entities (LSEs) on a per MWh basis.[11]

This is incorrect. First, the PTO UDC does not bill LSEs, it bills end-use customers. Similarly, there would be no possible reimbursement by either the CAISO or the UDC to LSEs because they are not paying any of the charges. Neither LSEs nor distributed energy resources pay for transmission.

The Clean Coalition also incorrectly says:

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9 Issue Paper at 5.

10 SCE TOU-8 tariff.

11 Clean Coalition Comments on ESDER Phase 2 Issue Paper, at 3, 6.

> TAC pay for the CAISO-balanced transmission system, based on the Transmission Revenue Requirements (TRRs) associated with the amortization of historic transmission investments, return-on-equity for the transmission owners, and operations and maintenance of the transmission grid.[12]

This is not true. While the TAC is the TRR divided by EUML, the vast majority of the TRR is paid for through retail or wholesale customer rates that are established by the FERC in the transmission owner (TO) transmission rate cases.

There was some confusion on the Market Surveillance Committee call on June 17, 2016 when a representative of the Clean Coalition stated that all POUs are MSSs (although this is not stated in their proposal or their ESDER Phase 2 comments which include that proposal). As clarified below, not all POUs are MSSs; some are PTOs.

There are POUs and other entities who are also PTOs, not just IOUs, and their TRRs are included as part of the TAC. These POUs are also subject to settlement with the CAISO for the difference between what they recover from their retail customers and their TRRs. They are subject to FERC review of their TRRs because these flow into the CAISO's TAC. However, FERC does not determine their retail transmission rates as they are not FERC-jurisdictional.

There are POUs and other entities who are *not* PTOs and these are treated as metered subsystems (MSSs), the analogy proposed by the Clean Coalition. They are responsible for their own transmission costs, which are not part of the TAC. Clean Coalition wrongly states that non-PTO MSSs are "assessed TAC based on TED."[13] They are not. They pay the Wheeling Access Charge for use of the CAISO grid.

A Metered Subsystem is defined by the CAISO tariff as:

> A geographically contiguous system located within a single zone which has been operating as an electric utility for a number of years prior to the CAISO Operations Date as a municipal utility, water district, irrigation district, state agency or federal power marketing authority subsumed within the CAISO Balancing Authority Area and encompassed by CAISO certified revenue quality meters at each interface point with the CAISO Controlled Grid and CAISO certified revenue quality meters on all Generating Units or, if aggregated, each individual resource, Participating Load, Reliability Demand Response Resource, and Proxy Demand Resource internal to the system, which is operated in accordance with a MSS Agreement described in Section 4.9.1.[14]

The history of the creation of MSSs is that this arrangement was the result of some challenging negotiations at the time of the creation of the CAISO. MSSs generally

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12 Id. at 3.

13 Id. footnote 2.

14 CAISO tariff Appendix A.

operate their own generation to follow their own load, and operate their own transmission and distribution. They are responsible for congestion management and transmission line outages within or at their boundaries. Indeed, it is the nature of their configurations to serve their load that in part led to the creation of the MSS. These entities do not resemble ESPs or CCAs.

The ISO does not yet have a position on the Clean Coalition proposal, and has posted the June 2 issue paper in order to stimulate substantive stakeholder discussion and comments on this topic.

1. *At this point in the initiative, do you tend to favor or oppose Clean Coalition's proposal? Please provide the reasons for your position*.

CLECA does not support the Clean Coalition proposal for several reasons. First, it is not really a matter for the CAISO. If the Clean Coalition wants to change transmission rates, it could participate in TO rate cases at FERC, since that is where transmission rates are adopted. Second, if FERC were to approve the Clean Coalition's proposed changes and if they could be implemented, which is problematic, the result would shift transmission costs among load served by different LSEs, depending on how much "local DG" is used to serve them, assuming this could be tracked and reflected in billing to load. Third, Clean Coalition has not made the case that local DG does not use or benefit from the grid.

2. *Clean Coalition states that TED is better aligned with the "usage pays" principle than EUML is, because load offset by DG does not use the transmission system. Do you agree? Please explain your reasoning*.

Load served by local DG is not exclusively served by local DG unless it is not connected to the larger grid. If the DG is solar, the customer is served by other resources when the sun does not shine unless the solar is backed up by sufficient storage to assure that this does not happen, and this is not likely to be a cost-effective solution. The customer is also served by other resources when the DG is being maintained. In either case, the electricity serving the customer is most likely to come from the transmission grid unless there are very large amounts of local DG. Furthermore, the balancing of the grid with increasing amounts of VERs is done by the CAISO using flexible resources that are not local. Frequency levels are maintained by resources that are likely not to be local, as in the CAISO's frequency response decision to create a market for frequency response that may be supplied by hydro in the Pacific Northwest. The grid also provides voltage support.

3. *Clean Coalition states that using TED will be more consistent with the "least cost best fit" principle for supply procurement decisions, because eliminating the TAC for load served by DG will more accurately reflect the relative value of DG*

<u>compared to transmission-connected generation. Do you agree? Please explain your reasoning.</u>

No. The proposal is not the way to address the stated concern. If the issue is to achieve greater comparability between remote resources and local resources, some form of a transmission adder that only captures incremental transmission required for remote energy resources would be a more direct solution. We take issue with the notion that local DG avoids any existing transmission.

4. *<u>Clean Coalition states that changing the TAC billing determinant to use TED rather than EUML will stimulate greater adoption of DG, which will in turn reduce the need for new transmission capacity and thereby reduce TAC rates or at least minimize any increases in future TAC rates. Do you agree? Please explain your reasoning.</u>*

The Clean Coalition has failed to demonstrate that increased DG would in fact avoid the need for incremental transmission. Whether future TRR increases can be avoided depends on why additional transmission is being added, which is an empirical question.

5. *<u>In the issue paper and in the stakeholder conference call, the ISO pointed out that the need for new transmission capacity is often driven by peak load MW rather than the total MWh volume of load. This would suggest that load offset by DG should get relief from TAC based on how much the DG production reduces peak load, rather than based on the total volume of DG production. Please comment on this consideration.</u>*

First, as we have stated previously, DG does not pay a TAC rate. LSEs do not pay the TAC rate. In fact, neither of these entities contributes to TRR recovery. MSSs and exports pay the WAC, which is related to the TAC rate.[15] Second, transmission rates paid by end users are set in the FERC TO cases. If LSEs or DG are concerned about how transmission costs are recovered, they can intervene in FERC TO cases.

It is true that FERC allocates transmission cost responsibility based on demand, but that is unrelated to the TAC rate, which is the total PTO revenue requirement divided by EUML. In theory you could take the total PTO revenue requirement and divide it by EUML in the form of kW, but there is no point to doing this. This is because while basing the TAC and the WAC on demands rather than kWh, it would not result in a different recovery of WAC revenue nor would it change the allocation of TAC revenues among the PTOs. This WAC revenue that results from the use of the CAISO-controlled grid by non-PTOs gets credited back to the various PTOs in proportion to their share of total PTO revenue requirement. Similarly, TAC revenues are ultimately returned to the respective PTOs in proportion to their respective transmission revenue requirements.

15 It could be the HVAC or the LCAC depending on where they export.

6. *Related to the previous question, do you think the ISO should consider revising the TAC billing determinant to utilize a peak load measure in addition to or instead of a purely volumetric measure? Please explain your reasoning.*

No. There does not appear to be any purpose to the exercise.

7. *Do you think adopting the TED billing determinant will cause a shift of transmission costs between different groups of ratepayers? If so, which groups will pay less and which will pay more? Please explain your reasoning, and provide a numerical example if possible.*

Yes, if there were ultimately different transmission rates for customers of different LSEs based on their DG share. However, this could only be accomplished by a FERC TO order that established those different rates. Proponents would have to intervene at FERC and make this argument. In addition, there would have to be some way of metering the in-front-of-the-meter (IFOM) DG to subtract from metered load. This is really not a CAISO issue, but a FERC issue, because FERC would have to adopt different billing determinants and ultimately set rates. Lastly, such a proposal would not be able to benefit electricity service providers (ESPs) and direct access customers. There would be no way for an ESP to pursue a local DG option because ESPs do not have service territories in which to put IFOM DG, which would lead to inherently inequitable treatment among LSEs.

8. *Do you think a third alternative should be considered, instead of either retaining the status quo or adopting the TED billing determinant? If so, please explain your preferred option and why it would be preferable.*

No. See the response to questions 5-7.

9. *Do you think that ISO adoption of TED by itself will be sufficient to accomplish the Clean Coalition's stated objectives (e.g., incentives to develop more DG)? Or will some corresponding action by the CPUC also be required? Please explain.*

It is not the role of transmission pricing to create incentives for DG. As demonstrated in our answer to question 7, the relationship between transmission revenue recovery and DG can only be addressed in a FERC TO case, not by the CPUC nor by the CAISO.

10. *What objectives should be prioritized in considering possible changes to the TAC billing determinant?*

The entire TAC mechanism is not based on cost causation, but rather on having non-PTO users of the system with no PTO load and PTO users with varying individual TRRs pay part of the TRR in a postage stamp environment. Therefore, there is no reason to change the TAC billing determinant.

11. *What principles should be applied in evaluating possible changes to the TAC billing determinant?*

See answer to question 10.

12. *Please add any additional comments you'd like to offer on this initiative*.

None at this time, other than to note that there is a serious lack of understanding about how transmission rates are set, who sets them, and who pays them that must be rectified and that the proposed changes are not warranted.