Stakeholder Comments Template

Review Transmission Access Charge Wholesale Billing Determinant

June 2, 2016 Issue Paper

Submitted by	Company	Date Submitted
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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.

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.

   At this point in the initiative, SolarCity tends to favor Clean Coalition's proposal. SolarCity notes that historically, most generation was interconnected at transmission-level voltages and conveyed to end-use customers through the transmission system. Under such a system, it may have been fair and equitable to assess the TAC on each kWh of EUML, since each kWh consumed by an end-used customer would have flowed across the transmission system.

   With the emergence of distributed energy resources (DERs) however, it is no longer true that each kWh of energy consumed by an end-use customer has arrived via the transmission system. In many instances, electricity is now generated and distributed to customers entirely at distribution-level voltages. For example:

   - In net energy metering, at times when generation exceeds onsite load, power flows from a rooftop solar system on one building to neighboring buildings over the distribution system
   - California has a number of wholesale solar energy programs for RPS compliance where energy is produced and consumed entirely at the distribution level. These programs include the Solar Photovoltaic Program (SPVP), Renewable Auction Mechanism (RAM), and Renewable Market Adjusting Mechanism (ReMAT)
   - California has recently begun soliciting for and developing energy storage projects that can produce and deliver energy at distribution voltages. For example, in the recent Southern California Edison (SCE) Local Capacity Requirements (LCR) request for offers (RFOs), SCE is soliciting energy storage resources will be sited at both the transmission and distribution levels, as well as the customer level.

   The recent emergence of DERs on the distribution grid has significant potential to reduce costs to ratepayers by deferring or replacing needed transmission investments. In fact, FERC Order 1000 specifically requires the consideration of non-transmission alternatives (NTAs) – including energy efficiency, demand response, distributed generation, energy storage, and fossil generation sited at the distribution level – in lieu of transmission investments if they are more efficient and cost-effective.

   Implementation of FERC Order 1000 is already hobbled by the lack of a cost recovery and allocation mechanism for NTAs, which reduces the incentive for utilities or other entities to propose them in lieu of transmission investment. Assessment of the TAC at the EUML makes implementation of Order 1000 even more difficult by further diminishing the incentive for utilities to deploy resources at the distribution level that can displace or defer transmission investment through local distributed generation.

   Assessing the TAC at the TED can improve the fairness and equity of transmission cost allocation, send price signals that more accurately reflect the costs and benefits of energy generation resources, and improve implementation of Order 1000 by creating an economic incentive for utilities and other load-serving entities (LSEs) to pursue non-transmission alternatives (NTAs) that generate energy at distribution level voltages.

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.

SolarCity agrees that the TED is better aligned with the "usage pays" principle than the EUML, because the EUML method is arbitrarily inconsistent in its assessment of the TAC to situations that, for engineering purposes, are effectively the same.

In some instances, assessing the TAC at the EUML is consistent with the "usage pays" principle – for example, when behind-the-meter DG serves on-site load without exporting energy to the distribution grid past the primary meter. In that case, DG that does not use the transmission system avoids TAC charges, which is fair and consistent with the "usage pays" principle.

In other instances, however, the EUML method results in the TAC being assessed on energy that does not move over transmission lines and is inconsistent with the "usage pays" principle. The following example illustrates how assessing the TAC at the EUML inconsistently applies the usage pays principle:

- Situation 1: A commercial facility has a 500 kW solar PV system on its roof under a net metering arrangement. The load of the facility is large enough that the facility consumes all of the energy behind the meter and does not export.
- Situation 2: A commercial facility has a 500 kW solar PV system on its roof under a lease agreement, whereby the utility leases the roof space to own and operate a utility-owned solar PV system (for example, under SCE's SPVP program). The commercial facility has the same load as in Situation 1.

In both situations described above, energy is generated on the roof of a commercial facility and serves load on-site at the facility. The only difference between the two is that in the second situation, the energy flows through a utility meter and possibly some utility distribution equipment before passing through the customer's meter to serve on-site load. Nevertheless, the utility would be assessed the TAC in the second situation, but not the first, even though neither situation relies on the transmission system to convey the energy from the generator to the customer.

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 compared to transmission-connected generation. Do you agree? Please explain your reasoning.

SolarCity agrees that assessing the TAC at the TED makes sense on principle from a cost causation standpoint, but it is unclear that Clean Coalition's proposal will make the procurement process more consistent with the least cost best fit (LCBF) principle

In the current LCBF methodology used in the renewable portfolio standard (RPS) program, transmission cost is accounted for by assigning to each project the marginal transmission cost necessary to interconnect that project or make it fully deliverable for resource adequacy (RA) purposes. Projects that do not cause added transmission investment are not assigned transmission costs in LCBF.

If the TAC assessment were changed to the TED, cost accounting for transmission-sited projects would likely be unchanged. For distribution-sited projects, however, it is likely that the utility would be able to subtract the value of avoided TAC charges from the cost of those projects. This change might be more consistent with the LCBF principle, depending on one's interpretation of that principle.

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>

Based on SolarCity's understanding of how transmission costs are accounted for in the LCBF valuation framework, it is likely, but not certain, that Clean Coalition's proposal will stimulate greater adoption of DG.

Currently, DG adoption is driven by a number of laws, policies and programs implemented by the CPUC and Energy Commission (CEC), including SGIP, NEM, the 1.3 GW storage mandate, the LCR solicitations, the combined heat and power program, the new solar homes partnership (NSHP), and the Title 24 Zero Net Energy (ZNE) homes mandate.

Some of these programs, such as NEM, rely on a cost-benefit analysis for authorization at the CPUC. In the most recent NEM Decision, parties offered widely divergent views of how transmission should be accounted for the cost-benefit analysis, with utilities opining that DG solar should be afforded no value for avoided transmission, and the solar parties arguing that solar DG should be credited for avoided transmission at the marginal transmission cost of $87/kW-year. The CPUC did not ultimately rule on which view of avoided transmission is correct for purposes of DG cost-effectiveness.

Moreover, the CPUC is currently in the process of overhauling its cost-effectiveness protocols, and it is not clear if the agency will determine an avoided transmission value for DG in this overhaul.

Changing the TAC assessment to the TED would create a clear, simple and unambiguous way to value the avoided transmission cost of DG solar exports, but it is unclear whether this value would be in addition to or in place of an avoided marginal transmission value that might be adopted by the CPUC in the future. It is also not clear whether the value of avoided TAC charges would be significant enough to have a material impact on DG cost-effectiveness.

Also, as mentioned above, using the TED method might allow utilities to subtract avoided TAC payments from the cost of distribution-sited RPS projects, which could improve their competitiveness in LCBF assessments – but again, it is not clear that change in LCBF value would be significant enough to change the outcome of RPS solicitations.

In addition to LCBF and cost-effectiveness, utilities might independently pursue additional DG projects and programs if they are able to reap the benefits of those projects for their ratepayers through lower TAC charges. And changing the TAC billing determinant might make utilities more likely to favor DG resources – or less likely to oppose them – in their advocacy at the Legislature and regulatory bodies, which could lead to greater deployment of DG in the long run.

It is important to note, however, that the outcomes above are somewhat speculative, and thus greater adoption of DG as a result of changing the TAC assessment is not certain to materialize.

5. 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.

SolarCity understands that the CAISO is concerned that distribution-connected generation might not reduce transmission infrastructure needs due to the coincidence of solar PV generation with peak load, as noted in the June 2 Issue Paper.[1] This concern overlooks two critical facts.

First, rooftop solar PV has in fact been shown to reduce transmission infrastructure needs, as evidenced by the ISO's 2015-2016 Transmission Plan, in which $192 million in planned transmission investments were cancelled due to "a combination of energy efficiency and rooftop solar."[2]

Second, CAISO's concern about the ability of DERs to avoid transmission investment needs overlooks the fact that rooftop solar is not the only technology that produces energy on the distribution system. Fuel cells, biogas digesters, combined heat and power systems and battery storage units all generate power at distribution voltages, and many of these technologies are well suited to provide generation on peak. Shifting

[1] California ISO, Review Transmission Access Charge Wholesale Billing Determinant, June 2. 2016.
[2] California Energy Markets, "Cal-ISO Board Approves Annual Transmission Plan," April 1, 2016.

retail TOU periods and wholesale time-of-delivery factors will likely provide incentives for these generators to produce power at peak times.

In particular, battery storage has significant potential to produce energy at the distribution level at peak times that can avoid transmission investment as well as generation capacity and distribution system equipment. With the enactment of the CPUC's 1.3 GW energy storage mandate in 2013 and the recent revamp of the Self-Generation Incentive Program, which allocates 75% of the budget to storage, battery storage located on the distribution system, both behind and in-front-of the meter is likely to become much more prevalent.

Battery storage provides a good example of how assessing the TAC at the EUML is unfair and distorts economic incentives. A third party under contract with a utility might deploy battery storage behind the meter on the distribution grid to charge at off-peak times and discharge to the grid at on-peak times – which could help alleviate the need for new transmission investments. In doing so, however, the utility might actually be assessed the TAC twice on the same kWh of energy – once when the battery charges and again when the battery discharges and the energy is consumed by other end-use customers.

In the example above, not only would the utility deploying battery storage fail to be incented or rewarded for avoiding a needed transmission investment, but it would be further penalized by having the TAC assessed both on battery charge and discharge. This outcome works counter to FERC Order 1000, which requires consideration of non-transmission alternatives in transmission planning.

While granting relief from TAC charges on the basis of DG's contribution to peak load reduction might make sense from a cost-causation standpoint, it would be arbitrary and discriminatory to apply this principle only to DG production, and not to the TAC assessment on load in general. Such a system would likely bias resource planners toward generation over other means to reduce peak load, like demand response.

6. <u>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.</u>

SolarCity does not have an opinion at this time on whether 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, as we lack data on the relative contributions to transmission costs from peak demand and volumetric energy consumption. If peak demand is a significant contributor to transmission costs, then from the perspective of economic efficiency and resource allocation, it may make sense to allocate the TAC on the basis of peak demand.

However, even if CAISO were to use peak demand as the basis for billing determinant, the CAISO should still assess the TAC at the TED, rather than at the EUML. That's because loads with peak demand served by generation on the distribution system (for example, battery storage), would not be contributing to the peak-demand-driven transmission costs.

Moreover, assessing the TAC on peak demand at the EUML rather than the TED would remove the economic incentive utilities might have to address peak load through battery storage or other NTAs that can reduce the need for new transmission investment and lower costs to ratepayers.

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.

In SolarCity recognizes that adopting the TED billing determinant would cause transmission costs to be re-allocated such that LSEs that rely on the transmission system to a greater degree will pay a slightly larger share of transmission costs than those that use the system to a lesser degree.

While this reallocation of costs is likely to be minimal in a state like California, where most LSEs pursue DG to roughly the same degree (as shown in Example 2 of the ISO issue paper), it might be more significant in a Western regional ISO, where DG policies vary significantly on a state-by-state basis. In such a regional system with widely variant DG policies, LSEs in California might be unfairly allocated transmission costs that are out of proportion to their use of the transmission system.

SolarCity does not feel it is necessary to provide a numerical example, since the CAISO Issue Paper on this topic provides an example that accurately captures any cost reallocation that would occur under a TED billing determinant. As shown in Example 1, LSEs that rely on local DG to serve load would achieve a cumulative surplus of $763.04, allocated proportionally to each LSE on the basis of the degree to which local DG is used to serve load. That surplus would be paid by LSEs that do not use DG to serve any load, and thus rely on transmission-sited generation to serve 100% of their load.

On the other hand, Issue Paper Example 2 accurately shows that in a situation where all LSEs rely on local DG to serve 20% of their load, no cost reallocation would occur by switching the billing determinant to the TED. It is important to note, however, that even in this scenario there would be advantages to assessing the TAC at the TED. In particular, LSEs would face price economic price signals for future investments that accurate capture the value of distributed resources, leading to more efficient allocation of capital compared with assessing the TAC at the EUML.

8. <u>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.</u>

   SolarCity does not propose a third alternative.

9. <u>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.</u>

   SolarCity believes the adoption of the TED will be sufficient to appropriately base an LSE's TAC allocation on the volume of energy it causes to flow over the transmission system.

10. <u>What objectives should be prioritized in considering possible changes to the TAC billing determinant?</u>

    SolarCity believes CAISO should prioritize two primary objectives in considering possible changes to the TAC billing determinant:

    First, CAISO should prioritize the allocation of transmission costs in a way that fairly and accurately reflects the use of the transmission system so that transmission costs are properly priced into energy resource investment decisions made by LSEs and others. The current EUML method does not reflect the fact that energy produced and consumed on the distribution system does not rely on the transmission system..

    Second, CAISO should implement TAC billing determinant reform with the objective of implementing FERC Order 1000, which requires distribution-sited resources (NTAs) to be considered as an alternative to new transmission investment.

    Because FERC Order 1000 does not include a cost recovery and allocation mechanism, NTAs are already disadvantaged in planning decisions compared with transmission investments whose costs can be allocated and recovered from benefitting customers. Assessing the TAC at the EUML makes implementation of FERC Order 1000 even more difficult, because it requires LSEs to pay TAC charges on generation sited at the distribution level, which further disadvantages NTAs in the planning process.

11. <u>What principles should be applied in evaluating possible changes to the TAC billing determinant?</u>

SolarCity recommends the following principles should be applied in evaluating possible changes to the TAC billing determinant:

- Fairly allocate of transmission costs: Most parties would likely agree that a fair allocation of costs would result in a system where costs are allocated roughly in proportion to benefits or usage of the system. Under the EUML method, however, a new community powered mostly by community solar and grid-sited storage, with only intermittent reliance on the transmission system, would contribute the same amount to the cost of the transmission system as a similar community relying entirely on power generated at the transmission level. This cost allocation is fundamentally unfair, in that it assigns costs that are out of proportion to usage of or benefit from the system.
- Accurately convey price signals: In addition to being unfair, a system that allocates costs in a way that is out of proportion to usage or benefits sends inaccurate price signals and leads to misallocation of resources. In effect, allocating the TAC at the EUML creates a positive externality whereby an LSE that provides system benefits through reduced reliance on the transmission system is not able to capture those benefits. As such, LSEs have reduced incentive to deploy technologies that rely less – and thus impose fewer costs – on the transmission system.
- Implement federal transmission policy: FERC Order 1000 seeks to create efficiencies and reduce transmission costs by requiring regional planning and consideration of non-transmission alternatives that may be able to defer transmission investments at a lower cost. With no obligation to propose NTA solutions and no cost allocation mechanism, however, Order 1000 effectively cannot be implemented because no entity has a financial interest or other reason to propose NTAs. By changing the TAC billing determinant away from the EUML, CAISO could at least create some financial incentive to for LSEs to bring forth NTA solutions in regional transmission planning.

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

SolarCity has no additional comments.