Review Transmission Access Charge Wholesale Billing Determinant

Issue Paper

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Market & Infrastructure Policy

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1. Introduction and Background

The ISO is opening this initiative to consider whether to modify the billing determinant to which the ISO applies the transmission access charge (TAC) in its wholesale settlement process. The TAC is the ISO's mechanism for collecting revenues to compensate participating transmission owners (PTOs) for the costs of owning, operating and maintaining the transmission assets they have placed under ISO operational control. These costs are referred to collectively as the PTOs' "transmission revenue requirements" (TRR). Currently the TAC is designed as a volumetric rate that is charged to each MWh of internal load and exports, where internal load is the sum of end-use customer metered load data. This construct for recovering the TRR – i.e., a volumetric per-MWh charge to internal load and exports – is referred to as the TAC "billing determinant."

In October 2015 the ISO opened the TAC Options initiative to explore how to allocate costs associated with high-voltage transmission over a larger balancing authority area (BAA), which would be formed if additional transmission-owning utilities with load-service territories are fully integrated into the ISO.[1] In that initiative, Clean Coalition submitted comments arguing that the ISO should modify its calculation of internal load subject to the TAC. Instead of charging TAC to load measured at the end-use customer meters, Clean Coalition argued that the ISO should charge TAC to internal load measured at the transmission-distribution interface substation (the T-D interface), i.e., to a quantity they referred to as "transmission energy downflow" or TED.

With the proposed modification, the TAC billing determinant would be reduced by the amount of internal load that was offset by the energy produced by "local distributed generation" ("local DG"), which is comprised of DG connected on the utility side of the distribution system, as well as energy exported onto the distribution system by behind-the-meter generation, such as rooftop solar PV, during hours when that generation produces more energy than is consumed on-site in the same hour.[2] (The current method already excludes from TAC the load served by behind-the-meter generation that offsets load measured at the end-use customer meter.) Clean Coalition argued that this change is appropriate because the energy produced by local DG serves some of the metered load locally and does not rely on the transmission system. In the February 10 straw proposal for the TAC Options initiative, the ISO indicated its intention to

[1] All documents on the TAC Options initiative can be found at: http://www.ISO.com/informed/Pages/StakeholderProcesses/TransmissionAccessChargeOptions.aspx

[2] Energy generated by local DG would also affect the amount of electrical losses on the distribution system, but for simplicity at this stage of the initiative this paper ignores distribution losses. We will return to the subject of distribution losses later in the initiative as the need to address more precise calculation methodologies arises.

address this topic in the Energy Storage and Distributed Energy Resources Phase 2 initiative (ESDER 2).[3]

In discussing the Clean Coalition proposal in the March 22 ESDER 2 issue paper, the ISO noted three concerns. First, transmission infrastructure investment is driven mainly by peak load, not simply by MWh volumes. Adding utility-connected DG may offset some of the total energy that would otherwise come from the transmission grid, but may not reduce the peak load on the grid at all. Indeed, recent analysis of the impact of high amounts of solar PV indicates that peak load in some areas of the ISO system is being shifted to later in the day, after solar generation has declined. This means that the local DG may not reduce the system peak load, in which case it would not reduce the key driver of transmission infrastructure needs, and thus it would not be appropriate to collect TAC based only on TED as Clean Coalition advocates.

Second, current TAC rates reflect transmission infrastructure that has been planned, approved, built and placed in service to serve the load that existed or was forecasted at the time these investment decisions were made. The installation of DG at a later time to serve some of the load does not reduce any costs of the existing transmission facilities were built to serve that load.

Third, as a consequence of the previous point, using DG to serve load locally does not reduce the TRR that must be collected via TAC, which reflects the actual capital, maintenance and operating costs of existing transmission assets, and comprises the numerator in calculating the TAC rate. If the load associated with local DG were removed from the billing determinant (the denominator in calculating the TAC rate), the rate would increase for everyone else.

Many parties commented on this topic in their April 19 ESDER 2 written comments. Clean Coalition submitted extensive comments, which elaborated on their proposal and offered some numerical examples. The comments submitted by the other parties generally indicated whether the party tended initially to support or oppose the proposal, and in some cases raised concerns similar to those mentioned above. One additional point made by several parties was that this topic should not be included in ESDER 2, but should be addressed in a separate initiative that clearly identified TAC in its title, lest some parties who would otherwise be concerned with this topic overlook it because of its reduced visibility within an initiative dealing mainly with distributed energy resources.

The ISO has decided, based on these most recent stakeholder comments, to open this separate initiative to address the TAC billing determinant question raised and the proposal advocated by Clean Coalition. The present issue paper is intended to initiate substantive consideration and discussion of these issues with stakeholders.

The next section lists upcoming dates in this initiative. Section 3 describes how wholesale TAC settlement works today. Section 4 provides a brief overview of the Clean Coalition proposal, and section 5 offers simple numerical examples to illustrate how Clean Coalition's approach would affect the results of the settlement process. Section 6 then identifies policy and methodology questions to be considered in this initiative.

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[3] All documents on the ESDER 2 initiative can be found at: http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResourcesPhase2.aspx

2. Timetable of activities

Date	Activity
June 2, 2016	Post issue paper
June 14	Stakeholder conference call
June 17	Market Surveillance Committee meeting, discussing this topic
June 30	Written comments due
Dates TBD	ISO straw proposal and subsequent activities

3. How TAC settlements work today

It is useful to clarify how the TAC settlement process works today. The ISO assesses TAC based on end-use metered load, which differs from gross load in a very important and practical way.[4] If the end-use customer has behind-the-meter (BTM) devices such as rooftop solar PV, energy storage, or back-up generation that is used to offset some of the customer's energy consumption, the consumption served by those devices will not register on the end-use meter and so will not be subject to TAC.

In contrast, the term gross load is more appropriately used to mean the total energy consumed by the end-use customer, irrespective of whether that energy is supplied by an on-site device or comes from the distribution grid. It is important not to obscure this difference because gross load, used in this correct sense, plays a key role in planning and procurement activities in California and in the industry in general.

Next, it is important to understand that both federal (FERC) and state (CPUC) regulators play key roles in how TRRs are recovered. FERC approves each PTO's filed TRR, which sets the amount of money to be recovered through the chain of ISO wholesale TAC charges, retail transmission charges to end-use customers, and remittance of the funds to the PTO. FERC also approves the mechanism or billing determinant the ISO uses to assess the wholesale TAC.

At the same time, the CPUC sets the retail transmission charge as a component of the rate structure of each investor-owned utility (IOU). An important implication of this is 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. As the examples below will show, this aspect becomes interesting in the case where non-IOU load-serving entities (LSEs) serve retail customers within an IOU's service territory.

Today, independent LSEs that operate within an IOU service territories and use the IOU distribution systems to deliver energy to their retail customers – i.e., retail direct access electric service providers (ESPs) and community choice aggregators (CCAs) – have the option of performing the retail billing themselves or utilizing the retail billing services of the IOU utility distribution company (UDC) in whose territory they operate. In either case, as well as for an IOU

4 We note that both the ISO tariff and Clean Coalition (consistent with the ISO tariff) use the term "Gross Load" to mean the same thing as end-use metered load, which misses the distinction we describe in this section.

LSE, the LSE's scheduling coordinator (SC) provides the end-use metered load data to the ISO for settlement purposes.

If the non-IOU LSE performs its own retail billing, the ISO assesses TAC to the SC for the LSE commensurate with the end-use metered load data. The LSE then recovers the TAC costs from its retail customers. As long as the billing determinants used at wholesale and retail are the same, the LSE does not have any surplus or shortfall between what it collects from retail end-use customers and what it pays to the ISO. If, 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.

Alternatively, if the non-IOU LSE uses the IOU UDC billing service, the ISO assesses TAC to the SC for the UDC and the UDC collects the retail transmission charge from customers. In contrast to the previous case, in this case any shortfall or surplus resulting from a difference in the wholesale and retail rates and billing determinants will fall on the UDC rather than the LSE. If such surplus or shortfall is related to LSE procurement practices, however, the UDC will presumably need to redistribute the surplus or shortfall to the LSEs appropriately.

4. Brief overview of the TED-based TAC proposal

In comments submitted to the ISO on April 18 in the ESDER 2 initiative, Clean Coalition[5] proposed that the ISO assess wholesale TAC based on what they called "transmission energy downflow" (TED) measured at each transmission-distribution interface substation, rather than today's practice of assessing TAC on metered end-use load. The TED value at a given T-D interface for a given settlement interval would reflect the end-use metered load minus the energy produced by "local DG" (the sum of utility-side DG and any BTM generation that produced more energy than the load at the same customer site consumed during the same settlement interval), plus the energy delivered across the T-D interface that was lost due to distribution system thermal losses.

Clean Coalition also proposed the following provisions for implementing their approach.

> "First, the Clean Coalition suggests changing CAISO TAC billing from the LSE to the distribution provider.
>
> "Second, the distribution provider would need to properly allocate transmission costs to each LSE within their service territory in proportion to the transmission usage of LSE energy portfolios."

Per the explanation in the previous section, the mechanism proposed in Clean Coalition's first point already exists today as an option for non-IOU LSEs, though it is not required for all such LSEs. Clean Coalition's second point seems to recognize the issue raised at the end of the previous section, namely that the UDC could incur a surplus or shortfall between what it pays to the ISO for TAC and what it recovers from retail customers at the CPUC's approved retail rate,

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5 The complete Clean Coalition comment submission is available at the following link. Stakeholders are urged to read these comments in preparation for the discussions in this initiative. http://www.caiso.com/Documents/CleanCoalitionComments-EnergyStorageandDistributedEnergyResourcesPhase2-IssuePaper.pdf

and this surplus or shortfall would result from the use of local DG by LSEs with retail customers in the area. As we discuss later in this paper, solving this latter concern is not a trivial exercise.

The following examples illustrate how the Clean Coalition proposal would work in conjunction with either of the billing options available for LSEs today.

5. Examples to illustrate the TED-based TAC billing determinant

The following simple examples illustrate how the above discussion would work in practice. The examples build upon the following assumptions and simplifications.

1. There is a single IOU PTO distribution/transmission service territory.
2. The examples focus on a single ISO load settlement period (i.e., one hour).
3. The PTO's total TRR for the settlement period is $21,600. This number is chosen for convenience; any similarity to actual TRR for an actual PTO is purely coincidental. This TRR amount reflects the costs of existing transmission facilities only; in these examples we do not consider potential avoidance of future transmission upgrades.
4. The total end-use metered load (EUML) for the hour is 1440 MWh, which yields a wholesale TAC rate of $15.00 when divided into the TRR.
5. In example 1, total DG production for the hour is 60 MWh, for a TED value of 1380 MWh, which would yield a wholesale TAC rate of $15.65 for the same TRR if the TED-based billing determinant were adopted.
6. In example 2, we assume that all LSEs obtain 20 percent of their energy to serve load from local DG, for a total of 288 MWh of DG and a TED value of 1152 MWh, resulting in a TAC rate of $18.75.
7. The CPUC does not modify the retail transmission charge rate or billing determinant, irrespective of whether the ISO does or does not change the wholesale approach. Thus the UDC or the non-IOU LSE will charge retail transmission rates that are based on EUML and consistent with the $15.00 wholesale rate.
8. To give the example some different procurement scenarios, we consider three distinct T-D interface substations plus the rest of the system, with a different non-IOU LSE serving load at each interface in addition to the LSE function of the IOU.
9. The examples are simplified by ignoring distribution system losses.
10. The examples assume that when there are multiple LSEs serving load within the local distribution area served by a single T-D interface substation, we can accurately assign shares of the TED metered load to each of those LSEs. This is generally not possible today. First of all, the ISO does not receive settlement quality meter data (SQMD) for load at individual T-D interfaces. Second the ISO does not settle load on a nodal basis. Most wholesale load settlement uses either default load aggregation point (DLAP) prices or in some cases custom LAP prices. These are weighted averages of the locational marginal prices (LMPs) at the T-D interfaces that comprise the DLAP or custom LAP, and are applied to the total end-use metered load over the same set of T-D interfaces. Thus, although the settlement process envisioned in these examples is not conceptually impossible, the rules and principles for how to perform the calculations and the systems

for acquiring, communicating and processing the necessary data would need to be developed and implemented.

Example 1. Table 1 provides a summary of the load data to be used for settlement. In this example each of the LSEs relies to a different degree on local DG to serve their load, and as a result each LSE sees a different impact of the TED-based TAC compared to the current TAC billing determinant.

	Interface 1		Interface 2		Interface 3		Rest of System		Total MWh
	IOU	ESP1	IOU	ESP2	IOU	ESP3	IOU	ESPs	
End-use Metered Load (MWh)	100	40	150	10	120	20	1000	0	1440
DG Production (MWh)	20	15	0	10	15	0	0	0	60
Net Load at T-D Interface (TED)	80	25	150	0	105	20	1000	0	1380

Table 2 illustrates the financial settlements under the approach where the non-IOU LSE performs its own retail billing. With this approach there is no need for the UDC to allocate TAC revenue surplus or shortfall to the non-IOU LSEs.

	Interface 1		Interface 2		Interface 3		Rest of System	
	IOU	ESP1	IOU	ESP2	IOU	ESP3	IOU	ESPs
TRR charge by ISO to LSE per EUML	$1,500.00	$600.00	$2,250.00	$150.00	$1,800.00	$300.00	$15,000.00	$0.00
TRR charge by ISO to LSE per TED	$1,252.17	$391.30	$2,347.83	$0.00	$1,643.48	$313.04	$15,652.17	$0.00
LSE recovers from retail customers	$1,500.00	$600.00	$2,250.00	$150.00	$1,800.00	$300.00	$15,000.00	$0.00
LSE surplus or shortfall	$247.83	$208.70	($97.83)	$150.00	$156.52	($13.04)	($652.17)	$0.00

Table 3 illustrates the financial settlements under the approach where the UDC performs retail billing on behalf of the non-IOU LSE. With this approach the UDC would have to allocate shares of any TAC revenue surplus or shortfall to the appropriate LSEs.

	Interface 1		Interface 2		Interface 3		Rest of System	
	IOU	ESP1	IOU	ESP2	IOU	ESP3	IOU	ESPs
TRR charge by ISO to UDC per EUML	$2,100.00		$2,400.00		$2,100.00		$15,000.00	
TRR charge by ISO to UDC per TED	$1,643.48		$2,347.83		$1,956.52		$15,652.17	
UDC recoveres from retail customers	$2,100.00		$2,400.00		$2,100.00		$15,000.00	
UDC surplus or shortfall	$456.52		$52.17		$143.48		($652.17)	
LSE shares of surplus or shortfall	$247.83	$208.70	($97.83)	$150.00	$156.52	($13.04)	($652.17)	

<u>Example 2.</u> Table 4 provides a summary of the load data to be used for settlement. In this example all LSEs rely to the same degree on local DG to serve their load; i.e., 20 percent. As a result there is no impact of switching to the TED-based TAC method.

	Interface 1		**Interface 2**		**Interface 3**		**Rest of System**		**Total MWh**
	IOU	**ESP1**	**IOU**	**ESP2**	**IOU**	**ESP3**	**IOU**	**ESPs**	
End-use Metered Load (MWh)	100	40	150	10	120	20	1000	0	1440
DG Production (MWh)	20	8	30	2	24	4	200	0	288
Net Load at T-D Interface (TED)	80	32	120	8	96	16	800	0	1152

Table 5 illustrates the financial settlements under the approach where the non-IOU LSE performs its own retail billing. With this approach there is no need for the UDC to allocate TAC revenue surplus or shortfall to the non-IOU LSEs. But more to the point of this example, if all LSEs utilize local DG to serve the same percentage of their load, there is no impact of applying the TED-based TAC billing determinant.

	Interface 1		**Interface 2**		**Interface 3**		**Rest of System**	
	IOU	**ESP1**	**IOU**	**ESP2**	**IOU**	**ESP3**	**IOU**	**ESPs**
TRR charge by ISO to LSE per EUML	$1,500.00	$600.00	$2,250.00	$150.00	$1,800.00	$300.00	$15,000.00	$0.00
TRR charge by ISO to LSE per TED	$1,500.00	$600.00	$2,250.00	$150.00	$1,800.00	$300.00	$15,000.00	$0.00
LSE recovers from retail customers	$1,500.00	$600.00	$2,250.00	$150.00	$1,800.00	$300.00	$15,000.00	$0.00
LSE surplus or shortfall	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

We can draw some observations from the above examples.

1. For fixed amount of TRR, adopting the TED billing determinant would reduce the denominator of the TAC rate calculation and thereby increase the TAC rate.
2. Because we assumed the CPUC does not modify retail transmission rates and there is no change to the TRR amount to be collected, any difference between the TAC charged by the ISO at the wholesale level and the transmission revenues collected from retail customers will fall on the LSE serving retail customers in the area.
3. Under the approach where the UDC does the retail billing, assuming there is an accurate method for the UDC to allocate shares of any TAC revenue surplus or shortfall to the appropriate LSEs, the end result of the settlement is the same as it would be if the LSE does its own retail billing.
4. Applying TAC based on TED, with the assumption that TED shares at each T-D interface could accurately be assigned to each LSE serving load at the interface, would result in a financial surplus for an LSE that relies more on local DG within the same area where it serves load (i.e., the same T-D substation area), and a financial deficit for an LSE that uses less or no local DG in its load area.
5. When we look at example 2, however, in which all LSEs utilize local DG to serve the same percentage of their load, switching to the TED-based TAC billing determinant has no impact.

6. Questions raised by the TED-based TAC proposal

For purposes of this issue paper, the ISO is identifying a number of questions and issues for discussion with stakeholders, and requests that stakeholders provide their views on these in the upcoming discussions and in written comments. At this time the ISO is not offering proposed resolutions to any of these questions, but wants to be sure that all aspects and implications of the proposal are clearly articulated and visible to enable a thorough assessment of the merits of the proposal and development of the appropriate resolution. Likewise, the ISO does not claim that the list of issues and questions in this section is complete, and requests that stakeholders identify any additional questions or issues that need to be addressed that the ISO may have omitted from this document.

The questions below involve both the level of policy (objectives, principles, etc.) and the level of methodology and implementation. At this point, to get as many of the issues as possible on the table, the ISO has not tried to categorize the various issues.

1. What policy objectives should any change to the TAC wholesale billing determinant achieve? Clean Coalition's comments indicate that their proposal is needed to (a) enable fair comparison of renewable procurement options (particularly related to the application of the "least cost best fit" (LCBF) methodology), (b) develop distribution resources plans (DRPs), and (c) appropriately avoid and defer transmission and distribution investments.

   Similarly, some parties commented that DG offers benefits at the level of system costs (i.e., reduced losses and reduced need for transmission investment) as well as local environmental, economic and resilience benefits, benefits that are not reflected in the current TAC billing determinant.

How should these considerations figure into an assessment of possible changes to the TAC billing determinant? Are there other objectives that should be included?

2. What guiding principles should the ISO follow in developing any proposal to change the TAC billing determinant? Clean Coalition's comments refer to a "usage pays" principle, i.e., the principle that parties benefitting from use of the transmission system should pay for it. How does this principle apply to the TED-based TAC proposal? Are there other principles that should be included?
    a. Clean Coalition argues that end-use load that is offset by local DG does not benefit from the transmission system. Is it correct to say that such load gets *no benefit* from the transmission system?
    b. Alternatively, would it be correct to say that end-use load that is offset by local DG receives *less benefit* from the transmission system than load that is served by energy delivered across the T-D interface? If so, how might such reduced benefits be quantified?
    c. Since need for transmission infrastructure is driven by peak load rather than total energy consumed, would it be appropriate to assess the benefit provided by local DG and a corresponding reduction in TAC allocation based on the extent to which the local DG reduces peak loan at a given T-D substation?
3. Some stakeholders commented (in ESDER 2 comments) that any change to the TAC billing determinant should not result in a shift of costs among different parties who pay the TAC. Example 1 illustrates how the TED-based approach, for fixed amount of TRR, will shift some TAC costs from LSEs that utilize more local DG as a share of their end-use metered load to LSEs that utilize less. In contrast, example 2 illustrates how, if all LSEs use local DG to serve the same percentage of their load, the TED-based approach has no impact. If it is also true that load served by local DG relies less on transmission than other end-use load, how might a principle of avoiding cost shifts be balanced with the principle of cost-benefit alignment in the TAC billing determinant?
4. The examples provided above focus on allocation of TRR for existing transmission facilities; thus far we have not addressed the potential for local DG to offset or defer the need for new investment in transmission infrastructure. In considering changes to the TAC billing determinant, is it appropriate to distinguish between TRR for existing facilities and avoided costs of new transmission investment? How might this concept be applied in the design of a modified TAC billing determinant? For example, how could the effect of local DG adoption on reducing transmission investment be measured?
5. To paraphrase the over-arching argument advanced by Clean Coalition, they claim that adopting a TED-based TAC billing determinant will result in more favorable assessment, in LSE resource procurement decisions, of DG resources in comparison to transmission-connected resources. This more favorable assessment is appropriate because end-use load served by local DG does not rely on the transmission system and, moreover, local DG provides environmental, economic and resilience benefits that currently do not enter the procurement calculations. Changing the TAC to a TED-based billing determinant will stimulate more DG on the system, increasing the proportion of end-use metered load that is served by local DG, which will reduce the need for new transmission investment and thereby reduce future increases in transmission costs for all ratepayers.

The ISO recognizes that the above paraphrase of Clean Coalition's argument may be over-simplified, but believes that all of the lines of logic in the above paragraph need to be considered and commented on by stakeholders in order to have a complete, fair and transparent assessment of the pros and cons of adopting a TED-based wholesale TAC billing determinant. The ISO offers the present issue paper to provide a useful starting point for such an assessment.