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 Clean Coalition is a nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise. The Clean Coalition drives policy innovation to remove barriers to procurement and interconnection of distributed energy resources (DER)—such as local renewables, advanced inverters, demand response, and energy storage—and we establish market mechanisms that realize the full potential of integrating these solutions. The Clean Coalition also collaborates with utilities and municipalities to create near-term deployment opportunities that prove the technical and financial viability of local renewables and other DER.

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The following organizations and individual stakeholders are in general support of the Clean Coalition's TAC campaign and proposed approach.

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Environmental Defense Fund

Sierra Club

Local Energy Aggregation Network

350 Bay Area

Enphase

Center for Biological Diversity

Center for Climate Protection

Local Clean Energy Alliance

Sustainable Silicon Valley

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BBL Solar Design & Consulting

California Consumers Alliance

Californians for Energy Choice

Carbon Free Mountain View

Carbon-Free Palo Alto

Berkeley Climate Action Committee

Commercial Solar Design

Community Choice Partners

Community Renewable Solutions LLC

Dynamic Grid Council

East Bay Clean Power Alliance

Energy and Policy Institute

Institute for Local Self-Reliance

Integrated Resources Network

Menlo Spark

Microgrid Media

Microgrid resources Coalition

Mirasol Development LLC

Nutter Consulting

Preserve Wild Santee

Pristine Sun

San Diego Energy District

Simply SolarSLO Clean Energy

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<u>Issue Paper</u>

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

The Clean Coalition continues to support its proposal to shift the TAC billing determinant to TED. The proposal merits support for a number of reasons. First, the proposal would align TAC payments with usage, ensuring that the utilities benefitting from the transmission system are paying proportionally. Additionally, the proposal would also create a more level playing field for DG projects in procurement decisions by providing value for local projects. Additional DG investment would save ratepayers billions of dollars over the next 20 years through delayed or avoided transmission investments. Furthermore, the proposal would aid in the creation of Distribution Resources Plans and bring all utilities under CAISO jurisdiction consistent TAC treatment. We discuss each of these benefits in detail below.

A. The Clean Coalition proposal is more fair because it aligns the TAC system with the Usage Pays Principle

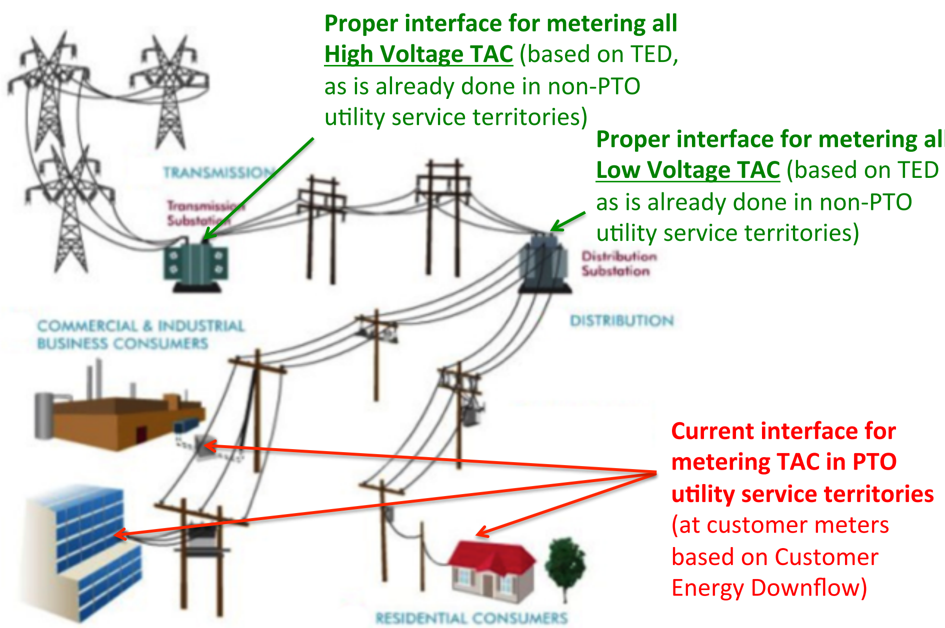
CAISO should assess transmission costs in proportion to measured usage of the transmission system and in line with the Usage Pays principle. Changing the TAC billing determinant to TED would ensure that the TAC system more closely aligns TAC liability with usage of the transmission system, resulting in a more fair cost-allocation system. CAISO's current billing determinant for TAC is the EUML or Customer Energy Downflow (CED),[1] which aggregates all energy used by end customers except for what they consume from their own behind-the-meter generation. This approach is not aligned with the Usage Pays principle because a customer's CED is not always drawn from the transmission system. The most important example of this is the part of a customer's CED that is served by DG resources, which connect directly to the distribution grid and do not rely on the transmission system. Since CED does not exempt energy from TAC liability, the customer is paying transmission charges on energy that does not actually use the transmission system.

[1] The Clean Coalition avoids use of the term Gross Load because of the potential for confusion across

The Usage Pays principle is established in Federal Energy Regulatory Commission (FERC) Order 1000 as well as in the original TAC design. FERC Order 1000 requires all regional and independent transmission operators to use a principles-based approach to allocating transmission costs, ensuring that costs are roughly commensurate with estimated benefits and that costs are not allocated involuntarily to ratepayers who do not benefit.[2]

CAISO applied the Usage Pays principle to its existing TAC system, but circumstances have since changed. When CAISO first began operating in 1997, almost all load was met with transmission-sourced energy, meaning that CED was a relatively accurate reflection of how much energy was sourced through the transmission system. With increased deployment of DG, however, the CED no longer reflects the quantity of energy actually using the CAISO system, and therefore no longer reflects the Usage Pays principle. The TAC fix aligns CAISO with FERC Order 1000 and the Usage Pays principle by ensuring that only transmission-sourced energy incurs a TAC, resulting in a more predictable and fair TAC system.

Importantly, the Clean Coalition proposal would allocate costs for each category of voltage in accordance to its use. For example, low voltage (LV) transmission revenue requirements (TRR) would be divided among the total kilowatt-hours of energy comprising the TED that flow from the low voltage transmission interface to the distribution grid. Similarly, high voltage (HV) TRR would be allocated among the TED comprised of energy flowing from HV transmission facilities to LV transmission facilities. The graphic below depicts both the current and the proposed metering points for all utilities under CAISO's jurisdiction.



Fixing the TAC billing determinant by changing it from CED to TED would also allow CAISO to fairly allocate the costs of any super-high voltage (SHV) transmission facilities under an expanded balancing authority area. CAISO is currently reviewing potential TAC options under an expansion to include some utilities outside of California. The Clean Coalition's

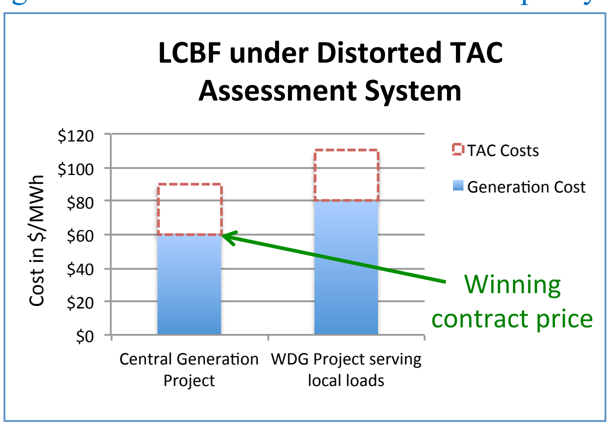
[2] Order No. 1000, *Transmission Planning and Cost Allocation*, 136 FERC ¶ 61,051, at p. 585 (2011).

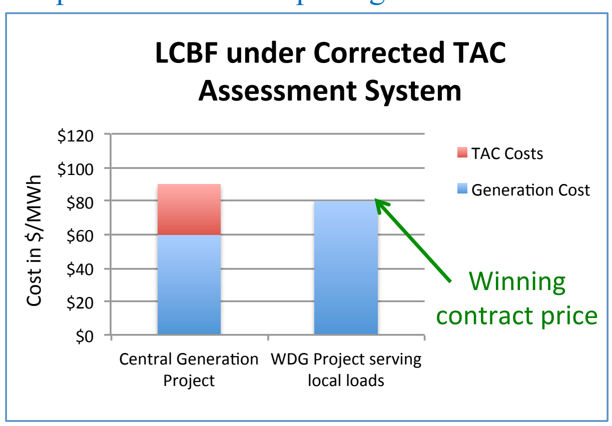
proposal could easily be extended to allocate costs for any new SHV transmission facilities based on the TED of energy from the SHV system to the HV system, ensuring that parties benefitting from the SHV facilities are carrying the costs. For example, costs of SHV transmission facilities should be allocated based on the energy down-converted from SHV transmission facilities to HV transmission facilities, or the TED at the SHV-HV interface. The Clean Coalition proposal would ensure just allocation of resources at varying voltage levels in alignment with the Usage Pays principle.

B. The Clean Coalition proposal would level the playing field for DG in utility procurement processes

The procurement playing field is not currently level because PTO utilities receive no credit for using DG to reduce their impact on the transmission system. This means that PTO utilities—and their customers—with higher penetrations of DG subsidize centralized generation by paying for transmission that centralized generation uses, but DG does not.

This subsidy plays a critical role in procurement decisions. Utilities evaluate the relative value of energy projects through a Least Cost Best Fit (LCBF) methodology. LCBF requires utilities to select resources that have the lowest cost and that best fit their system needs, subject to California Public Utilities Commission (CPUC) review and approval. However, when PTO utilities like Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) apply LCBF, they ignore TAC because all energy in these utility service territories is currently subject to TAC, regardless of whether energy is delivered through the transmission system. As a result, LCBF compares only the relative energy generation cost, adjusted by system losses and transmission upgrades that would be paid by ratepayers, and ignores the difference in transmission capacity and operation costs comprising TAC.





After CAISO modifies the TAC and receives FERC approval, the CPUC will not need to take any action to update the LCBF methodology. LCBF has a transmission cost component, which includes a TAC component that is currently identical for all projects. After reforming the TAC, the very next procurement decision using LCBF would reflect a TAC cost benefit for DG. Centralized generation would then have an LCBF transmission component that includes TAC, whereas transmission components for DG would not.

C. The Clean Coalition proposal would result in significant ratepayer savings by deferring transmission upgrades

The most significant impact of incentivizing the development of DG is the potential to defer or avoid transmission upgrades. The potential cost savings for consumers are enormous. For example, increased utilization of DER, most notably rooftop solar, has already resulted in PG&E canceling $190 million worth of low-voltage transmission upgrades in the 2015–2016 transmission planning process.[3]

The current TAC system fails to recognize the cost-saving potential of DG. Increased DG deployment results in savings by preserving existing transmission capacity, reducing demand for additional transmission investment, and lowering line losses. Without recognizing this cost-saving potential of DG, the lack of a TAC cost signal in procurement will result in excess investment in transmission resources over time, resulting in substantial and unnecessary costs to consumers.

Eliminating the TAC market distortion will result in increased deployment of DG, which will defer or avoid investments in transmission infrastructure and save California ratepayers billions of dollars in avoided transmission costs. Even a modest boost in DG annual growth will reduce the expected $80 billion ratepayer cost of new transmission investment over the next 20 years and slow the associated rapid growth of TAC rates. Further, the TAC rate could potentially decline as load growth is met with local resources and existing transmission assets depreciate.

D. The Clean Coalition proposal would aid in developing cost-effective Distribution Resource Plans

Public Utilities Code Section 769 mandates that electrical corporations file Distribution Resource Plans (DRP) to identify optimal locations for the deployment of distributed resources, including "distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies." Changing the TAC wholesale billing determinant would directly influence the DRP Locational Net Benefits Assessment (LBNA) methodology currently being implemented to identify the types, quantities, and locations of DER that offer the lowest net cost options to ratepayers in meeting customer needs. With additional cost-effective options, utilities will have more opportunity to develop and implement distributed generation as part of their DRPs.

On a related note, new DG resources are required to pay for 100% of any distribution grid upgrades required by their interconnection. Therefore, when DG resources win procurement decisions, the utilities and ratepayers benefit from cost-effective energy—as well as grid upgrades at no additional cost—further enabling distributed energy resources and additional flexibility in developing DRPs.

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[3] California ISO, *2015-2016 Transmission Plan* (Mar. 28, 2016), *available at* https://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf.

E. The Clean Coalition proposal would levy the TAC consistently across all utility service territories under CAISO's jurisdiction

CAISO currently assesses the TAC in different ways, depending on whether a utility is a Participating Transmission Owner (PTO). For example, CAISO assesses TAC on non-PTO utilities based on their Transmission Energy Downflow (TED), the amount of energy down-converted from the high voltage grid to the low voltage transmission grid and from the low voltage transmission grid to the distribution grid. Assessing TAC on Transmission Energy Downflow means that ratepayers appropriately pay TAC only on each kWh of energy delivered through CAISO's transmission system.

In contrast, PTO utilities are inappropriately assessed TAC based on EUML or Customer Energy Downflow (CED) as measured at customer meters. CED is the aggregate of customer energy usage measured by customer meters (not including behind-the-meter generation that is consumed on site), but including energy that was generated on the distribution grid, such as net energy metering (NEM) exports from other locations. As a result, PTOs pay TAC on every kilowatt-hour delivered at the customer level, even if that energy was not delivered through the transmission system. This disconnect between usage and paying TAC is the reason for reviewing this issue and attempting to align the TAC system in PTO utility service territories with the Usage Pays principle. Implementing the Clean Coalition's TAC fix would result in a single, consistent TAC practice under CAISO's jurisdiction by bringing all utilities under the TAC treatment currently reserved for non-PTO utilities.

2. <u>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.</u>

The Clean Coalition's argument is that the volumetric basis for transmission charges should consistently reflect the volumetric usage of the transmission system as measured by the MWh of TED. Currently, when a load-serving entity (LSE) reduces delivery of electricity MWh from the transmission system through energy efficiency, this is appropriately reflected in a proportional reduction in TAC. However, when an LSE achieves the same reduction in transmission usage through the use of DG, they do not receive the same reduction in TAC.

Using TED as the wholesale billing determinant rather than EUML or Customer Energy Downflow (CED) is better aligned with the Usage Pays principle because TED marks the end of the transmission system and therefore better reflects transmission usage related to the quantity of energy delivered through the transmission system. As mentioned above, the CED approach is not aligned with usage because a customer's metered energy may not always utilize the transmission system—a small but significant amout of Customer Energy Downflow is served by DG.

End-use load offset by DG benefits from the transmission system only in proportion to its <u>use</u> of the transmission system, and TAC payments should be aligned accordingly. Therefore, when a utility uses transmission-sourced energy to meet 95% of its load, it should only incur TAC liability for 95% of its load. The best way to capture this is to use TED as the TAC billing determinant. The current EUML approach fails to differentiate between local and remote transmission-dependent resources, masking the impact on transmission investment driven by procurement of remote resources. This lack of recognition for avoiding delivery of energy through the transmission system discourages LSEs from procuring local resources, and this failure to differentiate between these resource choices disproportionately assigns the costs associated with energy delivery.

The TED proposal offers a clear and simple solution where utilities pay TAC in proportion to the amount of energy they pull from the transmission grid. This is the most straightforward method to quantify how much each utility benefits from the transmission system. The method is consistent with the established volumetric basis for TAC and has already been employed by CAISO for the non-PTO utilities.

In contrast, any change in the underlying TAC structure from a simple per-kilowatt hour charge would necessarily be more complicated, and would likely require the addition of a separate tie-in or backfeed option charge to the current fee structure. This alternative would require a more fundamental change to the TAC structure, as well as additional effort to identify a suitable alternative. For these reasons, the Clean Coalition recommends simply changing the wholesale billing determinant rather than pursuing alternative pricing structures.

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.

As previously noted, the current Customer Energy Downflow (CED) approach fails to differentiate between local and transmission dependent resources, masking the impact on transmission investment driven by procurement of remote resources. This lack of recognition for avoiding delivery of energy through the transmission system discourages LSEs from procuring local resources. Adoption of the TED billing determinant would clearly indicate transmission delivery costs and would allow appropriate consideration of differences in delivery costs in procurement decisions.

The LCBF methodology is the approach employed to reflect the relative ratepayer costs of proposed energy projects, and a change in the TAC billing determinant would result in a reduction in actual LSE and ratepayer delivery costs associated with DG procurement. The LCBF is simply a means for cost differences to be considered in utility procurement decisions.

4. 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.

The opportunity for an LSE to reduce transmission charges will improve the competitiveness of DG solutions when LSEs seek energy supplies, which will in turn result in higher levels of local generation than would otherwise occur. To the degree that increases in demand are met through local resources and programs, the need for new transmission facilities will be reduced or deferred, and the savings will be distributed in direct proportion to each LSE's reliance on local and transmission-sourced energy.

Changing the TAC billing determinant to TED would result in an immediate decrease in the LSE's total delivered cost of energy from DG resources and would send a significantly advantageous price signal in favor of non-transmission resources in procurement decisions. It is not clear exactly how much additional DG a change in the TAC billing determinant would attract, but a modest projection of 10% annual growth in local renewable energy generation would result in significant impacts after ten years, as illustrated in the example below.

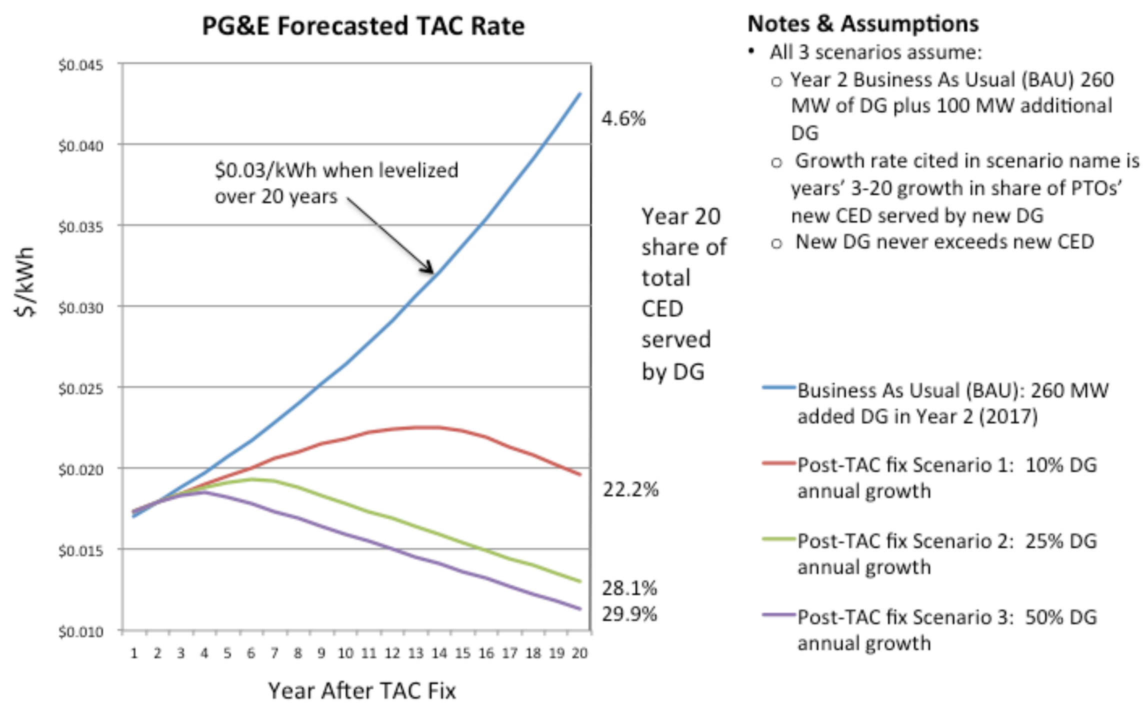
This example shows the long-term impact on a variety of LSEs, including utilities like PG&E as well as community choice energy providers like Marin Clean Energy. Using current and projected PG&E TAC rates and projected DG deployment, the Clean Coalition estimated that a 10% annual increase in DG growth over the business-as-usual baseline would result in a 8.3% decreased transmission revenue requirement over a 10 year period.

Note that the TRR growth in the bottom half of the chart is reduced due to 10% annual growth in DG under the TED approach, resulting in lower total TAC payments, allocated in proportion to each LSE's transmission use and local generation procurement. Importantly, almost all LSEs experience significant savings due to the substantially reduced TRR.

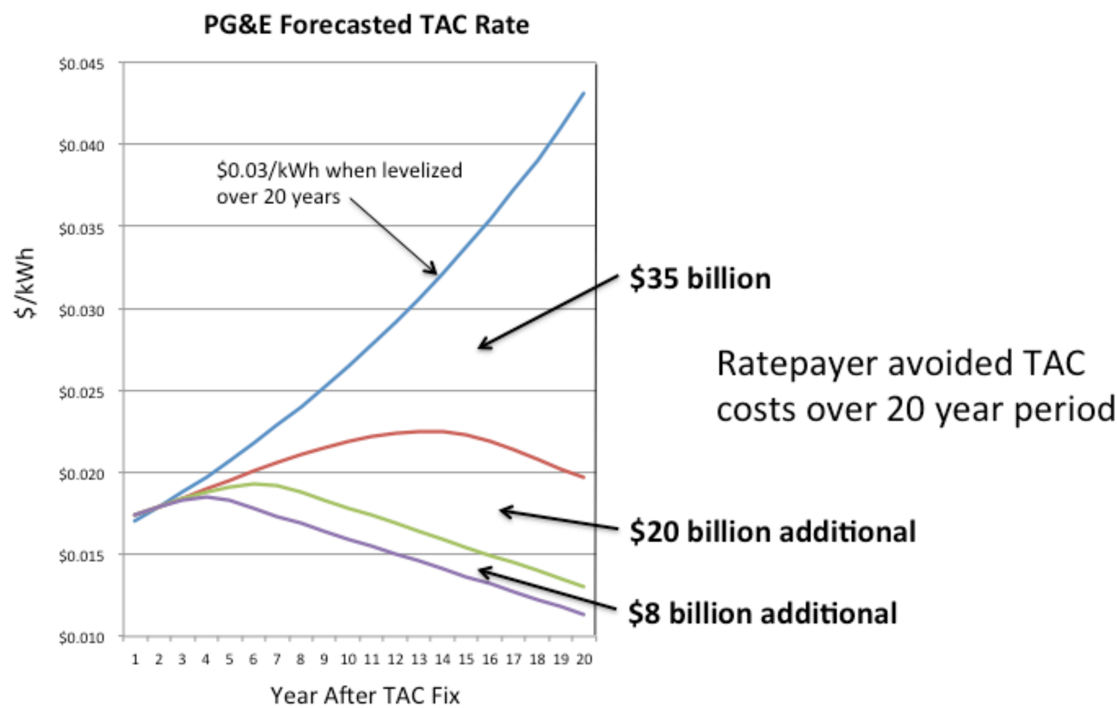
2026 SCENARIO - Impact Comparison

		Business as Usual Case Transmission Revenue Required: $2,640,000 (2026 projected)				**TED Billing Determinant Case** Transmission Revenue Required: $2,420,000 (reduced due to DG meeting a share of load growth)				
LSE	**DG (MWh)**	**LSE EUML (MWh)**	**% Share of Total EUML**	**TAC Rate per MWh (2026 projected)**	**TAC payments (in thousands)**	**TED (MWh)**	**% Share of Total TED**	**TED-based TAC Rate per MWh (2026 projected)**	**New TAC payments (in thousands)**	**% of LSE EUML subject to TAC**
IOU	4	70	64%	$24.00	**$1,680**	66	66%	$24.20	**$1,597 (-$83)**	94%
CCA	6	30	27%	$24.00	**$720**	24	24%	$24.20	**$581 (-$139)**	80%
ESP	0	10	9%	$24.00	**$240**	10	10%	$24.20	**$242 (+$2)**	100%
Total	10	110	100%	$24.00	**$2,640**	100	100%	$24.20	**$2,420 (-$200)**	91%
Notes	9% energy sourced below T-D interface (10% annual DG growth rate from 2016)	Current TAC billing determinant	Share of total TAC (now)	TRR/EUML; reflects CAISO's projected 7% annual TAC increase	TAC Rate x EUML	Proposed TAC basis	Share of total TAC (proposed)	TRR/TED; TRR is reduced due to DG meeting share of load growth	New TAC Rate x TED	

The key long-term impact of the Clean Coalition proposal is that both the TRR and the TAC rate would decline significantly over time relative to business as usual. Changing the TAC assessment point eliminates the TAC market distortion that currently undervalues DG resources in PTO utility service territories and results in increased deployment of local renewables. In addition, higher penetrations of DG would slow the need for additional investments in transmission infrastructure and result in substantial avoided transmission costs for all ratepayers over time—significantly slowing the alarming growth in TAC rates, and potentially even lowering it. Clean Coalition analyses show that a 10% annual growth rate of DG would save California ratepayers at least $35 billion in avoided transmission costs over 20 years—including ratepayer costs for capital investment in infrastructure and PTO return on equity—which is illustrated in the TAC impact graphs below. The first chart below shows the large reductions in TAC rates achieved over 20 years by eliminating the TAC market distortion and assuming 10% annual growth in DG, thereby increasing the share of LSE load met by DG resources in 2036 from 4.6% to 22.2%.



In the second chart, the area between the blue curve and the other curves represents avoided ratepayer transmission costs over the 20-year period.



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>

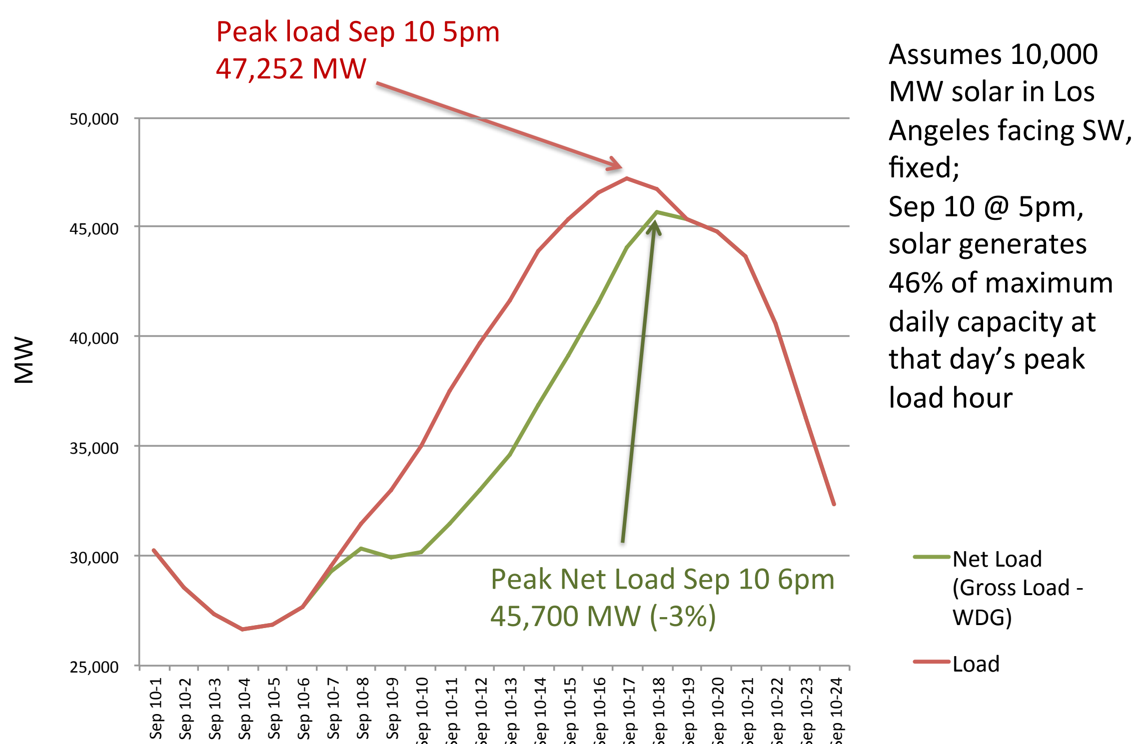
The Clean Coalition recognizes that peak load is a significant driver of transmission investment, but exempting load offset by DG from TAC only based on how much it reduces peak load conflates two separate concepts: TAC as a usage fee, and incentives for reducing peak load.

The current TAC system was designed as a per-kilowatt-hour volumetric usage fee and intentionally includes no peak load component. The TAC cost recovery system is not designed or intended to incentivize changing peak load conditions. Redesigning the system to incorporate a peak load component addresses a different issue than this initiative, and the two matters should not be conflated.

Proposals for the addition of a peak load factor in TAC assessments are beyond the scope of the volumetric billing determinant correction recommended by the Clean Coalition, and the potential for subsequent future consideration and development of any such proposals in no way warrants delay in correcting the volumetric component of TAC. The proposed correction would neither conflict with nor be negated by the addition of a peak demand component in the future.

Peak loads also reflect Time of Delivery rates in procurement contracts and Time of Use rates in consumption. Each factor's contribution and their interaction should be considered in broader policy development, integrated resource planning, and market design. This overarching coordination is being addressed in other stakeholder processes and CPUC proceedings that would benefit from the proposed TED correction to the billing determinant.

That said, we note that additional local renewables do reduce load on the transmission system, including peak loads. As such, the change in billing determinant will broadly contribute to a positive impact on peak transmission loads. In the case of local solar, more than 30% of solar nameplate power production contributes to reducing peak transmission usage, which occurs during the later part of daylight hours. Increasing deployment of local solar, therefore, slows or avoids the need for additional transmission capacity investment. For example, CAISO's peak load for 2015 was September 10th at 4:53pm, and though not operating at peak capacity, local solar resources were producing energy to help meet the peak Transmission Energy Downflow, or TED. For example, a typical 1 MW_{DC} west-facing rooftop solar installation in Burbank, California, would still produce 354 kW_{AC} at 5pm on a typical September 10th day.[4] Peak loads typically occur during the months of July and August when solar generation would be even greater in the late evening, but wholesale distributed generation (WDG) and NEM systems substantially reduce peak TED at all seasons in which peak TED might occur in California. The chart below displays the relationship between the solar generation profile and the 2015 peak net load.



[4] Based on NREL System Advisor Model, standard PV Watts configuration, TMY 3 solar irradiance 8760 hourly data. Output varies by date, location, and orientation.

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>

The Clean Coalition urges CAISO to adjust the TAC wholesale billing determinant now rather than working to incorporate a peak load measure to the TAC system. The peak load measure is a separate, broad issue far beyond the comparatively narrow problem of TAC impact on DG. The immediate TAC reform is straightforward and should be resolved immediately, regardless of whether CAISO opts to undertake a more long-term effort to consider incorporating a separate peak load demand charge.

As mentioned above, redesigning the system to incorporate a peak load component addresses a different issue than this initiative. The two matters are complimentary but distinct, should not be conflated, and may be appropriately addressed separately. Delaying correction of the volumetric component of TAC is not warranted, and continued reliance on the EUML or Customer Energy Downflow (CED) approach will result in additional avoidable long-term TAC rate increases while negatively impacting statewide Distribution Resource Plans, major utility DPR pilot programs, and long term procurement decisions by LSEs.

Furthermore, multiple tools to incentivize reduced peak load conditions are currently under development at CAISO and the CPUC. Peak demand, load profiles, ramping, and coordination of loads with generation resources and costs are topics being addressed by the CPUC through Time-of-Use (TOU) and Time of Delivery rate structures, procurement, and customer incentives. As California develops a new Integrated Resource Plan, TOU customer billing, and Integrated Distributed Energy Resources programs, the state will increasingly realize opportunities to align loads with the generation profiles of generating resources, energy storage, and demand response.

7. <u>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.</u>

First, it is important to note that the TAC proposal functionally removes an existing cost shift, where costs that should fall on transmission-sourced energy are partially shifted to DG. Utilities are paying the same fees for transmission usage regardless of how much they rely on DG to meet local load, and the same utilities receive no credit for reducing transmission usage and freeing up transmission capacity.

Second, there will be a negligible shift in transmission costs if the TED billing determinant is adopted, but that shift would reflect appropriate cost allocation among beneficiaries of the transmission system. Costs would shift from LSEs with significant DG profiles to LSEs with little to no DG resources, in proportion to how much each LSE relies on the transmission system.

The most appropriate balance of avoiding cost shifts with the principle of cost-benefit alignment is to align the TAC structure with the Usage Pays principle. The existing TAC system was designed to reflect the Usage Pays principle, and it worked well when EUML was a reasonable representation of how much each utility actually used the transmission system. However, this method is no longer reasonable. Adopting a wholesale billing determinant that aligns cost-causation with transmission usage is far more defensible than operating under an obsolete attempt to align costs and benefits.

Any immediate change in cost responsibility would be proportional to the difference in current DG penetration between PTO utilities. Current DG penetration for the PTO utilities is less than 2%, meaning that the difference in DG penetration would be far less than the proportional change seen in the Issue Paper's Example 1. Any actual cost shift would likely be a fraction of a percent between utilities, and would be an appropriate incentive for making transmission capacity available. The TAC proposal incentivizes LSEs to use transmission only when cost-effective, or to fulfill customer demand from local distributed energy resources. This will ensure that the cost impact appropriately depends on the amount of DG being used by each LSE.

As a more realistic example of the potential cost shift, we provide the following examples. In this chart, we modeled a single PTO utility service territory that has customers served by three LSEs: the PTO investor-owned utility (IOU), a Community Choice Aggregator (CCA), and an Energy Service Provider (ESP). The columns in blue the status quo, and the columns in green reflect the changes if TED becomes the TAC billing determinant.

2016 Scenario - Impact Comparison

		Business as Usual Transmission Revenue Required: $1,650,000				**TED Billing Determinant Case** Transmission Revenue Required: $1,650,000 (a change in TAC billing determinant does not affect TRR)				
LSE	**WDG (MWh)**	**LSE EUML (MWh)**	**% of Total EUML**	**TAC Rate (now) per MWh**	**TAC payments (in thousands)**	**TED (MWh)**	**% of TED**	**New TAC Rate (per MWh)**	**New TAC payments (in thousands)**	**% of LSE EUML subject to TAC**
IOU	1.4	70	64%	$15.00	**$1,050**	68.6	64%	$15.28	**$1048 (-$2)**	98%
CCA	0.6	30	27%	$15.00	**$450**	29.4	27%	$15.28	**$449 (-$1)**	98%
ESP	0	10	9%	$15.00	**$150**	10	9%	$15.28	**$153 (+$3)**	100%
Total	2	110	100%	$15.00	**$1,650**	108	100%	$15.28	**$1,650**	98%
Notes	2% is the highest percentage of EUML met by DG in a PTO utility service territory today	Current EUML TAC basis	Share of total TAC basis (now)	TRR/EUML	TAC Rate x EUML	Proposed TAC basis	Share of total TAC basis (proposed)	TRR/TED	New TAC Rate x TED	

This example highlights three immediate results from the Clean Coalition proposal. First, the change in TAC basis does not affect the TRR. The Clean Coalition proposal causes no increase in the total TAC revenue recovered from all LSEs. Regardless of how usage is measured, the TAC rate will always result in recovery of the entire TRR from LSEs. The initial total aggregated TAC would still equal the current TRR. As always, TRRs are guaranteed and will continue to be fully recovered. The difference over time, however, is that WDG and NEM exports grow faster by eliminating the market distortions that currently disadvantage them, and less transmission investment leads to lower TRR and TAC for all ratepayers over time.

Importantly, changing how TAC are assessed would not cause existing transmission facilities to be underutilized. WDG and NEM exports together currently provide less than 2% of the energy provided by utilities. Additional DG will serve load growth, but DG is highly unlikely to grow fast enough to outpace load growth, meaning that there will be a continued need for central generation and transmission infrastructure at existing—and possibly even higher—levels. However, additional DG will slow the pace at which additional transmission infrastructure may be needed. Since total demand for electricity continues to increase, the Clean Coalition's analyses all show WDG and NEM exports growing at a rate that never exceeds CAISO load growth. Transmission-dependent central generation would then be left to provide for the current load and repowering requirements, and existing transmission would continue to be robustly utilized. There is no plausible local generation growth scenario in which the change in TAC measurement would lead to stranded transmission assets or costs.

Second, the initial TAC rate increases, but barely. By changing the TAC basis to TED, the denominator in the TAC rate formula would decrease to the extent that there is existing WDG and NEM exports, and the TAC rate would increase accordingly, since the per kilowatt-hour TAC rate is set by dividing the TRR by total kilowatt-hours of usage. If usage were consistently measured via TED as the Clean Coalition proposes, the TRR numerator would remain unchanged, but would initially be spread across a slightly smaller (less than 2%[5]) denominator, so that the TAC rate would increase by a similarly slight amount (less than 2%). This can be seen in the example by comparing the original TAC rate of $15.00/MWh to the new TAC rate of $15.28/MWh. Given that most LSEs are meeting negligible levels of their loads from DG resources, actual TAC rates would increase by significantly less than 2%. For example, PG&E has robust ReMAT and NEM participation, but is projecting to meet only 1.8% of its total electric load with DG by the end of 2016.

The change in total TAC payments between PTO utilities would be no greater than the current difference between their shares of loads served by WDG and NEM exports, which the Clean Coalition expects to be a fraction of a percent. Some LSEs will pay negligibly more or less

[5] According to Distribution Resources Plan filings, the highest percentage of Gross Load met by WDG plus NEM exports in a PTO utility service area is less than a 2% in California, so the maximum projected change in TAC rate would be less than 2%. Importantly, TRRs, which equal aggregate TAC payments, do not change at all.

in TAC, due to differences in portfolios of WDG and NEM exports.[6] This can be seen by comparing current TAC payments to the newly proposed TAC payments. In our example, the LSEs with WDG resources (i.e., the IOU and the CCA) each saw a decrease in payments of less than $2,000 or 0.8%, and the ESP saw an increase in total payments of $3,000 or 2%. Any adjustment, no matter how negligible, simply corrects current inaccuracies in accounting for each utility's contribution to transmission costs. In the future, all utilities will have clear market signals to procure energy based on lowest total cost of energy plus delivery—opting to either procure transmission-dependent generation and pay TAC, or to pursue DG and avoid TAC.

Third, the TAC allocation between ratepayers within the same LSE does not change at all. In passing the TAC payment through to ratepayers, LSEs divide their total TAC liability by the LSE CED to produce a transmission cost rate, which is then charged to customers based on an LSE's self-determined basis. Unless a LSE decides to allocate transmission costs differently—like providing credit for customers that participate in local renewables offerings that avoid transmission costs—all of the LSE's customers will experience exact same transmission costs. It is likely that as LSEs expand procurement of local renewables, then customers participating in local renewables programs will benefit from the value of those local renewables in avoiding TAC.

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.

   A third alternative need not be considered at this time.

[6] The major investor-owned utilities have published information citing the following contracted ReMAT capacity as of March 1, 2016:

- Pacific Gas & Electric: 41.331 MW (http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/ReMAT/index.page)
- Southern California Edison: 27.851 MW (https://sceremat.accionpower.com/ReMAT/doccheck.asp?doc_link=ReMAT/docs/FIT/2013/documents/i.%20Capacity%20and%20Price%20Calculations/ReMAT%20Capacity%20Calculations%20Program%20Period%2015.pdf)
- San Diego Gas & Electric: 14.95 MW (http://www.sdge.com/regulatory-filing/654/feed-tariffs-small-renewable-generation)

Additionally, they have submitted the following progress towards meeting the NEM program limits of 5% of aggregated customer load:

- PG&E: 1,952.56 MW (http://www.pge.com/en/mybusiness/save/solar/nemtracking/index.page)
- SCE: 1,334.9 MW (SCE Advice Letter 3391-E)
- SDG&E: 547.4 MW (SDG&E Advice Letter 2879-E)

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.

We note that the central objective behind this proposal is not to create an "incentive to develop more DG" but: 1) to properly allocate transmission costs in accord with FERC principles,[7] and 2) to establish appropriate market pricing signals to reflect actual costs of delivering energy in procurement decisions, in order to determine the most cost effective balance between transmission and non-transmission resources. The current Customer Energy Downflow (CED) basis for TAC fails these tests and creates a market price distortion in favor of transmission-reliant resources that actively discourages development of DG and artificially drives demand for additional transmission and associated increases in transmission costs.

Under the current approach, TAC rates have increased dramatically since 2000, with HV rates statewide increasing from less than \$2/MWh to more than \$10/MWh. CAISO has projected a 7% annual growth in HV TAC rates, and regional LV transmission TRR are comparable. If current trends continue the cost of transmission will approach and ultimately exceed the cost of energy, underscoring the importance of addressing the factors driving the increases in TAC rates. The market distortion created by the EUML or CED billing determinant is not the only factor, but a solution is important to address the growth in TAC rates.

After CAISO makes the TAC fix and FERC approves it, the CPUC will not need to take any action to ensure that the LCBF, LBNA, and other cost effectiveness methodologies incorporate the TAC fix because these evaluations have a transmission cost component. However, the current EUML or CED basis for TAC assessment, which is currently identical for all PRO utility methodologies, masks actual ratepayer impacts. After CAISO makes the TAC fix, procurement decisions using LCBF and LNBA will reflect a TAC cost benefit for DG. Centralized generation would then have a transmission component that includes TAC, whereas DG would not.

The Clean Coalition supports refinements in planning, procurement, and cost effectiveness methodologies to improve recognition of the costs and benefits of all resource options. A change in the TAC billing determinant will be an important step in achieving this.

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

Multiple policy objectives would be accomplished by changing the TAC wholesale billing determinant to the TED. These objectives are explained in detail above in response to Question 1 and are listed briefly below. The most important policy objective is to provide appropriate market pricing signals that align the TAC system with the Usage Pays principle and ensure that TAC volumetric assessed liability directly reflects actual volumetric use of the

[7] Order No. 1000, *Transmission Planning and Cost Allocation*, 136 FERC ¶ 61,051, at p. 585 (2011).

transmission system. This is an important component in successful overall application of cost effectiveness methodologies.

The objectives should also include the following:

- Save billions for electricity customers by avoiding transmission investments and deferring transmission upgrades
- Aid in developing cost-effective Distribution Resource Plans
- Increase fairness by aligning the TAC system with the Usage Pays principle
- Bring consistent TAC treatment to all utility service territories under CAISO's jurisdiction, including for the anticipated superhigh voltage TAC associated with an expanded CAISO
- Level the playing field for DG in utility procurement processes
- Provide consistent treatment of energy efficiency and DG for LSEs

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

As stated previously, the most important principle in evaluating possible changes to the TAC billing determinant is to ensure that TAC liability directly relates to actual use of the transmission system. See the response to Question #1 for additional detail.

FERC Order 1000 outlines six general transmission cost allocation principles (internal citations omitted):

1. *The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs.*
2. *Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities.*
3. *If a benefit to cost threshold is used to determine which facilities have sufficient net benefits to be included in a regional transmission plan for the purpose of cost allocation, it must not be so high that facilities with significant positive net benefits are excluded from cost allocation. A transmission planning region or public utility transmission provider may want to choose such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a greater ratio.*
4. *The allocation method for the cost of a regional facility must allocate costs solely within that transmission planning region unless another entity outside the region or another*

transmission planning region voluntarily agrees to assume a portion of those costs. However, the transmission planning process in the original region must identify consequences for other transmission planning regions, such as upgrades that may be required in another region and, if there is an agreement for the original region to bear costs associated with such upgrades, then the original region's cost allocation method or methods must include provisions for allocating the costs of the upgrades among the entities in the original region.

5. *The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.*
6. *A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional plan, such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements established by state or federal laws or regulations. Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this Final Rule.*[8]

Additionally, it is important to remember that all transmission revenue requirements will continue to be met and that changing the TAC billing determinant to TED would not cause existing transmission facilities to be underutilized. Current DG energy production provides less than 2% of the energy provided by utilities. As noted above, additional DG will serve load growth but is highly unlikely to outpace load growth, meaning that there will be a continued need for central generation and transmission infrastructure at current—and possibly even higher—levels. However, additional DG will slow the pace at which additional transmission infrastructure is needed, saving ratepayers significant amounts of money. Since total demand for electricity will continue to increase, the Clean Coalition's analyses all show that DG projects grow at a rate that never exceeds projected CAISO load growth, leaving transmission-dependent central generation to provide for the current load and repowering requirements, and for existing transmission to continue to be robustly utilized. There is no plausible local generation growth scenario in which the change in TAC measurement would lead to stranded transmission assets or costs.

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

    No further comment at this time.

[8] *Id.*