# Stakeholder Comments Template

| Submitted by | Company | Date Submitted |
|---|---|---|
| Katherine Ramsey<br>(202)709-8063<br>katie@clean-coalition.org<br><br>Sahm White<br>(831)425-5866<br>sahm@clean-coalition.org<br><br>Doug Karpa<br>(415)860-6681<br>doug@clean-coalition.org | Clean Coalition | July 26, 2017 |

Please use this template to provide your written comments on the stakeholder initiative:

**"Review Transmission Access Charge Structure"**

Submit comments to InitiativeComments@CAISO.com

**Comments are due July 26, 2017 by 5:00pm**

**A broad range of organizations support the goal of correcting the CAISO tariff language to assess Transmission Access Charges (TAC) on a utility's metered TED, better aligning charges with cost causation. The positions expressed herein are consistent with those expressed in the prior stakeholder process. Supporters designated with an * confirmed review and endorsement of these specific comments, and no supporters expressed disagreement.**

350 Bay Area
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Appraccel
BBL Solar Design & Consulting
Berkeley Climate Action Coalition
California Alliance for Community Energy
California Consumers Alliance
Californians for Energy Choice
Carbon Free Mountain View
Carbon-Free Palo Alto
CalSEIA
Center for Biological Diversity
Center for Sustainable Energy
Civic Solar
Commercial Solar Design
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Community Environmental Council
Community Renewable Solutions LLC
Dan Kammen (UC Berkeley Energy & Resources Group)*
Dynamic Grid Council
Earthwise Energy
East Bay Clean Power Alliance
eMotorWerks
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TeMix
Terra Verde Renewable Partners
UCLA Luskin Center for Innovation
Voltaic Capital Markets LLC
Vote Solar
Yaskawa Solectria Solar

## General Comments

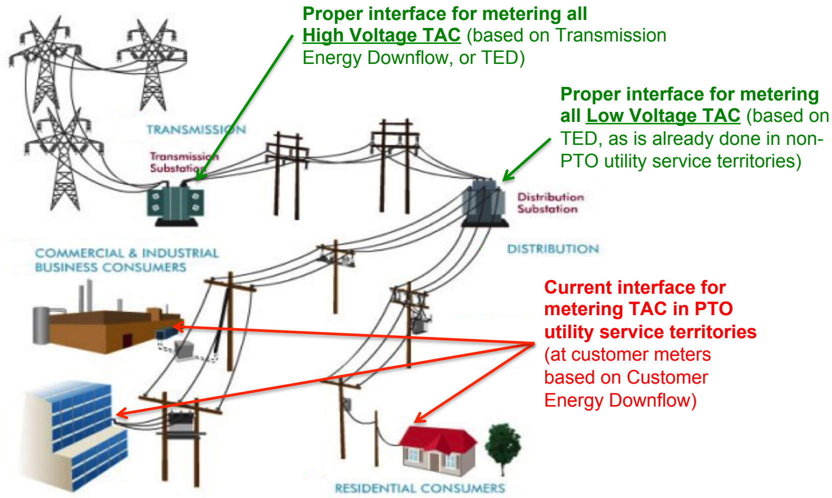
### I. CAISO should first change the point of measurement of transmission usage to the end of the transmission grid before considering how to calculate transmission fees.

CAISO should first change where usage is measured as the basis for calculating transmission access charges (TAC), regardless of how charges for that usage of the transmission grid is ultimately calculated. Changing the measurement of transmission usage to the end of the transmission grid by using transmission energy downflow (TED, or the hourly load flowing from the transmission-distribution interface substation) is a discrete and fundamental issue that can and should be addressed first.

As currently scoped, there are two basic issues to be addressed in this initiative: (1) *where* to measure transmission usage, and (2) *how* to measure transmission usage. Where to measure transmission grid usage is a straightforward and simple issue that can be resolved independently of the more complex and technical issue of how best to adjust the underlying TAC structure—based on total downflow, peak downflow or other bases. Resolving the measuring point first would resolve three pressing issues. It would establish a consistent TAC basis for all customers throughout CAISO territory. It would correct the fundamental inability of customer energy downflow (CED) or the end-use customer metered load to accurately measure transmission grid usage. Last, it would better reflect the contributions of distribution energy resources (DER) in reducing transmission usage and future investments. The Clean Coalition looks forward to contributing to addressing the question of how to measure transmission usage—whether volumetric, demand-based, or a hybrid approach—but the much more direct and simple problem of where usage is measured is a necessary precursor to that discussion.

### II. The best location to measure transmission usage is at the boundary of the transmission grid, not the customer meter.

Transmission energy downflow (TED) is the only rational metering point for measuring transmission grid usage and best reflects good rate design principles. Regional, high voltage transmission grid usage should be measured at the end of the high voltage transmission grid, and measurement of usage of the low voltage transmission grid should be measured at the transmission-distribution interface. The transmission grid boundaries provide consistent, unbiased, and technology-neutral points of assessment for measurement of transmission usage. Regional TAC (costs associated with CAISO-operated facilities operating >200 kV), the TED should be measured at the substations connecting Regional facilities to Local facilities. For Local TAC (costs associated with CAISO-operated facilities operating ≤200 kV), the TED should be measured at the transmission-distribution interface substation.




Historically, the CED billing determinant was a useful proxy for measuring usage of the transmission grid in an era when all of California's energy came from central resources. Today, however, the recent growth of California's distributed generation (DG) output means that CED is no longer a useful reflection of transmission usage. Since a major benefit of DER is avoiding new, expensive transmission investments, the transmission usage should not include output from resources that expressly avoid delivery over the transmission grid. Thus, CED is no longer appropriate the appropriate measure of transmission grid usage to allocate transmission costs. Instead, transmission charges should reflect transmission usage, and transmission costs should be based on metering at the end of the transmission grid. The cost allocation principles outlined in the Issue Paper are best realized by using the TED.

## III. The current billing determinant does not accurately represent transmission usage.

The TAC billing determinant for Participating Transmission Owner (PTO) utilities charges fees for transmission grid usage inaccurately and without regard to whether energy is delivered via the transmission grid. Currently, PTO utilities pay TAC based on the end-user customer metered load as measured by the customer energy downflow (CED)—identified by aggregating all ratepayer meters on the distribution grid. However, since a portion of the consumed power is not delivered via the transmission grid, the CED method results in assessing TAC on DG output. This produces a misalignment between charges and transmission grid usage; the CED billing determinant obscures the relationship between delivery and delivery costs. This discourages DER in PTO utility territory and effectively creates a cost shift whereby customers consuming DG output are paying more than their fair share, effectively subsidizing the transmission grid and central generation.

In sharp contrast, non-PTO utilities pay accurately for transmission usage, based on meters at the end of the transmission grid. As described in the Background White Paper, non-PTO utilities pay for transmission through wheeling access charges (WAC) based on the net load measured at their point of interconnection with the ISO grid.[1] For most non-PTO utilities, the interconnection point is a transmission-distribution interface or an interface point between ISO transmission infrastructure and the non-PTO's transmission infrastructure. As a result, non-PTO customers pay in direct proportion to their utility's usage of the transmission grid. To the extent that non-PTO utilities generate their own local power that does not require transmission assets, the non-PTO utility pays no WAC on energy generated and consumed locally without use of the transmission grid. Thus, their customers are not required to subsidize transmission assets their non-PTO utility avoided using.

The Clean Coalition proposal is to therefore use the transmission energy downflow (TED), the gross load[2] flowing at each substation as a more precise measure of transmission usage. For Regional, high voltage TAC (costs associated with CAISO-operated facilities operating >200 kV), the TED should be measured at the substations connecting Regional facilities to Local facilities. For Local, low voltage TAC (costs associated with CAISO-operated facilities operating ≤200 kV), the TED should be measured at the transmission-distribution interface substation. This metric better captures the proportional usage of each transmission grid, more closely adheres to the principles of good rate design, and ultimately better reflects cost causation.

## IV. DER can—and do—reduce both existing and future transmission costs by decreasing peak load conditions, meeting policy goals without requiring new transmission investment, and providing energy services to increase reliability.

DER, particularly distribution-connected generation, reduce the stress on the transmission grid and avoid the need for future transmission grid investment. As discussed below in responses to questions 4 and 6, DER deployment has put some recent transmission projects on hold. In addition, DER can meet at least some portion of California's renewable portfolio standard (RPS) targets without creating a need for new transmission investment. Thus, even though policy goals are often cited as driving transmission investment, there is no solid connection between RPS goals and transmission investment when DER can meet those same policy goals without incurring transmission costs.

[1] Background White Paper (Apr. 12, 2017) at 11.

[2] The Issue Paper (p.3) conveys the Clean Coalition's proposal as being to use the hourly net load at each transmission-distribution (T-D) interface substation, meaning the metered customer load net all local distributed generation. We clarify that our proposal is actually to use the *gross* load as metered at the transmission grid interfaces. The TED should not be reduced by any exports from that distribution interface onto the transmission grid. Rather, all energy flowing from the transmission system to the distribution grid should be subject to TAC under the Clean Coalition proposal.

## V. Transmission planning is separate from transmission access charges, because the transmission access charges shape the need for transmission.

Accurate TAC are critical to efficient transmission planning. As noted in the Issue Paper, CAISO relies on resource portfolios provided by the California Public Utilities Commission (CPUC) to determine where resource procurement will be needed and therefore new transmission will be required. However, whether these resource procurement needs ever materialize or are approved by the CPUC in the first place depends strongly on whether the remote resources are actually the most cost effective for supplying load. The CPUC will be ill-equipped to determine the most cost-effective resource portfolio if the true costs of delivery are not accurately reflected in the costs associated with various resources. Certainly, the CPUC and the California Energy Commission (CEC) establish needs, but transmission projects will be canceled if the needs do not materialize. However, whether those needs materialize will be shaped by whether the TAC accurately captures cost causation by different resources. Until the TAC metering point is corrected to avoid DG output, TAC will not accurately capture transmission cost causation and the transmission planning process will be distorted in favor of building more transmission.

## VI. A broad coalition of stakeholders supports a transition to using TED to assess transmission grid usage

The Clean Coalition is supported by a broad coalition of stakeholders, environmental groups, communities, and companies in seeking to improve the assessment of transmission access charges.

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.

# Responses to Comment Template

## 1. Suggested modifications or additions to proposed scope of initiative.

The issue paper proposed two main topics for the scope of this initiative. If you want to suggest modifications or additions to the proposed scope, please explain how your proposed changes would fit with and be supportive of the two main topics.

**Comments:**

a. **The scope should first focus on the proposed change to TED as the point of measurement for the TAC billing determinant, as a more just and reasonable in accordance with FERC cost-allocation principles on transmission pricing policy. Based on that determination, the initiative should then address whether the current TAC billing determinant or some modification is the most efficient, just, and reasonable approach.**

This initiative should start with the simpler and more fundamental issue of measuring transmission usage at the edge of the transmission grid. As currently scoped, the central issues in this initiative are where to measure transmission usage and how to charge for that usage. Regardless of how usage is defined (based on a volumetric or demand or hybrid approach), *where* transmission usage is measured is a discrete and fundamental issue that can and should be addressed first. The TAC market distortion on DG output and cost-shift created by the existing CED billing determinant are the major motivations for engaging in this initiative, and CAISO has pledged to address that issue to the California legislature and to stakeholders. Addressing those issues is far more closely tied to the question of where usage is measured. No matter the underlying structural changes to be considered and implemented, we will still need to decide where we measure transmission usage. Since establishing the point of measurement of transmission usage is entirely separate from question of what formula to use, there is no reason to delay consideration, adoption, and implementation of an alternative measuring point.

In light of the dependencies between these issues, the Clean Coalition recommends that CAISO first consider stakeholder input on the most appropriate location to measure transmission usage. CAISO has already requested feedback from stakeholders on *how* to measure transmission usage, but has not yet requested stakeholder input on *where* to measure transmission usage. The Clean Coalition recommends that CAISO provide additional detail on where transmission usage is measured currently, and directly solicit responses from stakeholders on where transmission usage should be measured in accord with the FERC principles and guidance. Through that process, CAISO should be in a position to evaluate whether use of end-user customer metered load (CED) or TED is the more just and reasonable approach to cost-allocation. The Clean Coalition's position is that the current CED measurement of transmission usage fails to uphold FERC and Bonbight cost allocation principles, and that the TED is unquestionably the more just and reasonable billing determinant for all CAISO customers.

b. **The scope should aim to ensure that the TAC billing determinant does not distort the market for distributed generation or any other resources.**

The current CED billing determinant no longer meets the just and reasonable standard for cost allocation because the growth in DG output has made use of CED an unreliable measure of transmission usage. Thus, the TAC system no longer reflects usage and requires revision.

Measuring transmission usage at CED creates a significant cost shift between PTO utilities and ratepayers. Utilities using more cost-efficient DER effectively subsidize transmission an investment because the CED includes DG output and reflects more transmission usage than is merited. PTO utilities that use DG output to reduce their impact on the transmission grid see no reduction in TAC charges from that reduced impact because all end-user metered load is subject to TAC, even when that energy is generated and consumed locally without utilization of the transmission grid. This means that PTO utilities (and their customers) with higher penetrations of DG are paying more than their fair share of transmission costs and subsidizing centralized generation. The CED billing determinant therefore shifts the costs of the transmission grid onto utilities and customers who use the transmission grid less than others.

This distortion also results in inefficient energy procurement because this cost shift 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 apply LCBF, they ignore TAC fees because all energy in their utility service territory is currently subject to TAC, regardless of whether energy is delivered through the transmission grid. Under the existing TAC billing determinant, LCBF compares only the relative energy generation cost, adjusted by grid losses and transmission upgrades. Since TAC is applied to all resources, LCBF ignores the difference in transmission usage and operation costs between remote and local distributed resource procurement. Furthermore, since PTOs ultimately receive some portion of TAC charges as reimbursement for their transmission investments, load serving entities (LSEs) in PTO utility territories are incentivized to favor remote resources, artificially driving the demand for additional transmission investment and increasing total ratepayer costs.

Using the TED to measure transmission usage would establish a consistent basis for all customers throughout CAISO territory and would correct the fundamental inability of CED to reflect the contributions of distribution resources in reducing transmission usage. While there are a variety of reasons to also evaluate the TAC structure, these complex considerations should be reviewed after CAISO has addressed the much more direct and simple problem of where usage is measured.

### c. CAISO should clearly establish what problems are being addressed by proposed changes to the TAC.

CAISO must clearly lay out the problems to be addressed by any change prior to moving to revise the billing determinant for TAC. No parties to date have established precisely what issues would be addressed by changes to TAC volumetric structure. The Clean Coalition has laid out a set of clear problems with using end-use customer metered load to measure transmission usage that need to be addressed. However, no equivalent problem statement has been stated to motivate the review of the TAC structure. We recommend that the scope of this initiative specifically identify the goal of revisiting the TAC volumetric structure. Furthermore, since the issues with using CED are well established, CAISO should move first to resolving those while this proceeding clarifies the goals of any revisions to the formula for calculating TAC.

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

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

**Comments:**

In CAISO's evaluation of how other ISOs and RTOs charge for transmission usage, we recommend that additional consideration be paid to *where* each ISO/RTO is metering usage for its various charge components. The Issue Paper provided valuable insight into how other ISOs and RTOs calculate transmission charges—under various volumetric, demand, and hybrid approaches—but the Issue Paper is markedly less clear on where that usage is defined and measured. As described above, the question of how to calculate usage charges should be answered after we have addressed the much more direct and simple problem of where usage is measured.

However, the examples of other ISO/RTO TAC structure are only of limited utility, because few RTOs/ISOs seem to have given sharp attention to the issue of how the location of transmission usage affects fairness and market distortions. For example, in our own research into how different ISO/RTOs measure transmission grid usage, the Clean Coalition found that at least one ISO gave conflicting reports of how transmission charges are calculated based on tariff language and staff statements. This highlights the lack of awareness and attention to whether transmission cost allocation distorts the market for DER and DG output. In large part, such lack of clarity may reflect that DG was generally not a factor when most of these tariffs were designed. Major disputes have arisen over how new transmission cost allocation recognize differentials between LSEs due to varying degrees of transmission use, and over LSE's or region's ability to meet its own load or policy goals. For these reasons, the Clean Coalition agrees with CAISO representatives' statements at the July 12th stakeholder meeting that examples from other ISOs or RTOs should provide insight on the CAISO TAC structure, but may not be directly relevant. Regardless of how other ISOs and RTOs charge for transmission grid services, California should be at the forefront of resolving how to best ensure that transmission charges are not improperly allocated to DG output.

Nonetheless, the Clean Coalition has found anecdotal evidence that other ISOs (specifically ISO-New England and NYISO) use the transmission energy downflow (TED) or a transmission-distribution interface meter to quantify transmission use for all or some components of their TAC-equivalents.

For example, the ISO-NE tariff defines Regional Network Load (the basis for regional network service charges) as:

> "**Regional Network Load** is the load that a network Customer designates for Regional Network Service. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery."[3]

ISO-NE staff had verbally confirmed with the Clean Coalition in January 2016 that they measure transmission downflow at the step-down from transmission to distribution grid to assess their Regional Network Service Charges. This can be harmonized with the tariff definition of Regional Network Load (above) if a Network Customer designates the T-D interface as the Point of Delivery. Confirmation from ISO-NE could clarify whether this is the correct assessment of their metering methodology.

Regardless of the structure of other ISO/RTO's transmission usage charges, none of these tariffs have expressly considered whether these charges are appropriately structured for an energy system with substantial penetration by distributed resources. California has significantly more installed capacity from distributed solar PV resources than any other state,[4] but even California has less than 5% of its energy derived from DER. Consequently, it is to be expected that that no other ISO/RTOs have taken up consideration of how transmission charges affect DER, and that California should be the first state to directly address whether transmission charges are disproportionately hindering DER.

[3] ISO-NE open access transmission tariff, Section I.2.2.

[4] The U.S. Energy Information Agency reported that as of September 2015, California had 3,057 $MW_{AC}$ installed, versus the next closest state of New Jersey, with 793 $MW_{AC}$ in distributed solar PV installed capacity. U.S. Energy Information Agency, "EIA electricity data now include estimated small-scale solar PV capacity and generation," *Today in Energy* (Dec. 2, 2015), available at https://www.eia.gov/todayinenergy/detail.php?id=23972

### 3. Today's volumetric TAC rate structure.

Do you think it is appropriate to retain today's volumetric TAC rate structure ($ per MWh of internal load or exports) going forward? If so, please explain why. If not, please indicate what type of change you think is preferable and why that change would be appropriate.

**Comments:**

The Clean Coalition sees the main question at this juncture to be *where* to measure transmission usage rather than *how.* Whether to retain the volumetric rate structure is a fair and appropriate question to ask, but this issue can be separate from the question of where transmission usage is measured. Regardless of the rate structure or definition of what constitutes "use," the most appropriate measuring point for quantifying the usage is at the end of the transmission grid. Any rate component for transmission services should be measured at the end of the transmission grid—in other words, as TED at the T-D interface. Cost allocation for ISO services should rationally be measured at the ISO boundary.

In addition, the current TAC system was designed as a volumetric usage fee for transmission service and intentionally includes no peak load component. The TAC cost recovery system is not designed or intended to incentivize changing peak load conditions. The Background White Paper highlighted that the CAISO is an energy market, not a capacity market, and the current volumetric structure reflects that and aligns with the market structure.[5] Since the Issue Paper states that this initiative will not consider modifying or expanding its transmission service offerings, the original justification for the volumetric structure (CAISO operating as an energy market) will likely persist. Any proposals to change the volumetric structure should therefore include a rationale for why the alternative structure would still reflect CAISO's energy only transmission service.

Stakeholders should be clear that frequency regulation and resiliency services are not exclusively provided by the transmission grid to the distribution grid. Rather, these services may come from either source to the benefit of either. Although CAISO has not approached the transmission grid with this kind of transactive energy services concept, there may be value in starting a process of considering full valuation of such services. For example, while frequency regulation is currently mostly provided by remote generation, distribution connected batteries stand to be the primary providers of fast primary reserves and of enhanced (under one second) frequency response going forward. However, if CAISO does wish to consider valuing such services as a component of the TAC, it is critical that that the TAC not only apply some kind of flat fee for the services provided by the transmission grid, but that some component of resiliency fees also be remitted to DER

[5] Background White Paper at 13.

providers who provide resiliency back-up and frequency regulation services to the transmission grid.

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

Do you think DG energy production reduces costs associated with the existing transmission system? Please explain the nature of any such cost reduction and suggest how the impact could be measured. Do the MWh and MVAR output of DG provide good measures of transmission costs avoided or reduced by DG output? Please explain your logic.

**Comments:**

As outlined above, stakeholders should prioritize considering where to measure transmission usage and analyzing how the CED creates a cost-shift and market distortion against DG output in our energy markets. Thus, the Clean Coalition recommends that instead of delving into details on the benefits of DER, this initiative address where to measure transmission usage first. Again, we emphasize that the best place to measure ISO service to the distribution grid is at the T-D interface. The boundary of the transmission grid provides a consistent, unbiased, and technology-neutral point of assessment for measurement of use of the transmission grid.

Ultimately, ISO cost allocation should be agnostic to activities on the distribution grid unless they impact ISO costs. Regardless of technologies or methods employed on the distribution grid to mitigate transmission impacts, only the impacts actually realized within the ISO sphere of operations should be used as the basis for assignment of costs and allocation of TAC. As such, it is inappropriate to assign costs based on any measurement at the end-use customer interface rather that at the transmission interface.

DER unequivocally reduce and have reduced costs associated with the existing transmission grid in two distinct ways. First, DER have already avoided transmission investments reflected in existing transmission infrastructure. To the extent that existing DER have reduced the need for remote generation to serve load, they have also reduced past transmission investment costs. DG and other DER have reduced the quantity of existing transmission sunk costs to the extent that these resources have been included in TPP forecasts and modeling. In several instances, transmission projects have been cancelled or deferred based on fast DER deployment in areas to be served (see section A below for additional detail). Because there is less existing transmission infrastructure than there would have been in the absence of DG, the costs associated with the existing grid have already been reduced.

Since existing DER have already decreased transmission costs, load served by DG output should not be subject to TAC. TAC covers annual TRR associated with sunk costs (e.g., construction and financing costs) and on-going costs (e.g., operations and maintenance costs), both of which would be higher if not for significant recent deployments of DER.

Furthermore, all existing transmission investments have been made to enable remote generation to serve load. Those sunk investments serve only to allow remote generation to serve load and were only ever justified based on that need, so recovering those investments should be done based only on the energy for which the sunk costs were originally incurred. In other words, only energy utilizing the transmission facilities should be subject to transmission charges. Barring examples of transmission investments justified to deliver DG energy, there is no rationale for recouping those investments from DG output, which those assets were never intended to serve.

Second, DG reduce the need for future O&M to the extent as they avoid that usage to the extent that operations and maintenance (O&M) costs are incurred due to usage,. DER contributes to lowering some O&M costs at the transmission grid level, especially if operated in coordination with ISO operational signals, even if the costs related to ownership, operations, and maintenance of existing transmission facilities are generally low. This is a complex topic currently under investigation nationally and in California, as well as in several CPUC proceedings and working groups (including the newly established DRP Track 1, Locational Net Benefits Assessment – DER Avoided Transmission Value subgroup, in which ISO staff are participating).

Regardless of the degree to which DER reduces O&M costs by reducing energy flow, operations and maintenance costs are incurred essentially exclusively to ensure that remote resources can reach customers. Thus, since the cost causation of operations and maintenance is overwhelming driven by the need to deliver remote generation energy to customers, the operation and maintenance component of TAC should be overwhelmingly derived from charges the delivery of on remote generation energy.

The Issue Paper established that there are four main drivers of transmission investment contributing to the sunk costs of the existing transmission grid, and DG output addresses some, and potentially all of these as discussed below

a. Thermal capacity, or increases in peak demand
b. Policy-driven goals
c. Economic drivers (to access cheaper energy)
d. Reliability needs

### a. Capacity investments: DG's contribution in reducing peak demand has already reduced costs associated with the existing transmission grid.

DG output has already reduced peak demand and thus lowered costs to build new transmission facilities to meet peak demand. Looking forward, DG and other DER address growing peak demand by delivering energy during peak load conditions. As a result, additional DG output will reduce overall load on the transmission grid, including peak loads. Changing the billing determinant to TED will broadly contribute to a positive impact on peak transmission loads on the existing grid.

For example, in PG&E's 2015 Distribution Resources Planning (DRP) report, the utility estimated that DER reduced their 2014 annual peak load by 2,742 MW (13.5%), with local PV generation being the second largest component.[6] This rose to 3,695 MW by 2016 (17.3%), of which generation accounted for 1,273 MW after adjusting for effective capacity during the peak hour.[7] Thus, existing DER, including DG, have already reduced existing transmission investment and both past and future TRR associated with this investment.

In the case of distributed solar specifically, more than 30% of solar nameplate power production contributes to reducing peak transmission usage, which occurs during later daylight hours. Increasing deployment of distributed solar, therefore, slows or avoids the need for additional transmission capacity investment. The chart below displays the relationship between the solar generation profile and the 2015 peak net load. CAISO's peak load for 2015 was September 10th at 4:53pm, and though not operating at peak capacity, distributed solar resources were producing energy to help meet the peak Transmission Energy Downflow, or TED. 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.[8] 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.

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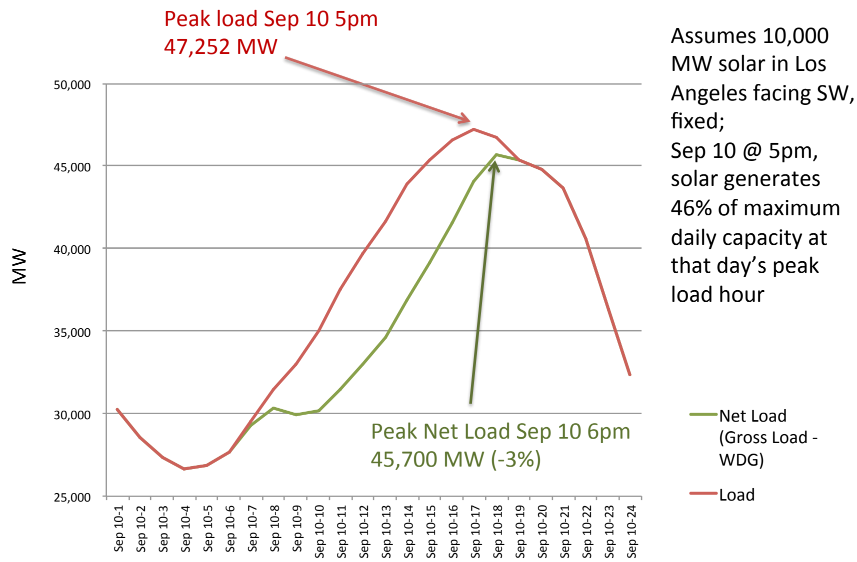
[6] Pacific Gas & Electric Company 2015 Distribution Resources Plan, Section 2.d.iii.1. *DER Growth Scenarios Impact at System Level Peak Demand*, pp. 119-122, available at: http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_RevisedFinal.pdf.

[7] Id.

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




Ultimately, peak transmission capacity is determined entirely by the peak TED of remote generation. Transmission needs are driven by procurement decisions to meet customer load with remote resources, whether or not that peak load is reduced by energy efficiency, demand response, customer load shifting, energy storage, or distributed generation. None of these elements contribute to the drivers of transmission investment.

**b. Policy goals: DG's contribution in both providing RPS qualifying energy and in reducing the RPS annual metered load basis has already reduced policy driven costs associated with the existing transmission grid.**

To date, most Renewable Portfolio Standards (RPS)-eligible energy has been met with remote generation, and past transmission planning has reflected those procurement decisions. DG output could both provide RPS-qualifying energy and reduce the RPS annual metered load to reduce policy-driven investments needed to access RPS resources associated. For example, ReMAT program procurement of 750 MW of wholesale DG is RPS-eligible and is already included in IOU RPS procurement planning. This procurement was mandated by legislation in 2008, expanding upon prior AB 1969 targets from 2006. This reduced the need throughout the past decade for new remote renewable generation and any transmission that would have otherwise been planned and built to access new resources required to meet RPS targets. These resources have not been more heavily utilized in part because the TAC distorts the DER market by failing to correctly attribute transmission costs to remote generation that first justified those investments.

**c. Economic drivers: DG reduces transmission costs associated with economic drivers based on its correlated generation profile and location.**

DG reduces costs caused by congestion and losses, reduces costs of economically driven projects, and improves the availability of the transmission grid to meet emerging needs and economic opportunity. First, DG generation profiles and location can reduce the marginal costs of energy by reducing congestion and line losses. Second, freeing up transmission capacity of the transmission grid in turn reduces both past and future costs associated with development of economically driven transmission projects. Finally, DG also improves the availability of the existing grid to meet emerging needs and economic opportunity by freeing up transmission capacity. This increases access to least cost resources at any location and improves market efficiency.

More importantly, as LSEs deploy more DG, freeing up transmission capacity DG allows the benefits of the existing transmission grid to flow to other LSEs. As LSEs with more cost-effective DG opportunities deploy that DG, capacity will be freed for use of by other LSEs for which remote generation may be more cost effective. By allowing these LSEs to use existing infrastructure rather than building new resources, DG deployment keeps costs down for both LSEs and promotes market efficiency. As proportional usage of the transmission grid shifts over time between LSEs, reflecting differential usage of local generation, the benefits will flow to new beneficiaries. Thus, market efficiency and fairness would be promoted by having these recipients proportionately share the costs of the existing grid. However, allowing costs to follow benefits can only be achieved when transmission charges are applied only to energy using the transmission grid.

**d. Reliability drivers: DG has proven reductions in transmission costs associated with reliability needs.**

Varied DER can address local reliability needs while simultaneously avoiding new transmission investment. For example, in one report, researchers confirmed that battery energy storage resources could provide frequency and voltage stability services (along with other energy services) to the grid.[9] The energy storage resource was capable of holding the correct output voltage throughout operations as well as providing proper frequency response to varying real power load conditions.[10] Furthermore, real world deployments in geographically bounded areas, such as Kauai, have demonstrated that photovoltaic solar plus storage can cost effectively meet the full suite of reliability needs.[11] While these approaches are being proven in real-world contexts, reducing demand for remote resources for reliability needs would require removing market distortions that disincentivize DER, such as the TAC structure, and creating energy services markets to enable DER to actively compete against transmission-based energy services.

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[9] Khalsa, Amrit S., and Surya Baktiono. *CERTS Microgrid Test Bed Battery Energy Storage System Report: Phase 1.*, 2016, available at https://certs.lbl.gov/sites/all/files/aep-battery-energy-storage-system-report-phase1.pdf.
[10] *Id.* at 18-20.
[11] *AES' New Kaua'I Solar-Storage 'Peaker' shows how Fast Battery Costs Area Falling,* https://www.greentechmedia.com/articles/read/aes-puts-energy-heavy-battery-behind-new-kauai-solar-peaker, January 16, 2017.

## 5. <u>Potential shifting of costs for existing transmission infrastructure.</u>

If the TAC rules are revised so that TAC charges are reduced or eliminated for load offset by DG output, and there is no reduction in the regional transmission revenue requirements that must be recovered for the existing transmission infrastructure, there will be an increase in the overall regional TAC rate that presumably will be paid by other load. How should this initiative take into account this or other potential cost shifts in considering changes to TAC structure?

**Comments:**

The goal of this initiative should be to define a TAC structure that best upholds the core principles of rate design and ultimately allocates costs to customers based on their proportionate use of the transmission grid. Any changes to the current TAC structure that advance that goal will result in a more just and reasonable system, even if there are resulting corrections in cost responsibility, because costs would correspond directly to actual use of the transmission grid.

CAISO should take into account and correct the existing cost shift from energy from remote generation onto energy produced by distribution-connected generation. The *current* TAC structure shifts the costs of the transmission grid onto customers served by DG output by charging them for transmission grid service disproportionately to their actual usage. By spreading transmission requirement costs across all metered energy—including locally generated and consumed DG output—the TAC system spreads transmission costs to energy that is not delivered via the transmission grid. In this way, the current TAC structure aligns neither cost causation nor benefits with cost allocation. Portions of transmission costs are effectively shifted from parties who use the transmission grid relatively more to parties who use DG output to avoid transmission costs. Furthermore, by applying transmission charges to the energy that does not need transmission to deliver to customers, the current TAC structure provides a subsidy for remote generation. The Clean Coalition's proposal to use TED as the TAC billing determinant would *correct this existing cost shift*, rather than create a new cost shift.

Over time, TAC rates would grow more slowly under the proposed change of location of the billing determinant, because the total transmission revenue requirement would grow more slowly over time with avoided transmission investments. The Clean Coalition has modeled the impact and estimates that the TAC rate will be lower than "business as usual" projections in approximately 3 years, and that total revenue requirements will be reduced by more than $38 billion over 20 years if the growth rate of DG development doubles relative to "business as usual" projections under the current tariff. The sharp growth of TAC rates is a serious concern for all parties, and fixing the TAC cost shift should help alleviate the upward pressures. The TAC rate would increase by a small amount, roughly 4%, initially if non-transmission dependent energy were not charged for transmission services, but the total costs would not increase. However, the increase in TAC rates will be smaller the sooner the change is made, as DG represents a very small but growing fraction of the total energy delivered in the state. As that fraction grows, the bump in the TAC rates grows proportionally larger.

The Clean Coalition has analyzed what the likely cost impacts would be to ratepayers if the billing determinant were moved from the CED to the TED, and there are two important results: (1) immediate cost impacts between utilities would be minimal, and (2) long-term transmission savings would be widespread and dramatic.

### a. Immediate Cost Impacts

To illustrate how the proposed change will impact LSEs in PTO utility service territories, we provide the following examples. In the chart below, the Clean Coalition 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).

| 2016 Scenario | IOU | CCA | ESP | Total | Notes |
|---|---|---|---|---|---|
| LSE Customer Energy Downflow (CED, in GWh) | 70 | 30 | 10 | 110 | *Current TAC wholesale billing determinant* |
| % of Total CED | 64% | 27% | 9% | 100% | *Share of total TAC basis (now)* |
| TRR (in thousands) | NA | NA | NA | $1,650 | *Total Transmission Revenue Required* |
| TAC Rate per kWh (now) | $0.0150 | $0.0150 | $0.0150 | $0.0150 | *TRR/CED* |
| TAC payment (in thousands) | $1,050 | $450 | $150 | $1,650 | *TAC Rate x CED* |
| DG output (GWh) | 2.8 | 1.2 | 0 | 4 | *4% is the highest current % of DG in any PTO utility service territory* |
| Share of LSE CED served by DG | 4% | 4% | 0% | 4% | |
| TED (GWh) | 67.2 | 28.8 | 10 | 106 | *Proposed TAC basis* |
| % of TED | 63.4% | 27.2% | 9.4% | 100% | *Share of total TAC basis (proposed)* |
| TRR (in thousands) | NA | NA | NA | $1,650 | *Remains unchanged* |
| TED-based TAC Rate (per kWh) | $0.0157 | $0.0157 | $0.0157 | $0.0157 | *TRR/TED* |
| TED-based TAC payments (in thousands) | **$1,046 (-$4)** | **$448 (-$2)** | **$156 (+$6)** | **$1,650** | *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 transmission revenue requirement (TRR). The Clean Coalition proposal causes no increase in the total TAC revenue recovered from all LSEs. Regardless of how usage is measured, the CAISO TAC rate will always result in recovery of the entire TRR from LSEs. The total aggregated TAC would still equal the same current TRR because the formula for identifying the volumetric TAC rate is essentially the TRR divided by the total end-use customer metered load billing determinant (in PTO utility territories, this is the CED). As always, TRRs are guaranteed and will continue to be fully recovered.

Second, the TAC rate increases, but barely. By changing the TAC basis to TED, the denominator in the TAC rate formula would decrease only to the extent that DG output contributes to the LSE's portfolio, and the TAC rate would increase proportionally. If usage were consistently measured via TED as the Clean Coalition proposes, the TRR numerator would remain unchanged, but would be spread initially across a slightly smaller denominator (less than 4% smaller[12]), so that the TAC rate would increase by a similarly slight amount (less than 4%). This can be seen in the example by comparing the original TAC rate of $15.00/MWh to the new TAC rate of $15.70/MWh. Given that most LSEs are meeting such small portions of their gross loads from DG output, actual TAC rates would increase by significantly less than 4%.

The change in total TAC payments between PTO utilities would be no greater than the current *difference* between their shares of loads served by DG output, which the Clean Coalition expects to be a fraction of a percent. The ESP example shown above shows the most extreme potential case of cost shift for any California electric service provider. Some LSEs will pay negligibly more or less in TAC, due to differences in portfolios of DG outputs.[13] In our example, the LSEs with the maximum current DG output of 4% (i.e., the IOU and the CCA) each saw a decrease in payments of 0.4% and 0.9% respectively, whereas the ESP saw an increase in total payments of 4%. This adjustment is fair because it corrects current inaccuracies in accounting for each utility's contribution to transmission costs. Because the ESP is using the transmission grid more intensively in proportion to its load, it pays proportionally more in TAC than the other LSEs. In the future, all utilities will have

[12] According to Distribution Resources Planning filings, the highest percentage of Gross Load met by WDG plus NEM exports in a PTO utility service area is less than a 4% in California, so the maximum projected change in TAC rate would be less than 4%. Importantly, TRRs, which equal aggregate TAC payments, would not change at all.

[13] 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)

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 other DER to 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 gross load 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, such as 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.

### b. Long Term Cost Impacts

Many of the longer-term trends in costs would be shaped by removing barriers to the use of DER and the avoidance of unnecessary transmission investments. 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 dependent resources in procurement decisions. It is not clear exactly how much additional DG a change in the TAC billing determinant would attract, but even 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.

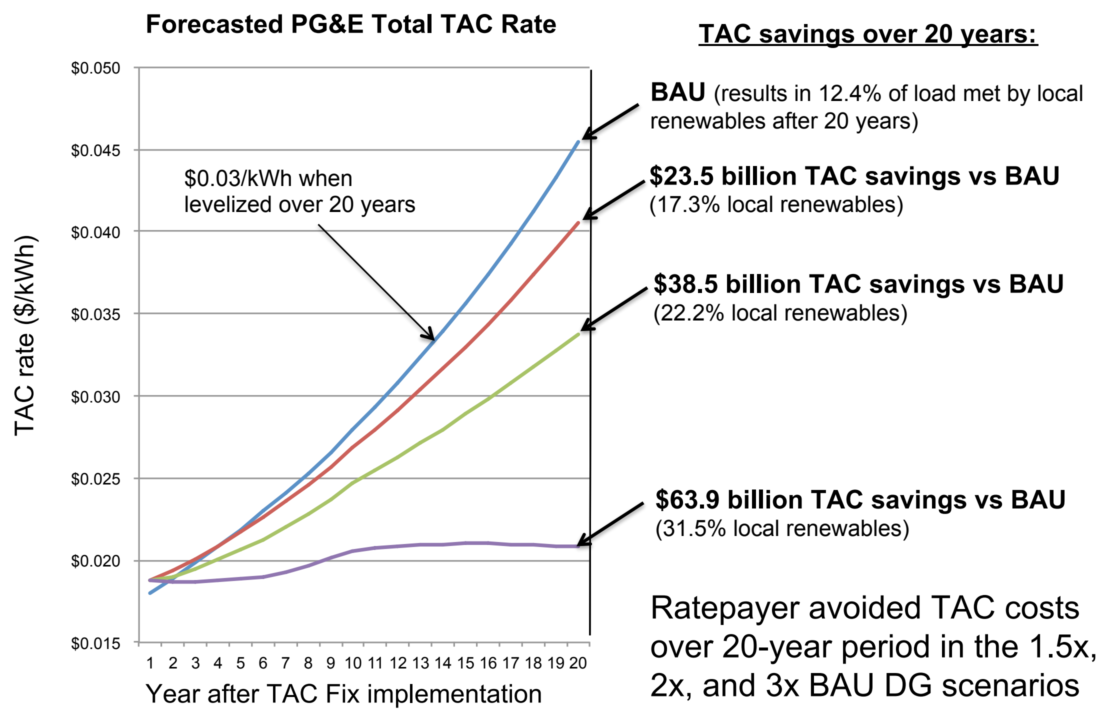
This example shows the long-term impact on a variety of LSEs, including utilities like PG&E as well as community choice energy providers like Marin Clean Energy. Using current and projected PG&E TAC rates and projected DG deployment, the Clean Coalition estimated that a 10% annual increase in DG growth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

| 2036 Scenario | IOU | CCA | ESP | Total | Notes |
|---|---|---|---|---|---|
| LSE Customer Energy Downflow (CED; in GWh) | 70 | 30 | 10 | 110 | Current CED and TAC basis |
| % of Total CED | 64% | 27% | 9% | 100% | Share of total TAC basis (now) |
| TRR (projected 2035, in thousands) | NA | NA | NA | $5,740 | Total Transmission Revenue Requirement |
| TAC Rate per kWh (projected 2035) | $0.052 | $0.052 | $0.052 | $0.052 | TRR/CED |
| TAC payment (in thousands) | $3,653 | $1,565 | $522 | $5,740 | TAC Rate x CED |
| DG output (GWh) | 8.00 | 12.00 | 0.00 | 20.00 | 18% energy sourced below T-D interface |
| Share of total LSE CED served by DG | 11% | 40% | 0% | 18% | *Increased to 2 x BAU case* |
| TED (GWh) | 62.00 | 18.00 | 10.00 | 90.00 | Proposed TAC basis |
| % of TED | 68.9% | 20.0% | 11.1% | 100.0% | Share of total TAC basis (proposed) |
| TRR (in thousands) | NA | NA | NA | $4,470 | Reduced (due to deferred need for new capacity) |
| TED-based TAC Rate per kWh (projected 2035) | $0.0497 | $0.0497 | $0.0497 | $0.0497 | TRR/TED; TRR is reduced to DG meeting share of load growth |
| TED-based TAC payments (in thousands) Savings | **$3,079 (-$573)** | **$894 (-$671)** | **$497 (-$25)** | **$4,470** | New TAC Rate x TED (and change from business-as-usual) |

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. Over the long run, even LSEs that deliver no DG output to their customers would see long-term savings through decreased TAC liability.

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 them. Clean Coalition analyses show that a doubled growth rate of DG would save California ratepayers at least $38 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 chart below shows the large reductions in TAC rates achieved over 20 years by eliminating the TAC market distortion and assuming 1.5x, 2x, and 3x annual growth in DG. A moderate 2x annual growth scenario would increase the share of LSE load met by DG resources from 4.6% today to 22.2% in 2036. These declines in TAC rates would be driven by meeting load growth with local resources and through depreciation and full recovery of existing transmission assets.




The area between the blue curve and the other curves represents avoided ratepayer transmission costs over the 20-year period. Even under a conservative estimate, the total ratepayer savings would be nearly $40 billion.

Finally, placing DER on a level playing field would save ratepayers money without risk of stranding or under utilizing transmission assets. The differences over time are that DG output grows faster by eliminating the market distortions that currently disadvantage DER and less transmission investment leads to lower TRR and TAC for all ratepayers over time. However, these benefits do not pose a risk to the transmission grid. The TAC rate formula guarantees that the full TRR will be recovered, and a change in where transmission usage is measured would not impact the ability to fully recover the TRR.

Importantly, changing how TAC are assessed would not cause existing transmission facilities to be underutilized. DG output currently provides approximately 4% of the energy provided by utilities. Increased DG deployment will serve load growth, but DG output is unlikely to grow fast enough to outpace load growth, resulting in the continued need for central generation and transmission infrastructure at existing—and potentially even higher—levels. However, slowing the growth of transmission investments would still save California ratepayers enormous sums of money in comparison to the business-as-usual scenario.

Since total demand for electricity continues to slowly increase, the Clean Coalition's analyses all show DG output growing at a rate that never exceeds 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 DG growth scenario in which the change in TAC measurement would lead to stranded transmission assets or costs.

## 6. Potential for DG and other DER to avoid future transmission costs.

The issue paper and the July 12 presentation identified a number of considerations that the transmission planning process examines in determining the need for transmission upgrades or additions. Recognizing that we are still at an early stage in this initiative, please provide your initial thoughts on the value of DG and other DER in reducing future transmission needs.

**Comments:**

The issue before us in this initiative is the allocation of cost recovery, not the development of avoided cost calculation. It is not necessary for the ISO to evaluate the capabilities or performance of individual DER facilities or technologies in this context, and attempting to do so would both duplicate work elsewhere already addressing avoided cost analysis, and would add great and unnecessary complexity to the scope of issues before us. Specific avoided cost calculations might be appropriate when seeking a more cost effective non-transmission alternative to meet a specific, identified future transmission need, but is not necessary or practical for allocating TRR cost recovery. Rather than exempting particular resource types or specific facilities from TAC, metering transmission usage at the T-D interface would provide a consistent, unbiased, and technology-neutral point of assessment for measurement of use of the transmission grid. Thus, the details of estimating avoided costs for each distributed resource type should be deemed outside of the scope of this proceeding.

Instead, this initiative should evaluate the relationship between load growth as it appears to CAISO at the Regional-Local transmission interface or the transmission-distribution grid interface (T-D-interface), which is the relevant scale of analysis for transmission planning. Each area of the distribution grid—as it appears the T-D interface—may appropriately be considered as a single aggregated DER comprised of both load and generation. Each distribution area has particular performance, profile, and demands that requires transmission services and drives future transmission grid investment. Facilities interacting with each other within the distribution grid should be understood as physically comparable to a non-islanded microgrid, a non-PTO utility, or a metered subsystem, as only their combined profile impacts the ISO. DER generation and loads that are fully or partially mitigating below the ISO interface should be treated as an aggregation, because the impacts to transmission needs and planning are only those actually experienced at the ISO boundary. Cost recovery based any other basis creates inefficient price signals as well as inappropriately allocates costs of transmission to entities that have already mitigated their cost contribution.

Regardless of the DER deployed within a distribution grid, the aggregate effect of DER at least mitigates the distribution area load on the transmission grid and thereby reduces the need to meet load with remote resources through the transmission grid. As a result, DER can potentially mitigate significant levels of transmission investment. As discussed above, the Clean Coalition estimates that tripling the rate of DER deployment could contain the growth in the TAC rate over 20 years, cutting that rate by over half relative to the expected business as usual projections.

If avoided transmission investment and associated costs are deemed within the scope of this initiative, then—as discussed above—DER can potentially significantly reduce future transmission costs associated with new transmission to meet any of the four identified drivers of investment.

- DER are capable of providing reliability services both within the distribution grid and in support of the transmission grid, and are beginning to do so through the participation of demand response and energy storage.[14] The systems and markets for dispatch and coordination of DER are just beginning to be developed and deployed for ISO operational use.
- DER directly reduce demand for transmission infrastructure investments needed to access resources associated with RPS requirements. DER contribute both RPS qualifying energy and reduce the RPS annual metered load basis for which renewable generation is required.
- DER can reduce the need for economically-driven transmission projects by freeing up capacity on existing transmission to avoid congestion and losses, and opening up constrained access to least cost generation facilities.
- In the same manner, DER development can mitigate growing load, and reduce this related capacity driven investment.

Beyond this, it is important to note that the actual cost of a transmission project goes far beyond just the initial construction costs. PTOs are regularly guaranteed a 10.5% return on equity, plus the costs of operations and maintenance typically surpass the construction costs. The total cost of building, financing, operating and maintaining any transmission asset will end up increasing the overall ratepayer cost of any transmission investment between 5 and 10 times the original construction cost over a 50-year time period. If calculating the actual avoided cost to ratepayers, the total lifetime TRR including O&M must be considered, not just the initial capital investment.

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[14] *See, e.g.,* Tierney, Susan F., "The Value of "DER" to "D": The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability," *Analysis Group, Inc.*, at ES-2 and 18-19, available at: http://www.analysisgroup.com/uploadedfiles/content/news_and_events/news/value_of_der_to%20_d.pdf.

The primary benefit of DER to transmission planning is proximity to load. By generating electricity close to where it will be consumed, DG and other DER can meet local needs without relying on transmission infrastructure to deliver energy to load. By doing so, DER frees up existing transmission capacity that had previously been required to serve those loads, allows the existing transmission grid meet the remaining demand for more years before reaching capacity limits, and defers demand for future transmission investment.

DER deployment and energy efficiency has already resulted in the deferral or cancellation of planned projects. For example, residential rooftop and industrial-scale solar power solar halted PG&E's plans to construct the Gates-Gregg 230 kV transmission line project.[15] The project would have cost between $115 million and $145 million to construct, plus additional transmission costs would have accumulated to provide the return on equity, operations, and maintenance costs over the facilities lifespan that triple the ultimate TRR cost to ratepayers.[16] Similarly, the 2015-2016 CAISO Transmission Plan saw PG&E cancel a planned $192 million transmission project due to energy efficiency and distributed generation.[17] In addition, the New York Public Service Commission approved an indefinite extension of Consolidated Edison's (Con Ed) Brooklyn-Queens Demand Management Program, which allowed Con Ed to spend up to $200 million on non-wires alternatives in order to avoid spending $1 billion on new transmission facilities to accommodate growing load.[18]

The current CED-based TAC assessment system fails to recognize the transmission cost reduction of DG. Without recognizing the effects on cost causation, the lack of a TAC cost signal in procurement drives excess demand for remote generation and associated investment in transmission resources, resulting in substantial and unnecessary costs to consumers. In contrast, eliminating the existing TAC market distortion by shifting to the TED billing determinant 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 growth of TAC rates.

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[15] Sheehan, Tim, "Solar growth puts Fresno high-voltage line on hold," *The Fresno Bee* (Dec. 20, 2016), available at http://www.fresnobee.com/news/local/article122063189.html.
[16] *Id.*
[17] Pyper, Julia, "Californians just saved $192 Million Thanks to Efficiency and Rooftop Solar," *GreenTech Media* (May 31, 2016), available at https://www.greentechmedia.com/articles/read/Californians-Just-Saved-192-Million-Thanks-to-Efficiency-and-Rooftop-Solar.
[18] Wood, Elisa, "Con Ed Gets Okay on More Non-Wires Alternatives: "What Was New Has Become Normal," *MicroGrid Knowledge* (July 24, 2017), available at https://microgridknowledge.com/non-wires-alternatives-con-ed/.

## 7. Benefits of DERs to the transmission system.

The issue paper and the July 12 discussion identified potential benefits DERs could provide to the transmission system. What are your initial thoughts about which DER benefits are most valuable and how to quantify their value?

**Comments:**

Ultimately, DER provide a wide range of useful benefits to the transmission grid, including avoidance of transmission investments, energy services, such as frequency or voltage regulation, and resiliency. However, establishing which are most valuable absent a market mechanism is both difficult and outside of the scope of this proceeding, since this proceeding is concerned with allocating costs rather than establishing precise valuation metrics.

Regardless of the particular service at issue, the best way to quantify the value of DER benefits is to measure transmission use in a way that distinguishes transmission grid usage from other functions. The current Customer Energy Downflow (CED) approach fails to differentiate between local and transmission-dependent resources, masking the impact that procurement of remote resources has on transmission investment. This obscures the benefits of DG by failing to recognize the avoiding transmission use. Adoption of the TED billing determinant would more clearly indicate transmission delivery costs and would allow appropriate consideration of differences in delivery costs in procurement decisions.

Not only does the current TAC structure subsidize remote generation, but it also fails to value the same service provided by DER comparably. For example, when a LSE reduces delivery of electricity MWh from the transmission grid through energy efficiency, this is appropriately reflected in a proportional reduction in TAC liability. However, when an LSE achieves the same reduction in transmission usage through the use of DG output, they receive no similar reduction in TAC. Unless stakeholders aim to depress the deployment of DER, the effect serves no purpose and runs counter to both California policies and principles of rate design.

As discussed above, using TED as the billing determinant rather than CED would resolve this problem in a technology-neutral way. This structure would better reflect actual transmission usage, as quantified by TED. As a result, TAC would be agnostic with respect to what technology reduced transmission use, provided the technology reduced overall gross load or peak demand. A technology-neutral TAC would allow the most cost-effective options for meeting customer needs to emerge and would better align with FERC's stated cost allocation principles and the Bonbright principles of rate design.

End-use metered load offset by DG benefits from the transmission grid only in proportion to its actual usage of the transmission grid, and TAC payments should be aligned accordingly. As LSEs are able to meet higher portions of their load with DER, they have a proportionately lesser need for energy services from the transmission grid. For example, an LSE with a diverse DER portfolio is better able to balance voltage and ensure no net impact on frequency through the use and dispatch of its local DER. As LSEs move toward such an approach (and not all will), the dependency on transmission services will decline, but their TAC payments will not.

As a result, the current structure creates a perverse structure in which the more a LSE is able to mitigate its impacts on the transmission grid, the more expensive the marginal cost of transmission services. As the total cost of services stays constant, the actual services used declines, leaving the ration increasing as the use of services declines. This marginal cost increases because the LSE deploying DER effectively pays twice for services: once for the services it obtains from the DER, and a second time for "services" not provided by transmission grid connected resources. Therefore, instead of maintaining a market-distorting TAC charge for cost recovery, the charges for transmission use must decline as an LSE uses less transmission-sourced energy and services.

The TED proposal offers a clear and simple solution to this problem in which LSEs 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 grid. 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 to a rather straightforward change in where usage is measured, any change in the underlying TAC calculation from a simple per-kilowatt hour charge would necessarily be more complicated. We anticipate that working through the process of establishing a new TAC formula to incorporate components other than a volumetric charge would take months to years to complete. For these reasons, the Clean Coalition recommends simply changing the wholesale billing determinant rather than pursuing alternative pricing structures.

## 8. Other Comments

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

**Comments:**

Measuring transmission usage at the TED is unequivocally the superior approach to assessing TAC, under both FERC and Bonbright principles. Each principle is either agnostic towards the billing determinant or cuts strongly in favor of using TED. Absent a compelling case for an alternative determinant, CAISO should therefore adopt the TED billing determinant, as it more strongly aligns with these fundamental principles as a matter of policy and law.

The FERC rate principles support a TED-based billing determinant as follows.

## 1. Transmission pricing must meet the traditional revenue requirement.

Regardless of the billing determinant, the CAISO cost recovery process ensures that the full transmission revenue requirement will be recovered, such that this principle is agnostic to the choice of billing determinant.

## 2. Transmission pricing must reflect comparability.

Charging TAC based on TED would improve comparability and market fairness by eliminating a cost shift that subsidizes remote generators and contributes to transmission owner profits. FERC's comparability principle requires that electric utilities with transmission facilities offer open access that is "not unduly discriminatory or anticompetitive," in terms of the same or comparable basis, and under the same or comparable terms and conditions.[19] Undue discrimination could refer to the treatment of different customers as well as discrimination in the rates and services offered to third parties versus the utility's own use of its transmission grid.[20] Similarly situated resources must be treated similarly, and rates must not discriminate against resources that do not contribute to utility or transmission owner profits. Thus, a rate structure that distorts market signals in favor of remote resources violates the principle of comparability by providing favorable treatment to resources that drive increased infrastructure investment and transmission revenues.

The current TAC structure treats neither all resources nor all customers equally. Currently, transmission costs are allocated using two different billing determinant methods, depending on whether the customer utility is a PTO or non-PTO. PTO utilities pay TAC based on the CED, whereas non-PTO utilities pay wheeling access charges (WAC) based on their interface with CAISO facilities, generally at the TED. DG resources in non-PTO utility territory are subject to a different transmission fee system from DG resources in PTO utility territory, as DG output in PTO utility territory is subject to transmission fees while the same output avoids transmission fees in non-PTO utility territory. The PTO utility territory methodology shifts costs from customers using more centrally-generated energy (which requires extensive and expanded transmission infrastructure) onto customers using more DG output and therefore do not use transmission infrastructure as extensively.

By being located close to load, DG resources can deliver energy directly to load without utilizing the transmission grid, and DG output is therefore fundamentally different from transmission-delivered energy output. There is no reason for a transmission tariff to subject DG output to transmission charges unless that output is actually delivered via the

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[19] *American Elec. Serv. Corp.*, FERC Docket No. ER-93-540-001 67 FERC ¶61, 168, *order on certified question*, 67 FERC ¶61,317 (May 11, 1994).
[20] *Id.*

transmission grid. However, using the CED billing determinant captures DG output by metering on the distribution grid and subjects it to a charge for a transmission grid it does not utilize. Artificially increasing the cost of DG output by attaching TAC creates exactly the kind of undue discrimination and anticompetitive market conditions against DER that the comparability principle aims to eliminate.

The CED methodology not only creates incomparability between resources, *but also between customers*. By charging PTO utility customers for the upkeep and construction of transmission assets on DG output, the TAC structure distorts the market against DER and artificially obscures true cost causation. It artificially inflates the price of DG output by tacking on extra charges, and it decreases the apparent cost of using transmission infrastructure by spreading those costs more widely than is appropriate. In shifting costs associated with remotely generated energy onto DG output, the TAC subsidizes precisely those resources that drive increased investment while also inflating revenues for transmission owners. Thus, the structure of the TAC suffers precisely from the kind of bias in favor of generation that that the principle of comparability prohibits.

These first two principles reflect fundamental requirements, whereas the following three principles reflect goals that a utility must try to meet but may be balanced against one another.[21] Given that the CED billing determinant directly violates the comparability principle by creating undue discrimination and anticompetitiveness to DER, the analysis could be concluded here that the current PTO utility TAC methodology needs to be revised. However, for the sake of completeness, we continue to analyze the TAC structure using the remaining principles below.

**3. Transmission pricing should promote economic efficiency.**

Charging TAC based on TED would also improve economic efficiency because charging TAC on DG output artificially obscures the true cost causation of transmission investment. While procuring remote generation requires the use—and often new construction—of additional transmission assets, procuring DG resources does not. By obscuring this critical difference, the current TAC structure makes remote generation appear artificially cheaper by ignoring the associated delivery costs. As a result, procurement decisions like the Least Cost Best Fit methodology often lead to procurement of remote generation where DG resources is actually cheaper overall. This incentivizes higher cost procurement and economic inefficiency for customers. Thus, this principle strongly favors adoption of TED as the basis for the billing determinant.

**4. Transmission pricing should promote fairness.**

As described above, applying TAC to DG resources forces customers of DG output to subsidize customers of remote generation. As has been demonstrated in several instances,

[21] Issue Paper at 9.

the use of DG resources can lower both the costs and environmental impacts for society as a whole. Yet, under the current TAC structure, customers, LSEs, and utilities that proactively move to deploy and support DG resources that benefit all ratepayers are penalized and forced to subsidize the transmission costs of those who rely more heavily on remote generation. Thus, those moving to avoid new transmission investments are subsidizing those who are driving the greatest transmission investments for all ratepayers. This constitutes an existing cost shift and is fundamentally unfair to ratepayers and DG resources. (See the above response to question 5 for additional detail on the existing cost shift.)

Instead, customers in all CAISO territory—whether in a PTO or non-PTO utility territory—should pay transmission charges only on the energy that they actually receive from the transmission grid. This reflects the simple User Pays principle that the Clean Coalition has mentioned frequently in previous comments, and it speaks to the basic principle of fairness. There is no reason for PTO utility customers to be paying TAC on energy that is generated and delivered via the distribution grid. Instead, using the TED billing determinant would provide a more accurate measure of transmission usage, as is currently in pace for non-PTO utility territories. Thus, the fairness principle cuts strongly in favor of removing the existing cost-shift on DG output customers by moving the billing determinant for transmission services to the end of the transmission grid.

**5. Transmission should be practical.**

Using TED as the TACbilling determinant is practical, simpler than using CED, and already in place for non-PTO utilities. From a technical standpoint, there is little difference between applying TAC at either location, but from a political and social acceptance standpoint, requiring ratepayers to pay for services they are not using raises profound questions of the legitimacy and acceptability of the structure of the TAC. Furthermore, the TAC structure appears to be designed to promote transmission owner profits at the expense of ratepayers, as there is a misalignment of DG output's cost causation with DG output's TAC.

Similarly, the Bonbright principles argue strongly in favor of adopting TED as the measurement of transmission grid usage. The measurement of usage at TED is practical, simple, and understandable. It follows the simple principle that TAC should pay for actual use of the transmission grid, fostering public acceptance. It is transparent and not subject to varying interpretations. Provided the TRR is established, it guarantees the recovery of a fair return, and should be stable from year to year as TED system-wide stays relatively stable. If implemented soon, the TAC rate would very slightly increase by a small percent, as DER currently makes up a small proportion of any LSE's energy portfolio. As we have emphasized, TED is a more fair approach in which the payments reflect the cost of service and would avoid undue discrimination (amongst customers of different LSEs that act to avoid transmission grid impacts, amongst technologies, and amongst energy providers). Finally, the use of TED would promote efficiency and discourage wasteful over-investment in transmission services.

Taken together, all five policy principles from FERC's Transmission Pricing Policy Statement and the Bonbright principles support moving the TAC billing determinant to the transmission-distribution interface. <u>The boundary of the transmission grid provides a consistent, unbiased, and technology-neutral point of assessment for measurement of use of the transmission grid.</u> This would result in a more competitive and less discriminatory TAC methodology and would directly resolve the existing TAC market distortion on DG output. We urge the CAISO to change where transmission usage is measured in PTO utility service territory to the TED.