Stakeholder Comments Template

Review TAC Structure
Stakeholder Working Groups

This template has been created for submission of stakeholder comments on the Review Transmission Access Charge (TAC) Structure Working Group Meetings that were held on August 29 and September 25, 2017. The working group presentations and other information related to this initiative may be found on the initiative webpage at: http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx

Submitted by	Organization	Date Submitted
Doug Karpa *Matt Renner*	*Clean Coalition* *World Business Academy*	*October 13, 2017*

Upon completion of this template, please submit it to initiativecomments@caiso.com. Submissions are requested by close of business on **October 13, 2017.**

Please provide your organization's comments on the following issues and questions.
NOTE: See last page for definitions of some key acronyms and terms.

The Clean Coalition submits these comments on its behalf. They are co-signed by the World Business Academy.

The Clean Coalition proposal encompasses one regulatory change by CAISO, and a series of regulatory changes that would be conducted by the IOUs in their FERC tariffs at the direction of the CPUC. We have held meetings with CPUC staff, several CCAs and one utility and received initial responses which have informed our proposal as it currently stands. The Clean coalition will be pursuing support for the corresponding changes to LV-TAC and billing from the CPUC and other stakeholders.

CAISO changes:

1) Move the location of the billing determinant to Transmission Energy Downflow at the T-D interface (T-D TED). This remains the simplest approach, given the network architecture of the transmission grid and radial architecture of the distribution grid. Other stakeholders pointed out that the necessary T-D meter upgrades would be cost-effective given the benefits and may be required for IOUs to engage in more sophisticated management of the distribution grid in any event.
2) Calculate the HV-TAC using T-D TED as the denominator

<u>CPUC and IOU changes</u>

1) Revise LV-TACs to a parallel structure to CAISO's new T-D based TAC structure in the TAC tariff submitted to FERC.

2) Establish an overcollection and refund mechanism to allocate DG credits to LSEs.
    a. Retain the existing delivery charge billing structure for customers, which would apply the new TAC to customer energy downflow as is done currently, albeit at a slightly higher per kWh rate. The overcollection would be directly the result of DG deliveries within each distribution area.
    b. The Utility Distribution Company (UDC) refunds a proportional share of the overcollection to each LSE that has procured DG output that serves local load where the DG is located.
        i. The DG output report in each distribution area would be based on the scheduling coordinator data associated with each LSE. Additionally, as appropriate, LSEs would be credited with the metered or estimated DG contribution from their NEW customer's exports to the distribution grid.
        ii. DG output can only be credited as supporting local load up to the local load at each time increment. This should mean that DG output is credited only when the TED for the distribution area is equal to or greater than zero for that time interval. DG that backflows up to the transmission grid is not credited. DG would be certified as serving local load when built and the last DG certified as serving local load would be the first not-credited under backflow conditions (First in, Last out). This would enable projects to evaluate their economics without major changes wrought by subsequent projects and allow each project to be built where backflow conditions are less likely.
    c. The overcollection payments to each LSEs must be spent for ratepayer benefit. For example, the overcollection payments could be used to reduce rates directly or to offset delivery charges for customers subscribing to high or all DG products offered by the LSE (e.g., MCE's "Local Sol" product.)

3) Current IOU LCBF and CCA procurement methods are already structured to properly account for the change in TAC structure and should need no further revision to shape procurement as intended.

[An alternative approach to the overcollection and refund method would be to create LSE-specific TAC delivery rates reflecting each LSE's local load serving DG contribution. Under this mechanism, the customers of each LSE pay distinct delivery charges based on each LSE's TED contribution after deducting DG-derived TED from total load as a basis for proportional allocation of TAC for the IOU territory. Also, the tariff should be revised to allow a separate delivery charge class for customers subscribing to local DG product offerings. These could constitute additional "customer classes" much like those already established under utility FER TAC tariffs based on the relative cost contribution of each customer class.]

1. **One concept for allocating the costs of the existing transmission infrastructure is to charge each user of the grid in accordance with their usage of or benefits received from the grid. What do you believe is the most appropriate way to measure each end-use customer's or load-serving entity's (LSE) benefits or usage of the grid? What specific benefits should be considered? Please explain you answer.**

Usage and benefits are two separate considerations. Usage refers to actual present use to deliver energy and energy services, while benefits largely represent either hypothetical needs (e.g., 'back up power") or services otherwise compensated for (e.g. frequency regulation through frequency markets).

Ultimately, the overwhelming use of the transmission grid is to deliver energy to customers. Thus, measurement of the *usage* of the grid should be based on how much energy is delivered across the transmission grid, which is the Transmission Energy Downflow at the T-D interface. This structure is both aligned with rate design principles and is simpler than measuring at the HV-LV interface.

Any measurement of transmission usage must be distinguished from distribution usage. Transmission usage is most appropriately measured at the transmission level. If measured externally to the transmission system (*e.g.*, CED), that measurement must be corrected to account for comingled usage and benefits provided not by the transmission system, but by distribution resources. Although theoretically possible, such an approach is logistically far more complex.

Some relatively small fraction of transmission grid cost recovery could be reserved to reflect benefits to customers separate from usage. Conceptually there are three categories of benefits. First, usage is still the best indication of benefit of the grid, since the actual delivery of energy is a realized benefit. Second, potential benefits of having a grid system, like "ready to serve" or "backup power," are those that may translate into actual use or may never actually occur. For most services and assets, these potential benefits are folded into usage charges. (For example, all people benefit from having a working taxi service, but we recover the entire costs of taxi services from usage fees rather than charging non-users a charge to reflect the potential benefit that they may use a taxi someday.) The third category of benefits are those derived from the joint operation of the distribution and transmission grids, such as reliability (since failures on any part of the grid can be addressed with dispatch onto other parts of the grid.), frequency regulation, etc.

Rate design principles may cut against expressly splitting out a benefit component of the rate structure in the TAC for three reasons. First, non-usage related benefits have a fairly indirect relationship to cost-causation, if any. As such, pricing and cost allocation should provide clear price signals to discourage cost causation, and not discourage maximization of benefits free from cost causation. Thus, when non-usage benefits are considered, it is critical to ask whether these benefits shape transmission planning and spending.

Often, the delivery of energy is the primary function and cost driver, and the appropriate measure of this cost-driver would be the average contribution to local, regional, and system-wide coincident peak capacity. At the most extreme, an islandable micro-grid with connection to CAISO will continue in operation regardless of whether it is islanded. Thus, it will not *inherently* use or benefit from the grid based simply on whether the connection is open or closed, although some abstract benefits analysis might suggest that the benefit it receives depends on whether it is connected, even if it uses no services from the grid. Indeed, benefits may flow in either direction as between Balancing Authorities, such that it isn't clear whether the microgrid should provide a "benefits fee" to the transmission operator or the other way around. In reality, an islandable grid that meets its own load would not appear in any transmission planning process as driving a need for new transmission.

Thus, any measurement of transmission usage must be distinguished from distribution usage, and is most appropriately measured at the transmission level. If measured externally to the transmission system, the measurement must be corrected to account for comingled usage and benefits not provided by the transmission system.

Second, the complexity of a precise quantification of abstract benefits for rate design may be more difficult than the marginal reduction in market distortions would warrant. Although we may be able to list many customers benefits that are not proportional to usage, the magnitude of these benefits may be so small relative to the basic benefit of receiving energy that the extra complexity of the rate design would simply not be worth the benefit of a strict accounting for these relatively small value (or rarely realized) benefits.

Third, several non-usage benefits already have independent mechanisms to pay for those benefits. For example, frequency regulation is a system wide joint transmission-distribution benefit that is quantified and paid for through frequency regulation markets. Where such mechanisms exist, compensation for those benefits should be handled independently from TAC or as a separate component.

2. **The example the ISO presented at the August 29 working group meeting (slides 21-22 of the ISO presentation) illustrated how using transmission energy downflow (TED) as the high-voltage TAC billing determinant (instead of end-use metered load) affects all ratepayers of each utility distribution company (UDC) irrespective of which LSE serves that load. If the ISO were to adopt TED as the billing determinant for the high-voltage TAC, what further procedures would be needed to ensure that the benefits of reduced TAC payments go to the correct LSEs that make the decisions to procure DG? Please explain your answer.**

Based on our conversations with stakeholders and CPUC staff, we believe that existing procurement methods, such as least cost-best fit, would reflect changes in the TAC structure as they are currently used. However, since the billing for TAC goes to the UDCs and thence to ratepayers, ideally the existing structure of the delivery charge tariff would need to be modified to deliver the appropriate price signal to procuring entities to align the revenue flows with procurement. This would require a change in the delivery charge tariff by the UDCs under direction from the CPUC.

<u>Over-collect and refund</u>

Our proposed methodology would continue to have each UDC charge all customers a uniform transmission delivery charge based on CED, as they do now, and then remit overcollections to each LSE for the avoided TAC from their documented local load-serving DG procurement. Under this proposal, any DG project serving local load (e.g., without backflow) would be eligible for a TAC refund, since it would reduce TAC as billed from CAISO to the UDC and contribute to the overcollection.

This method has several beneficial aspects. First this method would provide a direct financial signal to each LSE directly proportional to their DG procurement. Second, by allowing for DG outside of LSE territories to qualify, this proposal would allow the most cost-effective DG to be deployed rather than requiring an LSE's DG serve load within its UDC's service territory. Thus, the refund is a direct representation of the savings from avoiding TAC. Although this would require accounting and transfer payments for procured metered distributed generation by LSEs in other UDC territories to properly allocate over-collections, this would maximize the flexibility for LSEs to pursue the most cost-effective procurement.

Given that there may be potential difficulties with the preferred overcollection and refund method, an alternative method would be for the IOUs to revise delivery charge tariffs to charge distinct delivery charges to each LSE's customers as a distinct set of customer classes such that customers have different delivery rates depending on the DG procurement of their LSE. These would constitute additional "customer classes" much like those already established under utility FERC TAC tariffs based on the relative cost contribution of each customer class. This would also allow the UDC to account for LSE DG procurement, allocate the total TAC appropriately, and still bill customers directly while allowing LSEs to differentiate themselves based on lower delivery charges for customers.

This would involve some accounting mechanisms to balance accounts between UDCs if there were to be credits for DG built outside of the UDC territory. It likely would also require a market process for selling the WDG TAC credit in external UDC territories to LSE's in the territory. While this would be relatively simple, it still represents an additional contract process associated with each LSE procurement occurring in CAISO territory outside of its UDC. The frequency of such future contracts is unknown.

3. **The ISO could (a) continue to use the end-use metered load (EUML) or customer energy downflow (CED) as the basis for assessing high-voltage TAC, or (b) propose a change to assess HV TAC based on downflow at the transmission-distribution interface (T-D TED), or (c) assess HV TAC based on downflow at the interface between the high-voltage and low-voltage transmission systems (HV-LV TED). Does your organization prefer one of these approaches at this time? Please explain the reasons for your preference.**

Yes, Option b, then c.

As described in some of our prior filings, T-D TED is the clearest and most accurate measure of the delivery of energy and other services from transmission. T-D TED directly measures usage at the boundary of the transmission system, regardless of whether this is volumetric, time of delivery, or demand based. Although TED could also be used as a measure of usage between the HV and LV systems, the networked structure and potential for energy flows not directly related to a downstream load may complicate allocation of measured usage, as was pointed out by CAISO staff. Due to the radial structure of the distribution system, a clear boundary exists at the T-D interface that is not as clearly present between the HV and LV transmission grids.

4. **Does your organization believe that any of the options in the previous question present any potential problems or issues that have not been identified or explained during the stakeholder process thus far? If so, please explain. Also, please indicate what other analyses could be done to help understand the impacts of changing the point of measurement?**

No. The use of the T-D TED would require installation of revenue quality meters, but otherwise the proposal uses existing billing data to implement. Based on a $2,000 cost of revenue quality meters, we anticipate the total capital cost to be on the order of $2 million statewide. These revenue quality meters would also support IOU abilities to play a larger role in managing the distribution grid and services.

5. **Does your organization believe that the ISO should change *only* the point of measurement utilized for assessing TAC apart from considering other changes to the TAC structure? Alternatively, should the ISO change the point of measurement in conjunction with other changes to the TAC structure? Please explain your position.**

Changing the point of measurement is the top priority, because this is the primary driver of market inefficiencies in energy procurement. We would support a decision to change only the point of measurement as a first step, with additional processes to evaluate other changes later.

The Clean Coalition would be open to examining other aspects of the structure of the TAC, including demand charges or time of use. Certainly, deploying more DER will be a key strategy for containing transmission costs in coming decades, but other strategies may also be sensibly deployed.

6. **Does your organization believe that changing the point of measurement for assessing TAC to use TED instead of metered customer demand will result in increased procurement of DG by LSEs? Please explain your position.**

Yes. Changing the point of measurement for TAC to reflect DG contributions will change the relative costs of procurement, if the procuring LSE receives the price signal (which may require additional mechanisms beyond incorporation into IOU LCBF, since the CCA procurement methods are not reviewed by the CPUC.) Our conversations with stakeholders indicate that existing LCBF methodologies and CCA procurement generally would correctly capture this change even as they exist currently. Thus, more DG would be procured overall.

This change would make those projects with generation costs within approximately 3 cents per kWh of central generation cost-competitive in procurement where they are not currently.

LSEs will realize costs or savings in the delivered cost of energy for their customers based on their procurement portfolio, which can be reflected in lower customer rates. As we have shown in presentations, the price differential between average DG procured under ReMAT and the average transmission sourced RPS procurement is far smaller than even the HV TAC rate alone. On this basis, market demand for DG should increase until the supply curve reaches price parity with the cost of transmission sourced resources plus TAC.

As described above, accounting for LSE's proportionate contribution of DG relative to TED will be necessary for the LSEs to individually realize the cost savings rather than having the savings spread evenly across all LSEs in the UDC territory.

7. **Does your organization believe that increased procurement of DG by LSEs will reduce the need for future investment in transmission infrastructure? Please explain your position.**

Yes. All four drivers of transmission infrastructure investment can be addressed or mitigated with DG resources.

First, DG can and does directly address peak load. The nature of the load curve for the state still retains a peak within the key solar window, which means that increased PV DG would shift the peak to a lower and later peak. This would in turn reduce the need for new transmission build to meet peak load. In the out years, this PV is expected to increasingly be deployed with co-located storage which will enable DG to address evening peak loads as well, provided the appropriate cost signals exist to incentivize dispatchability. Similarly, the introduction of default TOU rates for residential customers, and adjustments to TOU rate schedules, will incentivize customers to shift load toward lower cost periods. To the degree that TOU rates align with DG production profiles, especially the PV profiles, peak demand will align with DG supply.

Second, DG can meet RPS requirements to reduce policy driven load. Certainly, the IOUs will need to procure RPS-eligible resources to meet requirements, but wholesale DG resources are every bit as eligible to satisfy RPS requirements as central generation. To the extent that these resources have similar production profiles, there is a 1:1 replacement and reduction in required transmission capacity to access RPS resources. Additionally, even non-RPS qualified DG, such as behind the meter NEM resources directly reduce the RPS MWh basis. Thus, by reducing the total generation, this production will reduce RPS transmission capacity at a 1:2 ratio with a 50% RPS requirement, for example. Thus, increased renewable DG can clearly ameliorate policy cost drivers.

Third, DG can reduce transmission use, freeing up capacity to flexibly obtain economical central generation without needing new transmission build. Currently, some transmission build will be proposed to provide the flexibility to enable more cost-effective resources to be deployed to meet load. However, much of that need will be driven when existing lines are at capacity and prevent the use of these cheaper resources. Increased DG deployment in constrained areas along the transmission grid can open transmission capacity to allow access to cheaper resources using existing lines that otherwise would be at capacity or facing higher congestion losses. Thus, DG can also assist with creating the flexibility to access the most cost effective central resources. In addition, DG offers additional cost competition among all resources to drive down the marginal cost of both procurement contracts and CAISO market prices. As is well documented in Germany, increased use of renewables, primarily DG PV, has had a marked Merit Order impact on dispatched prices and reduced the cost of conventional energy supplies for ratepayers.

Fourth, DG can meet local reliability needs, alleviating the need to install transmission lines to deal with N-2 contingencies, for example. Some transmission build will be proposed to provide reliability services. However, frequently local load, voltage balancing and short circuit duty can be provided by local resources instead of building new transmission lines into load pockets. DER have recently been shown to be viable alternatives to either peaker plants or new transmission lines in the Moorpark subarea. The Clean Coalition documented that solar+storage resources can cost effectively meet the needs associated with the Ellwood Peaker refurbishment, and CAISO developed a critical demonstration that distributed resources could provide reliability services in the Moorpark sub area instead of building a new peaker. Both studies demonstrate that distributed resources can supplant the need for new transmission to provide reliability.

8. **The Clean Coalition provided a spreadsheet and documentation (available at the ISO's TAC initiative web page link on page 1) showing their approach for estimating the savings from avoided future transmission investment that could result from increased DG procurement in response to the ISO adopting TED as the point of measurement for assessing TAC. Does your organization believe that Clean Coalition's analysis provides a reasonable projection of transmission cost savings as a result of DG growth? Please explain your position.**

Yes, although we recognize that the model is a first approximation with many assumptions to be evaluated and perhaps critical refinements to be made based on this foundation going forward. Note that while the model is populated with the best available data, it is designed to be indicative rather than forecasting precise results, and allows stakeholders to input different values and assess how this influences the degree of impact from increased DG deployment, based on the current volumetric measurement approach.

9. **If you do not agree with Clean Coalition's projections of transmission cost savings, what approach would you suggest for estimating savings from reduced need for future investment in transmission that could result from increased DG development?**

The next additional refinement to our model might be to assess what needs past and future transmission projects are designed to meet, and develop submodels for the different drivers to assess how much each driver could be offset with DG under different assumptions of growth in DG deployment.

The existing model incorporates current peak load impacts from existing DG portfolios, but does not project changes in TOU influenced load shape changes. The MWh focus is most appropriate for assessing reduced RPS driven investment, Inclusion of economic based investment, and projections regarding transmission drivers would be helpful, but not essential for assessing the fundamental merits of TED.

10. **The ISO must decide what types of analyses to perform to evaluate alternative TAC approaches, and how to prioritize them. Please provide your organization's view on what analyses would be most useful, and indicate the relative importance of each analysis you recommend to assist the ISO in determining which analyses should take precedence.**

First, Among the most critical and controversial analyses would be to analyze the future growth of transmission costs and the drivers of transmission growth. While we recognize that some of the factors that have driven transmission build in the past may not continue drive future transmission investment, while new drivers of transmission are likely to develop, especially as RPS requirements climb and storage and EV are deployed as part of building and transportation electrification.

As part of that analysis, CAISO should evaluate the applicability, strengths and weaknesses of various projections of TAC growth. For example, some of the current projections only model currently approved projects, but do not forecast as yet unplanned projects that will address future Grid Needs which have not yet reached the thresholds required to trigger project planning.

Second, CAISO may wish to assess the structure of the DG market to derive better estimates of the increase in DG deployment from changes in procurement costs. As illustrated in our presentation and discussed above, the actual expected increase in DG deployment is going to depend on how many projects need prices between the generation prices of remote generation and the remote generation price plus transmission costs. Projects that cost more than that will not be procured in any event.

Beyond the questions related to TED and DG, the impact of demand charges and TOU rates should be evaluated, drawing from the CPUC proceedings establishing these in rates, and the historical impact where these have been applied to customer classes. A combination of load shaping, local resource development, and availability of least cost resources (after accounting for associated transmission costs) is likely to result in the most effective policy.

Under our proposal, the question of backflow between LV and HV transmission is less critical, but if there is only minimal flow, CAISO may consider measuring HV usage at the LV-HV interface.

11. **How can the ISO evaluate the downstream financial impacts of potential changes to the TAC structure? What data would best inform the ISO and stakeholders of the potential impacts to various entities? Does your organization believe the ISO should focus on this question now, or wait until potential TAC structure options are better defined (e.g., after the ISO issues a straw proposal)? Please explain your position**.

CAISO would need to calculate the TAC under each format for a common set of data representing conditions today and under future conditions of high, medium or low increases in DG deployment rates, as well as any non-volumetric basis for charges.

While changes such as TED allow each LSE to economically optimize their resource portfolio over time with minimal immediate impact, shifting away from the current volumetric basis may create substantial immediate cost shifts which are related to differences in LSE load shapes that cannot be mitigated (due to climate or customer class).

Certainly, the impacts on the TAC rate can be calculated based on data on total load by LSE, total DG (from scheduling coordinators), total gross NEM exports (which each IOU provides in filings in reports on NEM in our understanding), and TRR. Calculating the propagation to customer bills would simply be a percentage increase of the transmission portion of delivery charges under existing tariffs. The overcollection refund payments for LSE could be estimated from the LSE specific DG and NEM export data mentioned above. (Alternatively, CAISO could use similar data to calculate how LSE specific customer delivery charges would change under an LSE-specific delivery charge regime. Although these calculations involve factors outside of CAISO jurisdiction, they would still prove useful in evaluating the approximate magnitude of changes. Also, CAISO should evaluate the magnitude of changes that would occur should CAISO wait until DG makes up more than the 4% of the total energy in California by modeling the corrections involved when DG represents 10% of California's energy supply.

CAISO already has much of the key data to calculate the financial impacts in the TAC filings. CAISO's TAC filings include the total load and TRR data, while the IOUs can provide both NEM export and DG procurement data. Doing a simple model now would be useful before the straw proposal to provide an estimate of the magnitude of any changes, while this model can be developed further in future iterations to evaluate other proposed changes.

We note that the Clean Coalition TAC Impact model provides a basis for assessing differential impacts of DG and TED and LSEs

12. **How are transmission needs and costs driven by the delivery of energy versus the provision of capacity necessary to meet peak load conditions? Please explain your position**.

At first pass, the ultimate layout of the transmission system is designed with meeting peak load with two transmission lines down at any given time. However, within that frame work, energy delivery also drives additional costs on top of the peak load drivers. For example, some transmission projects are built to secure RPS resources or to allow transmission grid flexibility to meet energy needs with the cheapest resources, separate from any needs to meet peak load. These drivers add costs on top of the minimum peak load design that are independent of the peak load. These needs are driven to deliver energy conforming to certain requirements (price, renewables-generated) and so are driven by the delivery of energy not peak load. Thus, the answer is a combination of the two factors based on the different functions the transmission grid serves. Naturally, many transmission projects provide benefits on several drivers such that it may not be possible to neatly assign projects to particular drivers.

13. **In considering potential changes to the TAC structure, what kinds of changes would best align with the impacts of energy delivery, peak load and other drivers of new transmission investment? Please explain your answer.**

First, the T-D interface TED measures use of the grid to deliver energy based on the energy actually flowing on the grid. Whether we seek to capture total energy flow, time of use, or peak demand, it is the actual energy flow across the interface that measures these aspects of grid usage.

Second, the best alignment should be judged in large measure based on an evaluation of the impacts of the TAC rate structure. While some may feel that rate structures such as a flat fee or CED-based fees may have some philosophical appeal, they would utterly fail to provide pressures to constrain future transmission growth and so not represent a most cost-effective approach nor would not deliver benefits to ratepayers.

From those principles, as demonstrated the T-D TED creates incentives for economical transmission investment in ways the CED basis for TAC rates and charges does not. Similarly, there are solid arguments for charges related to peak usage including demand charges or time of use charges or other peak cost driving related charges.

Finally, as the users of transmission change, the cost of use should follow the current user. Customers should not be charged more for an asset simply because planners in the past did not accurately forecast who would be using an asset. Charging the actual users of an asset is far fairer than charging the predicted users. Even if past transmission projects were built for particular future projected use, the cost recovery for the projects should be based on how the project is actually used, not how planners thought it might be used. Thus, even if the population of users of an asset changes over time, the most appropriate way to charge for the asset is to charge based on actual use at any given time, allowing the market to evaluate the best balance between resources which do or do not incur TAC delivery charges. Billing for actual use at each point in time ensures that users pay in proportion to their use over the lifetime of the system. The alternative would be to charge different customers different rates for their use today depending on whether the transmission asset was built "for them" or whether they are part of a new and then unforeseen class of users. It would be difficult to defend to customers that they're being charged more because planners predicted they'd use the asset, even if they're not using it.

Furthermore, charging customers for assets independent of actual use represents a sharp departure from pricing models for almost every other asset. With any other product, the value of assets is folded into the charges for using the asset. Taxis are recovered by fares paid by people using them, not by fees on those who might use them in the future or by fees on those the taxi owner thought might use the taxi when it was purchased. Grocery stores do not charge "shelf maintenance fees" to people who do not shop in them but might someday. Cell phone networks are billed to existing customers, and are not billed to those who aren't using those networks, until they do use those networks. In all of these cases, the costs of the asset plus profits are paid for by those using the assets.

Charging individuals other than the users also creates perverse incentives to overuse an asset. Where costs are independent of use, the per use cost actually declines the more the asset is used. Conceptually, by locking in charges to those originally forecast to be users creates incentives for those individuals to use the assets for which they are paying and exclude new users. This would be a barrier to flexibility where the asset can be put to new uses by charging the new users for that use.

14. **What are the cost drivers of operating and maintaining the existing transmission system and what, if anything, could materially affect these cost drivers? In particular, does your organization believe that increasing the share of load served by DG can reduce any costs associated with the existing transmission system? Please explain your position.**

As a first approximation, increased DG would not affect O&M costs of existing transmission assets. Although reducing peak use can reduce the wear and tear on components over time, O&M schedules and costs are not likely to be changed appreciably. Unless DG deployment allows whole lines to be abandoned, the O&M costs are committed costs that were incurred when the project was approved even if the payments are made over time. However, reducing the need for additional transmission capacity will reduce the total O&M costs associated with the transmission system, and these savings will increase over time.

As outlined, these O&M are costs incurred on behalf of those for whom the grid is maintained (e.g., those who use it.). Certainly, parties who no longer use the transmission grid (e.g., customers who move out of state or die) are not those whose use would be affected by degradation caused by a lack of O&M. Thus, while DG deployment will not affect the O&M costs, it is likely to shift somewhat the makeup of the beneficiaries of that spending.

Since DG deployment is likely to meet only a portion of new load growth, but unlikely to displace existing load from service by remote resources, we anticipate that the existing grid will continue to serve load that exists today using remote resources as it is today. Increased DG deployment would almost entirely have impacts on new transmission, which will roughly serve new load or new needs (e.g., future RPS procurement, future reliability constraints.).

15. **Please offer any other comments your organization would like to provide on the material discussed in the two Review TAC Structure Working Group meetings (August 29 and September 25), or any other aspect of this initiative.**

The Clean Coalition has expanded the scope of our efforts to incorporate coordinated changes by the IOUs in their TAC tariffs to ensure that the linkage from CAISO charges to LSE procurement function as intended. We have had positive responses from the stakeholders we have met with and have several additional meetings with other stakeholders in coming weeks. If these conversations are as productive as our meetings to date, we are hopeful of working toward a consensus proposal supported by most (if not all) stakeholders to create a consolidated multi-agency proposal for transmission charges.

<u>Related Acronym Definitions:</u>

- **Community Choice Aggregator (CCA):** One type of non-utility Load Serving Entity that can operate in an investor-owned utility service area.

- **Customer Energy Downflow (CED):** Metered energy delivered from the grid to an end-use customer measured at a customer meter, also referred to as end-use metered load (EUML). Customer energy consumption that is met by output of DG located behind the same customer meter is not included in CED. Also, CED does not include any production of DG behind the customer meter in excess of consumption behind the same meter during the same interval.

- **Distributed Energy Resources (DER):** Energy resources connected at distribution level, either on the utility side or the customer side of the customer meter, without regard to technology type or size. DERs include distributed generation (DG), energy storage of various types, EV charging stations, as well as demand response and energy efficiency.

- **Distributed Generation (DG):** Generating resources deployed at the distribution system level, either on the utility side or the customer side of the customer meter; DG is one type of DER.

- **Electric Service Provider (ESP):** One type of non-utility Load Serving Entity that can operate in an investor-owned utility service area.

- **End Use Metered Load (EUML):** Another term for customer energy downflow (CED).

- **High Voltage (HV):** Transmission system 200kV and above.

- **Low Voltage (LV):** Transmission system below 200kV.

- **Transmission Energy Downflow (TED):** Gross metered energy flow measured at specified transmission system interfaces, either (a) from high-voltage to low-voltage transmission **(HV-LV TED)**, or (b) from transmission to distribution **(T-D TED)**. TED measurements do not reflect energy flows in the opposite direction from LV to HV transmission or from distribution to transmission.