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**
Steve Hance	*Silicon Valley Power*	*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.

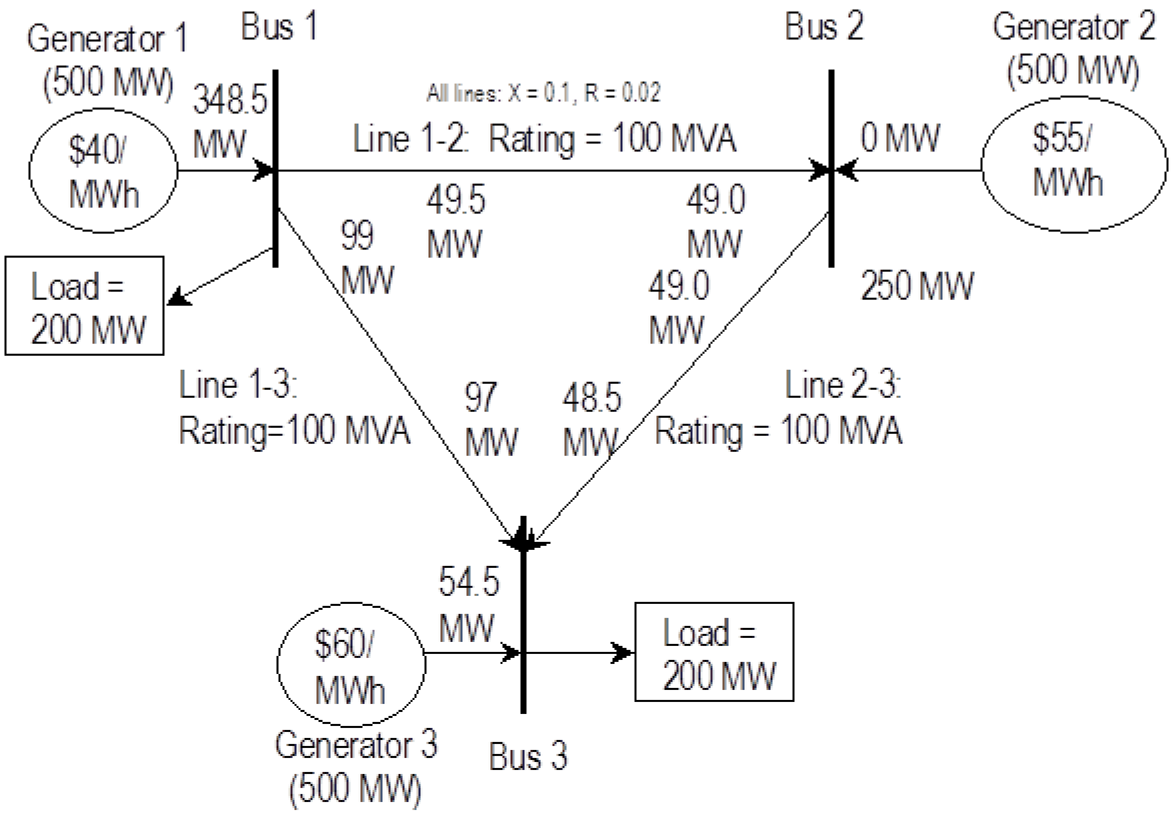
1. *One concept for allocating the costs of the existing transmission infrastructure is to charge each user of the grid in accordance with their usage of or benefits received from the grid. What do you believe is the most appropriate way to measure each end-use customer's or load-serving entity's (LSE)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

   Silicon Valley Power ("SVP") submits that allocating costs of the transmission infrastructure - based on usage or benefits in the context of Distributed Generation ("DG") - needs to take into account factors including: (1) the location of a DG resource; (2) the output characteristics of the DG resource as it relates to peak demand and the need for transmission as a back-up supply resource; and (3) whether the location and characteristics of the DG resource reduce transmission costs caused by peak load demand by reducing the need to invest to address transmission constraints. The cost of transmission congestion appears in the Locational Marginal Price ("LMP") that is calculated at various nodes, but, for load, is ultimately socialized through Default Load Aggregation Point ("DLAP") pricing. As discussed in SVP's comments below, price signals to incent beneficial placement of DG to reflect reduced costs or increased benefits are not created by Transmission Energy Downflow ("TED"). Rather TED appears to result in a subsidy to all DG regardless of transmission benefits, which is inappropriate. Further, TED doesn't appear to account for the degree to which Integrated Resource Plans (IRPs) and related procurement processes incorporate incremental transmission costs into their procurement plans. Thus, SVP suggests that the appropriate place to address DG incentives and/or subsidies is in LSE IRP and Local Regulatory Authority ("LRA") procurement processes.

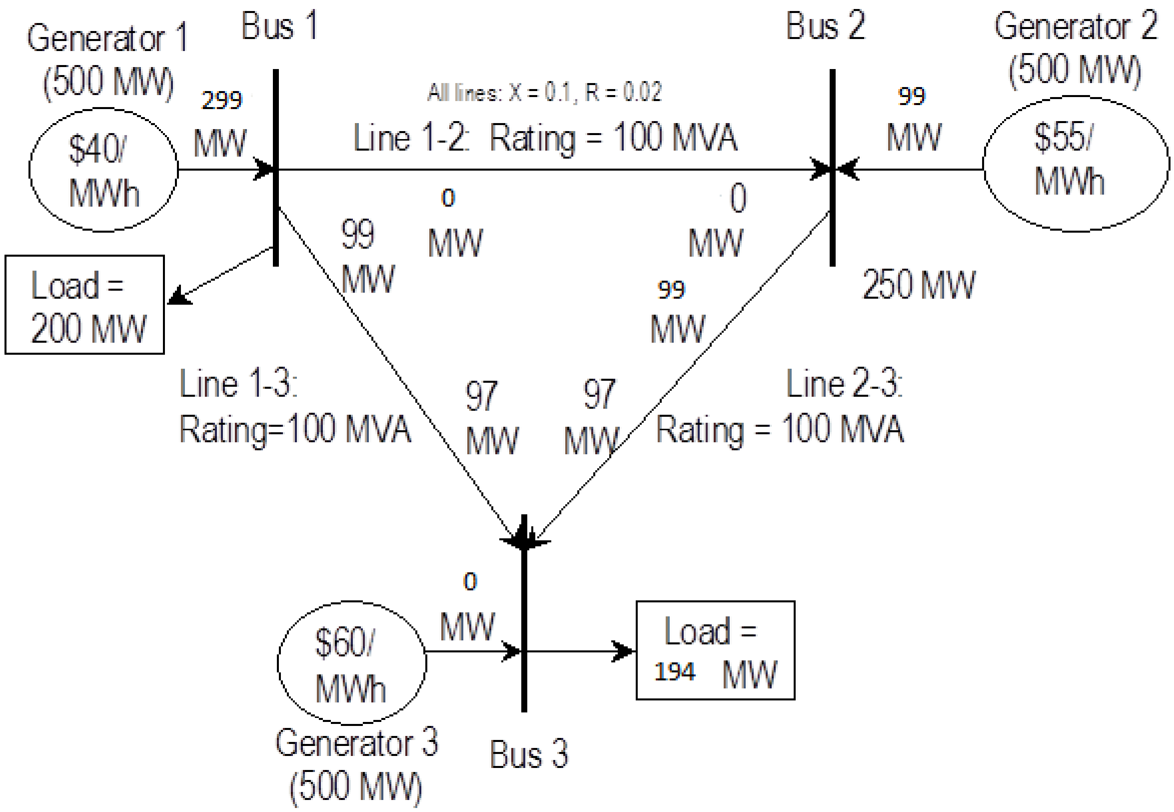
In regards to Transmission Access Charge ("TAC") structure, with the understanding that the transmission grid is designed to meet peak demand, it would be appropriate to allocate a portion of the TRR based on peak usage (in addition to a volumetric component). The existing purely volumetric rate design does not reflect the costs of transmission investment necessary to meet peak demand, and simply changing the location where volumetric usage is measured will not indicate whether DG resources are capable of reducing peak demand and the associated need for transmission investment. Additionally, all LSE load is charged the DLAP from an energy scheduling perspective (through Scheduling Coordinators representing the load of the LSEs) - where in theory the averaged DLAP price is lower than the sub-LAP price would be for congested areas of the grid.

SVP utilizes the following Three Bus example from the CAISO BPM for Market Operations[1] to illustrate how DLAP LMPs can be affected by transmission upgrades or the location of a new distributed generating facility (also, please see our response to question number 4, below regarding DG placement) – see below diagram. In this example, Line 1-3 is fully loaded at its rated capacity causing the need for generation from Generator 3 to serve load at Bus 3. This then results in a DLAP price which is the weighted average of the load node LMPs times the load served by those LMPs. (200 MWh * $40/MWh + 200 MWh * $60/MWh)/400 MWh = $50/MWh for the DLAP. If Line 1-3 was reconductored to a 200 MVA rating the load at Bus 1 and Bus 3 could be served using only Generator 1, causing the LMP at Bus 3 to drop to $40/MWh and resulting in a new lower DLAP of $40/MWh - which benefits the LSE serving load at Bus 1 and the LSE serving load at Bus 3 even though the reconductoring of Line 1-3 was performed to serve load at Bus 3 only. When you think about this being applied to more than a simple Three Bus model it gets much more complicated, but it is safe to conclude that transmission facilities developed to reduce transmission constraints provide benefits to all LSE's that pay the DLAP - even if the specific transmission upgrades may not directly serve an LSE's particular load pocket. The benefit of lower DLAP prices will not accrue to each LSE equally. LSEs using a greater volume of energy will receive a greater benefit, so for two LSE's with equal peak demand, the one with a higher load factor will benefit more from transmission investment that reduces congestion (and thereby reduces the DLAP pricing), because the LSE with the higher load factor will use more energy. This supports a conclusion that some portion of the TRR should be recovered through a volumetric component.

[1] https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Operations



The Three Bus figure below reflects changes to the above figure which illustrates SVP's point that volumetric rates do not capture the stand-by benefits provided by transmission investments, and supports the consideration of a demand charge component to be utilized along with a volumetric component. SVP suggests considering what would happen if Generator 3 was taken out of service for maintenance, and for simplicity, let's also assume that the load at Bus 3 was only 194 MW vs. 200 MW so the load can be reliably served without overloading any transmission element. Without Generator 3 available the load at Bus 3 would be served with a combination of Generation output from Generator 1 and Generator 2, where Gen 1 output is 299 MW and Gen 2 output is 99 MW causing flow on Line 1-3 and Line 2-3 to be 97 MW for each line ending at Bus 3. Assuming this outage of Generator 3 only occurred for a few hours of the year, this additional loading of the transmission grid by 48.5 MW on Line 2-3 (and the need for its existence from a reliability perspective) isn't captured by having only a volumetric charge – a charge that doesn't highlight the standby nature of the transmission system needed to reliably serve load.



In this example, it is clear that Line 2-3 is needed at its existing rating to reliably serve load even though its full capacity is only needed during a few hours a year when Gen 3 is unavailable. SVP suggests expanding on this scenario somewhat by adding that the load at Bus 1 is represented by "ABC" LSE, and the load at Bus 3 is represented by "XYZ" LSE - where this specific depiction of the system represents the moment in time of the system peak. Let's further assume that the load factor of ABC is 80% and XYZ is 30%, meaning that on an annual basis ABC consumes 200 MW*8760 hours*.8 = 1,401,600 MWh and XYZ consumes 194 MW * 8760 hours * .3 = 509,832 MWh. Assuming the use of a TAC rate that only uses a volumetric component, ABC will pay 73.33% of the TRR, and XYZ will pay 26.67% of the TRR - when ABC contributes to 50.76% of the peak demand, and XYZ contributes to 49.24% of the peak demand. This example illustrates that LSE XYZ benefits from both the reduction of LMPs through DLAP pricing and the cost allocation of the TRR through a purely volumetric rate, while LSE ABC pays for a considerably larger portion of the TRR while it benefits to a much lower extent than LSE XYZ from the reduction in LMPs through DLAP pricing.

SVP strongly believes this market participant initiative will not be able to develop TAC billing determinants that results in a perfect allocation of costs based on benefits. That said, SVP submits that a combination of demand and energy TAC billing determinants is necessary to yield just and reasonable results, whereas use of only volumetric rates fails to properly reflect the costs of transmission investments needed to meet the peak demand of each LSE. Keeping that in mind, some of the key factors in determining benefits of the transmission system for various LSE's are:

a. Peak Demand
b. Load Factor

   c. PTO or Non-PTO
   d. DLAP benefit or burden on a particular LSE

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.*

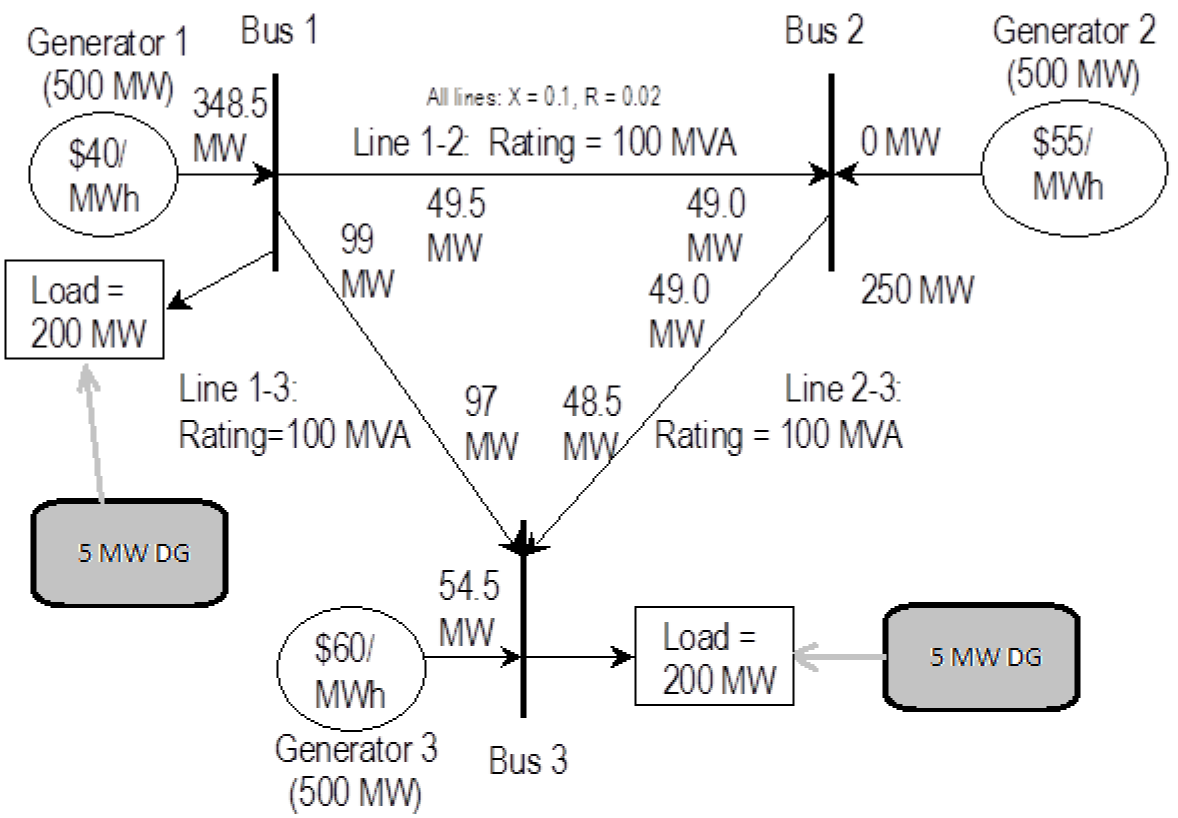
   SVP believes that the LSEs who procure DG are compensated through a valuation of the PPA price associated with the specific DG project and the LMP of the DG resource. Right now, the particular LMP at a node reflects the value of generation at that node, and what is lacking is a means for the generation developer to lock in that value on a going forward basis through a means other than the PPA with a UDC/LSE – as the presence of the new DG will affect the existing LMPs. Implementing TED for all DG should not be the mechanism used to incent the growth of DG because it does not provide price signals that reflect the varying benefits (or burdens) of DG based on location and output characteristics.

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.*

   For the reasons expressed above and in the following sections, SVP believes EUML is the most appropriate location to measure transmission benefit, but TAC should also be adjusted to utilize a combination of peak usage and volumetric flow. For the reasons described in the other responses in this template, if TAC continues to be collected primarily based on volumetric usage, then today's existing application of TAC should continue (as non-PTO investment in transmission is not recovered from all CAISO system users). Additionally, there may be the need to make adjustments for LSE's who on an aggregated basis do not receive a benefit through DLAP pricing (see example discussed in question 1).

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?*

SVP believes the TED approach will not result in the desired price signal to incent DG deployment at locations where the economic benefits of avoided future transmission in the Clean Coalition model will be realized.



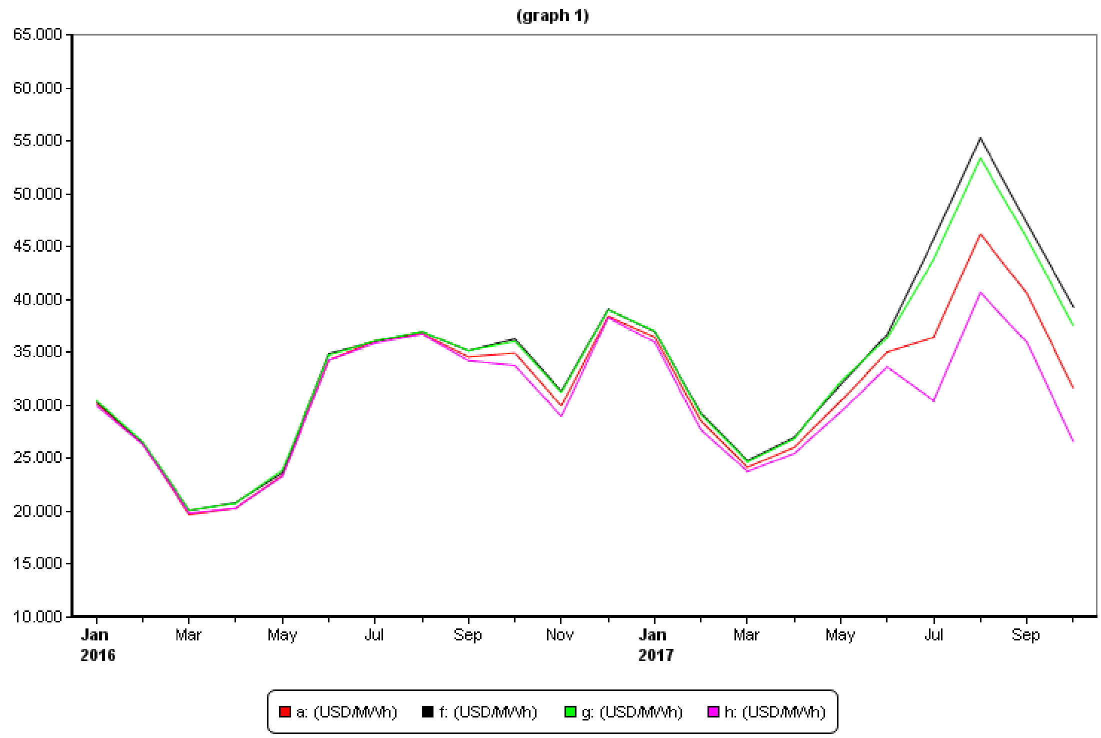
Using the Three Bus model (see above) again from the CAISO's BPM, SVP creates a scenario where 5 MW of DG was added to serve the load at Bus 1. SVP understands that under the TED allocation proposal there is a perceived benefit of some future avoided transmission cost that will be realized - when in fact the result would be simply to reduce the output of the cheapest generator. That is, no new transmission would be avoided, but the LSE responsible for the DG receives a benefit of lower TAC charges while other Market Participants would pay correspondingly higher TAC charges. We can also look at adding 5 MW of DG to serve the load at Bus 3, where there is a reduction in the need for generation from the output of the highest cost generator, but for this moment in time, based on only 5 MWs of output, the DLAP price would be unchanged since Generator 3 is still setting the LMP at that load node. In this case the DG is capturing its locational value in the LMP specific to its generator. What the market needs is the ability to capture this same value if 55.5 MW of DG was deployed at Bus 3. In this scenario, the LMP at Bus 3 would go to $40/MWh and the DLAP would also drop from $50/MWh to $40/MWh, benefitting all LSEs. Once this amount of DG is deployed the market signal for its need is eliminated[2], and SVP understands that there is no forward market instrument currently available to the DG developer to hedge the exposure to the decreasing nodal LMP. This essentially results in their investment having a stranded cost if they did not have a fixed price

[2] This issue also exists for non-DG generation.

PPA. SVP suggests this is much more of a procurement issue that falls under the jurisdiction of the CPUC or LRA of the LSE when LSEs are conducting their IRP and procurement processes. For example, if historical LMPs indicate that a specific load node, or subset of the DLAP, has an LMP significantly higher than the applicable DLAP during the projected hours of output associated with the proposed DG project, then it would make sense that the procurement requirements established by the LRA would require DG at that location to be sought/procured. Assuming a DG project's output at such a location did not lower area peak use and transmission still needs to be developed to serve that peak demand at that moment in time - but the DG project also gives access to cheaper cost resources during non-peak usage hours - then such non-transmission cost benefits could be accounted for in the procurement process when evaluating the benefits provided by the DG resource. This would result in DG providers receiving sufficient credit – as do remote utility scale generation – in the evaluation portion of LSEs' IRP and procurement processes. It is inappropriate to reflect those local energy pricing benefits through transmission pricing when the DG is not producing transmission benefits.

SVP submits that other analysis could be done to help further understand the ramifications of changing the point of measurement – which could include something like the following:

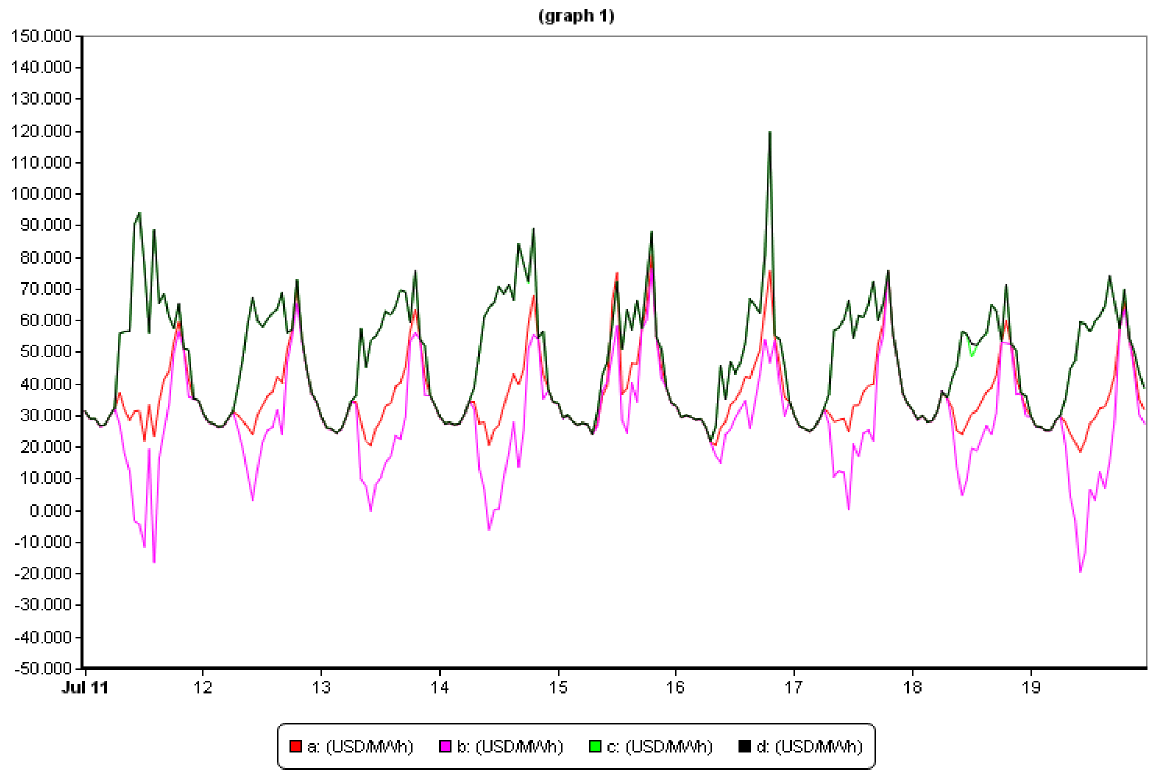
To the extent certain load nodes, or pockets of load nodes, have historically exhibited significantly higher LMPs than the applicable DLAP, studies could look at these particular locations and ascertain why, or why not, DG has been deployed at these locations, or whether the existing LMP at such locations sufficiently provide the desired price signals. Such studies could also examine whether using a TAC billing determinant measuring location such as TED is any more likely to result in the development of DG in desired locations (as opposed to at other less desirable locations) from a transmission congestion perspective. SVP observes that the area around the UC San Diego campus may be a good candidate for a case study. That area appears to have three load nodes (UCM_6_N001, UCM_6_N002, UCM_6_N006) and one GEN node (UCM_6_N110), all of which have the same LMP value. Looking at these particular LMPs and comparing them to the DLAP_SDGE-APND appears to indicate that there is significant value to locate DG in this area. SVP believes such a case study is likely to show that TED does not necessarily result in a price signal beyond the existing signal already given by the LMP. Comparing the value that could be extracted from the market at other load nodes in the general vicinity of the UCM_6_N00X load nodes - such as at TOREYPNS_6_N001, MESARIM_6_N001, and ELLIOT_6_N004 - if an equal amount DG was deployed at any of these alternative locations, both with or without TED applied, will provide insight into whether TED consistently provides a beneficial price signal (or simply results in an additional value stream to DG regardless of whether it is located where the system most needs it).



The graph above is the monthly average DA LMP for the following load nodes:

Red line is DLAP_SDGE-APND
Green line is TOREYPNS_6_N001
Black Line is UCM_6_N001
Violet Line is ELLIOT_6_N004

The below image is the same four LMPs looked at on an hourly basis from July 11, 2017 – July 19, 2017. Two of the load nodes (UCM and TOREYPNS) appear to have significant price signals that would indicate the deployment of solar PV would be beneficial, while the ELLIOT load node does not appear to be as valuable of a location from a transmission benefits perspective. SVP posits that the implementation of TED - as it has been proposed – appears to give the same benefit to all three load nodes. Accordingly, while TED may benefit an entity relying on DG to serve its load, it does not reflect the value of DG from a transmission congestion relief/locational perspective. Accordingly, using TED does not comport with cost causation principles because it provides benefits to DG which are not necessarily related to benefits to the transmission system.



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.*

SVP does not believe the CAISO should change the point of measurement associated with the TAC - unless studies clearly show that doing so would cause DG to be deployed only where there is a clear transmission system benefit. As of now SVP believes the TED proposal simply amounts to an across-the-board subsidy to DG that may or may not provide future transmission benefits (where such benefits will ultimately depend on where the DG is developed). Simply providing a subsidy to make DG economical at a location where it currently is not economical does not provide the assurances needed to justify the change. Using the graphs above to illustrate this point, the load node ELLIOT_6_N004 had a historical value during this past summer that was lower than the SDG&E DLAP price. Under the LMP model that conveys that the transmission system at this point is not as congested as the average of the SDG&E system, adding DG to serve load here is not beneficial from a transmission congestion perspective. Moving the TAC billing determinant to the transmission-distribution interface would result in an additional revenue stream to DG located at this load node even though it does not provide a transmission benefit. The desired outcome should be to locate DG at the higher priced load nodes, not to create a subsidy for DG deployed anywhere on the system regardless of benefit.

Instead of changing the point of measurement utilized for assessing TAC, SVP believes it would be more appropriate to allocate some portion of the TAC through peak demand. Such an allocation determinant will more closely align with a key driver of the need for transmission, peak demand, and with the fixed cost nature of transmission development. It also will make evaluating alternatives to transmission development - such as DG – easier, provided the DG resource provides a reduction in peak demand. Simply unloading a transmission segment or constraint during times of non-peak use does not necessarily eliminate the need for a transmission upgrade, but instead results in an under-utilized asset while shifting costs.

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 assessing TAC could result in a significant subsidy to DG regardless of location or future transmission cost benefit. A subsidy of this magnitude should cause an increased amount of DG deployment, but with no guarantees that the deployment will be at the most beneficial locations from a transmission cost avoidance viewpoint. Unless it provides transmission benefits, DG should not be subsidized through lower transmission charges for the load it serves. Again, SVP believes that the procurement need of DG falls under the jurisdiction of the CPUC or other LRA of the LSE as does the related IRP process.

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.*

SVP believes that generation deployment at the right locations in the transmission and/or distribution system could result in some decrease in future transmission investment. However, SVP does not believe that TED will automatically result in a price signal that will cause DG development at needed locations. Landfill gas projects connected to the distribution system will be dependent on the location of the landfill, solar will be developed where land is available and is cheapest, etc… Simply allowing DG to be developed anywhere there is current demand - and allowing that existing load to avoid some share of the TAC – without a corresponding reduction in peak demand - will not eliminate the need for future transmission development.

Having retail rates that most reflect how costs are incurred at the wholesale level will have the most effect on the need for future transmission investment. Knowing that many capital costs in this industry are driven by peak demand needs, but utilizing an allocation of such costs through a volumetric basis makes it risky for LSEs to then pass these costs on to retail customers in a rate structure that is different than how the LSE is charged at the wholesale level. An example would be your typical residential rate structure with no demand charge, and a flat or tiered energy rate with no time of use period. This type of structure does not incent the end user to invest or modify behavior in a manner that avoids the need for future investment. Roof top solar is a perfect example where rate structures such as net metering have incented investment by end users that does not necessarily avoid the future investment in infrastructure, but instead shift some of these costs to others not capable of partaking in similar investment options. This is not to say the initial stages of roof-top solar build out didn't realize some of these benefits, but it is important to keep in mind that during these initial stages the output of roof top solar did reduce the system peak demand. That is not necessarily true for future deployment of roof-top solar, and this highlights the problems that are caused when rate designs don't match how costs are incurred. Future investment in transmission infrastructure will likely be most impacted by energy storage devices and their locations. With the understanding that reducing peak loading of the transmission grid is what will be needed to avoid future investment in new transmission, rates on the wholesale side of the business need to reflect this (utilize peak demand) to get the proper price signal.

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*

   SVP is not convinced that the documentation provides a reasonable projection of transmission cost savings resulting from DG growth. The Clean Coalition's modeling approach assumes that growth in transmission costs is directly linked to growth in energy usage. The recent significant increases in TAC charges during a timeframe with declining or flat energy usage, demonstrate that this assumption is not valid. Other factors have significant bearing on the need for new transmission, including growth in demand (rather than energy) and the location of future generation resources. Moreover, transmission capital costs are not driven solely by load; but also by other factors, such as public policy goals (renewable portfolio system goals, once-through cooling and nuclear power plant retirements, economic projects, etc.) that increase transmission capital costs. Furthermore, Clean Coalition's analysis ignores the degree to which CPUC-jurisdictional entities' IRPs and procurement processes incorporate incremental transmission costs into their procurement plans. The Clean Coalition's spreadsheet model assumes that TED will result in DG being located only at locations where transmission constraints will be unloaded. As stated earlier, in general TED will simply result in many transmission paths that are not currently constrained to be unloaded further. It will not reduce current debt service payments, O&M costs of existing transmission, or eventual replacement of existing infrastructure as it ages. As we have seen from many Transmission Owner Tariff cases, a significant portion of the rising Transmission Revenue Requirements is purportedly caused by costs of existing transmission - not new builds needed for reliability or growing load.

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?*

SVP does not have a specific suggested approach at this time. However, whatever mechanism is utilized needs to reflect the locational and operational characteristics of the specific DG resources, and the corresponding transmission benefits (or lack thereof) the DG provides.

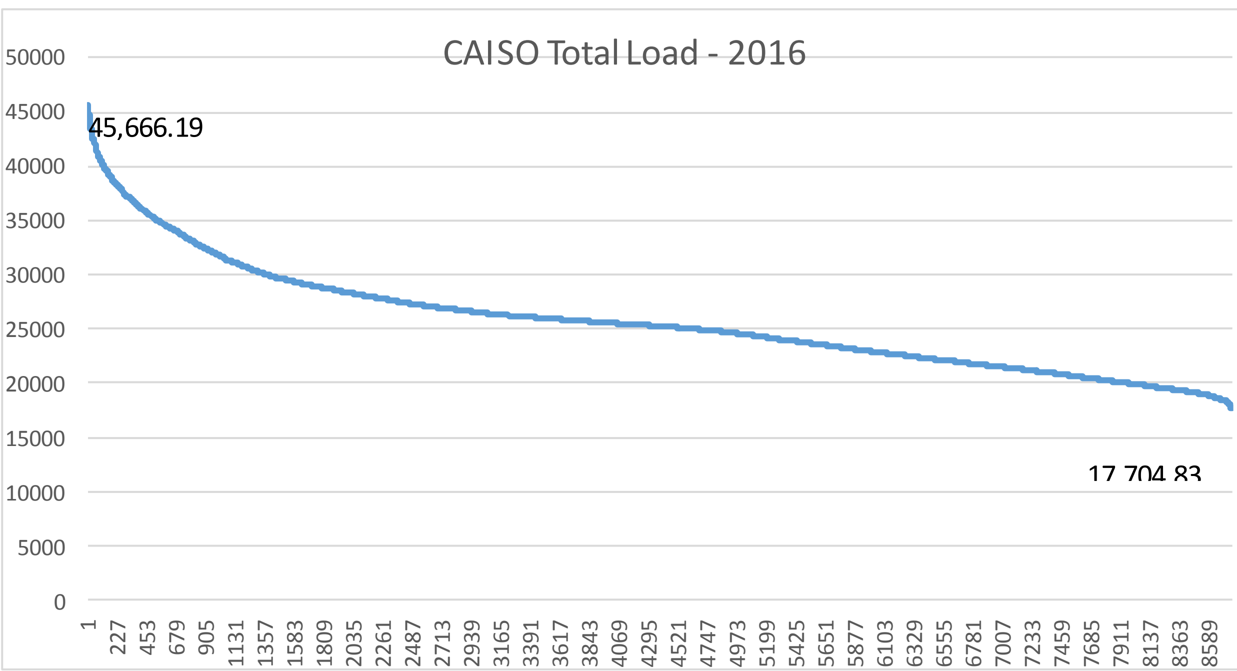
10. *The ISO must decide what types of analyses to perform to evaluate alternative TAC approaches, and how to prioritize them. Please provide your organization's view on what analyses would be most useful, and indicate the relative importance of each analysis you recommend to assist the ISO in determining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

SVP understands that the vast majority of transmission costs are fixed, and the costs do not change based on the volumetric flow. Additionally, since all loads are charged the applicable DLAP regardless of their individual LMP or sub-LAP, the CAISO should focus on a result from any change to the TAC billing determinant that results in the greatest potential to both (a) avoid future transmission costs, and (b) lower DLAPs. SVP submits that transitioning from a purely volumetric rate at the EUML to a TAC rate at the EUML that is allocated based on a combination of both volumetric flow and peak usage has a much higher probability of success in providing price signals that will increase resource development in a manner that will avoid future transmission costs. Energy storage in the form of batteries is one of the long term solutions to the ramping needs of the CAISO, but the technology as it exists now can't overcome the economic hurdles resulting from energy arbitrage opportunities in today's markets. SVP questions the ability of TED to incent the deployment of energy storage at the distribution level, and it may make storage less economical because energy storage consumes more energy than it returns to the system. A purely volumetric rate structure actually makes it less likely that energy storage will be deployed in the most beneficial manner. The energy arbitrage opportunities that could be provided by energy storage devices make the most sense if they are located in areas that have both constrained transmission during portions of the day and under-utilized transmission during other portions of the day. SVP understands these types of energy storage devices are much more likely to provide future transmission savings if they are located in load pockets such as the load UCM_6_N001 node discussed above. SVP suggests the CAISO study the effect on DLAP prices that the deployment of a significant amount of energy storage would have at these types of locations vs. an equivalent amount of energy storage located at the site of a proposed utility scale project.

Other potential studies or analysis to consider:

From a TRR perspective, how would it be best to determine what amount of the TRR should be recovered through a peak demand based component (versus a volumetric component) - if it is determined that a demand component is just and reasonable and will provide desirable price signals?

Do load duration curves provide any insight that would aid this discussion? The graph below depicts the CAISO Total demand in 2016 with a peak demand of 45,666.19 MWh and a minimum demand 17,704.83 MWh. One way to look at this data is that the transmission system is being utilized at its maximum extent when the system is peaking, and not providing any standby service to any LSE at this point in time. What would the volumetric rate need to be to fully recover the TRR if this level of usage (45,666.19 MWh) was maintained all 8760 hours of the year? If that value for the volumetric rate was used, and the balance of the TRR was recovered through a demand charge based on peak usage, what would this demand rate be? Is this a rate structure that could be implemented with relative ease based on forecasts now provided by LSEs? For PTO's with formula rates or stated rates, does this type of structured allocation present issues with determining proper amounts that would flow into the balancing accounts? Assuming DG reduced the demand component of the LSE's transmission cost allocation, but not the volumetric component, or vice-versa, does this structure ultimately give the price signal that avoids future transmission infrastructure investment? Over time SVP believes a TAC based in part on a demand charge will ultimately reduce peak demand, and increase transmission usage during periods of under utilized usage. This in turn will drive more and more of the TRR to be recovered through the volumetric component of the rate as peak demand is reduced, and less to be recovered through a demand charge that would be allowed to be avoided. Essentially it becomes a self-adjusting rate that is function of transmission peak usage.



Assuming this concept merits further analysis, such analysis must consider individual peak days. For instance, this past September 1st the CAISO set a new annual peak and the four highest peak hourly loads for the entire year occurred on that date, and six of the top twenty hourly peak loads occurred on that date. This indicates that the typical energy storage device contemplated today - with a 1 – 4 hour discharge duration - will not be sufficient to eliminate the peak demand during this type of weather event, but a combination of other DG - such as solar PV and energy storage - could effectively mitigate this peak demand when deployed together.

Date	Op Hour	MW
9/1/2017	17	49,343.38
9/1/2017	16	49,089.4
9/1/2017	18	48,730.62
9/1/2017	15	48,417.51
9/1/2017	19	47,046.96
9/1/2017	14	46,440.02

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.*

SVP believes there may not be enough information on various options now to evaluate the downstream financial impacts of potential changes to the TAC structure. What may be available at this time is information that would allow the CAISO to create an evaluation matrix comparing and contrasting various options. A straw proposal could establish the criteria used to evaluate each proposal, and responses to the straw proposal could then refine or add to the evaluation criteria that will be used once proposals are ultimately made by either the stakeholders or the CAISO.
An example of such a matrix is as follows:

	Proposal					
Evaluation Criteria:	Volumetric only	TED	Demand only	Volumetric and Demand	Time of Use	Other
Meets Ratemaking Principles:						
1						
2						
3						
4						
Balance of Benefits with Costs						
High Load Factor LSE						
Low Load Factor LSE						
Ease of Implementation						
Settlements						
Ability to understand						
Consistent with Retail Rate Design						
Price Signals						

Ability to incent Investment where needed						
Works to produce a least cost dispatch						
Reduces future transmission investment						
Other						

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.*

    See SVP's prior responses above.

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.*

    SVP believes load served in a PTO service area should incur a combination of a volumetric charge based on EUML, along with a demand component based on EUML with some netting of generation capacity available during time of system peak. To get credit for a TAC reduction of the demand component the energy resource either needs to be online and producing energy, or bid into the CAISO market and able to produce the quantity of the energy bid at the time of the system peak. This could potentially also apply to Demand Response programs provided they can be called upon by the CAISO either directly or through the LSE.

    This type of rate design is more likely to incent investment in energy storage than would other rate designs (including TED), and also ensures all LSE connected to the transmission system pay for the services and benefits that the transmission system provides.

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.*

SVP suspects volumetric flows on transmission facilities have a negligible impact on the O&M costs associated with those facilities. Many O&M activities are required independent of flows, such as vegetation management, facilities inspections, insulator washing, etc… Absent a showing that reductions in flows results in measurable and significant reductions in O&M costs, SVP does not believe DG will result in material decreases in costs associated with the existing transmission system.

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.*

Related Acronym Definitions:

- **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.