

**Transmission-Energy Downflow is a superior Transmission Charge Basis Rate Design**

Clean Coalition White Paper

CAISO First Straw Proposal, Review Transmission Access Charges Stakeholder Process

February 15, 2018

**I. Summary**

- 1) Transmission-Energy Downflow (TED) remains a superior basis for assessing transmission charges with fewer distortions and costs shifts when compared to Customer Energy Downflow, no matter whether examined from the standpoint of allocating embedded historical costs, current use and benefits, or incentives and market distortions. Consequently, TED is a superior approach under the standards applied in FERC Order No. 1000. Even if the existing structure has been approved under prior orders, the current structure is a strictly inferior rate design.
- 2) The formula for the calculation of Transmission Access Charges from the measure of usage should expressly incorporate allocation based on services provided, as valued by the total market transactions. While Demand Charges are a crude tool, they do not reflect drivers, benefits, or market incentives as effectively as a structured TAC.
- 3) In order to shape a strictly superior rate design, the Clean Coalition supplements the current TED proposal with two additional mechanisms
  - a. A Seniority-based cost allocator triggered only if Distributed Generation deployment exceeds growth of customer load. This would allow charges to follow contemporary use of the transmission assets where new users make use of capacity freed by DG. However, in the unlikely case of stranded transmission assets associated with actual declining transmission use (as opposed to mitigated continued growth), credit for

an LSE's DER reduction in transmission load would not reduce their allocated costs for assets developed for their customers' benefit.

- b. A TAC formula allocator that assigned total revenue requirement cost recovery between a fixed component, a volumetric component and demand charge, based on the proportion of the transmission value and cost driver stack as follows:

Component	Basis
Fixed Component	Proportional to Market Value of stand-by power option relative to total energy market value
Demand Charge	Proportional to proportion of transmission projects for peak demand
Volumetric charges	All remaining costs

- 4) In addition, many of the arguments and rationales presented for retaining the use of CED are not supported by evidence or depend on conclusions that have not been demonstrated. The Clean Coalition therefore urges CAISO to abandon unsupported rationales and to engage in the specific analyses that would provide a sound empirical basis for reforming CAISO's transmission access charge tariff.

## **II. Organization**

These comments are organized into three parts.

First, an evaluation of the relative strengths of TED- and CED-based TAC is evaluated on each of the three identified bases for analysis:

- 1) Ability to allocate historical embedded costs based on cost causation
- 2) Ability to allocate costs based on current benefits and usage
- 3) Ability to send non-distorting efficient economic signals

The TED-based TAC is strictly superior on all criteria

Second, a review of standards for rate design laid out by FERC, primarily in Order No. 1000 which unequivocally require incorporation of allocating costs based on benefits and not just historical planning triggers.

Third, A review of the role of substantial evidence in administrative decision making, including a review of the critical outstanding factual questions that have not be addressed.

Fourth, a summary of the additional refinements of the TED-based TAC proposal that CAISO should consider incorporating into the TAC structure.

### **III. Transmission Energy Downflow is the superior allocator regardless of the basis of cost allocation.**

#### **A. Cost Allocation proceeds under a combination of considerations.**

Use of Transmission Energy Downflow better reflects rate design principles, no matter which basis for evaluation is chosen. Both FERC and this stakeholder process have identified three separate bases upon which to allocate costs of transmission infrastructure<sup>1</sup>:

- 1) historical customer demand for transmission “for which the grid was built,”
- 2) current benefits and use of the transmission grid, and
- 3) the incentives to shape behavior of entities driving future cost trends.

Transmission Energy Downflow (TED) is a better cost allocator to reduce unjustified cost shifts under all three bases. Therefore, continued use of Customer Energy Downflow (CED) is unjustified and unsupportable under FERC Order no. 1000.

#### **1. Basis 1: Historical Customer Demand shows that using Customer Energy Downflow causes a cost shift onto those LSEs which have helped reduce transmission use.**

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<sup>1</sup> See CAISO Straw Proposal, Section 7.1.

First, a CED-based rate structure shifts costs onto the customers of LSEs that have historically deployed DG and thus avoided use of the transmission grid.<sup>2</sup> Since the inception of CAISO, transmission planning has been based on *transmission* load, which reduces customer load for all DG, whether behind the meter or in front of the meter as a “load modifier” before modeling and planning transmission needs. Thus, LSEs that have deployed DG have reduced the transmission load and therefore planned transmission and transmission investment.

However, even though these LSEs have reduced the amount of transmission needed relative to the amount of total energy used, they are still billed at the same rate as LSEs that have not reduced or offset their need for transmission at all. Thus, per unit energy or capacity, they pay a higher rate and have costs of the (reduced) transmission system shifted onto them.

The various cases involving different transmission demand in the planning process illustrate the cost shift and demonstrate that the CED-based TAC creates a cost shift onto the customers of LSEs reducing transmission investment and costs for all ratepayers. In the following cases, TAC structures that allocate costs that accurately reflects the historical cost causation are highlighted in green and structures that fail are highlighted in red.

### **CASE 1: Historical Cost Causation: Equal Transmission use**

Consider two Utility Distribution Companies (UDC) (e.g., PG&E, SCE, or SDG&E) each with 50 GWh of end customer load and no DG in the first planning period. Transmission planning is based on the full 100 GWh and TAC is based on 100 GWh in total regardless of the point of measurement.

Here, the cost allocation is equal at 50% each.

*This is analogous to the historical situation before the development of Distributed Generation. This characteristic that TED-based and CED-based TAC perform identically is the case for all transmission planned before the advent of DG penetration.*

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<sup>2</sup> Please see Section V below.

<b>CASE 1: Equal transmission use</b>	<b>UDC 1 Load</b>	<b>UDC 2 Load</b>
Customer Load	50 GWh	50 GWh
DG	0 GWh	0 GWh
Transmission Load	50 GWh	50 GWh
Total Transmission load	100GWh	
Transmission load contribution	50%	50%
Cost Assignment (CED)	50%	50%
Cost Assignment (TED)	50%	50%

**CASE 2: Historical Cost Causation: Unequal Transmission use because of avoided use.**

Instead, consider these two Utility Distribution Companies (UDC) (e.g., PG&E, SCE, or SDG&E) each with 50 GWh of end customer load but one with 10GWh of DG (20% of load) in 2010. Transmission planning is based on the full 100 GWh and TAC is based on 100 GWh in total regardless of the point of measurement.

Here, the second UDC actually reduced the amount of transmission needed by more than 10%, but under the CED cost allocation ends up pays 13% more per GWh of contribution to transmission planning, while the UDC that did not help reduce overall transmission load actually pays 11% less per GWh. This results in a cost shift from customers of the non-avoiding UDC and onto the customers of the UDC that did avoid transmission use. This penalizes those UDCs that are reducing overall system costs.

*Here, CED-based TAC clearly results in a cost shift where DG is accounted for in planning, but not in TAC.*

<b>CASE 2: Unequal transmission use</b>	<b>UDC 1 Load</b>	<b>UDC 2 Load</b>
Customer Load	50 GWh	50 GWh
DG	0 GWh	10 GWh
Transmission Load	50 GWh	40 GWh
Total Transmission load planned for	90GWh	
Transmission load contribution	56%	44%
Cost Assignment (CED)	50%	50%
Relative price	-11%	+13%
Cost Assignment (TED)	56%	44%

**CASE 3: Historical Cost Causation: Unequal transmission use in the second planning period with offsetting DG eliminating the need for additional investment.**

Consider that the same two UDCs from Case 1 in the next planning cycle. Both started with 50 GWh of customer load. The first LSE sees growth in load of 10 GWh in total customer load. The second LSE sees no load growth, but procures 10 GWh worth of DG. Thus, the first UDC relies entirely on transmission-connected resources, while the second offsets that growth with DG to serve its own load.

- 1) As a result, the total use of the transmission grid does not increase because UDC 2 is freeing transmission capacity for UDC1 to use.
- 2) Again, although UDC 2 is helping constrain transmission investment by freeing up capacity for others to use, under the CED-based TAC, UDC 2 is *penalized*. TED accurately shows that the total transmission load remains at 100 GWh, and TAC is split 60:40, proportional to cost causation in transmission planning. However CED indicates 110 GWh of transmission “use” is subject to cost recovery, and TAC is split 55:45, resulting in a 55%:45% cost assignment despite the fact that the UDC 2 is freeing up existing capacity for UDC 1 to use. Although UDC 2 is acting to prevent overall system costs from increasing 10%, it ends up paying more. Thus, CED shifts costs onto the UDC that has acted to reduce overall costs.

*Here, CED results in a cost shift when DG frees capacity for others and that capacity finds a user.*

<b>CASE 3: Offset transmission Load Growth</b>	<b>UDC 1 Load</b>	<b>UDC 2 Load</b>
Customer Load	60 GWh	50 GWh
Change	+10 GWh new load	-10 GWh DG reduction
Transmission Load	60 GWh	40 GWh
<b>Total Transmission flow</b>	<b>100GWh</b>	
<b>Transmission Load Growth</b>	<b>0 GWh</b>	
<b>Total Customer Energy Downflow</b>	<b>110 GWh</b>	
Transmission load contribution	60%	40%
Cost Assignment (CED)	56% (60 GWh/110GWh)	44% (50GWh/110 GWh)
Relative Price per GWh	-9%	+12.5%
Cost Assignment (TED)	60% (60GWh/ 100GWh)	40% (40GWh/100GWh)

**CASE 4: Historical Cost Causation: Unequal transmission use in the second planning period with DG avoiding overall use of the transmission grid.**

The only corner case in which TED is not flatly superior is the case in which overall transmission load decreases over time due to DG deployment.



Consider the same two UDCs from Case 1 in the next planning cycle. Both started with 50 GWh of customer load. In the second planning period, neither load grows, but the second LSE procures 10 GWh worth of DG. Thus, overall transmission load actually declines.

However, retaining CED-based TAC amounts to an claim that overall transmission load *will be* decreasing, because under any other circumstance, a CED-based system imposes a cost shift on UDCs that engage in reducing overall costs.

*Here, the simple TED does not follow the 50%-50% split that was the basis for past transmission planning because of declining overall load. This Case shows that in cases of declining load, allocation of the cost of stranded assets may be an issue. This is distinct from the case where customer load growth is mitigated by DG resulting in less growth or no growth in transmission load. Here, there would be a need for a stranded asset cost allocator.*

<b>CASE 4: Overall transmission use declines</b>	<b>UDC 1 Load</b>	<b>UDC 2 Load</b>
Customer Load	50 GWh	50 GWh
Change	0 GWh	-10 GWh DG reduction
Transmission Load	50 GWh	40 GWh
<b>Total Transmission flow</b>	<b>90GWh</b>	
<b>Transmission Load Growth</b>	<b>-10 GWh</b>	
<b>Total Customer Energy Downflow</b>	<b>100 GWh</b>	
Transmission load contribution (from first planning period)	50%	50%
Cost Assignment (CED)	50% (50 GWh/100GWh)	50% (50GWh/100 GWh)
Cost Assignment (TED)	56% (50GWh/ 90GWh)	46% (40GWh/90GWh)
Relative Price per GWh	+12.5%	-9%
Cost Assignment (TED with junior reduction charge)	50%	50%

***Seniority based true-up mechanism***

Ideally, the TAC should provide the correct outcome regardless of the changes in circumstances. Although it is exceptionally unlikely that DG would ever grow enough to offset load growth in an era of fuel switching and EV growth, it is conceivable. Therefore, the following principle should apply:

New users are allocated cost recovery for resources they use as the senior use, unless there is no new user, in which case the original UDC that triggered the transmission remains responsible as a junior guarantor.

Thus, transmission that is freed up by DG deployment that finds a new user is paid for by the new user (see Case 3). If, however, freed capacity goes unused, then the UDC that contributed to the planning load acts as a secondary guarantor of that cost recovery.

Since CAISO would know both when overall load has declined and which UDCs were responsible for the load decline, any shortfall in TRR recovery would be assigned to the UDC(s) responsible for the unused infrastructure.

Under such a system, the TED-based TAC would perform as well or better in reflecting the historical cost drivers than a CED-based system under all scenarios.

**2. Basis 2: Using TED eliminates cost shifts onto customers of UDCs that are actively avoiding using transmission assets.**

***a. Identifying and evaluating benefits: Use is one of a set of benefits.***

The second basis for evaluating transmission cost recovery rate designs identified by both FERC and CAISO is whether a rate design accurately allocates costs based on which customers are currently using and benefitting from the transmission system. On this basis as well, TED is strictly superior to CED in all cases.

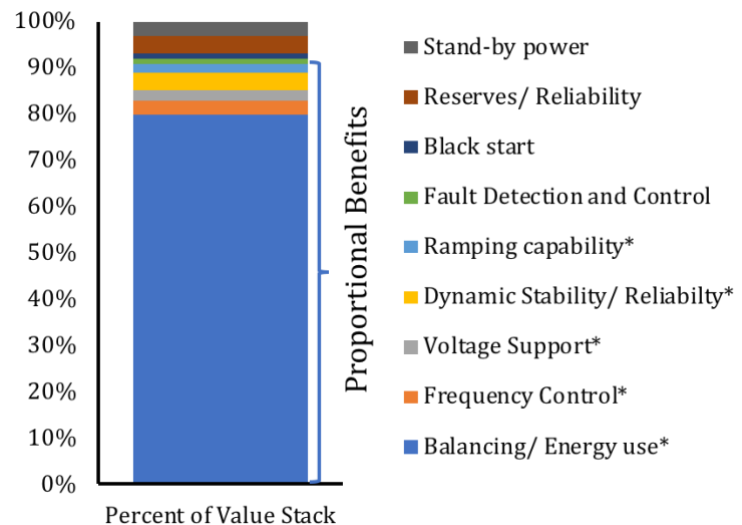
Identifying the beneficiaries of grid services and allocating costs proportional to those benefits involves identifying the benefits, evaluating their relative contribution to the full value stack of benefits of the transmission grid, and then allocating costs based on the degree to which different beneficiaries receive those benefits.

Benefits is a broad category of services and uses that add up to the full value stack of benefits provided by a transmission grid. These benefits fall broadly into “active” benefits that derive from using the grid and “passive” benefits that come from being connected to the grid without using the grid. The first category is largely benefits that are related to active energy delivery and services specific to managing the transmission grid and transmission assets. The second category are benefits that derive from having the option of using the grid.

#### *Transmission services v. proportional services*

Many “transmission” benefits or services are not strictly speaking benefits provided by the transmission grid, but are provided by *generation* no matter where it connects to the grid. These are not transmission-specific services, but are general services that are provided partly by transmission-connected assets and partly by distribution-connected resources. Services are provided by both distribution and transmission connected generation (none are provided by the transmission grid itself) in equal measure, so none can be characterized as “transmission services.”

**Figure 1 - Grid Benefits value stack conceptual illustration.**



The energy system delivers a range of benefits to customers, but that full set of benefits must add up to 100% of all value. Many values are proportional to transmission usage, such that cost allocation should also be proportional to transmission usage. (The values here are chosen to be illustrative and would require empirical estimation to evaluation in practice.)

These services and benefits only come from the transmission grid services only proportional to the degree to which transmission-grid resources provide them. For many grid system (transmission and distribution) services, the transmission grid provides only a fraction of the service, so the amount of services provided by the transmission grid is roughly proportional to the energy provided by transmission resources. For example, balancing generation with load is a system-wide service and if, for example, 90% of load is met with transmission resources and 10% from distributed resources, then the service is not a transmission-specific service.

Critically, proportional energy use is a reliable proxy for the degree to which benefits from a give resource are realized by a given customer group. This is the approach that CAISO has historically used in recovering costs based on volumetric measures. Those that use more energy are also getting more of the value from all the other services that come with that energy.

Different benefits call for different rate structures, and the diverse nature of benefits suggests that a hybrid of use-proportional and non-bypassable per customer charges would best reflect the distribution of these benefits. Charging for use-based benefits would then be assessed based on use of the transmission. This would apply to all proportional benefits, since customers would realize greater benefit with proportionally greater use of transmission-connected resources. On the other hand, existence benefits, such as back-up power, accrue whether the transmission grid is used or not. These benefits should instead be charged with a non-bypassable charge per customer rather than based on usage. A combination of two separate components would thus reflect the diverse characteristics of grid services.

***b. Most Benefits are realized by Customers proportional to their use of the transmission grid.***

CAISO has listed a number of potential benefits provided by the transmission grid, but the critical question is to what extent that the value of those benefits scales proportionally to use or to the relative role transmission assets play in the energy system. Since many of those services can be equally well performed by DG as transmission-

connected generation, these are actually services provided by a combination of transmission-connected resources and distributed generation.

**Energy Delivery/ Balancing (proportional):** The primary function of transmission is to deliver energy. Balancing is a function of ensuring that demand and load are met. However, customer load can be met with both DG and transmission-connected generation. Since the overall energy system involves energy consumed at the moment it is generated (except for energy storage), balancing services are in fact provided exactly proportionally between DG and Transmission. Thus, it is nonsensical to assert that balancing is any more a service provided by the transmission generation than it is by the distributed generation. The benefits provided by the transmission grid are proportional to how much energy is provided by transmission-connected resources.

**Frequency control (proportional):** Frequency maintenance is a function of the precise match of load and generation. In the first instance, maintaining frequency is a matter of matching load and generation and is proportional as balancing. Frequency control is otherwise a system-wide service that can be provided by either DG and remote generation equally. Neither can be said to be uniquely providing frequency stability to the whole system. If either falters, so does frequency.

In practice, frequency control is provided by the array of generators participating, who can be located anywhere. Thus, what proportion are transmission-connected is an empirical question, and statements that frequency control is a transmission grid service are misplaced.

In fact, since many DG resources are increasingly dispatchable due to co-located storage, increasingly DG can respond vastly faster and more efficiently than transmission connected turbines. Thus, frequency response is perhaps most properly thought of as a distribution grid service for which transmission grid can play a back-up role as turbine governors respond slowly. Particularly in light of FERC order No. 784, the distribution-connected energy storage is likely to displace slow-responding resources, leaving the distribution grid disproportionately responsible for frequency regulation.

Finally, since frequency control is managed through a distinct market, whether frequency regulation should be part of the rate design of TAC depends on whether those services are passed through to customers through TAC or some other mechanism. If they are not part of TAC, they are not germane to this discussion.

**Voltage support (proportional):** Maintaining local voltages within customer limits in particular is disproportionately a distribution generation service, not a transmission grid service. Voltage support depends critically on reactive power, which suffers massive line losses with distance. As a result, dispatching reactive power locally with advanced inverters is far more effective and efficient than relying on inefficient dispatch from distant generators. In this sense, voltage support also is best understood as distribution grid service that again is disproportionately best provided by DER.

**Dynamic stability (proportional):** To a real extent, dynamic stability services have similar system characteristics to frequency regulation or balancing in that the actual service is provided by rapid responses to small perturbations. As with frequency regulation, DER provide the fastest and most accurate responses to grid disturbances, fatally undermining any claim that dynamic stability is a specifically a transmission services. To our knowledge, CAISO has no distinct requirements or markets for dynamic stability, suggesting this service is proportionally too small to warrant distinct regulatory treatment.

**Ramping capability (proportional):** Ramping is another balancing function that turns on the characteristics of generation, not where it is connected. As ramping is increasingly handled through storage and demand response products, these are also likely to become distribution-provided services. Thus, there is nothing about the transmission grid that makes this specifically a transmission service. Again, how much the transmission grid is responsible for ramping capability is entirely proportional to how much transmission-connected resources are providing that particular service only.

**Fault detection and control (distribution/transmission domain specific):** Fault detection and control is only a transmission service with respect to transmission faults. Ultimately, modern approaches to fault detection depends entirely on where the fault in question is located. Certainly, when transmission components such as transmission lines or bulk generators fail, then fault detection services are handled on the transmission grid. Distribution grid faults however, can and are handled through distribution level monitoring and modeling resources. Thus, it is unclear how fault detection could be thought of as a transmission service. Where the faults are transmission faults, those charges should be applied to transmission connected energy that depends on the transmission grid for delivery.

**Black start capability (distributed resources only):** As with fault detection and control, how black start can be conceived of as a service provided by the transmission grid is entirely unclear. Since black start services by definition are only needed during area-wide outages in which the grid cannot provide power, they are by definition NOT provided by the transmission grid, because it is the failure of the transmission grid that necessitates black start services in the first place.

In fact, black start services are only needed by resources that are unable to provide their own energy without the grid. Since PV and storage can provide their own black start capabilities and play a critical role in restarting or maintaining power in the face of transmission failures, suggesting that DER need the transmission grid to provide black start services fails to understand the nature of these technologies. The reality is that black start services are almost exclusively needed by transmission connected fossil fuel resources, and frequently these are provided by on-site solar emergency microgrids.

**Reserves (proportional):** Generally, reserves are provided by both transmission-connected and distributed resources. Furthermore, reserves are called into service regardless of whether it is local or remote resources that have failed. When outages occur, the ability to provide reliability services depend on the location and capabilities of the



resource, not where it is connected. Indeed, as we have seen in the context of the Moorpark subarea, frequently distributed resources are more reliable simply because they are located closer to load and not subject to transmission constraints that may prevent transmission-connected resources from providing reliability services. Thus, as with frequency regulation and voltage support, if anything reliability services are better provided by distributed resources, fatally undermining any assertion that such “backup power” is a specifically transmission-connected generator service.

**Back-up power option (transmission):** Although not listed by CAISO, several stakeholders have pointed to “back-up” power as a service provided by the transmission grid. In fact, this is the only listed service that can be properly characterized as a transmission-level service. This is also the only service that is an existence benefit rather than a use benefit,<sup>3</sup> because it has value whether or not it is ever used, much like resilience benefits of DER to deal with outages of the transmission grid.

As an existence benefit, the valuation of stand-by power is more similar to an insurance service or an option that has independent value even if never called on. Similar to those financial products, the value of the stand-by power option depends on the expectation value of the option. That is, the value should be related to the probability the option is called and the value or lost value that would be incurred if the option were not called. Since the probability of DER is quite low (and by some measures lower than the failure of the transmission grid), the value of the option is similarly going to be fairly low, even if it is not zero.

Empirically, the stand-by option value could be estimated either by a generalized failure rate and lost value of outage to yield an expectation value, or it could be estimated by reference to other energy option products that provide an option for access to energy in return for some payment.

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<sup>3</sup> Energy balancing, frequency management, and voltage support all depend on the joint effect of ALL energy dispatched by the grid and so is not separable from energy usage. Should all DER withdraw from generation and remove 5% of the grid energy, the impact is similar to the loss of any other 5% of generation, subject to locational effects. Thus, transmission-connected generation is no more a “but for” cause of system performance than DG is. In this sense, these are in no way transmission-specific services.

**c. *Benefits-based TAC structure and Valuation of services***

This structure suggests a per customer non-bypassable charge component be added to account for existence benefits.

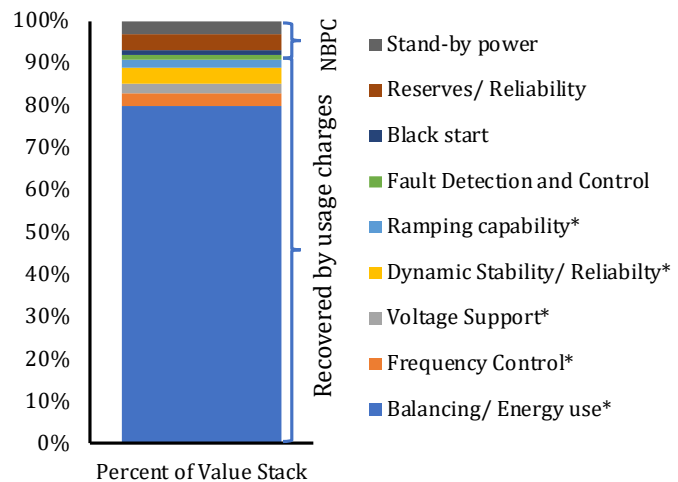
Reviewing the various benefits provided by the energy system reveals that most are provided by transmission-connected generation proportional to their usage overall.

Service	Type	Charge within TAC
Balancing/ Energy	Proportional	Volumetric
Frequency regulation	Proportional	None/ separately charged
Dynamic stability	Proportional	Volumetric
Reserve/reliability	Proportional	Volumetric
Ramping	Proportional	Volumetric
Voltage regulation	Local	None or volumetric
Black start	Local	None
Fault detection	Local	None
Back-up option	Transmission	Non-bypassable per customer charge

Assigning the proportion of TRR to be recovered from use-based or non-bypassable charges is again an empirical issue.

However, most if not all of these services actually have markets to compensate generators for providing these services. Thus, the relative value of each is a matter of comparing the total billing for each service category to the total spent on all energy services, including the delivery of energy. Since the total generation charges in the state for the moment exceed all payments for ancillary services and back-up power options, the large majority of TRR recovery would logically be

Figure 2: Illustration of structure of hybrid TAC structure.



Here, the same value stack is assigned to allocate costs based on volumetric-based charges (e.g., volumetric rates, demand charges or other charges derived from use patterns) and a non-bypassable per customer fee (labeled “NBPC”)

recovered through use based volumetric charges. As a simplifying matter, the non-bypassable component may be too trivial to be worth including, especially if concerns about LSEs avoiding transmission contributions are dealt with through the use of a seniority-based cost allocation to new users of existing infrastructure as suggested above.

**d. *TED-based TAC would remove the existing cost shift from customers of UDCs that have avoided transmission system usage.***

For those services which are proportional to use of the transmission system, Transmission Energy Downflow is unequivocally a superior basis for transmission access charges. In fact, the Customer Energy Downflow shifts costs onto the customers of UDCs which procure some proportion of their energy from DER. Since those DER also provide a range of services to the grid as a whole, the customers of UDCs that do not pay for their proportional transmission use are free riders on the UDCs that procure DG.

**CASE 5: A benefits-based evaluation of TAC structure.**

Consider two UDCs, both with 50 GWh of customer usage. UDC 1 relies entirely on transmission resources, while UDC 2 receives 10 GWh from DG. Here, assume that 80% of the value of the benefits from transmission use are proportional to transmission use and energy delivery. The non-proportional benefit accrues to both UDCs equally. Here, we use an arbitrary rate of \$100 total benefit value per MWh.

<b>CASE 5: Benefits-based</b>	<b>UDC 1 Load</b>	<b>UDC 2 Load</b>
Customer Load	50 GWh	50 GWh
DG procurement	0 GWh	-10 GWh DG reduction
Transmission Load	50 GWh	40 GWh
<b>Total Transmission flow</b>	<b>90 GWh</b>	
<b>Total CED</b>	<b>100 GWh</b>	
Proportional Value (MWh x \$100/MWh)	\$5,000,000	\$4,000,000
Non-Proportional Value	\$1,125,000	\$1,125,000
Total Transmission Benefit Value	\$6,125,000	\$5,125,000
<b>Total Transmission-Proportional value</b>	<b>\$9,000,000</b>	
<b>Total Transmission non-proportional value</b>	<b>\$2,250,000</b>	
<b>Total Transmission value</b>	<b>\$11,250,000</b>	
Relative proportion of transmission benefit	54.4%	45.5%
<b>Cost Assignment (CED)</b>	<b>50% (50 GWh/100GWh)</b>	<b>50% (50GWh/190 GWh)</b>
<b>Relative Cost shift</b>	<b>+9%</b>	<b>-9%</b>
Proportional (TED) Transmission Responsibility	55.6% (50 GWh of 90 GWh) (\$5,000,000)	44.4% (40 GWh of 90 GWh) (\$4,000,000)
+20% non-bypassable component	\$1,125,000	\$1,125,000
Overall responsibility	54.4%	45.5%

*Here, CED imposes almost a 10% cost shift that penalizes the customers of the UDCs doing the most to alleviate transmission congestion.*

By adjusting the TED-based TAC to include a non-bypassable component, the TED-based TAC can match the benefits here. In this example, because this includes a non-bypassable component, this structure would mean that a UDC that met all their load with DG would still be responsible for 10% of the total charges (half of the 20% non-bypassable component in this example. Also, even without the non-bypassable charge component, because the proportional component is greater than 50% of the total the TED proportional cost allocation of 55.6%/44.4% is closer to the actual 54.4%/45.6% benefit division, than the 50%/50% division implied by the CED. Thus, even by itself, the TED-based TAC would be better aligned with the assigning costs to beneficiaries.

**3. Basis 3: TED-based TAC is less distorting to economic efficiency than CED-based TAC.**

***a. CED-based TAC results in failure to send any price signal for delivery costs means that delivery assets will be over-consumed.***

As the Clean Coalition has repeatedly demonstrated, the inability to differentiate between generation sources in terms of delivery costs means that more expensive resources are procured than is economically efficient. As a simple matter, society bears the real costs of both generation and delivery infrastructure. If resources that incur lower combined generation and delivery costs are made to appear artificially expensive, then more expensive resources will be procured at the expense of resources that are in fact cheaper in real terms. This constitutes a distortion of the market for energy.

At a more nuanced level, modeling by the Market Surveillance Committee has confirmed that for transmission investments that are variable and can be deferred by Distributed Generation, the TED-based measure is more economically efficient.

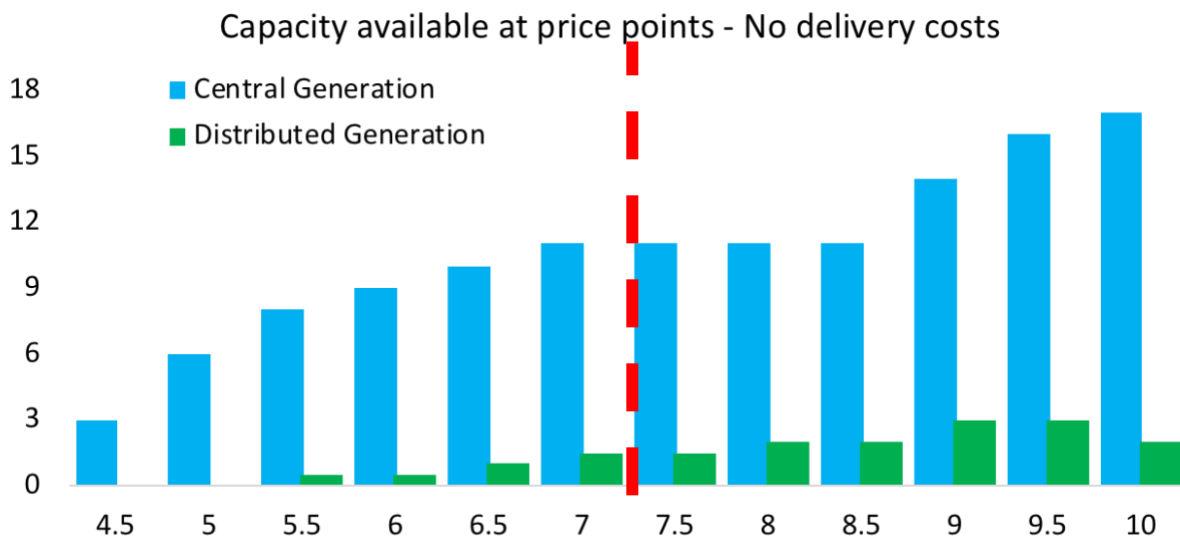
Overall, there are two key economic distortions that result from a CED-based TAC and therefore higher overall ratepayer costs because of the market inefficiency: 1) over procurement of resources that have higher real costs in terms of delivery and generation and 2) overinvestment in transmission.

***b. CED results in procurement of higher total cost resources by ignoring the differences in true delivery costs.***

As a basic issue, evaluating procurement bids based on combined generation and delivery costs when there are real differences leads to lower overall costs.

**Case 6: CED distorts the market and raises overall costs.**

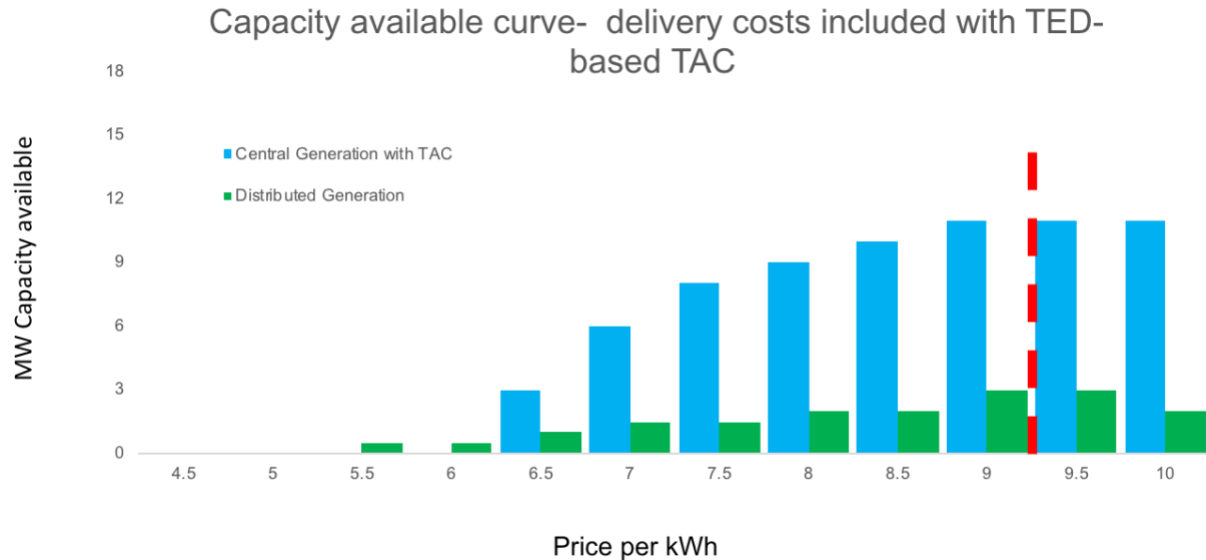
Consider an LSE engaging in a RFO under the CED TAC structure that does not differentiate between delivery costs and therefore is ignored. Here, the LSE is selecting the lowest cost 50 MW of capacity. In this numerical example, the LSE selects bids up to 7 cents/ kWh. Of course, all bids also result in 2 cents/KWh TAC charge, for an average price of 8.125 cents per kWh.



**CASE 7: Same distribution of bids under the TED-based TAC.**

Here, the parameters are exactly the same as in Case 6, except under a TED-based TAC. Bids for transmission-connected resources face different TAC charges so the costs of delivery are included in bid evaluation. Thus, the TAC charges are added into the generation price to compare all-in total costs. Here, the clearing price is therefore higher at

9 cents/kWh. however, the total average cost is lower than in the first case at 7.8 cents/kWh.



As a result, not only does the LSE face lower overall costs, but also procures roughly double the amount of DG.

*Thus, accounting for the differential costs of transmission delivery between local and remote resources results in both lower costs and increased procurement of DG.*

***c. CED-based TAC therefore results in over-procurement of remote generation results in over-investment in transmission.***

As a theoretical matter, where DG is undervalued, the deferral or avoidance value of DG cannot be realized. Without deferral and avoidance of infrastructure investment, more investment will be made than is optimal. The Market Surveillance Committee model presented by Prof. Ben Hobbs, confirmed that to the extent that DG can “displace bulk generation, then ... the result would be enough savings in network costs to yield a net cost savings from the proposed [TED-based] TAC system.”<sup>4</sup> Since it is abundantly clear that

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<sup>4</sup> B. Hobbs, Some Simple Economics of TAC Allocation to Distributed Front-of-Meter Generation, MEMO (DRAFT) at

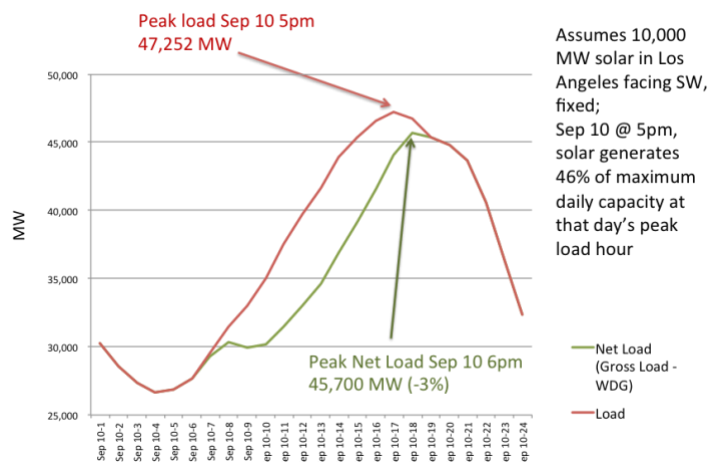


neither distribution costs nor transmission costs are fixed, this is the only modelled case that is relevant to the analysis of the TAC.

Clearly, a fundamental point is that DG can and does displace transmission investment and has since the beginning of CAISO. As noted above, CAISO's own transmission process plans for transmission load only once customer load met by DG has been subtracted. More critically, DG has the capability to replace transmission investment in each of the four primary drivers of transmission investment:

1. Thermal capacity, or increases in peak demand
2. Policy-driven goals
3. Economic drivers (to access cheaper energy)
4. Reliability needs

**Peak Demand:** DG's contribution in reducing peak demand has already reduced costs associated with the existing transmission system, and continues to do so. At system peak, every MW generated on the distribution system that meets local demand directly reduces peak demand on the transmissions system. As demonstrated in our model of the impact of moving 10,000 MW of solar to the distribution grid would reduce peak transmission flows and move these later (See Figure 5). With the deployment of co-located storage, DG increasingly become capable of addressing peaks outside of the solar window.



Ultimately peak transmission capacity is determined entirely by the peak transmission energy flow from remote generation. Anything that reduces the need for LSEs to procure remote resources to meet local load will reduce peak transmission flows, whether or not

that peak load is reduced by energy efficiency, demand response, customer load shifting, energy storage, or distributed generation. Thus, any of these load modifiers will reduce the need for transmission investment, as CAISO recognizes in the planning process. However, of these load modifiers, DG is the only one that is subject to TAC charges.

These reductions are not only theoretical, but California has seen real reductions in peak demand from DG and cancelled or deferred projects because of DG. 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. 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.

**Policy goals:** As stakeholders have noted, a substantial portion of transmission investment has been driven by RPS and the need to connect to renewable generation. However, since DG PV contributes to RPS targets every bit as much as remote solar, DG offsets RPS-related investment at least on a 1:1 basis. For example, ReMAT program procurement of 750 MW of wholesale DG is RPS-eligible and is already included in IOU RPS procurement planning. 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. DG resources have not been more heavily utilized in the RPS in part because the TAC distorts the market by failing to correctly attribute transmission costs to the remote generation that justified those investments in the first place.

**Economic drivers:** DG reduces transmission costs associated with economic drivers based on its correlated generation profile and location. DG reduces economic drivers in three distinct ways. First, DG can be the most economically advantageous resources, but ones that do not need expensive transmission to access. This means DG supplants bulk generation directly. Second, DG frees up transmission capacity, so that the benefits of the existing transmission grid can flow to other LSEs without needing to build more

infrastructure. DG frees up transmission capacity, so that other economically advantageous transmission-connected projects can be accessed without substantial additional investment. Third, DG can reduce the marginal costs of energy by reducing congestion and line losses. Taken together, these factors reduce both past need for economic-driven investment and free current capacity to meet emerging needs and economic opportunity.

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

Varied DER can address local reliability needs while simultaneously avoiding new transmission investment. For example, in one report, researchers confirmed that battery energy storage systems could provide frequency and voltage stability services (along with other energy services) to the grid. CAISO's own research has demonstrated that batteries can replace the need for transmission lines into the Moorpark subarea. If designed as co-located solar and storage, DG represents a direct alternative to building transmission for reliability needs. Furthermore, real world deployments in geographically bounded areas, such as Kaua'i, have demonstrated that photovoltaic solar plus storage can cost effectively meet the full suite of reliability needs.

***d. How much transmission spending can be avoided is an empirical question.***

The Clean Coalition has provided data and direct examples to demonstrate that DG can, does, and has reduced transmission investments. While other stakeholders have conjectured that this is not accurate, no solid evidence has been presented to support these statements.

Ultimately, this is a critical question that must be resolved, and determining how much DG can avoid or control transmission investment requires empirical analysis. Evidence from CAISO and SDG&E have suggested that peak-driven investment alone accounts for 25% to 40% of transmission investment. Adding in investment from the other drivers suggests that a majority of transmission investment is deferrable.

Resolving this fundamental question can be addressed in part by looking at new investment from the four drivers relative to the total TRR. Alternatively, CAISO could conduct a sensitivity analysis by running the TPP models under different projected levels of DG in order to evaluate the relationship between increased DG and transmission needs.

It is tremendously important that if CAISO is going to make decisions that could cost Californians tens of billions of dollars that it do so based upon substantial evidence. As CAISO itself said in the Straw Proposal, “Linkages between policies and transmission cost incurrence and benefit should be sufficiently demonstrated.” We entirely agree, but point out that CAISO has not as yet developed a body of evidence with which to evaluate what proportion of transmission investment is avoidable, and how that relates to the level of DG that may come online.

**4. Regardless of the basis for analyzing the TAC structure, TED is clearly superior to CED across most realistic or likely scenarios.**

TED-based TAC structures perform better on matching historical costs to customers who drove those costs, on matching cost allocation to the current beneficiaries, and would drive better incentives for a clean energy economy. No matter which of the three frameworks is adopted, the TED-based TAC is simply a better rate design.

**IV. Ratemaking Principles emphasize that costs should follow benefits**

***a. FERC Order No. 1000 clearly gives preference to allocating costs based on the beneficiaries of the transmission system, not the historical customer demand.***

CAISO’s emphasis on evaluating the cost allocation primarily on the basis of past cost causation without consideration of the present beneficiaries runs squarely counter to the direction of FERC, current practice, and CAISO’s own statements.

In Order no. 1000, FERC emphasizes that cost causation turns on the analysis of the benefits of transmission infrastructure and not on only ‘who the system was built for.’ Without the focus on beneficiaries, “cost allocation methods used by public utility transmission providers may fail to account for the benefits associated with new transmission facilities and, thus, result in rates that are not just and reasonable or are

unduly discriminatory or preferential.”<sup>5</sup> In rejecting a purely backward-looking approach based on transmission planning, FERC “affirmatively require[es] costs of transmission facilities to be allocated to beneficiaries...” in FERC Order no. 1000.<sup>6,7</sup> Thus, “the cost causation principle provides that costs should be allocated to those who cause them to be incurred and those that otherwise benefit from them.”<sup>8</sup> Cost allocation should “ensure that beneficiaries of service provided by specific transmission facilities bear the costs of those benefits regardless of their contractual relationship with the owner of those transmission facilities.”<sup>9</sup>

The “beneficiaries pay” principle is particularly important to developing a defensible tariff because the failure to assign costs to current beneficiaries risks creating free rider issues. Thus, FERC expressly directed that transmission cost allocation follow the beneficiaries, whether or not they are planned for, because otherwise “the Commission could not address free rider problems associated with new transmission investment” <sup>10</sup>.

Courts have similarly endorsed “[FERC’s] system-wide benefits analysis [as meeting] the requirements of the cost causation principle, that is, to compare ‘the costs assessed against a party to the burdens imposed or benefits drawn by that party.’”<sup>11</sup> Thus, FERC’s position that costs should be assigned to the beneficiaries or users of transmission assets is exceptionally well supported.

Furthermore, FERC acknowledges that these beneficiaries can and do change over time. In fact, the beneficiaries include those customers realizing a benefit “either at present or in a likely future scenario,”<sup>12</sup> which implies that benefits are not expected to remain fixed or for cost allocation to be set in stone at the time of project approval. Indeed, in

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<sup>5</sup> FERC Order no. 1000, Paragraph 495.

<sup>6</sup> FERC Order no. 1000, paragraph 507.

<sup>7</sup> We note that in the Issue Paper, CAISO cited to a 1994 policy statement, which has been superseded by FERC Order no. 890, which in turn has been superseded by FERC Order no. 1000. Furthermore, the straw proposal cites a FERC decision from 1997 as being consistent with FERC Order No. 1000, even though FERC Order No. 1000 was not issued until

<sup>8</sup> FERC Order no 1000, Paragraph 535.

<sup>9</sup> FERC Order no. 1000, Paragraph 539.

<sup>10</sup> FERC Order no 1000, Paragraph 535.

<sup>11</sup> FERC Order No. 1000, paragraph 508, citing *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361. (D.C. Cir. 2004).

<sup>12</sup> FERC Order No. 1000, Paragraph 544.

crafting the rule, FERC was well aware that careful evaluation of the beneficiaries was necessary, “given that the benefits and beneficiaries of a particular project may change over time, particularly in the case of a large project that provides regional and interregional benefits.”<sup>13</sup>

***b. Cost allocation should also consider the incentives and efficiencies created by the tariff.***

CAISO is also remiss in rejecting consideration of the impacts of its tariff structure on California ratepayers based on a legally misguided notion that the tariff should be primarily focused on “fair” cost allocation, while giving short shrift to the economic inefficiencies CAISO’s tariff introduces into the energy market.

First, economic efficiency is a key ratemaking principle under FERC’s 1994 Policy Statement, as recognized in the issue paper. The Bonbright principles also recommend that rate design “discouraging wasteful use of service while promoting all justified types and amounts of use....” In fact, CAISO recognizes that “[i]n the Transmission Pricing Policy Statement, the Commission stated that this means that transmission pricing should promote good decision-making and foster efficient expansion of transmission capacity, efficient location of new generation and load, efficient use of existing transmission facilities, including the efficient allocation of constrained capacity through appropriate market clearing mechanisms, and efficient dispatch of existing generation.”<sup>14</sup>

***c. Cost allocation balances theoretical precision with practical efficacy for the parties subject to the charges***

Finally, a lack of perfect alignment with all theoretical cost drivers or the existence of potential corner cases is not a justification for retaining an existing structure that performs worse under virtually all reasonably foreseeable possibilities. FERC emphasizes that rate-making does not require exacting precision. “[W]hile the cost causation principle requires that the costs allocated to a beneficiary be at least roughly commensurate with the benefits

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<sup>13</sup> FERC Order No. 100, paragraph 509.

<sup>14</sup> CAISO Issue paper, FN 7.

that are expected to accrue to it, the D.C. Circuit has explained that cost causation ‘does not require exacting precision in a ratemaking agency’s allocation decisions.’”<sup>15</sup>

Choosing between alternative rate structures is not although there may be corner cases that the tariff does not perfectly capture, this is not a justification for retaining a worse rate design. In the stakeholder process, objections that particular instances are not perfectly captured have been used by stakeholders to suggest that no reform should be conducted. However, ultimately where one design is better under all or most circumstances, that design should be chosen.

## **V. Rate Design must be based on substantial evidence**

At this stage, we urge CAISO to give credence only to statements and positions that have substantial evidentiary support. It is an axiom of California administrative decision-making that the agency must support findings with substantial evidence and those findings must support the conclusion reached. In order to meet this standard, decision makers “must set forth findings to bridge the analytic gap between the raw evidence and ultimate decision or order.”<sup>16</sup> Furthermore, generally such findings are to be “supported by substantial evidence in light of the whole record.”<sup>17</sup>

Although CAISO has given substantial weight to “disagreements,” conjecture, or assertions in this process, it is fundamentally important to reasoned decision-making that CAISO rely on substantial evidence, which means “more than a mere scintilla. It means such relevant evidence as a reasonable mind might accept as adequate to support a conclusion.”<sup>18</sup> In at least one body of California administrative law, [a]rgument, speculation, unsubstantiated opinion or narrative, [or] evidence which is clearly erroneous or inaccurate... does not constitute substantial evidence.”<sup>19</sup> While these standards may not directly apply here, the principle that decision-making should rely on facts to support conclusions which in turn support the ultimate decision.

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<sup>15</sup> FERC Order No. 1000, Paragraph 504, citing MISO Transmission Owners, 373 F.3d 1361 at 1371.

<sup>16</sup> *Topanga Assn. for a Scenic Comm’ty v. County of Los Angeles* (1974) 11 Cal. 3d 506, 514.

<sup>17</sup> Cal. Code Civ. Proc. § 1094.5(c)

<sup>18</sup> *Richardson v. Perales*, 402 U.S. 389, 401 (1971)

<sup>19</sup> 14 Cal. Code Regs. § 15384



***a. Distributed Generation can and does displace bulk generation, leading to reduced need for transmission.***

The actual factual evidence presented in this proceeding, both in terms of modeling and actual evidence shows that distributed generation can and does displace bulk generation and reduce, defer, or eliminate the need for transmission. The Clean Coalition has presented analyses of how DG displaces bulk generation to reduce the need for transmission and provided several examples of DG eliminating the need for specific transmission projects which have been actual cancelled. Furthermore, CAISO and other stakeholders have conceded that the CAISO's own Transmission Planning Process is predicated on the fact that DG reduces the need for transmission planning. In CAISO's own TPP, the amount of load planned for is reduced by the amount of DG available. At this stage, although stakeholders have "disagreed" and stated their opinion that DG may not reduce the need for transmission investment or may do so in complex ways, none have yet adduced evidence showing where increases in DG have not reduced peak flows or met other needs that drive investment. The Clean Coalition has produced extensive modeling to show the relative scale of avoided transmission and provided open access to the model for others to improve or disprove. Yet, given both ample time to produce evidence and to develop better models and analyses, no other stakeholders have done so. Therefore, we suggest that a single well-supported position should have greater credence than a dozen unsubstantiated and unsupported views.

***b. Distributed Generation will be stimulated by Transmission Charges that reflect differences in real delivery costs.***

Similarly, The Clean Coalition has produced evidence to demonstrate how changes in the procurement would allow for efficient procurement and secure benefits resulting from increased DG deployment. Although the precise degree of response depends on many factors, the mechanism and process of stimulation has been demonstrated.

In particular, the stakeholders with familiarity with IOU procurement have agreed that the Least Cost Best Fit methodology is already structured to take into account differences in transmission charges if there were any. While LCBF accounts for differences



in the necessary inter-tie costs from generator to transmission grid, the wider implications for cost growth are not. This alone would at least promote such procurement as the IOUs engage in to place DG and remote generation on equal footing.

***c. Changes to CAISO's TAC structure are necessary, but not entirely sufficient to control TAC cost growth.***

The change in the point of measurement should be made, even if only some of the procurement in the state would be immediately affected. CAISO argues that because a change in the TAC tariff is not sufficient to change all procurement in the state, it should not be undertaken at all.

However, as a regulatory matter it is important that CAISO take this step for two reasons. First, for IOUs using the LCBF methodology, the change in the HV-TAC would propagate into existing procurement methodologies. Thus, contrary to CAISO's assertions, other actions would be needed to ensure that the price signals reach the IOU procurement offices.

Second, for those LSEs that do not use LCBF or fall squarely within the utility commission's jurisdiction, it is critical to ensure that they receive some compensation for their efforts. However, without the funding that this proposal would free up, there is no clear source of the extra funds needed to fund this program. Given the regulatory challenges in regulating CCA procurement directly, it is critical to provide a market incentive to reward LSEs for the avoided costs associated with DG procurement. Without the reform of TAC at the CAISO, making the necessary changes in the IOU tariffs and providing a financial mechanism becomes exceptionally difficult, while having CAISO either adopt a change in the TAC or do so provisionally conditional on corresponding changes in the IOU tariffs would make those corresponding changes vastly more likely to occur. Thus, if CAISO agrees in principle that the TED-based TAC is superior, it is critical that CAISO take some concrete action to signal that agreement and to prevent CAISO from having to revise the TAC again in future if the IOUs make the corresponding changes with CAISO reforms. Setting CAISO up to have to engage in a fourth stakeholder process to revise TAC again in the coming months would be a dubious use of staff time.

## **VI. Outstanding Factual issues**

Throughout this stakeholder process several critical factual questions have been raised that absolutely need to be addressed before findings supported by substantial evidence can be made.

### **1) How much transmission investment can be deferred through increased DG deployment?**

The Clean Coalition presented extensive studies of how DG can reduce transmission investment over the next 20 years, but various stakeholders have questioned those results without supplying any evidence in rebuttal. We urge CAISO to do a study using the TPP methodologies to evaluate a) how much additional transmission would have been required over the last 20 years if there had been no DG deployed in the state and b) how much transmission spending would be reduced under high, medium and low levels of customer load growth and high, medium and low levels of DG deployment. This level of modeling can provide critical insight into this fundamental factual question.

### **2) How are various ancillary services compensated and passed on to ratepayers?**

CAISO has raised issues of the various services provided “by the transmission grid” but several of those services are actually separately compensated. For example, frequency regulation is subject to a separate market, and other services such as voltage support are folded into other mechanisms. Providing clarity to stakeholders regarding how these services are currently compensated will give key insight into which services are to be compensated under TAC.

### **3) How much is spent in total on ancillary services relative to total spending on energy generation?**

CAISO has raised issues of the various services provided “by the transmission grid” but developed no quantitative or qualitative estimate of how important those services are relative to the value of energy delivery. It would appear that while those values are not

zero, neither are they a substantial fraction of the total value of services delivered by the grid.

- 4) What proportion of transmission projects have been driven by various market drivers?

The role of DG in avoiding growth from all four cited drivers is clear, but better data regarding the relative importance of each driver would be valuable.

- 5) What is the proportion of the TRR represents transmission build, operations and maintenance, or other components of the TAC?

These data would shed additional light on how much transmission spending is fixed and how much is variable and potentially responsive to changes in energy flows.

- 6) What are the actual projections of customer load growth and transmission load growth from various sources and under various conditions?

Several stakeholders have opined that transmission load will not be growing in future, but without any supporting evidence of analysis to bolster that claim. Given that there are various factors such as EV growth and fuel switching that could drive substantial growth in customer and transmission load growth, it is important to get clarity on what projections exist and CAISO considers reliable. Since this is a critical question to resolve to craft a rate design that can meet the needs of California customers, it would be remiss without some clarity on these projections.

## **VII. Revisions to the proposal to use the TED-based TAC.**

Through various conversations with stakeholders and CAISO staff, several critical additional elements could and perhaps should be incorporated into a change of location of measuring transmission use as TED. These are:

- 1) Incorporate a seniority-based backstop provision to allocate stranded assets. As discussed above, in the profoundly unlikely event that freed transmission assets can find no users, assign the costs to those for whom the investment was intended. This mechanism would essentially allocate declines in total system load to LSEs or UDCs

depending on the amount of avoided cost they'd engaged in in order to ensure that the costs of stranded assets cannot be avoided through aggressive DG deployment. We anticipate that with population growth, fuel switching, and EVs this is extremely unlikely. However, it would be prudent to incorporate a backstop mechanism in case load declines occur.

- 2) Incorporate a non-bypassable per customer component of the TAC as a hybrid charge. This would reflect the benefits that are unrealized through use of the transmission grid. This proportion can be estimated either through standard options pricing methods or by comparing the market value of services relative to all electricity spending, although given the relative spending on energy delivery services relative to all ancillary services, the bulk of TAC would be charged as proportional to transmission use. However, this would ensure that even a UDC or LSE that opts for a 100% DG portfolio would not see its TAC go entirely to zero to reflect the ongoing reliance on the transmission grid.

## **VIII. Conclusions**

Ultimately, the TED-based TAC remains the better rate design based on FERC Order No. 1000 principles, regardless of the basis of analysis. However, as various stakeholders have identified, there some refinements of the basic design to account for non-use proportional benefits and the potential for stranded assets that should be included. We look forward to continuing the factual and analytic process of establishing a robust and well-founded approach.