Stakeholder Comments Template

Submitted by	Company	Date Submitted
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The Issue Paper posted on June 30, 2017 and the presentations discussed during the July 12, 2017 stakeholder meeting can be found on http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx.

Please use this template to provide your written comments on the issue paper topics listed below and any additional comments that you wish to provide.

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

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

ORA's Comments:

The Office of Ratepayer Advocates (ORA) recommends limiting the scope of this initiative to a single topic, which is "whether to modify the TAC [Transmission Access Charge] billing determinant to reduce TAC charges in PTO [participating transmission owner] service areas for load offset by DG [distributed generation] output."[1] ORA provides comments on the existing volumetric TAC rate structure in response to question 3.

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

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

ORA's Comments:

The California Independent System Operator's (CAISO) Issue Paper includes a useful summary of the approaches to transmission cost recovery used by other independent system operators

[1] *Review Transmission Access Charge Structure Issue Paper*, June 30, 2017, CAISO, (Issue Paper), p.4. Available at http://www.caiso.com/Documents/IssuePaper-ReviewTransmissionAccessChargeStructure.pdf.

(ISO) and regional transmission operators (RTO).[2] This summary includes examples of region-specific considerations for cost allocation, as well as general considerations for cost allocation. For example, the demand-based cost approach of the Electric Reliability Council of Texas (ERCOT) considers the extreme weather conditions in the summer months in its region to allocate transmission costs based on summer demand.[3] In contrast, the Midcontinent Independent System Operator's (MISO) volumetric charge for its Multi Value Projects (MVPs)[4] considers the value MVP transmission projects provide.[5] Per MISO's transmission planning documents "a significant portion of the benefits associated with MVPs [e.g. wind projects] occur at times other than the peak demand,"[6] thus a usage charge was preferred for MVP's rather than a demand-based cost approach. The value provided by transmission projects is a common consideration that also is used in the Southwest Power Pool's "Highway/Byway" cost allocation methodology.[7] The Issue Paper's observations on PJM (PJM) Interconnection demand based approach illustrate the complexity of this approach.

3. <u>Today's volumetric TAC rate structure.</u>

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

ORA's Comments:

ORA recommends maintaining the current volumetric TAC rate structure at this time. Transmission service includes the delivery of energy using the bulk power transmission system from generation sources to substations, as well as the following related energy services:

1) Voltage Support, which maintains local voltages within customer limits;
2) Frequency Control, which balances load with demand;
3) Fault Control, which ensures safety when there is an outage;
4) Access to Black Start, which provides start-up energy when there is an outage;
5) Access to Ramping, which provides energy to meet extreme changes in demand; and
6) Access to Back-up resources, which provides energy in the event of a loss of local generation.

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[2] Issue Paper, pp. 13-18.

[3] Issue Paper, p. 15.

[4] *MISO Cost Allocation Issues White Paper*, September 14, 2015, p. 5. MVPs support public policy goals, provide economic value, or provide both economic value and reliability.

[5] Issue Paper, pp. 13-15.

[6] Issue Paper, p. 14.

[7] *Regional Cost Allocation Review* (RCAR II) SPP Regional Cost Allocation Review Report RCAR II, July 11, 2016, pp. 23-27. Available at https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf.

Collectively, these services maintain reliability and safety, and provide access to flexible energy resources to meet the needs of all the customers connected to the transmission system. Because these essential services are provided to all customers whenever they are needed, ORA supports allocating the cost for these services and energy delivery through a volumetric charge, which is transparent and reflects the value of the services.

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

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

ORA's Comments:

Distributed Generation (DG)[8] has reduced load on the transmission system. This contribution to the transmission system is considered in the CAISO Transmission Planning Process, and it has deferred proposed transmission infrastructure. [9]

However, further study is needed to determine the value of this benefit to the going forward costs of existing transmission, and specifically, if DG alone can reduce existing transmission costs, or if it must be paired with other Distributed Energy Resources (DERs)[10] such as storage.[11] ORA provides the following clarifications and considerations for this study.

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[8] DG customers include both behind the meter generation, and wholesale customers who participate in the CAISO market. ORA's comments regarding DG refer to behind the meter DG generation.

[9] Currently, the capacity for distributed generation (DG) to reduce gross load is considered in California's energy procurement and transmission planning processes. The California Energy Commission (CEC) forecasts DG load in its bi-annual Integrated Energy Policy Report. According to the CAISO's 2016-2017 Transmission Plan (pp.49-50), the CAISO's "reliability studies incorporate the incremental uncommitted energy efficiency amounts as projected by the CEC, distributed generation based on the portfolio provided by the California Public Utilities Commission (CPUC) and CEC, and a mix of proxy preferred resources including energy storage based on the CPUC LTPP 2012 local capacity authorization. These incremental preferred resource amounts are in addition to the base amounts of energy efficiency, demand response and 'behind the meter' distributed or self-generation that is embedded in the CEC load forecast."

[10] DERs, as defined by the CAISO in the July 12th TAC Structure stakeholder meeting, consist of all energy sources and programs that reduce load on the distribution system. This includes energy efficiency, demand response, behind the meter solar, storage, and electric vehicles.

[11] *Putting the Potential Rate Impacts of Distributed Solar into Context*, Galen Barbose, Lawrence Berkeley National Laboratory, January 2017, p.4. **(**"Utility energy efficiency programs and federal appliance efficiency standards together reduced U.S. retail electricity sales in 2015 by an amount that is 35-times larger than that of distributed solar."). Available at https://emp.lbl.gov/sites/default/files/lbnl-

- Existing transmission costs not only include the initial capital costs, but also the ongoing operating and maintenance costs, as well as capital required for ongoing asset management of the existing transmission infrastructure.[12]
- Existing transmission capital costs do not vary significantly with the quantity of energy delivered, or with the peak demand. Therefore, the installation of DG does not avoid existing transmission infrastructure costs. Based on the observed impact of DG on the grid, there are also unknown costs to support DG on the transmission system and to respond to its unique output and load profile. [13]

ORA agrees that the Megawatt-hour (MWh) (real power) and Mega Volt-Amp Reactive (MVAR) (reactive power) output of DG could provide good measures of future transmission expansion costs avoided or reduced by DG output.[14] However, in order to determine the impact of this output, a study conducted for a reasonable time period with data from all seasons is needed. At this time, this DG output information is not collected by a single entity, and for this reason, it may be necessary to validate the data collected through more than one entity.

5. Potential shifting of costs for existing transmission infrastructure.

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

ORA's Comments:

ORA provides the following information for consideration.

1007060.pdf. *See also Electricity Demand Stagnates Despite Growth Households*, Institute for Energy Research, February 18, 2014, p .2.

[12] Such transmission expenditures are not subject to the CAISO's transmission planning process. See Issue Paper, p. 20.

[13] The 2016-2017 CAISO Transmission Planning studies noted that the "increasing variable loading on the transmission system has resulted in more widely varying voltage profiles, [requiring additional].reactive control devices to maintain acceptable system voltages."*2015-2016 Transmission Planning Process Unified Planning Assumptions and Study Plan*, CAISO, March 31, 2015, pp. 14-15.

The CAISO stated at the July 21, 2017 TAC Structure Review meeting that the peak evening shift, attributed to the solar power window, has created a need for quick-start peaking resources, such as storage. The CAISO's July 12, 2017 Review of Transmission Access Charge Structure Stakeholder Meeting; see also Customized Energy Solutions Summary of California ISO (CAISO) Review Transmission Access Charge Structure Issue Paper, July 12, 2017, p. 7. Adding new quick-start resources could have both direct and indirect costs to the transmission system.

[14] Issue Paper, p. 22.

- Transmission projects are designed to serve peak loads throughout the day, including morning, afternoon and evening peak loads.
- Much of the existing transmission infrastructure was planned and constructed to serve peak load before DG came on-line.
- The transmission system provides the delivery of energy using the bulk power transmission system from generation sources to substations, and energy related services that provide reliable, safe, and flexible resources to all customers as enumerated in ORA's response to question 3.

If the TAC billing determinant were revised to exclude load offset by DG without a corresponding reduction in the existing regional transmission revenue requirement, DG customers would not pay for the reliability services they receive from the transmission system. Under this scenario, ratepayers without DG would pay a greater portion of the "sunk" transmission costs. Given that the existing transmission system was designed to provide reliability services to all customers, including customers on circuits that also include DG installations, reducing existing transmission capital costs for DG customers would result in unjustified shifting of those costs to California ratepayers without DG.

On a going forward basis, ORA recommends a study to determine the potential for DG to reduce the costs to maintain and operate existing transmission system. ORA also recommends evaluating the costs and benefits of DG to the transmission system in future CAISO Transmission Planning Processes to determine if new transmission system costs should be allocated differently for DG based on its contributions to the transmission system.

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

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

ORA's Comments:

DG and other DERs (i.e. storage and energy efficient lighting and appliances to comply with new California building code requirements) have contributed to the reduction in load and most recently the avoidance or deferral of low-voltage transmission (i.e. transmission lines less than 200 Kilovolts (kV)) projects.[15] The 2016-2017 CAISO Transmission Planning Process deferred

[15] *Putting the Potential Rate Impacts of Distributed Solar into Context,* Galen Barbose, Lawrence Berkeley National Laboratory, January 2017*, p. 4.* **("**Utility energy efficiency programs and federal appliance efficiency standards together reduced U.S. retail electricity sales in 2015 by an amount that is 35-times larger than that of distributed solar."); *see also Electricity Demand Stagnates Despite Growth*

several previously proposed low-voltage transmission projects because of load reductions attributed to DG and DERs.[16] Thus, current CAISO planning processes already acknowledge at least some of the benefits provided by DG and DERs.

Going forward, the following six factors should be considered in DG and DERs valuations for transmission upgrades.

1. Whether DG and DERs can provide reliability services: DG and DERs as a group have varying reliability capacity (i.e. frequency responses, voltage control, ramping and black start capacity). DG and other DERs technologies initially may not have been designed to respond or provide reliability services necessary for transmission upgrades and additions, but evolving technologies are improving DGs' and DERs' capacity to provide these services. Further study is still needed to determine DG's and DERs' reliability capacities in combination with new technologies, such as smart inverters, to reduce future transmission needs.
2. Whether DG and DERs can meet North American Electric Reliability Corporation (NERC) standards: Coordination between DG and DER installations and bulk power system requirements consistent with NERC standards would also be required for DG and DERs to serve future transmission needs.
3. Whether DG and DER provide locational value: Given that DG and DER technologies have different attributes that provide different contributions to the distribution system, the value of DG and DER depends on the needs of the given distribution system.[17] For example, Clean Coalition recently stated that there are locations on the grid where roof top solar would be beneficial and other locations where it would not.[18] Additionally, if DG is installed in areas of the transmission system where the local generation already

Households, Institute for Energy Research, February 18, 2014, p. 2. Available at http://instituteforenergyresearch.org/analysis/electricity-demand-stagnates-despite-growth-in-households-and-commercial-buildings/.

[16] 2016-2017 Transmission Planning Process Stakeholder Meeting, Presentation on Review of Approved Projects –North Area, Jeff Billinton CAISO, November 16, 2016, slides 101-107.

[17] *Value of "DER" to "D: The role of distributed energy resources in local electric distribution system reliability,* Sue Tierney ,Analysis Group Inc., April 21, 2016, Presentation to the CPUC Thought Leaders Forum," slide 4. (Available at http://www.analysisgroup.com/uploadedfiles/content/news_and_events/news/tierney_value_of_der_to_d_cpuc_thought_leaders_workshop_4-21-2016.pdf.); see *also* Utility of the Future, Massachusetts Institute of Technology, December 2016, p.3. (Available at http://energy.mit.edu/wp-content/uploads/2016/12/Utility-of-the-Future-Full-Report.pdf.) and *Distribution Resources Planning, a Foundation Policy for Modernizing the Grid*, John Bernhardt, Clean Coalition, June 12, 2017, presentation and webinar.)

[18] *Distribution Resources Planning, a Foundation Policy for Modernizing the Grid*, John Bernhardt, Clean Coalition, June 12, 2017, presentation and webinar.

exceeds local load, DG can increase the transmission system flows, and potentially negatively impact the system.

The "Value of DER to D" report produced by the Analysis Group smmarizes the analysis needed to determine the value of DER:

> "Ultimately, the value of a particular set of DERs to a particular distribution system depends upon two things: the goodness-of-fit between those DERs' attributes and the types/location/timing of reliability problems the utility needs to solve; and the existence of net economic benefits that result from pursuing the DERs as compared to the traditional utility solution. Distribution-system problems (e.g., thermal overloads on the system, due to load growth; voltage problems; old wooden poles that need replacement; service restoration after storms knock down poles and wires) vary in ways that are important for determining the relevance of particular DERs for addressing that problem as well as the costs of a traditional solution compared to a solution based on a portfolio of DERs. Some of these problems (e.g., deferring upgrades needed to mitigate anticipated reliability violations attributable to load growth) can be addressed by DERs with certain attributes at certain locations; but other problems (e.g., pole replacement) may not be avoidable by DERs." [19]

4. <u>Whether DG reduces the need for policy or economic transmission:</u> Development of behind the meter solar photovoltaic generation has historically put downward pressure on the need for load-driven reliability transmission projects. However, its impact on reducing the need for policy-driven and economic-driven projects is unclear. Furthermore, the load offset by DG can also rely on policy-driven or economically-driven transmission to access lower cost resources when the DG output is not available.

5. <u>Whether a DG or DER solution is the most cost effective solution</u>: To determine if a DG or other DER solution for a transmission project should be pursued over a traditional solution, a cost and benefit analysis must also be conducted consistent with the transmission planning process. If the DG and DER solution requires utilizing energy from DG or DER, investments in the distribution system may also be required to accommodate two-way energy flow, because the distribution system was designed for one-way power not two-way power flow.[20] Other improvements to the distribution

[19] *Value of "DER" to "D": The role of distributed energy resources in local electric distribution system reliability*, Sue Tierney, Analysis Group Inc., March 31, 2016, p. 24.

[20] ORA Staff phone interview with J.P. Dolphin, Pacific Gas and Electric Company, Grid Integration and Innovation Manager, Data Analytics Team, December 7, 2016; *see also Distribution Resources Planning, a Foundation Policy for Modernizing the Grid*, John Bernhardt, Clean Coalition, June 12, 2017 presentation and webinar slide 16.

system may also be required to transfer energy effectively and without compromising grid safety.[21]

6. Whether the CAISO and investor-owned utilities (IOUs) can use DERs when needed: For DG and DERs to replace traditional resources and transmission, the CAISO and IOUs must have the ability to dispatch DG or DER resources to meet energy and or energy service needs. To rely on a DG and DER solution for a needed transmission project, behind the meter DG or other DERs must be capable of being programmed through the CAISO transmission control systems and be able to guarantee the needed service through a service agreement. These agreements would be similar to generator agreements between IOUs and the CAISO and would commit DG or other DERs to provide energy and or energy services at certain times and through specified communication methods.

ORA supports the use of DG or other DERs as cost effective solutions for future needed transmission and related improvements. If the analysis during a planning process demonstrates that DG or other DERs can meet the specified need at a cost equal to or lower than a traditional solution, and DG or other DERs can commit to service agreements, then DG or other DERs should be the preferred solution.

As discussed in the CAISO July 12th Stakeholder Meeting, the future expected transmission costs will include costs to maintain the existing transmission system (operating and maintenance expenses and related capital expenses) as well as costs to integrate new renewables to meet the state's Renewable Portfolio Standard goals.

7. Benefits of DERs to the transmission system.

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

ORA's Comments:

The CAISO July 12 discussion and presentation on the potential benefits of DER highlighted the California "Energy Duck Curve" and suggested that storage was an option to address the peak shift due to the solar power window. Storage could be used to capture the surplus solar energy on the California grid in the afternoon, and then used to release this same energy to serve the later evening peak.

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[21] *Impact of Distributed Generation on Distributed System*, Angel Sarabia, Aalbery University Denmark, 2011, p. 29. Available at http://projekter.aau.dk/projekter/files/52595515/Report_Angel_Fern_ndez_Sarabia.pdf.

ORA supports on-going studies on storage and other DER options to address California's surplus solar energy in the afternoon, and the evening demand peak. Electric vehicles in combination with demand response tools and utility scale storage may address the "Energy Duck Curve" effectively and provide greater value to the grid then a traditional transmission solution.

This current CAISO initiative could benefit from the following California Public Utilities Commission (CPUC) efforts that are currently underway.

- The CPUC is expanding its avoided cost calculator through a current proceeding[22] to estimate system-level costs that could be avoided through the deployment of DERs. This avoided costs calculator includes avoided transmission cost estimates.
- The CPUC is also beginning a process to estimate locational differentiated avoided transmission costs[23] in the Distribution Resources Plan (DRP) Locational Net Benefits Analysis (LNBA) working group.[24] The benefits to be considered in the design of the TAC should be consistent with the LNBA, and visa-versa.

8. Other Comments

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

ORA's Comments:

ORA anticipates submitting additional comments with further analysis and considerations as this initiative proceeds.

[22] D.*16-06-007, Decision to Update Portions of the Commission's Current Cost-Effectiveness Framework, issued June 9, 2016, in R.14-10-003, Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Distributed Energy Resources.*

[23] The locational differentiated avoid transmission costs represent the avoided or deferred transmission costs that result from the deployment of a distributed energy resource in a given location.

[24] *Assigned Commissioner's Ruling Setting Scope and Schedule for Continued Long Term Refinement Discussions Pertaining to the Integration Capacity Analysis and Locational Net Benefits Analysis in Track One of the Distribution Resources Plan Proceedings*, June 7, 2017, pp. 12-14. Available at http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=189819375. *See also Assigned Commissioner's Ruling Granting the Joint Motion of San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company to Modify Specific Portions of the Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B,* August 23, 2016, Attachment A, at p. A35. Available at http://docs.cpuc.ca.gov/publisheddocs/efile/g000/m166/k271/166271389.pdf.