Stakeholder Comments Template

Transmission Access Charge Options Issue Paper

Submitted by	Company	Date Submitted
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This template has been created for submission of stakeholder comments on the issue paper for the Transmission Access Charge Options initiative that was posted on October 23, 2015. The issue paper and other information related to this initiative may be found at: http://www.caiso.com/informed/Pages/StakeholderProcesses/TransmissionAccessChargeOptions.aspx

Upon completion of this template please submit it to initiativecomments@caiso.com. Submissions are requested by close of business on **November 13, 2015.**

1. **One theme emphasized in the issue paper and in FERC orders is the importance of aligning transmission cost allocation with the distribution of benefits. Please offer your suggestions for how best to achieve good cost-benefit alignment and explain the reasoning for your suggestions.**

An overall consideration of the costs and benefits for a potential new Participating Transmission Owner (PTO) will, of course, be the primary factor for the utility, its customers, and state regulators in whether to move forward with full participation in a regional ISO. With respect to the transmission access charge, anticipated benefits do not justify any cost shifting of revenue requirements associated with existing, in-place facilities. Rather, the anticipated benefits may support a measure of socialization of the costs of new projects in operation after PacifiCorp or other utilities join the regional ISO. To achieve the stated goal of a common western market, the transmission access charge (TAC) should be revised to prevent any adverse cost shifting, especially of the costs of existing facilities.

While there is only a limited data set available, Energy + Environmental Economics (E3) produced a study of potential benefits associated with PacifiCorp's full participation in a regional market. E3 examined benefits for: (1) more efficient dispatch, (2) lower peak capacity, (3) more efficient over-generation management, and (4) renewable procurement savings. E3 projected benefits to each of PacifiCorp and CAISO as follows:

Total Savings (2020-2039)	Low (in 2015 $billion)	High (in 2015 $billion)
PacifiCorp	$1.6	$2.3
CAISO	$1.8	$6.8

These results lead to several important observations related to aligning the TAC with benefits and preventing adverse cost-shifting.

First, the numbers reveal that the distribution of benefits already favors existing California-based, CAISO customers. Any cost shifting of the revenue requirements associated with existing projects will exacerbate this differential on a dollar for dollar basis, decreasing the already lower benefits to the potential new PTO and its customers and increasing the advantage for California. Therefore, any "solution" that socializes the cost of existing facilities is an insurmountable obstacle to expanding the CAISO regionally.

Second, the disparity between benefits to California versus benefits to the joining utility may be greater than the numbers indicate at first read. Benefits shown in the PacifiCorp study are closer to being net for CAISO, but are gross for PacifiCorp. While the regionalization of the ISO will incur some modest incremental costs related to accommodating PacifiCorp and operating the enlarged system, the addition of PacifiCorp load will likely decrease the overall GMC rate for the current CAISO footprint. In contrast, PacifiCorp will have increased costs associated with payment of the GMC and additional system upgrades and facilities. Moreover, there will be the loss of certain transmission revenue credits as the new PTO shifts to a paradigm in which generators serving load within the expanded regional footprint do not pay for transmission.

Potential new PTOs, their customers, and their local regulatory authorities are unlikely to support participation in the regional market if there is a significant misalignment of the projected benefits. The regional ISO's TAC must at minimum prevent any adverse cost shifting, especially of the costs of existing facilities. Beyond initial integration, the solution for the TAC must acknowledge that the benefits to California that come with accessing the western region are far greater than the benefits to the individual western utilities of joining the market.

NV Energy supports reaching an understanding as to how benefits and costs will be aligned through the TAC, but requests further stakeholder engagement and the benefit of additional study and data from the CAISO to analyze the issue. Specifically, NV Energy would like further discussion, focusing on projected costs associated with new facilities, on the types of benefits, how those benefits will be valued, and how they will be allocated. For example, how should benefits be viewed and assessed for a project that must move forward to cure immediate reliability issues for one PTO, but that has incidental benefits of solving a potential future reliability issue for a neighboring PTO? How should benefits be assessed for projects that meet policy objectives not shared by all states? Answers to these questions in the context of future projects in the CAISO plan would significantly facilitate the development of sensible principles for allocating benefits and thereby aligning costs.

2. **<u>Please comment on the factors the ISO has identified in section 5 of the issue paper as considerations for possible changes to the high-voltage TAC structure. Which factors do you consider most important and why? Identify any other factors you think should be considered and explain why.</u>**

With respect to the factors identified in Section 5 of the Issue Paper, NV Energy submits that the most important factor is #1, whether the costs are associated with a new or existing facility. As described above, socializing any costs of existing facilities represents adverse cost shifting that will impede and possibly foreclose regionalization of the CAISO. The next most important factor is #5, identifying the beneficiaries. NV Energy believes that analysis of the purpose of the project (#4) is likely to be subsumed in the consideration of beneficiaries. Analysis of these factors is fundamental to determining how costs should be distributed to best match benefits.

Size (#2) and Scope (#3) are likely to be closely related, but even lower voltage projects - those that may facilitate the collection of renewable resources or associated with the under-build for higher voltage projects – may have regional beneficiaries.

Factors nos. 6 and 7 -- timing of facility approval and under what planning process – is important with respect to development rights. A potential PTO that has invested substantial sums on development activities associated with its approved transmission planning process should not be in the position of having those costs stranded as part of the integration.

Regarding the consideration of an exiting PTO, consideration #8, the transmission revenue requirements should flow with the facilities. If the facilities stay with the CAISO, then recovery should be under the CAISO rate. If the facilities are withdrawn, the revenue requirements would no longer be part of a CAISO charge. There should be no exit fee.

3. **<u>The examples in section 7 illustrate the idea of using a simple voltage-level criterion for deciding which facilities would be paid for by which sub-regions of the combined BAA. Please comment on the merits of the voltage-based approach and explain the reasoning for your comments</u>**.

NV Energy believes there are multiple possibilities as to how to apply the TAC and which new facilities should be socialized. NV Energy would like to see more data on the anticipated scope of these new facilities and how the regional ISO would value and assign benefits before opining on methods to allocate the costs of new projects. NV Energy advocates for more studies on the relative benefit to individual ratepayers across the different PTOs, and for stakeholder meetings that allow for in-person discussion of those analyses and related conclusions. A voltage-based criteria between a lower voltage local or zonal rate and a higher voltage socialized rate could be appropriate if it is justifiable as a proxy for understanding how PTOs will benefit relative to each other from the projects planned or in study. Without more information on the types of benefits that are driving projects and where those benefits land, however, NV Energy cannot evaluate if that is the right heuristic.

4. **<u>Please comment on the merits of using the type of transmission facility – reliability, economic, or public policy – as a criterion for cost allocation, and explain the reasoning for your comments.</u>**

As noted in response to Question 2, NV Energy recommends an approach that gives more weight to the anticipated beneficiaries than the type of project. Most transmission upgrades provide both reliability and economic benefits and can facilitate additional transfers of renewable resources.

5. **<u>Please comment on the merits of using the in-service date as a criterion for cost allocation; e.g., whether and how cost allocation should differ for transmission facilities that are in service at the time a new PTO joins versus transmission facilities that are energized after a new PTO joins.</u>**

As demonstrated by the tables provided in the Issue Paper, NV Energy submits that it will be crucial to use in-service date for cost allocation. New facilities can and must be treated differently than existing facilities. Moreover, FERC has supported such an approach.

In Docket No. ER14-2850, SPP proposed changes to facilitate the integration of the Western Area Power Administration – Upper Great Plains Region, Basin Electric Power Cooperative, and Heartland Consumers Power District (the "Integrated System Parties") to join SPP as transmission owning members. SPP modified the definition of "Base Plan Upgrade" in Schedule 11 of the SPP tariff to specify that the Integrated System Parties and SPP will commence regional cost sharing for projects with a "need-by" date on or after October 1, 2015 (the planned integration date). The Integrated System Parties' existing systems, as well as any planned transmission facilities on the Integrated System Parties' systems with a need-by date prior to October 1, 2015, will continue to be funded by the Integrated System Parties. Similarly, SPP's legacy system, and base plan upgrades with a need-by date prior to October 1, 2015, will continue to be funded by the prior SPP membership. Projects with a need-by date on or after October 1, 2015 are designated as base plan upgrades under the SPP Tariff, with regional cost recovery accomplished through the region-wide charges under Schedule 11 of the SPP tariff.

In accepting SPP's proposal, FERC noted:

> We appreciate the challenges that come with the integration of different regions with their own transmission planning processes and legacy transmission systems. There is no clear one-size-fits all just and reasonable approach for such an integration. Rather, in order to find a proposal to be just and reasonable, the proposal must respect both the principle of cost causation and the practical realities of a transition.

Southwest Power Pool, 149 FERC ¶61,113 at P.72 (2014). SPP had utilized a similar approach by creating new pricing zones to facilitate the entry of Nebraska Public Power District, Omaha Public Power District, and Lincoln Electric System.

FERC also noted the reciprocal aspects of the SPP proposal.

- We decline to require cost-sharing for the SPP and Integrated System Parties legacy transmission systems (i.e., transmission assets with a need-by date prior to the October 1, 2015 integration date), as requested by Kansas Commission. Specifically, although Kansas Commission asserts that the Integrated System Parties will gain benefits from use of the SPP legacy system and should therefore contribute to its costs, we find that Kansas Commission neglects to consider the benefits that the rest of the SPP membership will receive from the Integrated System Parties' legacy systems.

- Additionally, both current SPP members and the Integrated System Parties will be allocated costs for transmission projects not planned in the conventional planning processes that existed in the two regions prior to the integration date. The result will be the reciprocal; current SPP members will share in the costs of Integrated System Parties' transmission projects planned through a non-SPP planning process with a need-by date of October 1, 2015 or later, and Integrated System Parties except for the Federal Service Exemption, will share in the cost of transmission projects with a need-by date of October 1, 2015 or later that were planned through the SPP regional transmission planning process.

On rehearing FERC stated its expectation that "parties to a large-scale integration to negotiate the details of that integration, which includes the actual date of the integration and its use as a milestone for transitioning to procedures and cost allocations under a post-integration Tariff." *Southwest Power Pool*, 153 FERC ¶61,051 at P.40 (2015).

Given the significant differences in transmission rates between existing CAISO and PacifiCorp facilities and the prior discussion of benefits, the CAISO should give strong consideration to the SPP precedent as a means for moving forward in this stakeholder process.

Stated simply, it will be hard enough to study and confirm a just and reasonable methodology for the projected going-forward costs. There is unlikely to be any methodology that could justify the significant cost shifts associated with the existing facilities.

6. **<u>Please comment on using the planning process as a criterion for cost allocation; i.e., whether and how cost allocation should differ for transmission facilities that are approved under a comprehensive planning process that includes the existing ISO PTOs as well as a new PTO, versus transmission facilities that were approved under separate planning processes.</u>**

As noted in the SPP Orders discussed in response to Question 5, as long as the cost allocation methodology is reciprocal between the existing RTO customers and the new PTO, i.e., recognizes who is benefiting, it does not matter what planning process the projects were proposed under.

7. **<u>The examples in section 7 illustrate the idea of using two "sub-regional" TAC rates that apply, respectively, to the existing ISO BAA and to a new PTO's service territory. Please comment on the merits of this approach and explain the reasoning for your comments.</u>**

None of the scenarios in Section 7 draw a distinction between existing and planned facilities. A phase-in of existing revenue requirements is unnecessary and unlikely to preserve the benefits valuation needed to support new PTOs joining the regional market. Accordingly, NV Energy cannot comment on the possibility of using two sub-regional TAC rates at this time. Such an approach could be used for future projects in the event it was necessary to prevent costs shifts that would otherwise degrade anticipated benefits and make regional market participation uneconomic.

Additional data, focusing on projected transmission expansion costs could support voltage-based differentiations for cost allocations based on local (historic BAA boundaries), system wide or some form of hybrid. Whether the voltage cutoffs should remain 200 kV for local but be expanded to something higher (e.g. 345 kV) for system-wide with facilities between 200 kV and 345 kV being allocated under a hybrid approach is worth examining as part of the stakeholder process to determine if there is good cause to support the additional complexity.

8. <u>Please offer any other comments or suggestions on this initiative.</u>

NV Energy thanks the CAISO for the opportunity to comment on this initiative and offers a few additional thoughts. First, in Section 3 of the Issue Paper, the CAISO proposes to use the FERC Order No. 1000 criteria to assess its initiative. It is important to note that the Commission only suggested that Order No. 1000 apply to new projects, planned and constructed after the rulemaking's effective date. It was never meant to serve as a justification for a redistribution of the transmission revenue requirements associated with existing facilities.

The CAISO should work towards a TAC methodology that will facilitate the desired goal of regional expansion. To do so, the CAISO will need to resist the temptation to use projected benefits to the new PTOs as a justification for cost shifts. In addition, costs and benefits should not be artificially segregated to conduct this analysis. For example, assignment of transmission charges to new PTOs should not ignore the more immediate benefits of merger, including energy transfer opportunities and changes to the burden of the grid management charge. Such an approach will only further exacerbate the projected differential in benefits in favor of the existing CAISO customers – a result that is unlikely to permit new entry.