Stakeholder Comments Template

Transmission Access Charge Options

August 11, 2016 Stakeholder Working Group Meeting

Submitted by	Company	Date Submitted
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The ISO provides this template for submission of stakeholder comments on the August 11, 2016 stakeholder working group meeting. Topic 1 of the template is for comments on the default cost allocation provisions for new regional transmission facilities, the topic of the morning session of the working group. Topic 2 is for comments on the region-wide TAC rate for exports, which the presentation referred to as the "export access charge" (EAC) and was the topic of the afternoon session of the working group. The ISO invites stakeholders to offer their suggestions for how to improve upon the ideas discussed in the working group meeting.

The presentation for the August 11 meeting 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 **August 25, 2016.**

Topic 1. Default Cost Allocation Provisions for New Regional Transmission Facilities

Context

For purposes the working group discussion the ISO assumed that the current structure of the transmission planning process (TPP) would be retained for the expanded BAA. That is, the TPP would consist of a first phase for specifying and adopting planning assumptions including public policy directives that would drive transmission needs, as well as a study plan. The second phase would consist of a sequential process for performing planning studies and identifying reliability projects, followed by policy-driven projects, and finally economic projects. With each successive project category, the ISO may identify a project that serves the need of a project identified in a prior category, in which case the project would be labeled by the last category in which it was identified, but its cost allocation would reflect the benefits in all categories.

By design these two TPP phases take 15 months, at the end of which the ISO would present the comprehensive transmission plan for approval to the governing board for the expanded BAA. At the working group meeting the ISO also pointed out that while the concept of a "body of state regulators" or "Western States Committee" is still under discussion in the context of governance for the expanded BAA, no details have been developed or proposed regarding this entity's role with regard to transmission planning and cost allocation. Moreover, once the default provisions being discussed in the working group are finalized, filed and have been approved by FERC for inclusion in the ISO tariff, any variations or deviations from those provisions would also have to be filed and approved by FERC. Stakeholders should therefore view the current effort to develop default cost allocation provisions as determining the rules that would govern transmission cost allocation for the expanded BAA.

Stakeholders should assume for purposes of their comments that the current ISO TPP structure would be followed in an expanded TPP performed for the expanded BAA. Parties wishing to comment on or suggest alternatives to these assumptions may add any additional comments at the end of this topic.

Questions

1. The working group presentation assumed we would use the current Transmission Economic Assessment Methodology (TEAM) to calculate a project's economic benefits to the BAA as a whole and to each of the sub-regions. Currently TEAM calculates the following types of benefits: efficiency of the economic dispatch, reduction of transmission line losses, and reduction of resource adequacy capacity costs. Are these economic benefit types sufficient for purposes of cost allocation, or should other types of benefits be included? Please describe any additional benefit types you would include in the benefits assessment and suggest how they could be quantified.

Before stakeholders are asked to assess the ISO's proposed TEAM methodology, the ISO should present to the stakeholders how benefits are quantified in each major U.S. ISO/RTO's economic planning and/or cost allocation processes as well as in the other western planning regions (NTTG, ColumbiaGrid, WestConnect) and compare the ISO's proposal to the processes of these ISO/RTOs and western planning regions.

Future benefits, based on long-term production cost modeling, beyond a couple of years are highly fluid, variable, and sensitive to fundamental modeling assumptions. These assumptions (e.g. projections of fuel costs, amount and location of generation retirements and additions, load growth, costs of new resources especially newer technology, future contractual arrangements) in turn have large margins of error beyond a couple of years which can significantly impact benefits and power flows. Therefore, the Utah Office of Consumer Services (Utah OCS) questions whether using long-term production cost modeling to determine future benefits for use in one-time cost allocation is a valid and/or fair approach.

The ISO should be careful about including the reduction in resource adequacy capacity costs as a benefits:

- **Avoided cost of capacity may be different in different sub-regions due to regulatory differences or different new generation development opportunities.**
- **Avoided cost of capacity should take into consideration the regulatory compact in each sub-region.**
- **Avoided cost of capacity should net out other benefits such as impact on energy and ancillary services prices.**

2. The ISO's presentation suggested that a sub-region's avoided cost for a needed transmission project could be included among the benefits of a project with region-wide benefits. For example if project A with region-wide economic benefits enables sub-region 1 to avoid a reliability project B that would have cost $40 m, then the $40 m avoided cost should be included in the total benefits of project A for purposes of cost allocation to the sub-regions. Please comment on whether such avoided costs should be included in the benefits for cost allocation purposes.

It typically takes multiple years for a transmission enhancement to be built after the need for it is identified in the ISO's planning process. A project that is needed for reliability this year may turn out to be redundant next year based on next year's planning assumptions and analyses (example: PATH project in PJM). Including as a benefit the avoided cost of a transmission project that may or may not eventually be needed or built is highly speculative. Only projects which have been "approved" should be eligible for inclusion as an avoided cost benefit. At this time, the Utah OCS does not propose a final definition of what "approved" might mean but it could be a project that has been approved by an LRA such that it has obtained its necessary CPCNs and permits.

3. In the example of Question 2 a specific project B was identified to meet a reliability need, and so its avoided cost could be viewed as a realistic estimate of the cost to sub-region 1 of mitigating its reliability need. In many instances in practice, however, cost-effective projects may be identified that provide economic, policy and reliability benefits without the planners ever identifying less costly but narrowly-scoped hypothetical alternative projects that could serve to provide concrete avoided cost estimates. Do you think it is important to perform additional studies to determine meaningful avoided cost estimates to use in cost allocation, perhaps by identifying hypothetical alternatives that would not ordinarily be considered in the TPP? Are there other approaches you would favor for estimating avoided costs to use in cost allocation? What other methods should the ISO consider for allocating reliability or policy "benefits" to a sub-region absent a well-defined project that can be avoided?

No, there is no need to engage in highly speculative hypotheticals to find ways to socialize costs of reliability and policy-driven projects. When there is no well-defined or approved (see response to Question 2 above) project that can be avoided in a sub-region, the ISO should simply not use an avoided cost metric for the allocation of costs of reliability and policy-driven projects to a sub-region.

4. The cost allocation approach presented at the working group for projects with benefit-cost ratio BCR < 1) started by first allocating cost shares equal to economic benefits, and only after that allocating remaining costs to the sub-region(s) driving the reliability or policy need. In the discussion, some parties suggested reversing this order, i.e., to start by allocating a cost share to the sub-region with the reliability or policy driver base on the avoided cost of the reliability or policy project it would have had to build, and only then allocating remaining costs based on economic benefit shares. Please state your views on these two approaches, or describe any other approach you would prefer and explain your reasons.

The Utah OCS in its June 10 comments to the TAC Revised Straw Proposal stated:

> ***The Utah Office of Consumer Services believes that if a state's policy is driving the need for a project, then that state should initially be responsible for all the costs of the project. Once the project is in-service and actual benefits can be measured, then it would be appropriate to ask other states to share in the costs based on the benefits achieved. However, no non-policy state should have to bear any costs that exceed its benefits.***

The Utah OCS reiterates this position and believes that its position as stated above on policy-driven projects should also apply to reliability-driven projects.

5. The presentation at the working group suggested that all facilities > 200 kV planned through the expanded TPP would be assessed for potential region-wide economic benefits. Some parties suggested the ISO should apply threshold criteria to eliminate projects that clearly would not have region-wide benefits, rather than perform TEAM studies for all > 200 kV. Do you support the use of threshold criteria? If so, what criteria would you apply and why?

The Utah OCS has no comment on this issue at this time.

6. Do the details of TEAM, e.g., financial parameters, period over which present values are determined, etc., need to be pre-determined to maximize consistency of methodology and criteria across all projects, or should case-by-case considerations be taken into account?

See the Utah OCS' response to Question 1 above.

7. Should incidental benefits to a sub-region cause a cost allocation share for that sub-region even though the project would not have been built but for a reliability or policy need in another sub-region?

See the Utah OCS' response to Question 4 above.

8. Please offer any additional comments, suggestions or proposals that were not covered in the previous questions.

The Utah OCS proposes that the formation of a regional ISO include a Transition Period for cost allocation of new transmission projects. The cost of projects (reliability, policy or economic) built for one sub-region should be allocated entirely to that sub-region for a certain number of years (for example, five years). In the event of the expansion of the ISO

to include PacifiCorp and possibly other companies, this will allow all parties to gain a thorough understanding of the constraints, power flows and congestion patterns in a regional ISO footprint, which in turn will allow all parties to better assess costs and benefits of new regional transmission facilities. This is consistent with the Transition approach that went into effect in MISO when Entergy joined MISO.

Moreover, the Utah OCS does not necessarily believe that the CAISO's TPP should be automatically adopted as stated at the beginning of this comment template. The Utah OCS believes that the ISO should first fully educate stakeholders in the ISO's current TPP and then provide a comparison to the other transmission planning processes in the western region (NTTG, ColumbiaGrid and WestConnect) and to other ISO/RTOs in the United States. After such education and review, stakeholders may be comfortable adopting CAISO's TPP or may require some modifications.

Topic 2. Region-wide "Export Access Charge" (EAC) Rate for Exports and Wheel-throughs

Context

For the working group discussion, the ISO's presentation assumed a scenario where the current ISO BAA is expanded by the integration of a large external PTO such as PacifiCorp, and that the current ISO footprint and the new PTO would each be a "sub-region" with its own separate sub-regional TAC rate for load internal to the sub-region. The ISO further assumed that in this future scenario, only exports and wheel-throughs would pay the new EAC rate, while the "non-PTO" entities internal to the ISO BAA who currently pay the WAC would pay the sub-regional TAC rate. **Please assume the same in responding to the questions below.** If you wish to comment on or propose alternatives to these assumptions you can add any additional comments at the end of this section.

Questions

1. For an expanded BAA do you agree that a single region-wide access charge rate for exports and wheel-throughs is appropriate? Please explain your reasons. NOTE: This question is only about whether a single rate is appropriate, not about how that rate should be determined; the latter is covered in question 3 below.

PJM and MISO have a single region-wide access charge rate for export and wheel-through transactions while SPP does not. It is more important to implement an efficient rate design that respects the existing arrangements and revenue levels in the PacifiCorp sub-region.

The Utah OCS in its June 10 comments to the TAC Revised Straw Proposal stated:

> ***The Utah Office of Consumer Services needs additional information on how this WAC concept would affect transmission users in the PacifiCorp region. For example, how might it affect their utilization of PacifiCorp operated transmission systems in the future as compared to how they utilize it now (e.g. would it create constraints or barriers that don't currently exist) and how it would it affect their costs for using the transmission system.***

This same comment applies to the single region-wide access charge rate for exports and wheel-throughs that the ISO is proposing.

It is also important to ensure that each sub-region, at least initially, continues to collect as much in export/wheeling transmission revenues after the expansion as it would have absent the expansion. Reduced export/wheeling revenues would lead to higher net transmission costs for native/retail load and thus higher rates for end-use customers in that sub-region. On the other hand, raising PacifiCorp's export and wheel-through transmission rates significantly may allow PacifiCorp to increase its export revenues at the expense of significantly higher transmission costs for PacifiCorp's existing transmission-dependent customers.

To ensure a balance between these two concerns and to avoid a rate shock on any given group of customers, the ISO may need to implement a Transition Period where PacifiCorp continues to employ a similar transmission service rate design and charge similar transmission rates compared to the pre-expansion status quo for a certain number of years (such as five years). This will allow PacifiCorp and all stakeholders to observe the transaction volumes and any transmission revenue over-collections or shortfalls based on post-expansion market dynamics. Armed with this knowledge, the expanded ISO and stakeholders may proceed to harmonize or redesign transmission access charges across the expanded ISO at the conclusion of the Transition Period.

2. If you answered YES to question 1, do you favor the load-weighted average rate the ISO presented at the meeting, or another method for determining the single rate? Please explain the reasons for your preference.

See response to Question 1 above.

3. To distribute the revenues collected via the EAC, the ISO's presentation suggested giving each sub-region an amount of money equal to the MWh volume of exports and wheels from the sub-region times the sub-regional TAC rate. Please indicate whether you would support this approach or would prefer a different approach for distributing EAC revenues to the sub-regions.

See response to Question 1 above.

4. The working group presentation illustrated how the method of distributing EAC revenues to sub-regions would most likely produce "unadjusted" sub-regional shares that do not add up exactly to the amount of EAC revenues collected from exports and wheels. The presentation offered one approach for distributing any **excess EAC revenues** to the sub-regions. Do you support that approach, or would you prefer a different approach? Please explain.

See response to Question 1 above.

5. Suppose that in a given year the EAC revenues are not sufficient to cover a distribution to sub-regions that aligns with sub-regional TAC rates, as described in question 3. How would you propose the ISO deal with that situation? I.e., should the ISO ensure that each sub-region receives export revenues equal to its sub-regional internal TAC rate times the volume of exports from its facilities, drawing upon other TAC revenues if necessary, or should the ISO only return EAC revenues to sub-regions until the EAC revenues are used up?

Unlike the current CAISO transmission owners, PacifiCorp has bundled transmission, i.e., PacifiCorp's transmission costs are embedded in retail rates. Therefore, PacifiCorp's transmission costs are predominantly collected through retail rates versus collected through the revenue PacifiCorp receives from its FERC-approved OATT transmission rates. This is a rate design issue that the states that have jurisdiction over PacifiCorp's retail rates should determine.

6. If you answered NO to question 1, please explain what rules or principles you would prefer be applied to exports and wheel-throughs. Please discuss both (a) how you would propose to charge exports and wheel-throughs, and (b) how you would distribute the revenues collected to the sub-regions.

See response to Question 1 above.

7. Please offer any additional comments, suggestions or proposals that were not covered in the previous questions.