Review Transmission Access Charge Structure

Issue Paper

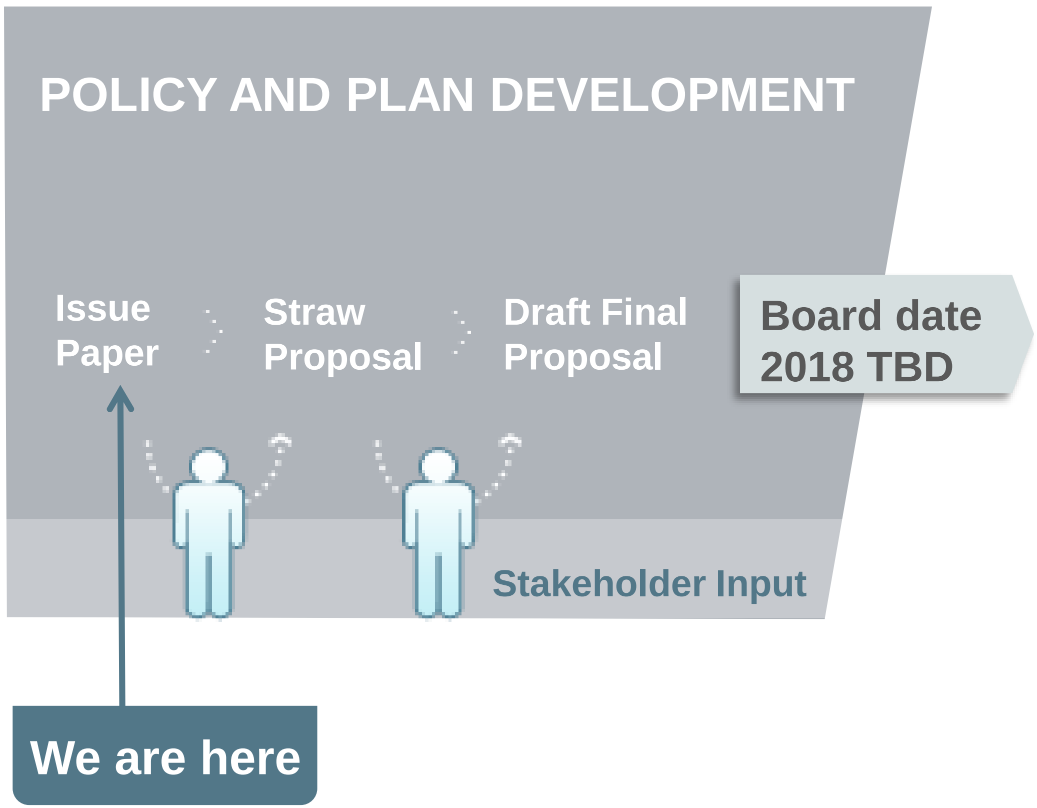
Stakeholder Meeting

July 12, 2017

Agenda

Time	Topic	Presenter
10:00 – 10:10	Introduction	Kristina Osborne
10:10 – 11:00	Background and scope	Lorenzo Kristov
11:00 – 11:30	Transmission rate design principles	Milos Bosanac
11:30 – 12:00	Transmission cost recovery in other ISOs/RTOs	Bill Weaver
12:00 – 1:00	Lunch	
1:00 – 1:45	Transmission cost recovery in other ISOs/RTOs – continued	Bill Weaver
1:45 – 2:55	Treatment of load offset by distribution-connected resources	Neil Millar
2:55 – 3:00	Next Steps	Kristina Osborne

ISO Policy Initiative Stakeholder Process



Initiative background and scope

Prior recent TAC-related initiatives

- “TAC Options” (10/15 – 12/16)
  - Focused on transmission cost allocation over a potentially expanded balancing authority area (BAA)
  - Did not address topics of current initiative
- “Review TAC Wholesale Billing Determinant” (6-9/16)
  - Convened to consider proposal to bill TAC to internal load based on “transmission energy downflow” (TED) rather than Gross Load (end-use metered load)
  - Closed in favor of opening a more holistic examination of TAC structure in 2017
- “Review TAC Structure” – current initiative

Proposed scope of current initiative

The ISO proposes two major TAC structure topics:

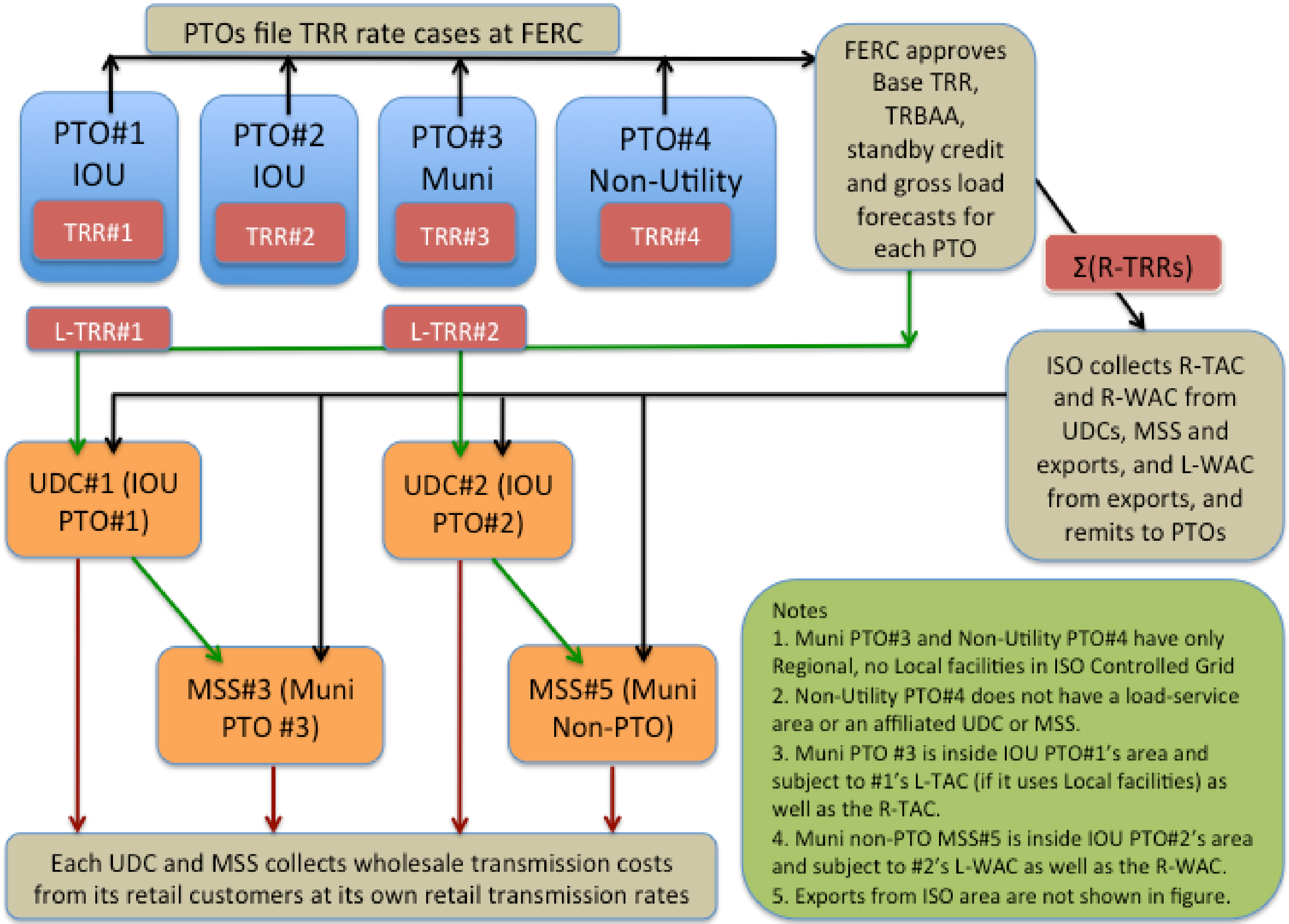
1. Whether/how to modify the TAC billing determinant to reduce TAC charges in PTO service areas for load offset by "DG output"
   - "DG Output" includes energy injections from (1) distribution-grid connected resources, and (2) behind-the-meter resource output that exceeds consumption at the same site during the same hour
   - For each settlement hour the difference [TED – Gross Load] reflects DG Output for the same hour
2. Whether to modify the current volumetric TAC structure to incorporate other approaches such as demand-based or time-of-use structure

The ISO invites stakeholders to suggest modifications or additions to the proposed scope

What’s proposed to be outside the scope?

- The existing regional-local bifurcation of transmission costs and cost recovery
  - “Regional” (>= 200 kV) costs are combined for the ISO area and collected by ISO via uniform system-wide rates
  - “Local” (< 200 kV) costs are collected by each IOU-PTO at its own rate for its own service territory
- Regional cost allocation for a potentially expanded BAA in the future
  - ISO’s 12/16 Draft Regional Framework Proposal remains the current proposal on this topic
  - Any policy changes resulting from the current initiative will carry over to any future regional discussions
- Alternative types of transmission service offerings (as offered by some other ISOs/RTOs)

How transmission cost recovery via TAC works today



From the ISO's April 12 background white paper that explains the current process for recovering costs through the transmission access charge (TAC):

http://www.caiso.com/Documents/BackgroundWhitePaper-ReviewTransmissionAccessChargeStructure.pdf.

Observations on today's cost recovery process

1. Transmission cost recovery is a complex process
2. The process is somewhat different for each of the PTOs that has FERC-approved costs to recover
3. The set of parties that recover transmission costs via the TAC is not identical to the set of parties whose customers pay the TAC
4. The ISO's role is limited to collecting TAC and WAC charges and remitting revenues to PTOs for
   – Regional facilities in the ISO Controlled Grid used by wholesale customers to serve internal load, and
   – Regional and Local facilities used for wholesale exports
5. The original volumetric TAC structure was established to align with the ISO's market-based approach for scheduling transmission use on hourly MWh volumes

Transmission rate design principles

Principles of Electric Transmission Cost Allocation and Pricing

- Through its *Transmission Pricing Policy Statement*, FERC has recognized general guiding principles for transmission pricing:
  - Must meet traditional revenue requirements
  - Must reflect comparability
  - Should promote economic efficiency
  - Should promote fairness
  - Should be practical
- The above principles are influenced by the *Bonbright* principles of revenue adequacy, optimal use of service, and fairness.

Cost Allocation – An Inexact Science

- FERC has generally required that approved rates reflect cost causation.
  - The concept that costs should be allocated to customers, where possible based on customer benefits and cost incurrence.
- Neither FERC or the courts have required that allocation of costs be with exact precision.
- More recently, in Order 1000, FERC identified cost allocation principles for new transmission facilities emphasizing the concept of cost causation – allocation of costs commensurate with benefits.
- Ultimately, the guiding ratemaking principles are influenced by the circumstances of the utility or ratemaking entity.

Transmission cost recovery in other ISOs/RTOs

FERC Order No. 888

"Because network service is load based, it is reasonable to allocate costs on the basis of load for purposes of pricing network service. This method is familiar to all utilities, is based on readily available data, and will quickly advance the industry on the path to non-discrimination. We are reaffirming the use of a twelve monthly coincident peak (12 CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks. Utilities that plan their systems to meet an annual system peak (e.g., ConEd and Duke) are free to file another method if they demonstrate that it reflects their transmission system planning."

Network Load (ISO-NE Tariff)

The Network Customer’s Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such nondesignated load.

RTO Billing Determinant Summary

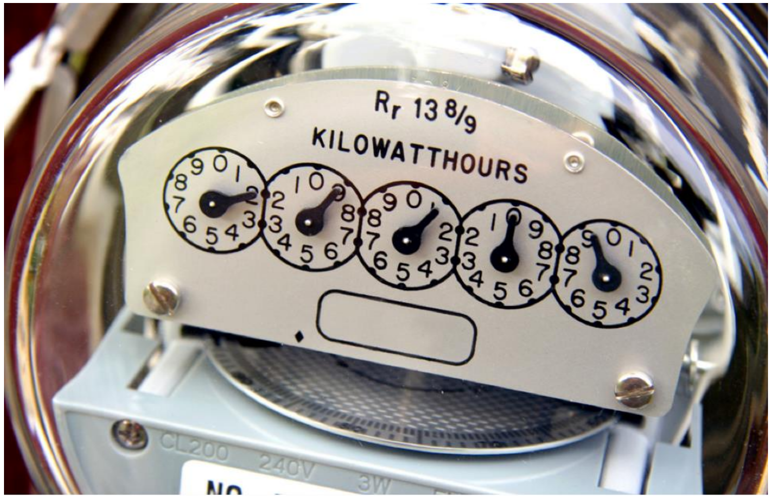
	Volumetric	Demand		
Basis	MWh/Gross Load	Monthly peak	Annual peak	Variable
Examples	CAISO NYISO MISO MVPs	SPP ISO-NE MISO NITS	ERCOT (4 summer months)	PJM
Intent	Correlates with beneficiaries ex post: Customers benefit from transmission as they use it.	Correlates with cost causation ex ante: Transmission costs were incurred to provide customers reliable service during peak demand periods.		

RTO Billing Determinant Summary (cont.)

	Volumetric	Demand
Pros	- Mirrors energy-based (not capacity-based) market - Easily understandable - Reflects benefits all year - Correlates with RPS-driven construction benefits (e.g., carbon reduction, production cost savings)	- Customers only pay in relation to their contribution to peak conditions (no more, no less) - Historically more common
Cons	Socializes costs incurred due to peak times and/or areas	- More complex than volumetric - Ignores benefits unrelated to peaks

Usage vs. Demand: MISO MVPs

"… the MVP is proposed to be applied on a usage (i.e., MWh) basis rather than a demand (i.e., MW) basis. . . . [A] usage-based charge is warranted because energy flows and the corresponding benefits will occur in all hours of the year, not just during peak demand. This is in contrast to many local facilities in existence today, which were constructed to meet the peak demand of the area in which they are located."



Usage vs. Demand: MISO MVPs

"For example, if wind generation is used to help meet the energy requirements of RPSs, only a small percentage of the energy generated by wind will occur during periods of peak demand, *i.e*., the small percentage of hours that drive demand-type charges. Furthermore, it is expected that a significant portion of the economic value associated with MVPs will be the reduction of production costs, an energy based measure, during the year. . . .

Usage vs. Demand: MISO MVPs

"Furthermore, the benefits of a market-wide economic dispatch are often more significant during off-peak hours, because fewer generation resources are required and more opportunity exists to use generation in one region to serve load in another. In any event, any effort to reduce production costs through transmission expansion that allows for a greater level of regional dispatch must be allocated throughout the year rather than just during the system peak hour(s) in order for the cost allocation to appropriately align with benefits."

Treatment of load offset by distribution-connected resources

Treatment of load offset by distribution-connected resources – considerations and questions

- Services provided by the transmission system
  - Transmission needs addressed in the ISO's transmission planning process
  - Other services provided by transmission
- Distribution grid-connected and behind-the-meter generation
- Impact of DER in offsetting new transmission costs
- Implications for costs of existing transmission

The ISO seeks stakeholder input regarding these issues and the extent distribution-connected resources can offset the need for transmission costs

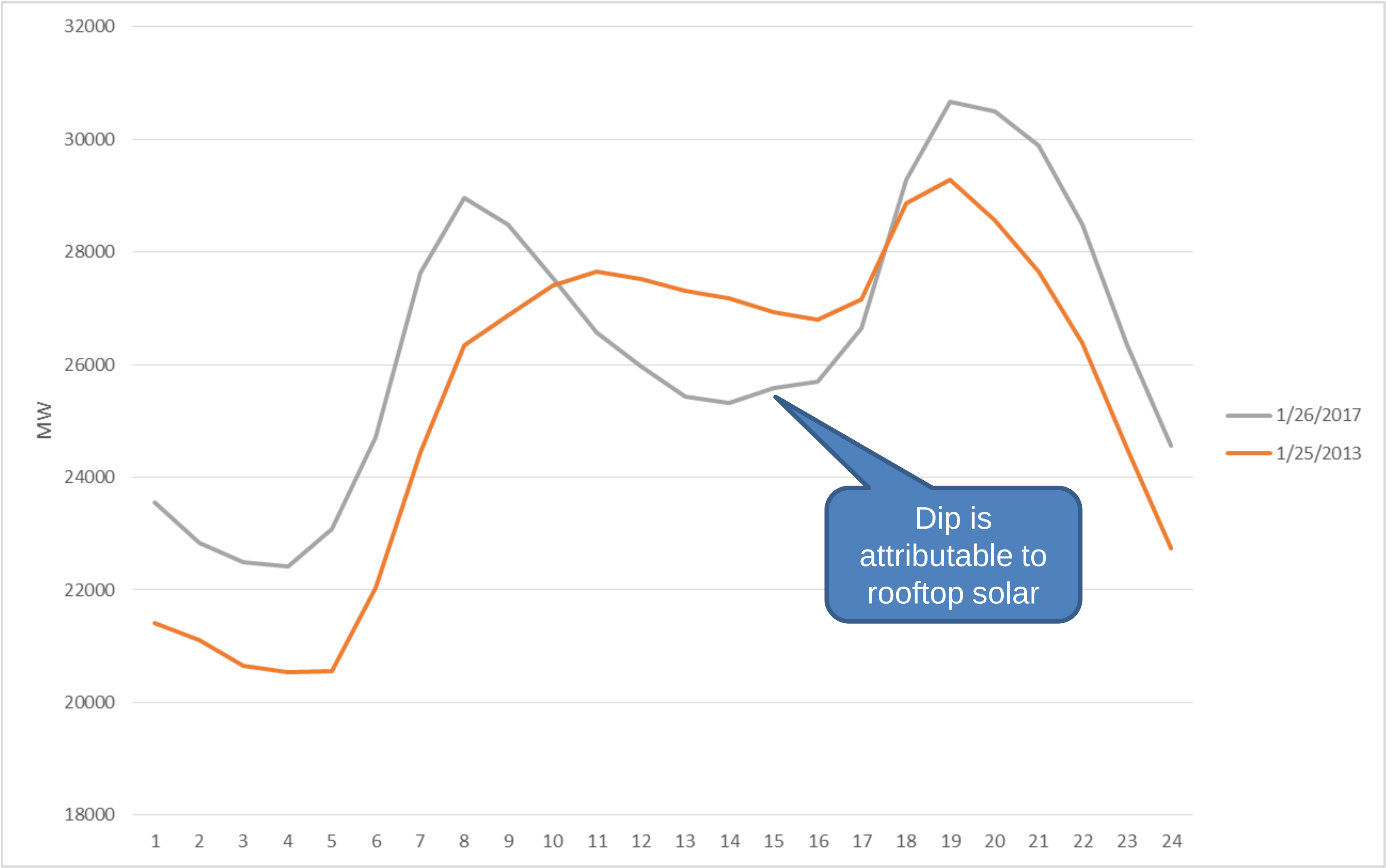
Services provided by the transmission system

- It is progressively more complex to consider services being provided in today's increasing range of technical choices, regulatory options, and policy objectives
- Transmission service needs addressed in the ISO's planning process consider primarily reliability, policy, and economic needs for reinforcement on behalf of customers
- Thermal, voltage support and stability, and dynamic stability limitations can all drive the need for transmission
- Other services provided by or enabled by the transmission system don't typically lead to new transmission reinforcements – frequency control, motor starting, short circuit current for fault protection, etc.

Distribution grid-connected and behind-the-meter generation

- There are two types of distribution-connected resources to be considered, for both their potential similarities and differences:
  - resources connected to the utility distribution system, and
  - behind-the-meter (BTM) generation that is almost exclusively photovoltaic. The BTM generation initially offsets customer load on site, and then can inject into the grid when its output exceeds the load.
- The structure of net energy metering (NEM) tariffs incentivizes the use of the grid to effectively provide storage for the excess production – which is almost entirely solar PV.
- Solar PV generation on the utility side of the customer meter will similarly impact the “duck curve” for net load served by other resources.

Changing Profile - ISO Controlled Grid Gross System Load



Role of DER in offsetting new transmission costs (issues)

- To what extent do DER materially and reliably reduce the need for transmission costs?
- Do the MW and Mvar output alone provide adequate measures of benefits?
- How should the change from more traditionally focusing on serving “peak” load to broader power transfer considerations and “peak shift” be taken into account?

Role of DER in offsetting new transmission costs (considerations)

- Consideration may be given to if:
  - The DER output profile materially impacts the level of system stress across the entire range of planning conditions and, if so, offsets the limiting technical issue
  - The load served by use-limited DER (such as solar PV) also relies on other sources of generation for services at other times – for reliability, policy or economic reasons
  - The DERs utilize smart inverters that can provide reactive power support/volt-var management along with other reliability functions – and to what extent this reflects onto the transmission system

Role of DER in offsetting new transmission costs (quantification)

- Where DER may provide benefits, how can we quantify the benefits a particular DER or set of DERs is providing to the transmission system?
  – Consider the avoided cost benefit of deferring or canceling a specific transmission project where easily identified?
  – If growth of DER is included in forecasts over time, how does the counterfactual get determined? Who determines what would have otherwise been built, if the determination is only for rate purposes?
  – Is a “counterfactual” approach sustainable as time goes by and DER proliferate? Is it less clear what the counterfactual would have been, *i.e.,* the specific transmission upgrades or reinforcements that are being deferred?
  – Are high level assumptions of potential benefits through cost of service study approaches reasonable?

Implications for costs of existing transmission

- The costs associated with transmission facilities already in service or that were planned and approved in prior transmission planning cycles and are under development are not avoidable.
- The TRR associated with these facilities, once approved by FERC, must be collected from ratepayers.
- What are the implications of this for cost allocation purposes?
- How should consideration of potential changes to the TAC structure take into account any potential shifting of the costs of existing transmission?

Next steps

The ISO requests stakeholder input on several specific questions in this initiative.

The ISO will post a template for stakeholder comments. The following are some key areas where ISO seeks input:

- Scope of initiative: please comment on any modifications or additions to the proposed scope you think are needed, and explain how these relate to the primary topics
- Transmission cost recovery in other ISOs/RTOs: Please comment on any useful lessons learned from these other approaches
- Load offset by distribution-connected resource output: Please comment on the questions posed in the issue paper and today's discussion regarding how to value the benefits of DER in avoiding transmission costs

Next Steps

Milestone	Date
Post issue paper	June 30, 2017
Stakeholder meeting	July 12, 2017
Stakeholder comments due	July 26, 2017
Stakeholder working group meeting	August 29, 2017

Written stakeholder comments on issue paper and July 12 meeting discussion due COB July 26 to InitiativeComments@caiso.com.

View full stakeholder process schedule on page 5 of the issue paper http://www.caiso.com/Documents/IssuePaper-ReviewTransmissionAccessChargeStructure.pdf

Materials related to the Review TAC Structure initiative are available on the ISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx