Transmission Access Charge Options
2nd Revised Straw Proposal

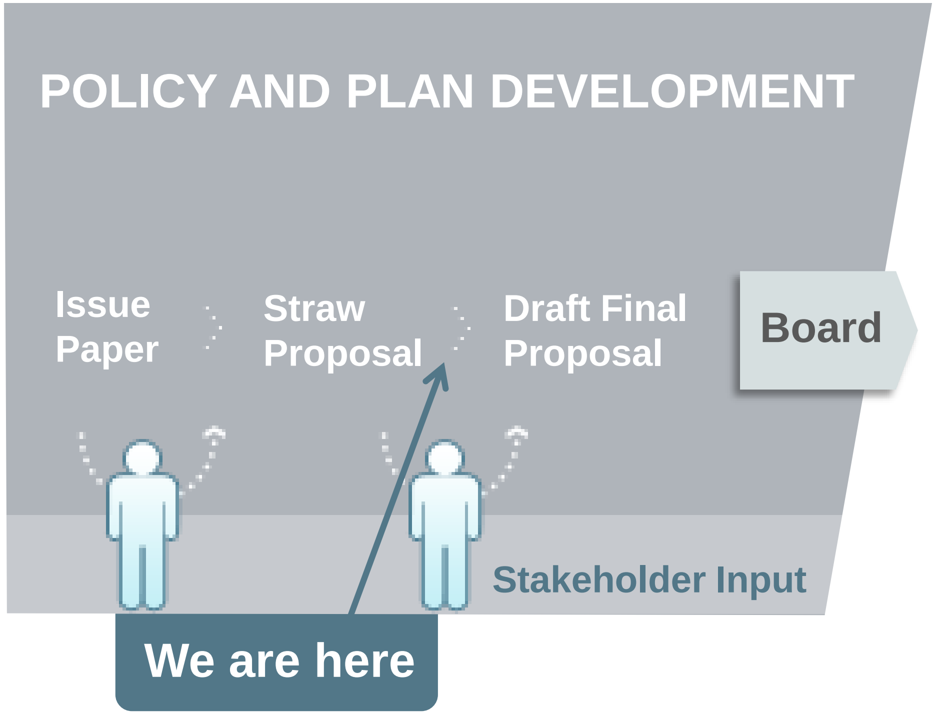
Stakeholder Meeting

October 7, 2016

October 7, 2016 stakeholder meeting agenda

Time (PST)	Topic	Presenter
9:00-9:10	Introduction and Stakeholder Process Overview	Kristina Osborne
9:10-12:00	Discuss 2nd RSP – discussion will follow sequence of topics in paper	Lorenzo Kristov
12:00-12:45	Lunch break	
12:45-2:45	Discuss 2nd RSP – continued	Lorenzo Kristov
2:45-3:00	Next Steps	Kristina Osborne

Stakeholder Process



Key Terms, Concepts and Assumptions

Terms, concepts, assumptions – 1

a) Proposal addresses cost allocation for high-voltage facilities (200 kV and above)
   - Cost allocation for “local” low-voltage facilities (< 200 kV) under ISO operational control will be PTO-specific

b) Use of “CAISO” refers to existing ISO BAA, controlled grid facilities, member PTOs, etc.

c) “Expanded ISO” refers to expanded BAA formed by integrating a new PTO with a load-service territory with the existing CAISO area

d) PTO#1 refers to the first new PTO to join to form the expanded ISO

Terms, concepts, assumptions – 2

e) “New” transmission facilities are those planned and approved through a new integrated TPP for the expanded ISO BAA

- Integrated TPP will begin in the first full calendar year that PTO#1 is fully integrated
- “New” may include a project under consideration as inter-regional prior to formation of the expanded ISO

f) “Existing” transmission facilities are those placed under operational control of expanded ISO that are not “new”

g) The existing CAISO area and the PTO#1 area will each be a “sub-region” under the expanded ISO.

- Subsequent new PTOs will each become a sub-region unless embedded in or electrically integrated with an existing sub-region

Embedded or electrically integrated new PTOs

– A new PTO is embedded within an existing sub-region if it <u>cannot import sufficient power into its service territory to meet its load</u> without relying on the transmission of the existing sub-region.

– Electrically integrated will be determined case-by-case, subject to Board approval, considering criteria such as those for IBAA (tariff sec. 27.5.3.8.1)
  - Number of interties between PTO and existing sub-region, and distance between them
  - Whether transmission system of new PTO runs in parallel to major parts of existing sub-region system
  - Frequency and magnitude of unscheduled power flows at applicable interties
  - Number of hours where direction of power flow reverses from scheduled directions

Terms, concepts, assumptions – 3

h) Expanded ISO will continue to charge TAC on per-MWh volumetric rate to all internal loads and exports

Structure of wholesale TAC does not prescribe or constrain structure of retail transmission charges

- CAISO PTOs under California PUC currently use volumetric rates for residential customers and combination of demand+volumetric for commercial and industrial customers
- Expanded ISO will charge TAC to utility distribution companies (UDCs) based on their end-use metered load
- Retail rate structure each UDC uses to recover TAC charges from retail distribution customers is not determined by ISO wholesale TAC charges

Cost Allocation for Existing Transmission Facilities

Costs of existing facilities will be recovered via “license plate” sub-regional TAC rates.

1. Sub-regional TAC will be charged to each MWh of load internal to the sub-region
   - “Non-PTOs” within a sub-region will pay the same sub-regional TAC rate
   - Exports and wheel-throughs from the expanded ISO will pay a region-wide export access charge (EAC) – discussed below
2. & 3. Each sub-region’s existing facilities comprise “legacy” facilities for which subsequent new sub-regions have no cost responsibility
4. High-voltage TRR for embedded or electrically integrated PTOs will be combined into the license-plate rate for rest of that sub-region

Default Cost Allocation for New Transmission Facilities

FERC Order 1000 requires that the ISO tariff contain "default" cost allocation provisions for new facilities.

5. May 20 proposal deferred this topic to proposed "body of state regulators"
   - New "Western States Committee" (WSC) proposal supersedes prior body of state regulators
   - Proposed WSC role with respect to cost allocation for policy-driven projects is discussed below
   - Details of WSC will be addressed as part of governance

- Default provisions developed in this initiative will apply unless and until FERC approves alternative provisions developed by WSC.

Cost allocation for new facilities – 2

6. A new transmission facility may be <u>considered</u> for cost allocation to multiple sub-regions if it is rated 200 kV or higher (high-voltage)
   - Costs for certain high-voltage projects – specified below – would be allocated entirely to the sub-region where they are built
   - Costs for low-voltage projects (below 200 kV) would be allocated entirely to the relevant PTO
7. ISO will use Transmission Economic Assessment Methodology (TEAM) to determine economic benefits to expanded ISO region as a whole and to each sub-region
   - ISO is updating TEAM documentation

Using TEAM results to determine sub-regional shares of economic benefits

- Production cost savings (from end-use ratepayer perspective) will be extracted from production simulation results
- Capacity benefits can be manually derived based on capacity requirements a sub-region basis
- Transmission line losses will be extracted from snapshot powerflow cases used for reliability analysis and extrapolated to calculate annual benefits
- The present value of annual benefits results will be calculated using social discount rate ranges

Cost allocation for new facilities – 3

8. ISO assumes for this initiative that a new integrated TPP for the expanded ISO will retain today's TPP structure
   - Three-phase process begins in January each year
   - Phase 1 (3 months) establishes unified planning assumptions and study plan
   - Phase 2 (12 months) performs studies, identifies best projects to meet needs, develops comprehensive plan and submits plan to Board of Governors for approval
   - Phase 3 – not relevant for cost allocation – entails competitive solicitation for eligible projects and selection of entity that will build and own the facility

Transmission planning process spans 15 months for phases 1-2, up to 23 months across all three phases.

March Year X | March Year X+1 | October Year X+1

Coordination of Conceptual Statewide Plan

ISO board approval of transmission plan

Phase 1

Development of ISO unified planning assumptions and study plan

- Specifies Local, State and Federal policy requirements and directives
- Demand forecasts, energy efficiency, demand response
- Renewable and conventional generation additions and retirements
- Input from stakeholders

Phase 2

Technical Studies and Board Approval

- Reliability analysis
- Renewable delivery analysis
- Economic analysis
- Publish comprehensive transmission plan
- ISO Board approval

Phase 3

Competitive Solicitation Process

- Receive proposals to build identified reliability, policy and economic transmission projects
- Evaluate proposals to meet qualification for consideration
- Take necessary steps to determine Approved Project Sponsor(s)

Multiple stakeholder meetings & comment opportunities

Continued regional and sub-regional coordination

In Phase 2, the ISO's technical analysis is conducted in three deliberate stages in identifying needs and solutions.

Reliability Analysis ☑
(NERC Compliance)

Policy Driven Analysis ☑
- Focus on renewable generation
- Identify policy transmission needs

Economic Analysis ☑
- Congestion studies
- Identify economic transmission needs

Other Analysis☑
(LCR, SPS, etc.)

Results comprise the comprehensive transmission plan

The analysis and project identification is staged – it is not three separate and parallel study paths.

- “Reliability projects” consider the relative benefits and costs of alternatives to meet the reliability need, but do not produce benefit-cost results.
- Policy needs may result in modifying a reliability project to meet both reliability and policy needs. The resulting project is a “policy-driven project.”
- Similarly, economic analysis may result in modifying a reliability-driven and/or policy-driven project, and the result is designated an “economic project.”
- Only economic projects require a benefit-cost analysis and resulting benefit/cost ratio of at least 1.0.
- If a policy or reliability project is modified to provide economic benefits, the economic benefits must exceed the incremental cost above the original project.

9. Default cost allocation for new transmission facilities

a) This proposal addresses cost allocation only to the granularity of the sub-region

   – A necessary first step before any more granular cost allocation

   – Additional granularity may be most relevant to policy-driven projects, where role of WSC and states may be important

b) For a <u>reliability project</u> that is designed only to meet a reliability need within a sub-region, allocate the full project cost to that sub-region

   – Benefits that are incidental or unintended by the planners will not be considered in cost allocation for such projects

   – Project is necessary to address a reliability need and would have to be built even with zero incidental benefits

9. New facilities – 2

c) For a <u>policy-driven project</u> connected entirely within the same sub-region where the policy driver originated, allocate full cost to that sub-region

d) For a <u>purely economic project</u> (not a modification of a reliability or policy-driven project, and having BCR > 1), allocate cost shares to sub-regions in proportion to their economic benefits (TEAM)

e) For an economic project that results from modifying a reliability or policy-driven project to obtain economic benefits greater than incremental project cost:
   - First allocate avoided cost of original reliability or policy-driven project to the relevant sub-region,
   - Then allocate incremental project cost to sub-regions in proportion to their economic benefits (TEAM)

9. New facilities – 3

- For category (e) above we may need to define a new transmission project category for cost allocation purposes
  - Not strictly an economic project because economic benefits only need to exceed incremental project cost
- Proposed rule for category (e) is the “driver first” approach; i.e., first allocate avoided cost of the reliability or policy driver, then allocate residual cost based on economic benefits
- Alternative “total benefits” approach presented in August 11 working group would include avoided cost in total benefits, then allocate cost shares to sub-regions based on benefits
- Example illustrates that these approaches produce different results: “driver first” allocates greater cost share to the sub-region with the reliability or policy driver.

9. New facilities – 4 – Example

- Cost of selected project = $100 million
- Sub-region A benefits
  - $30 million production cost savings (from TEAM)
  - Meets sub-region A reliability need, where sub-regional alternative would cost $60 million with no economic benefit
- Sub-region B benefits
  - $40 million production cost savings (from TEAM)
- Cost responsibility – “driver first” approach:
  - Sub-region A = $60M + $40M * $30M / $70M = $77M
  - Sub-region B = $40M * $40M / $70M = $23M
- Cost responsibility – “total benefits” approach:
  - Sub-region A = $100M ($30M+$60M)/($30+$40M+$60M) = $69M
  - Sub-region B = $100M ($40M)/($30+$40M+$60M) = $31M

9. New facilities – 5

f) Policy-driven projects involving more than one sub-region
   - Scenario 1: project is built in sub-region A to support policy mandate of sub-region B
   - Scenario 2: project supports policy mandates for sub-regions A and B
   - Both sub-regions receive benefits in most cases
   - “Driver first” allocation method requires credible avoided cost for an alternative to the selected project – often not available
   - Default provisions may be superseded by WSC action on cost allocation for policy-driven transmission projects

- Scenario 1: Allocate cost shares to sub-regions up to the amount of their economic benefits; allocate remaining cost to sub-region with policy driver
- Scenario 2: Allocate cost shares to sub-regions up to the amount of their economic benefits; allocate remaining cost to relevant sub-regions in proportion to their internal load for project in-service year

10. Competitive solicitation to build & own a new facility

All new transmission projects rated 200 kV or greater, of any category, will be open to competitive solicitation, with exceptions only as stated in ISO tariff section 24.5.1:

- When the facility involves “an upgrade or improvement to, addition to, or a replacement of a part of an existing PTO facility,” in which case …
- “The PTO will construct and own such upgrade, improvement addition or replacement facilities unless a Project Sponsor and the PTO agree to a different arrangement”

- This approach creates a level playing field for competitive solicitation across the expanded ISO BAA
- ISO’s May 20 proposal limited competitive solicitation to new facilities whose costs are allocated to multiple sub-regions or to multiple PTOs within a sub-region

ISO proposes to drop two provisions of prior proposal

11. ISO will drop the proposal to recalculate benefit & cost shares for sub-regions
    - Potential future changes in a sub-region's allocated cost create undesirable risk
    - Cost shares once calculated and approved will not be revised
12. ISO will drop the proposal to allocate cost shares to a new PTO for a new facility that was planned and approved before that PTO joined the expanded ISO
    - Prior provision could deter a TO from joining if it faced potential cost share for a project it had no role in planning
    - OTOH, new provision could incentivize a TO to postpone joining until existing PTOs approve projects it would benefit from

Region-wide Export Access Charge (EAC)

The ISO proposes to create a single region-wide export rate for all exports from the expanded BAA.

14. The “export access charge” (EAC) would apply to each MWh exported on high-voltage interties anywhere in the expanded ISO
15. The EAC would differ from today’s “wheeling access charge” (WAC) in important ways
    - Today ISO charges WAC to the internal load of non-PTO entities embedded within the ISO BAA, as well as to exports
    - Under the proposal, non-PTO entities would pay the same sub-regional TAC rate paid by other loads in the same sub-region
16. The EAC rate will be the load-weighted average of the sub-regional license plate rates; for two sub-regions 1 and 2:

$$\text{EAC rate} = (\text{TRR1} + \text{TRR2}) / (\text{Load1} + \text{Load 2})$$

17. Each PTO's export revenues in one year become an offset to its TRR in the subsequent year.

Apply the same principle to sub-regions by summing the terms for all PTOs within the sub-region

- Let EACrev1 = a sub-region's EAC revenues in year 1
- TRR2 = the sub-region's high-voltage TRR for year 2
- L2 = the sub-region's projected internal load for year 2
- TAC2 = the sub-region's license plate TAC for year 2

Then the sub-region's license plate rate is:

$$\text{TAC2} = (\text{TRR2} - \text{EACrev1}) / \text{L2}$$

The quantity (TRR2 – EACrev1) is the sub-region's "net" TRR to be collected in year 2, and will be used to calculate the EAC for year 2 as well as the license plate TAC

18. The ISO proposes that EAC revenues be allocated to sub-regions in proportion to their "net" TRRs

For two sub-regions with export quantities E1 and E2, the total EAC revenues = (E1 + E2) * EAC rate

The sub-regional shares of EAC revenues are:

- Sub-region 1 share = (EAC revenues) * TRR1 / (TRR1 + TRR2)
- Sub-region 2 share = (EAC revenues) * TRR2 / (TRR1 + TRR2)

19. Compare this to the approach presented in August 11 working group, with sub-regional shares proportional to the volume of exports on the sub-region's interties times its sub-regional TAC rate:

Sub-region 1 share

= (EAC revenues) * E1*TAC1 / (E1*TAC1 + E2*TAC2)

Sub-region 2 share

= (EAC revenues) * E2*TAC2 / (E1*TAC1 + E2*TAC2)

Example using 2015 data

- CAISO is sub-region 1 (ISO TAC rates, 10/19/15)
  - TRR1 = $2,071,851,575
  - L1 = 211,786,041 MWh
  - TAC1 = $9.78
  - E1 = 1,854,995 MWh
- PAC is sub-region 2 (Feb. 2016 TAC Options model)
  - TRR2 = $291,318,198
  - L2 = 70,675,826 MWh
  - TAC2 = $4.12
  - E2 = 34,996,078 MWh
- EAC rate = $8.37
- Consider two alternative scenarios: 25% and 50% reduction in PAC exports after formation of the expanded ISO BAA

2105 data example results

	100% E2	75% E2	50% E2
PAC export MWh	34,996,078	26,247,058	17,498,039
EAC revenues	$308,308,311	$235,111,110	$161,913,908
Export-weighted CAISO share	$34,451,739	$33,771,872	$32,548,809
Export-weighted PAC share	$273,856,572	$201,339,238	$129,365,099
TRR-weighted CAISO share	$270,301,807	$206,127,942	$141,954,078
TRR-weighted PAC share	$38,006,504	$28,983,167	$19,959,830
CAISO 2015 export revenues	$18,158,079	$18,158,079	$18,158,079

There's one more topic to mention.

ISO initiative in progress GIDNUCR = "Generator Interconnection Driven Network Upgrade Cost Recovery"

- Several stakeholders in GIDNUCR asked about how it would link to the TAC Options initiative
- Today, a generator is reimbursed for costs of low-voltage interconnection driven network upgrades by ratepayers within the PTO service area
- GIDNUCR is considering possible alternatives, such as recovery through the high-voltage TAC
- Outcome of GIDNUCR is still uncertain – the ISO has not yet posted a draft final proposal yet
- However GIDNUCR is resolved, ISO expects the outcome would apply consistently across the expanded ISO BAA.

Next Steps

Next Steps

- Stakeholder comments on 2nd revised straw proposal due October 28, 2016; submit to initiativecomments@caiso.com

- Subsequent activities on this initiative will be announced by market notice in the near future.