Briefing on Transmission Access Charge Options

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Market Surveillance Committee Meeting
General Session
September 19, 2016

Transmission access charge options (TAC Options)

Objective of ISO initiative –

Develop rules for allocating high-voltage (> 200 kV) transmission revenue requirements (TRR) in an expanded ISO balancing authority area (BAA) formed by integrating a new participating transmission owner (PTO) with a load service territory.

Topics for today's discussion

1. Update on initiative timeline
2. Cost allocation for transmission projects planned in an integrated planning process for the expanded BAA
3. Region-wide access charge rate for exports

Updated TAC options timeline

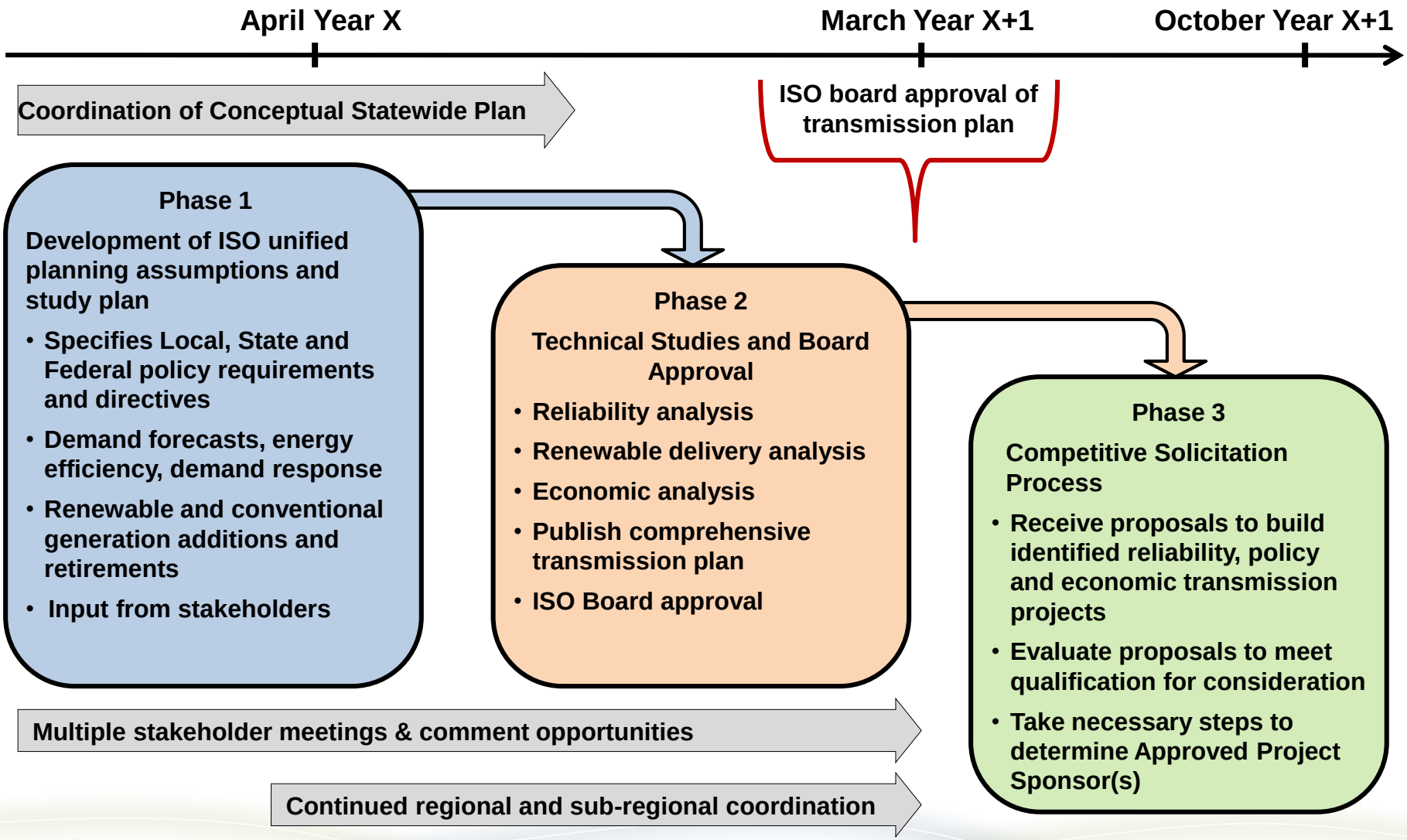
- Sept. 28 – ISO will post 2nd revised straw proposal
- Oct. 7 – Stakeholder meeting at ISO
- Oct. 21 – Stakeholder comments due
- Dec. dates TBD – Draft final proposal, stakeholder meeting and stakeholder comments
- 2017 Board date TBD – present final proposal to Board for approval

Cost allocation for new regional transmission projects

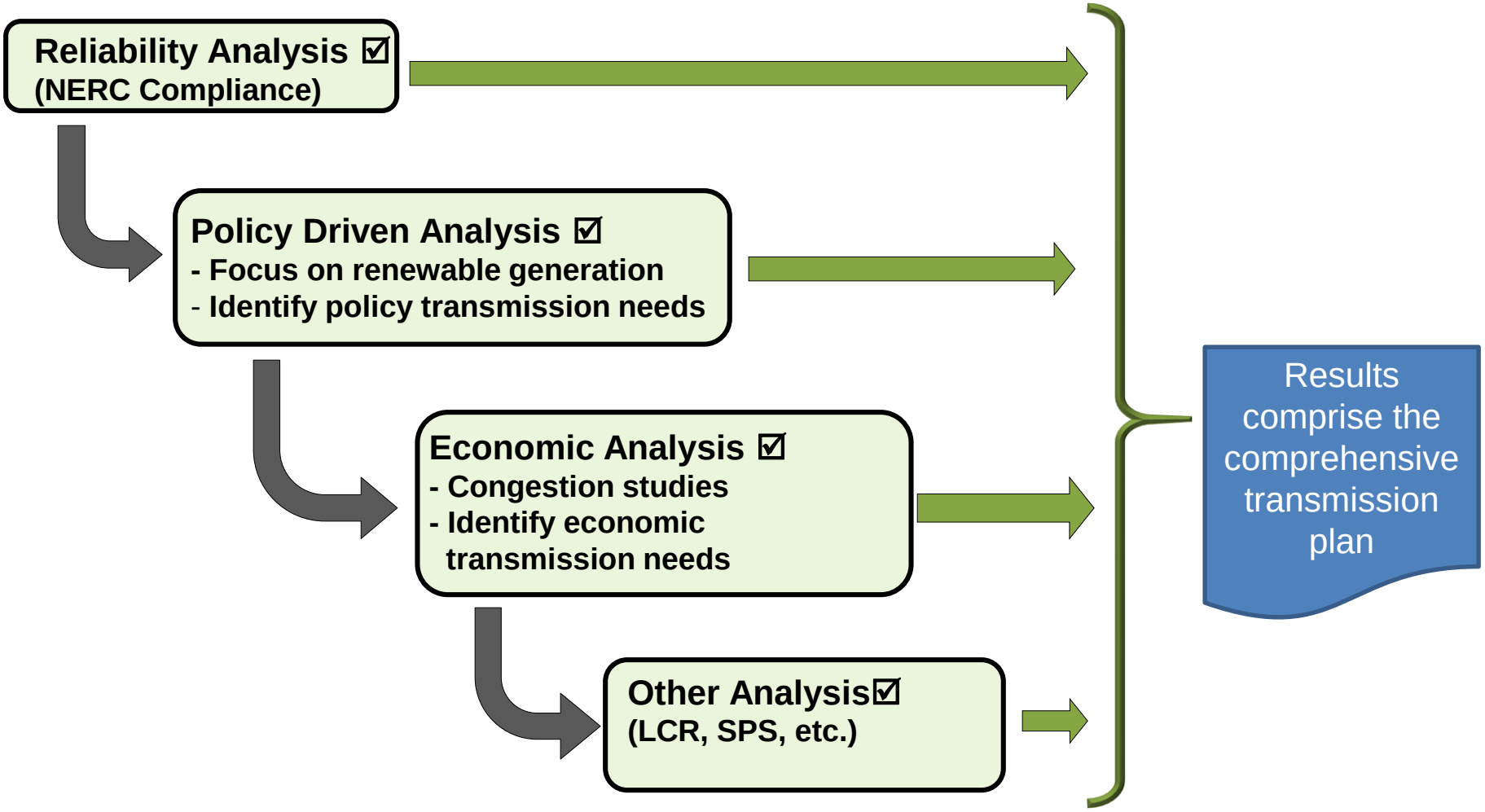
FERC order 1000 requires that the ISO tariff contain default cost allocation provisions for new facilities.

- New facilities are defined as transmission facilities planned & approved in an integrated transmission planning process (TPP) conducted by the ISO for the expanded BAA.
- A new facility will be considered for regional cost allocation if it is rated >= 200 kV (high voltage or HV)
- Assumptions for today's discussion:
  - The current ISO footprint and the new PTO will each be a "sub-region" within the expanded BAA.
  - Costs of existing facilities will be recovered entirely from each relevant sub-region through its own "license plate" TAC rate
  - New facilities rated < 200 kV will be recovered entirely from the territory of the PTO to whose system the facility connects
  - Transmission revenue requirements (TRR) are recovered via volumetric TAC rates charged to internal load and exports
  - The ISO's current TPP is a likely model for the structure of the future integrated TPP

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



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



The ISO proposes to use its Transmission Economic Assessment Methodology (TEAM) to quantify economic benefits of a transmission project.

- An economic project's estimated benefits must exceed its cost; its benefit-to-cost ratio (BCR) must be > 1.0
- The economic benefits of a reliability or public policy-driven project do not have to exceed the project cost
- TPP studies could identify an economic project that can replace a previously selected reliability or policy project
  - In this case the economic benefits of the project only need to exceed the incremental cost above the cost of the reliability or policy project that is avoided.
  - I.e., total BCR is > 1.0 if the avoided cost of the original project is included in the benefits of the economic project

Potential concepts for new project cost allocation

1. For a reliability project narrowly defined only to meet a reliability problem in a sub-region (SR), allocate the full cost of the project to that SR.
2. For a policy-driven project that is within the same SR that has the policy driver, allocate the full cost of the project to that SR.
3. For a purely economic project with BCR > 1 that is not an enhancement of or substitute for a previously defined reliability or policy project, allocate cost shares to SRs in proportion to benefits.

Potential concepts – page 2

4. For an economic project that is an enhancement of or substitutes for a reliability or policy-driven project, the economic benefits must exceed the incremental cost of the project.

   In this case apply one of two options:

   a) Allocate the avoided cost of the original project to the SR with the reliability or policy driver, then allocate the remaining cost to each SR in proportion to their benefits

   or …

   b) Include the avoided cost of the original project in the total benefits, and allocate costs shares to SRs based on benefits

Example of benefits determination for a project – considering “avoided costs”

- Cost of preferred (enhanced) 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 but with no economic benefit
  - Sub-region B benefits
    - $40 million production cost savings (from TEAM)
- Cost responsibilities under method (a):
  - Sub-region A = $60M + $40M*$30M/$70M = $77M
  - Sub-region B = $40M * $40M/$70M = $23M
- Cost responsibilities under method (b):
  - Sub-region A = $100M ($30M+$60M)/($30+$40M+$60M) = $69M
  - Sub-region B = $100M ($40M)/($30+$40M+$60M) = $31M

Potential concepts – page 3 – more complicated policy-driven projects

For the new integrated TPP:

- Policy mandates may be local, state-level, or national
- For local or state-level policy mandates, the TPP will receive input from local or state authority to translate the policy mandate into transmission needs
  - Analogy to today, the CPUC provides RPS portfolios reflecting renewable resource procurement patterns
  - TPP determines the transmission capacity needed to access the resource areas, and identifies upgrades if needed
- In the expanded BAA, policy drivers could come from multiple SRs and, in some cases, a transmission project could meet multiple SRs' policy needs

Potential concepts – page 4 – more complicated policy-driven projects

Two scenarios

1. Policy driver comes from SR1, transmission project is built in SR2's system
2. Policy drivers come from SR1 and SR2, transmission project satisfies both SRs' policy needs

Some cost allocation questions

- Scenario 1: How should benefits to SR2 be considered?
- Scenario 2: How should SR1 and SR2 benefit shares be determined?
- Both scenarios: If avoided costs are relevant, what kinds of alternatives should be considered and how might their costs be calculated? E.g., alternative ways to meet RPS

Single Region-wide Export Access Charge

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

- Call this new rate the “export access charge” (EAC) to distinguish from today’s “wheeling access charge” (WAC)
  - 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
  - Only exports and wheel-through schedules from the expanded BAA would pay the EAC
  - Consistent with above, assume that a new PTO embedded within an existing sub-region would be part of that sub-region, not a new sub-region

Conceptual structure of the proposed EAC

The EAC rate would be calculated as a load-weighted average of the sub-regional license plate rates

- Let TRR1 and TRR2 be the high-voltage TRRs for the two sub-regions
- L1 and L2 be the internal load MWh for the sub-regions
  - Then the sub-regional HV TAC rates are TAC1 = TRR1/L1 and TAC2 = TRR2/L2
  - And the EAC rate = (TRR1 + TRR2) / (L1 + L2)
- Let E1 and E2 be the export MWh for the sub-regions
- Then EAC revenues = (E1 + E2) * (EAC rate)

Concepts for allocation of EAC revenues – 1

Option 1. Each sub-region receives revenues proportional to the volume of exports on that 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)

Concepts for allocation of EAC revenues – 1

Option 2. Each sub-region receives revenues in proportion to its TRR

Sub-region 1 share

= (EAC revenues) * TRR1 / (TRR1 + TRR2)

Sub-region 2 share

= (EAC revenues) * TRR2 / (TRR1 + TRR2)

Example using 2015 data

Objective: Compare EAC revenues for each sub-region after regional expansion to export WAC revenues to CAISO before regional expansion.

- CAISO is sub-region 1 (ISO TAC rates, 10/19/15)
  - TRR1 = $2,071,851,575
  - L1 = 211,786,041 MWh
  - TAC1 = $9.78
- PAC is sub-region 2 (Feb. 2016 TAC Options model)
  - TRR2 = $291,318,198
  - L2 = 70,675,826 MWh
  - TAC2 = $4.12

2015 data example, page 2

- Weighted average EAC rate = $8.37
- Ezed = exports from CAISO to PAC = 1136 MWh
- E1 = exports on other CAISO ties = 1,854,995 MWh
- E2 = exports on other PAC ties = 34,996,078 MWh

Actual CAISO 2015 export WAC revenues (before forming expanded BAA)

= (Ezed+E1)*TAC1 = $18,158,079

2105 data example, page 3

Compare EAC revenues and revenue allocation after expansion of the BAA, under two allocation options and three export volume scenarios

- Scenario 1 – No change in export volumes
- Scenario 2 – PAC exports reduced by 25% due to integration into expanded BAA
- Scenario 3 – PAC exports reduced by 50% due to integration into expanded BAA
- Total EAC revenues = (E1+E2) * (EAC rate)

2105 data example results

	Scenario 1	Scenario 2	Scenario 3
PAC export MWh	34,996,078	26,247,058	17,498,039
EAC revenues	$308,308,311	$235,111,110	$161,913,908
Option 1 CAISO share	$34,451,739	$33,771,872	$32,548,809
Option 1 PAC share	$273,856,572	$201,339,238	$129,365,099
Option 2 CAISO share	$270,301,807	$206,127,942	$141,954,078
Option 2 PAC share	$38,006,504	$28,983,167	$19,959,830
CAISO 2015 export revenues	$18,158,079	$18,158,079	$18,158,079