Review TAC Structure Revised Straw Proposal Stakeholder Meeting

April 11, 2018

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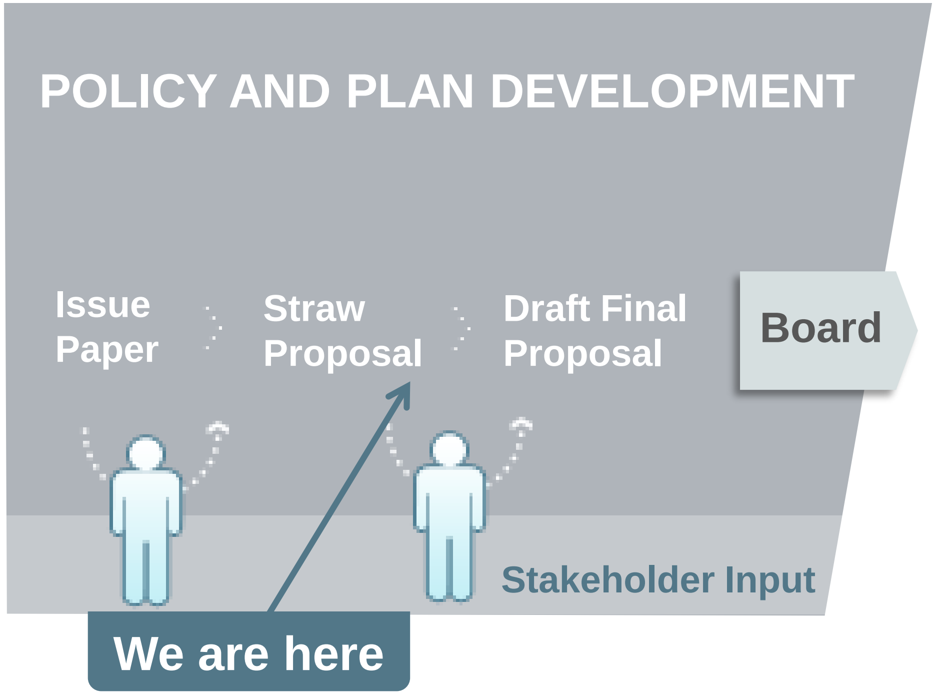
Agenda

Time (PDT)	Topic	Presenter
10:00 – 10:10 am	Welcome and introduction	James Bishara
10:10 – 10:30 am	TAC objectives	Chris Devon
10:30 – 11:00 am	Point of measurement issue	Chris Devon
11:00am – 12:00 pm	Hybrid billing determinant proposal	Chris Devon
12:00 – 1:00 pm	Lunch	
1:00 – 3:00 pm	Hybrid billing determinant proposal	Chris Devon
3:00 – 3:30 pm	Next steps and conclusion	James Bishara
3:30 pm	Adjourn	

Stakeholder Process



Initiative Schedule

Date	Milestone
April 4	Post revised straw proposal
April 11	Hold stakeholder meeting
April 25	Stakeholder written comments due
June 21	Post draft final proposal
June 28	Hold stakeholder meeting
July 12	Stakeholder written comments due
Sept 5,6	Present final proposal at CAISO Board meeting

TAC structure objectives

Overview of review TAC structure objectives

- ISO believes that potential TAC structure modifications should be designed primarily to consider and reflect:
  - Cost causation and cost drivers of the past
  - Current use & benefits provided by the system
- Due to constant changes in how system is planned and used the primary TAC objectives are not as closely aligned with current TAC structure as they may have been in the past
- TAC recovers costs of existing facilities and appropriate recovery of existing embedded costs is a very important consideration

TAC structure rate design objectives

- Modifications to TAC structure should meet objectives of FERC ratemaking principles and ISO cost allocation principles
- Major objectives that ISO intends to reflect in its proposed TAC structure modifications include two major concepts:
  - TAC structure should reflect cost causation and cost drivers when decisions to invest in transmission infrastructure were made
  - TAC structure should reflect use and benefits, which may be different than cost causation
  - The ISO supports a rate structure that fairly links the billing determinants to benefits accruing to users of the system

TAC design objectives that are not the primary focus

- ISO acknowledges that TAC structure can potentially modify future behavior and support specific policy goals
- ISO does not believe this should be a major focus for revisions the TAC rate design for a number of reasons:
  - Additional layer of UDC retail rates can mute the price signals the ISO TAC rate design might otherwise provide to end use customers
  - ISO bills UDCs for TAC, not LSEs, which are the entities that make generation procurement decisions
    - Additional ratemaking mechanism would need to be developed to properly assign any costs and benefits associated with DG procurement to individual LSEs

Point of measurement issue

ISO will maintain the current point of measurement at end use customer meters

- Embedded costs were incurred to serve customers and impact to existing cost recovery is a major issue
  - Existing system was planned and built to serve load and provide reliability services to customers
- Most stakeholders continue to express support for maintaining the point of measurement
  - Stakeholders voiced significant concerns that a change to point of measurement will inappropriately shift costs between UDC areas
  - Cost shifts that result from moving point of measurement may result in cost allocation that does not reflect costs incurred to meet needs of each UDC area and benefits provided to some customers

Moving point of measurement will create inappropriate outcomes and cannot provide an effective procurement incentive without other changes

- Changing point of measurement in an effort to incentivize LSEs to procure more DG may not be effective without developing additional measures
  - Resulting cost allocation will be dependent on other LSE procurement decisions in other UDC areas
- TAC currently billed through UDCs, not LSEs
  - Additional accounting mechanism would be needed to reflect impacts of individual LSE decisions within each UDC area

Future consideration of point of measurement

- ISO is willing to revisit point of measurement issue – for purposes of prospectively allocating costs of future transmission facilities – if state policy makers adopt retail rate changes that provide a transmission cost credit to LSEs that have procured DG resources
  - *i.e.*, relief from retail rate charges for certain new transmission facilities
  - Necessary changes are outside ISO’s purview

Hybrid billing determinant proposal

Hybrid billing determinant proposal

- ISO believes current volumetric measurement of usage for billing TAC may no longer reflect current benefits of system, particularly to deliver capacity on peak and for other reliability services
- ISO proposed modifications to current volumetric measurement to a hybrid billing determinant approach
  - Proposed modifications will utilize part volumetric and part peak demand measurements for assessing TAC charges
  - This approach would capture both volumetric and peak demand functions and benefits of system and mitigates some potential shortcomings if either used alone

Transmission system provides both energy and capacity functions and other reliability benefits

- Current volumetric approach may not reflect cost causation for peak load cost drivers
  – Also benefits associated with the delivery of capacity, especially during peak load periods
- ISO and majority of stakeholders believe that a hybrid approach is an appropriate change
  – Better reflects cost causation of the energy and capacity-reliability functions more accurately
  – Hybrid approach also captures the benefits accrued by users for these functions more appropriately

Frequency of peak demand measurements

- Frequency of peak demand measurements must be determined to implement a demand based billing determinant measurement for hybrid approach
  - *e.g.*, annual peak (1), seasonal peaks (4), monthly peaks (12), or daily peaks (365)
- Peak demand measurement frequency is intended to reflect the way transmission system has been planned and the benefits being provided
  - ISO believes it is appropriate to align frequency of peak demand measurements with customer's benefit from peak demand capacity-reliability function provided by transmission system

ISO proposes to utilize a 12CP (monthly) peak demand measurement frequency

- A 12CP approach strikes an appropriate balance in reflecting the way system has been planned and used to maintain reliability and benefit and serve loads
  - Given the unique circumstances on the transmission system, ISO must meet important reliability needs during different periods
- Proposed 12CP approach reflects both capacity and reliability functions and benefits provided to system users on a monthly basis
  - System is utilized to deliver monthly peak capacity needs of loads as required by CPUC RA requirements
  - Reliability issues identified in TPP during shoulder months and winter months can be reflected in 12CP approach

12CP approach provides advantages over lower frequency of measurements

- 12CP frequency can mitigate potential for certain UDC areas to avoid some potential costs that should be allocated to the area due to peak demand anomalies
  - *i.e.*, an abnormally high or low peak demand observation that might occur for one UDC area during the single annual system coincident peak hour (1CP)
- Lower frequency of CP demand measurements could result in costs being incurred, or avoided, by particular UDC areas inconsistent with the cost causation and benefits provided to particular UDCs
- 12CP frequency can avoid some potential for outcomes that could shift costs unreasonably
  - Including higher frequency of measurements can provide a less volatile overall reflection of UDC coincident peak demands
  - Provides a more appropriate allocation of the peak demand charge TRR component among UDC areas

Peak demand measurement: coincidence vs non-coincidence

- ISO has explored utilizing either a coincident peak demand measurement and non-coincident peak demand measurements (or both)
- Most stakeholders believe the ISO should only use coincident peak demand measurements
  - ISO agrees with these stakeholder recommendations
- Coincident peak demand measurement more closely reflects the objectives for TAC structure modifications

Determining TRR split under hybrid approach

- Need to determine what portion of TRR is collected through each component of hybrid billing determinant to implement proposed hybrid approach
  - What part of TRR will be collected under volumetric measurement versus peak demand measurement
- Previously proposed historical transmission cost categorization allocator method
  - Difficult to precisely determine cost drivers of the existing system associated with energy delivery versus capacity and reliability functions
  - Some stakeholders agreed that this approach could be useful
  - Many stakeholders indicated belief this approach would be difficult and controversial

ISO attempted to categorize historically approved TPP projects costs

- Categorization effort attempted to reflect the costs of the system associated with these functions of energy delivery versus capacity and reliability
  - Categorization approach was overly complex and problematic to accurately determine costs linked to specific energy delivery and capacity/reliability functions
  - ISO believes this approach may lead to false precision and result in extended disagreement between stakeholders because analysis appears too subjective

ISO proposes to utilize a system load factor calculation for HV-TRR split under hybrid approach

- After reviewing stakeholder feedback and potential options ISO believes a more accurate and less speculative method for splitting the HV-TRR is a system load factor calculation split
- ISO believes the system load factor also reflects the degree the system is being utilized for peak capacity delivery versus energy delivery functions
  - Will allow the ISO to calculate a HV-TRR split that reflects the utilization of the transmission system
  - System load factor proposal is more likely to withstand scrutiny because it is data-driven and comprehensible

Calculation steps and example figures for system load factor hybrid HV-TRR split

1. Start with approved annual HV-TRR
   – ($2,165,294,596 from the HV Access Charge Rates effective Jan 1, 2017)
2. Divide amount by annual system peak multiplied by 8760 hours in a year to determine amount of MWh's that reflect system utilization at 100% load factor
   – Reported system coincident peak (49,900 MW for 2017) multiplied by annual hours (8760): **49,900 MW x 8760 hours = 437,124,000 MWh**
3. Divide annual HV-TRR ($ 2,165,294,596) by 100% load factor MWHs calculated above (437,124,000 MWh) to calculate the volumetric rate: **$2,165,294,596 ÷ 437,124,000 MWh = $4.9535/MWh**
   – This volumetric rate ($4.9535/MWh for 2017) reflects the rate that would collect the full HV-TRR cost of the transmission system if all UDCs were 100% load factor utilities

Calculation steps and example figures for system load factor hybrid HV-TRR split (continued)

4. Using the PTO filed annual Gross Load (209,260,146 MWh for 2017), multiply this value by the volumetric rate determined above: **$4.9535/MWh x 209,260,146 MWh = $1,036,570,546**
   – This is the amount of revenue expected to be collected by the volumetric component
   – For this example year (2017) the volumetric component would comprise **~48%** of overall HV-TRR
5. Subtract the revenue determined for recovery through the volumetric component above from total TRR to determine remaining HV-TRR: **$2,165,249,596 - $1,036,570,546 = $1,128,724,050**
   – This remaining HV-TRR value expected to be collected through the peak demand component
   – For this example year (2017) the peak demand component would comprise **~52%** of overall HV-TRR

Proposed HV-TRR split approach applied to historic data

Proposed hybrid HV-TRR split formulation applied to prior annual historic data

Year	ISO Annual Coincident Peak Load (MW)	Filed Annual HV-TRR ($)	Filed Annual Gross Load (MWh)	Volumetric component TAC Rate ($/MWh)
2012	46,846	1,331,131,427	208,203,435	$ 3.2437
2013	45,097	1,718,985,660	209,747,674	$ 4.3513
2014	45,089	1,695,601,699	211,699,031	$ 4.2929
2015	46,519	1,999,620,213	212,120,690	$ 4.9070
2016	46,232	2,195,146,895	211,289,953	$ 5.4202
2017	49,900	2,165,294,596	209,260,146	$ 4.9535
Year	**TRR amount collected under volumetric component ($)**	**Volumetric HV-TRR portion (%)**	**TRR amount to be collected through peak demand charge ($)**	**Peak Demand HV-TRR portion (%)**
2012	675,355,136	51%	655,776,291	49%
2013	912,678,140	53%	806,307,520	47%
2014	908,799,341	54%	786,802,358	46%
2015	1,040,868,997	52%	958,751,216	48%
2016	1,145,237,728	52%	1,049,909,167	48%
2017	1,036,570,546	48%	1,128,724,050	52%

Setting HV-TAC rates and updating for approved TRR changes

- ISO will follow steps provided above for proposed system load factor calculation to split HV-TRR and determine the volumetric rate ($/MWh) and 12CP demand charge rate ($/MW) each year
  - See example rate calculation on next slide
- Continue to utilize the approved TRR values for each PTO to determine overall HV-TRR to be recovered for each year
- Annual system peak demand utilized to set the HV-TRR split components for volumetric and demand recovery will be taken from forecasted annual peak and 12CP average system peak demand provided through CEC demand forecast (also utilized for the ISO's TPP process)
- ISO will continue to provide updates to HV-TAC rates when PTO's provide updates to approved HV-TRR amounts as new assets are included or facilities are withdrawn from in the HV-TRR rate base by PTOs that receive approval under their FERC transmission rate proceedings

Example hybrid billing determinant rate formulation

- **Assume HV-TRR (HV-Transmission Revenue Requirement) = $2,366,000,000**
- Assume 50-50 (%) split of HV-TRR for this example:
  - HV-TRR to be collected under volumetric rate: $2,366,000,000 x 50% = **$1,183,000,000**
  - HV-TRR to be collected under 12CP demand charge rate: $2,366,000,000 x 50% = **$1,183,000,000**
- Volumetric billing unit: annual gross load (MWh) = **210,000,00 MWh**
- **Volumetric rate ($/MWh)** = HV-TRR to be collected under volumetric rate / volumetric billing unit: $1,183,000,000/ 210,000,000 MWh **= $5.63/MWh**
- 12CP peak demand billing unit: system average 12CP peak demand (MW) = 31,800 MW
- 1CP demand charge rate ($/MW) = HV-TRR to be collected under CP demand charge rate / CP demand billing unit: $1,183,000,000 / 31,800 MW = $37,201.25/MW
- **12CP demand charge rate ($/MW)** = 1CP demand charge rate / 12CP: $37,201.25 / 12 = **$3100.10/MW**

Billing determinant data utilized for settlements under hybrid billing determinant approach

- Continue to utilize gross load settlement data to determine each UDC areas volumetric usage and associated HV-TAC volumetric charges
  - Hourly average peak data is available through current UDCs gross load settlement data
- ISO will use each UDC's hourly average peak demand coinciding with each monthly system coincident peak hour to determine the 12CP monthly demand usage and associated HV-TAC 12CP demand charges
  - Because the 12CP demand charge rate will be set using the forecast annual system peak, the ISO will use hourly average coincident peak data

Analyzing hybrid billing determinant cost impacts to current UDCs

Existing TAC charge ($ million)

	2016	2017	2018	2019	2020
PG&E	$1,021.4	$1,084.5	$1,009.6	$1,063.1	$1,143.5
SCE	$1,028.5	$1,092.1	$1,016.7	$1,070.5	$1,151.4
SDG&E	$223.4	$237.2	$220.8	$232.5	$250.0
Anaheim	$27.5	$29.2	$27.2	$28.7	$30.8
Azusa	$3.0	$3.1	$2.9	$3.1	$3.3
Banning	$1.7	$1.8	$1.7	$1.7	$1.9
Pasadena	$12.6	$13.3	$12.4	$13.1	$14.1
Riverside	$25.8	$27.4	$25.5	$26.9	$28.9
Vernon	$13.0	$13.8	$12.8	$13.5	$14.5
Colton	$4.1	$4.4	$4.1	$4.3	$4.6
VEA	$5.4	$5.7	$5.3	$5.6	$6.0
CAISO Total	$2,366	$2,513	$2,339	$2,463	$2,649
Existing Rate ($/MWh)	$11.25	$11.96	$11.11	$11.63	$12.42

Analyzing hybrid billing determinant cost impacts to current UDCs (continued)

Proposed TAC charge for hybrid approach: 50/50 TRR split & 12CP ($ million)

	2016	**2017**	**2018**	**2019**	**2020**
PG&E	$991.3	$1,052.5	$979.9	$1,031.7	$1,109.8
SCE	$1,044.2	$1,108.7	$1,032.2	$1,086.8	$1,169.0
SDG&E	$236.5	$251.1	$233.7	$246.1	$264.7
Anaheim	$28.3	$30.0	$28.0	$29.5	$31.7
Azusa	$3.1	$3.2	$3.0	$3.2	$3.4
Banning	$1.7	$1.8	$1.6	$1.7	$1.9
Pasadena	$12.8	$13.6	$12.6	$13.3	$14.3
Riverside	$26.2	$27.8	$25.9	$27.3	$29.3
Vernon	$13.3	$14.1	$13.1	$13.8	$14.9
Colton	$4.2	$4.4	$4.1	$4.3	$4.7
VEA	$4.9	$5.2	$4.9	$5.1	$5.5
CAISO Total	$2,366	$2,513	$2,339	$2,463	$2,649
Volumetric - Gross Load ($/MWh)	$5.62	$5.98	$5.56	$5.82	$6.21
Coincident Peak 12 Periods - Gross Load ($/MW)	$37,312.09	$39,667.80	$36,858.30	$38,583.01	$41,187.69

Analyzing hybrid billing determinant cost impacts to current UDCs (continued)

Difference between proposed TAC charge and existing TAC charge (%)

	2016	2017	2018	2019	2020
PG&E	-2.950%	-2.950%	-2.950%	-2.950%	-2.950%
SCE	1.526%	1.526%	1.526%	1.526%	1.526%
SDG&E	5.865%	5.865%	5.865%	5.865%	5.865%
Anaheim	2.796%	2.796%	2.796%	2.796%	2.796%
Azusa	3.180%	3.180%	3.180%	3.180%	3.180%
Banning	-0.097%	-0.097%	-0.097%	-0.097%	-0.097%
Pasadena	1.647%	1.647%	1.647%	1.647%	1.647%
Riverside	1.347%	1.347%	1.347%	1.347%	1.347%
Vernon	2.423%	2.423%	2.423%	2.423%	2.423%
Colton	1.422%	1.422%	1.422%	1.422%	1.422%
VEA	-8.420%	-8.420%	-8.420%	-8.420%	-8.420%

Analyzing hybrid billing determinant cost impacts to current UDCs (continued)

Difference between proposed TAC charge and existing TAC charge ($)

	2016	2017	2018	2019	2020
PG&E	(30,127,162)	(31,988,972)	(29,779,795)	(31,356,864)	(33,727,689)
SCE	15,690,287	16,659,921	15,509,378	16,330,718	17,565,448
SDG&E	13,100,272	13,909,848	12,949,226	13,634,986	14,665,898
Anaheim	769,564	817,122	760,691	800,976	861,536
Azusa	94,063	99,876	92,978	97,902	105,304
Banning	(1,623)	(1,724)	(1,605)	(1,690)	(1,817)
Pasadena	206,724	219,500	204,341	215,162	231,430
Riverside	348,042	369,550	344,029	362,248	389,637
Vernon	314,694	334,142	311,066	327,539	352,304
Colton	58,262	61,862	57,590	60,640	65,224
VEA	(453,123)	(481,125)	(447,898)	(471,618)	(507,276)

Treatment of Non-PTO entities under hybrid approach

- May need to revisit the approach for measuring use of the system by Non-PTO entities to align with proposed treatment for PTOs
  - Non-PTO entities currently allocated transmission costs through WAC
  - May need align use measurement approaches for these entities with other proposed TAC structure modifications
- Stakeholder feedback was almost entirely supportive of evaluating the need for this alignment in treatment of these entities

ISO proposes to align WAC billing determinant approach for Non-PTO entities with proposed hybrid billing determinant measurement approach

- These entities are treated similar to internal loads in some important ways that support the ISO’s proposal
  - Their loads are planned for and served by the transmission system similarly to other internal loads
- ISO will adopt a hybrid billing determinant approach including peak demand and a volumetric measurement for Non-PTO entities to align with approach for measuring use of other traditional PTO/UDCs customers
  - ISO will modify WAC rates for transmission cost recovery from these customers
  - Both volumetric WAC rate and peak demand WAC rate components will be calculated consistent with proposed hybrid billing determinant approach modifications

Non-PTO entities proposed hybrid billing determinant measurement approach will result in new rates

- The ISO will calculate three separate and distinct WAC rates:

1. Volumetric rate same as current practice for traditional exports and wheeling
   - ISO will continue to calculate standard volumetric WAC rate used for normal exports and wheeling purposes in the same manner as currently done today
2. Hybrid billing determinant volumetric rate for Non-PTO entities
3. Hybrid billing determinant 12CP demand charge rate for Non-PTO entities

Next steps

- Stakeholders are asked to submit written comments by April 25, 2018 to: initiativecomments@caiso.com
- Comment template will be available at the following link: http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx

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