Review TAC Structure
Second Revised Straw Proposal
Stakeholder Meeting

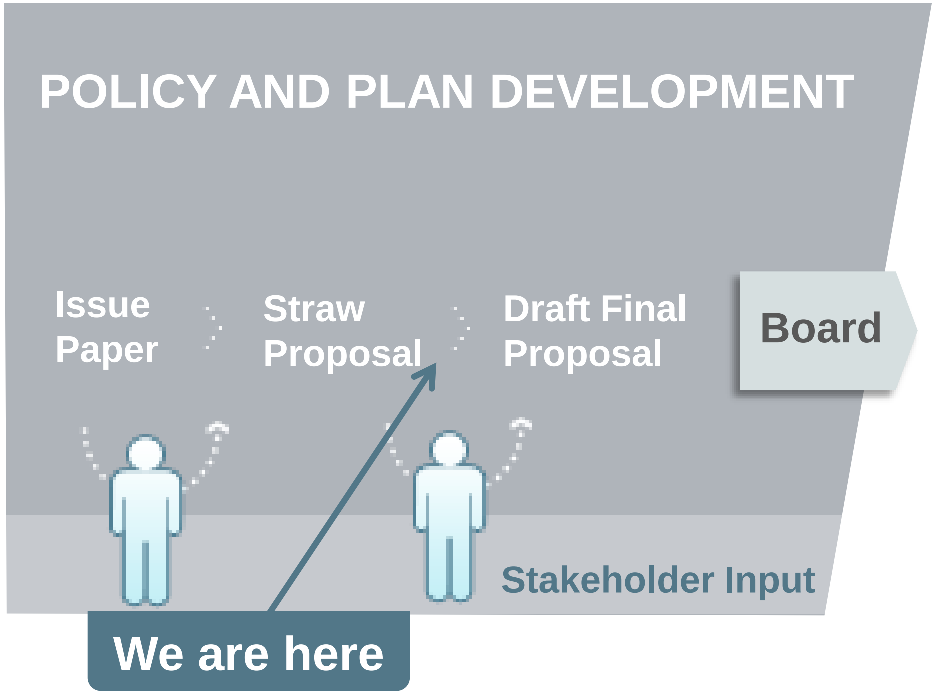
June 28, 2018

Chris Devon, Market and Infrastructure Policy

Agenda

Time (PDT)	Topic	Presenter
10:00 – 10:10 am	Welcome and introduction	James Bishara
10:10 am – 12:00 pm	Hybrid billing determinant proposal	Chris Devon
12:00 – 1:00 pm	Lunch	
1:00 – 2:00 pm	Hybrid billing determinant proposal (continued)	Chris Devon
2:00 – 2:30 pm	Point of measurement issue	Chris Devon
2:30 – 3:00 pm	Next steps and conclusion	James Bishara
3:00 pm	Adjourn	

Stakeholder Process



Initiative Schedule

Date	Milestone
June 22	Second revised straw proposal posted
June 28	Stakeholder meeting
July 18	Stakeholder written comments due
Sept 12	Post draft final proposal
Sept 19	Hold stakeholder meeting
Oct 10	Stakeholder written comments due
Feb 2019	Present final proposal at CAISO Board meeting

ISO TAC structure rate design objectives

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

Changes included in second revised straw proposal

- Includes clarification to implementation details for the hybrid billing determinant approach
  - More details and settlement example to help stakeholders understand the potential impacts
- ISO changed proposal to use PTO-specific peak demand TAC rates derived from PTO approved rate case forecasts and iterative PTO-ISO process to determine correct inputs
  - Previous proposal was to use CEC IPER demand forecast
  - Some stakeholders indicated concerns and ISO agrees
- Clarification and additional support for position on point of measurement of issue

Hybrid billing determinant proposal

Volumetric-only approach is no longer appropriate due to changes occurring in the ISO system

- Increasing customer-sited DG shifts costs under current volumetric-only approach
  - Costs are reduced for UDC areas with more DG production and shifted to UDCs with less DG production without related benefit
  - Proposed hybrid approach better aligns cost allocation with the capacity and reliability benefits provided by the system
- Current approach has resulted in TAC allocation benefitting lower load factor UDC areas and impacting higher load factor UDC areas
  - Volumetric-only approach does not reflect full impacts of high coincident peak demand, low load factor UDC areas, that have relatively lower volumetric use compared to high load factor areas

ISO proposes a hybrid billing determinant for HV-TAC

- Utilize part volumetric and part peak demand billing determinants for assessing TAC charges
- Proposed hybrid approach is an improvement over the current TAC structure
- Captures both volumetric and peak demand functions and reliability benefits provided by the system
  - Better reflects peak load cost drivers by including a demand charge component in TAC structure
- ISO and majority of stakeholders believe that proposed hybrid approach is an appropriate change

Bifurcation of HV-TRR under hybrid approach

- Must determine what portion of TRR is collected through each component of hybrid billing determinant
  - What amount of TRR will be collected under volumetric measurement versus peak demand measurement
- Previously proposed option for assigning the HV-TRR
  - Historic cost categorization approach was explored
  - Categorization approach too complex and subjective
- ISO proposes annual system gross load factor calculation
  - System load factor reflects the degree the system is utilized for peak capacity delivery versus energy delivery functions
  - Most stakeholders provided feedback in support this proposed HV-TAC bifurcation approach

Proposed LF calculation approach for HV-TRR bifurcation example with 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%

System-wide gross load factor approach is an appropriate solution for HV-TRR bifurcation

- Will be used to set proportions of HV-TRR applied to determine volumetric and peak demand TAC rates for each annual period
  - ISO will perform this calculation annually
  - Calculation of HV-TRR components will not be updated intra-year
- ISO will utilize forecasted annual gross load and forecasted coincident peak demand values from PTO approved demand forecasts

ISO will use approved PTO forecast data for system gross load factor calculation for TRR bifurcation and setting hybrid TAC rates

- Change to proposal from last iteration
- Forward looking HV-TRR split and annual hybrid HV-TAC rates will be based on PTO's filed forecast annual gross load (MWh) and annualized 12CP demand (MW)
- PTO FERC transmission rate case forecasts may need to be modified to include coincident peak load forecasts
- Aligns with need for PTO-specific peak demand rates for implementation of hybrid billing determinant proposal

Setting HV-TAC rates under hybrid approach

- ISO will continue to utilize approved HV-TRR values from PTOs to determine overall HV-TRR to be recovered for each year
- ISO has modified the proposal to use PTO specific rate case forecasts to set the HV-TRR split and resulting HV-TAC volumetric and demand rates
  - Annual gross load forecast and annualized system 12CP demand
- ISO will utilize PTO-specific HV-TAC rates for net settlement TAC invoicing (described in later slides)

PTO-specific peak demand TAC rates

- Stakeholders have indicated that there is a need to develop PTO-specific peak demand TAC rates similar to current PTO-specific volumetric TAC rates
- Allows ISO to utilize PTO specific peak demand forecast for setting the system-wide peak demand TAC rate
- Needed to implement correct allocation of TAC costs associated TAC net settlement invoicing and align rates and billing with PTO filed transmission rate cases
- To determine necessary PTO-specific forecasted monthly coincident peak demand data ISO may also need to develop an iterative process

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.*, 12CP, 4CP, 1CP
- Peak demand measurement frequency is intended to reflect the way transmission system is planned and used
- Should reflect benefits being provided by users by aligning frequency of measurements with benefits associated with peak demand capacity-reliability function provided by transmission system

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

- 12CP approach strikes an appropriate balance
  - Addresses issues related to BTM DG and load factor differences between UDC areas on a monthly basis, not just during the summer periods
- Reflects both capacity and reliability functions and benefits provided to system users on a monthly basis
- Widely accepted by FERC in other region’s rate design
- Most stakeholders have indicated support for 12CP frequency

12CP approach provides advantages over lower frequency of measurements

- Mitigate potential of certain UDC areas avoiding some costs due to peak demand anomalies
  - *i.e.*, abnormal high or low peak demand that might occur for some UDC areas during lower frequency of measurement such as 1CP or 4CP
- Less frequent measurements could result in costs allocated to particular UDC areas inconsistent with the cost causation and benefits provided
- More frequent measurements can provide a less volatile overall reflection of UDC coincident peak demands
- Aligns with many PTO's retail rate structures that utilize monthly peak measurements

Proposed hybrid HV-TAC rates formula

- ISO will determine volumetric HV-TAC rate ($/MWh) and 12CP demand charge HV-TAC rate ($/MW) each year**:**
- **Step 1:** Establish split of annual HV-TRR for hybrid billing determinant approach:
  - Multiply the total annual HV-TRR by the resulting percentage from the system-wide annual gross load factor calculation
- **Step 2:** Determine system-wide volumetric HV-TAC rate:
  - Divide the volumetric portion of HV-TRR by total filed annual gross load MWhs
- **Step 3:** Determine system-wide 12CP demand HV-TAC rate:
  - Divide the peak demand portion of HV-TRR by sum of PTO filed annualized 12CP demand MWs

Example hybrid HV-TAC rate calculation

- Assume 50% bifurcation of HV-TRR for example and inputs based on the January 2017 HV-TAC rate worksheet
- Total annual HV-TRR: **$2,165,294,596** and total annual gross load: **209,260,146 MWhs**

- **Step 1:** Portion of HV-TRR to be collected under volumetric rate: $2,165,294,596 x 50% = $1,082,647,298.
  - Remaining portion of HV-TRR to be collected under 12CP demand charge rate: $1,082,647,298
- **Step 2:** Volumetric TAC rate ($/MWh): $1,082,647,298 ÷ 209,260,146 MWh **= $5.1737/MWh**
- **Step 3:** 12CP Peak demand TAC rate ($/MW): $1,082,647,298 ÷ 380,496 MWs = **$2,845.3579/MW**

Example TAC rate worksheet for proposed hybrid rate design – Volumetric HV-TAC rate

PTO	Filed Annual TRR ($) *[1]*	Volumetric HV-TRR Amount ($) *[2]* *[50% assumed TRR split]*	Filed Annual Gross Load (MWh) *[3]*	HV Utility Specific Volumetric Rate ($/MWH) *[4]* *= [2] ÷ [3]*	Volumetric TAC Rate ($/MWH) *[5]* *= total [2] ÷ total [3]*	Volumetric TAC Amount ($) *[6]* *= [3] × [5]*
PG&E	468,014,921	234,007,461	91,500,000	$ 2.5575	$ 5.1737	473,392,711
SCE	1,030,478,735	515,239,368	88,983,449	$ 5.7903	$ 5.1737	460,372,854
SDG&E	404,386,165	202,193,083	20,467,098	$ 9.8789	$ 5.1737	105,890,437
Anaheim	29,782,928	14,891,464	2,507,620	$ 5.9385	$ 5.1737	12,973,651
Azusa	3,096,475	1,548,237	257,416	$ 6.0145	$ 5.1737	1,331,791
Banning	1,460,226	730,113	144,652	$ 5.0474	$ 5.1737	748,385
Pasadena	15,039,959	7,519,979	1,120,049	$ 6.7140	$ 5.1737	5,794,787
Riverside	35,543,842	17,771,921	2,180,985	$ 8.1486	$ 5.1737	11,283,742
Vernon	2,985,548	1,492,774	1,181,728	$ 1.2632	$ 5.1737	6,113,895
DATC Path 15	25,457,786	12,728,893	-	$ -	$ 5.1737	0
Startrans IO	3,224,199	1,612,100	-	$ -	$ 5.1737	0
Trans Bay Cable	120,454,400	60,227,200	-	$ -	$ 5.1737	0
Citizens Sunrise	10,573,065	5,286,533	-	$ -	$ 5.1737	0
Colton	4,110,870	2,055,435	372,179	$ 5.5227	$ 5.1737	1,925,539
VEA	10,685,478	5,342,739	544,970	$ 9.8037	$ 5.1737	2,819,506
ISO Total	**2,165,294,596**	**1,082,647,298**	**209,260,146**			**1,082,647,298**

Example TAC rate worksheet for proposed hybrid rate design – 12CP demand HV-TAC rate

PTO	Peak Demand HV-TRR Amount ($) *[7]* *[50% assumed TRR split]*	Filed Annualized 12CP Demand (MW) *[8]* *[from approved PTO rate case forecasts[18]]*	HV Utility-Specific Peak Demand Rate ($/MW) *[9]* *= [7] ÷ [8]*	Peak Demand TAC Rate ($/MW) *[10]* *= total [7] ÷ total [8]*	Peak Demand TAC Amount ($) *[11]* *= [8] × [10]*
PG&E	234,007,461	154,560	$ 1,514.0234	$ 2,845.3579	439,778,516
SCE	515,239,368	170,436	$ 3,023.0665	$ 2,845.3579	484,951,418
SDG&E	202,193,083	40,128	$ 5,038.7032	$ 2,845.3579	114,178,522
Anaheim	14,891,464	4,668	$ 3,190.1165	$ 2,845.3579	13,282,131
Azusa	1,548,237	504	$ 3,071.8995	$ 2,845.3579	1,434,060
Banning	730,113	264	$ 2,765.5788	$ 2,845.3579	751,174
Pasadena	7,519,979	2,088	$ 3,601.5227	$ 2,845.3579	5,941,107
Riverside	17,771,921	4,272	$ 4,160.0939	$ 2,845.3579	12,155,369
Vernon	1,492,774	2,184	$ 683.5046	$ 2,845.3579	6,214,262
DATC Path 15	12,728,893	-	$ -	$ 2,845.3579	0
Startrans IO	1,612,100	-	$ -	$ 2,845.3579	0
Trans Bay Cable	60,227,200	-	$ -	$ 2,845.3579	0
Citizens Sunrise	5,286,533	-	$ -	$ 2,845.3579	0
Colton	2,055,435	672	$ 3,058.6828	$ 2,845.3579	1,912,081
VEA	5,342,739	720	$ 7,420.4708	$ 2,845.3579	2,048,658
ISO Total	**1,082,647,298**	**380,496**			**1,082,647,298**
			ISO Total HV-TRR to be collected:	*[6] + [11]*	**$ 2,165,294,596**

Hybrid billing determinant cost impact analysis

- ISO has provided analysis of the potential cost impacts to UDCs due to proposed hybrid billing determinant
  - Includes some additional sensitivities requested
- Developed with TAC cost impact model previously described in prior proposals
  - Cost impact figures are only modeled impacts based on forecasts – does not reflect firm future outcomes – these figures are for illustrative purposes only
- Actual TAC rates and resulting cost allocation and billing for future years will be based on the approved PTO forecasts and actual usage measurements
  - Will differ due to differences in several potential variables; including projected overall HV-TRR, resulting volumetric and TAC rates, and monthly peak demand and volumetric usage

Hybrid billing determinant cost impact analysis

- TAC impact model utilizes publicly available data and this required ISO to apply load profiles to some smaller PTO UDCs for this analysis to avoid confidentiality issues
- This aspect of the modeling that has used load profiles of the larger PTO UDC areas applied to smaller UDC data is the source of potential discrepancies between this impact analysis and cost impacts that individual stakeholders have attempted to verify using actual settlements data or different forecast data

Hybrid billing determinant cost impacts to current UDCs – current TAC structure charges

TAC charges under current volumetric rate design

	2018	2019	2020	2021	2022
PG&E	$1,009.6	$1,063.1	$1,143.5	$1,223.6	$1,299.9
SCE	$1,016.7	$1,070.5	$1,151.4	$1,232.1	$1,308.9
SDG&E	$220.8	$232.5	$250.0	$267.6	$284.2
Anaheim	$27.2	$28.7	$30.8	$33.0	$35.0
Azusa	$2.9	$3.1	$3.3	$3.5	$3.8
Banning	$1.7	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.4	$13.1	$14.1	$15.0	$16.0
Riverside	$25.5	$26.9	$28.9	$31.0	$32.9
Vernon	$12.8	$13.5	$14.5	$15.6	$16.5
Colton	$4.1	$4.3	$4.6	$4.9	$5.2
VEA	$5.3	$5.6	$6.0	$6.4	$6.8
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Existing Rate ($/MWh)	**$11.11**	**$11.63**	**$12.42**	**$13.25**	**$13.94**

Hybrid billing determinant cost impacts to current UDCs – 12CP 50% TRR split TAC charges

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$979.9	$1,031.7	$1,109.8	$1,187.5	$1,261.5
SCE	$1,032.2	$1,086.8	$1,169.0	$1,250.9	$1,328.9
SDG&E	$233.7	$246.1	$264.7	$283.3	$300.9
Anaheim	$28.0	$29.5	$31.7	$33.9	$36.0
Azusa	$3.0	$3.2	$3.4	$3.7	$3.9
Banning	$1.6	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.6	$13.3	$14.3	$15.3	$16.2
Riverside	$25.9	$27.3	$29.3	$31.4	$33.3
Vernon	$13.1	$13.8	$14.9	$15.9	$16.9
Colton	$4.1	$4.3	$4.7	$5.0	$5.3
VEA	$4.9	$5.1	$5.5	$5.9	$6.3
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Volumetric - Gross Load ($/MWh)	**$5.56**	**$5.82**	**$6.21**	**$6.63**	$6.97
Coincident Peak 12 Periods - Gross Load ($/MW)	**$3,071.53**	**$3,215.25**	**$3,432.31**	**$3,663.12**	**$3,854.27**

Hybrid billing determinant cost impacts to current UDCs – 12CP 50% TRR split – $ impact

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(29,779,795)	(31,356,864)	(33,727,689)	(36,091,342)	(38,340,631)
SCE	15,509,378	16,330,718	17,565,448	18,796,444	19,967,878
SDG&E	12,949,226	13,634,986	14,665,898	15,693,692	16,671,756
Anaheim	760,691	800,976	861,536	921,913	979,368
Azusa	92,978	97,902	105,304	112,684	119,707
Banning	(1,605)	(1,690)	(1,817)	(1,945)	(2,066)
Pasadena	204,341	215,162	231,430	247,649	263,083
Riverside	344,029	362,248	389,637	416,943	442,928
Vernon	311,066	327,539	352,304	376,993	400,488
Colton	57,590	60,640	65,224	69,795	74,145
VEA	(447,898)	(471,618)	(507,276)	(542,826)	(576,656)
CAISO Total	0	0	0	0	0

Hybrid billing determinant cost impacts to current UDCs – 12CP 50% TRR split – % impact

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-2.9496%	-2.9496%	-2.9496%	-2.9496%	-2.9496%
SCE	1.5255%	1.5255%	1.5255%	1.5255%	1.5255%
SDG&E	5.8654%	5.8654%	5.8654%	5.8654%	5.8654%
Anaheim	2.7957%	2.7957%	2.7957%	2.7957%	2.7957%
Azusa	3.1805%	3.1805%	3.1805%	3.1805%	3.1805%
Banning	-0.0972%	-0.0972%	-0.0972%	-0.0972%	-0.0972%
Pasadena	1.6465%	1.6465%	1.6465%	1.6465%	1.6465%
Riverside	1.3468%	1.3468%	1.3468%	1.3468%	1.3468%
Vernon	2.4234%	2.4234%	2.4234%	2.4234%	2.4234%
Colton	1.4216%	1.4216%	1.4216%	1.4216%	1.4216%
VEA	-8.4204%	-8.4204%	-8.4204%	-8.4204%	-8.4204%

TAC net settlement invoicing example worksheets

- Following example worksheets for HV-TAC net settlements invoicing process demonstrates intended implementation of the hybrid rate design
- Provided to assist stakeholders in understanding the potential impacts of the proposal
- Demonstrates how the proposed hybrid billing determinants would be applied for settlements purposes

TAC net settlement invoicing example – TRR and volumetric TAC rate info

PTO Name	Total Filed Annual TRR ($) [1]	Volumetric HV-TRR Amount [2] [Assumed 50% split]	Filed Annual Gross Load (MWh) [3]	Percent of Total TRR [4] =[2] / sum of [2]	**HV Utility Specific Rate ($/MWH)** [5] = [2] / [3]	Percent of Total TRR (W/Load) [6] =[2] / sum of [2] w/Load	**Volumetric TAC Rate ($/MWH)** [7] = sum of [2] / sum of[3]
PG&E	$ 468,014,921	$ 234,007,461	91,500,000	21.62%	**$ 2.5575**	23.35%	**$ 10.3432**
SCE	$ 1,030,478,735	$ 515,239,368	88,983,449	47.61%	**$ 5.7903**	51.40%	**$ 10.3432**
SDG&E	$ 404,386,165	$ 202,193,083	20,467,098	18.68%	**$ 9.8789**	20.17%	**$ 10.3432**
Anahiem	$ 29,782,928	$ 14,891,464	2,507,620	1.38%	**$ 5.9385**	1.49%	**$ 10.3432**
Azusa	$ 2,107,197	$ 1,053,599	257,416	0.10%	**$ 4.0930**	0.11%	**$ 10.3432**
Banning	$ 3,096,475	$ 1,548,237	144,652	0.14%	**$ 10.7032**	0.15%	**$ 10.3432**
Pasadena	$ 1,460,226	$ 730,113	1,120,049	0.07%	**$ 0.6519**	0.07%	**$ 10.3432**
Riverside	$ 15,039,959	$ 7,519,979	2,180,985	0.69%	**$ 3.4480**	0.75%	**$ 10.3432**
Vernon	$ 35,543,842	$ 17,771,921	1,181,728	1.64%	**$ 15.0389**	1.77%	**$ 10.3432**
Colton	$ 4,110,870	$ 2,055,435	372,179	0.19%	**$ 5.5227**	0.21%	**$ 10.3432**
VEA	$ 10,685,478	$ 5,342,739	544,970	0.49%	**$ 9.8037**	0.53%	**$ 10.3432**
DATC Path 15	$ 25,457,786	$ 12,728,893	-	1.18%	**$ -**		**$ 10.3432**
Startrans IO	$ 3,224,199	$ 1,612,100	-	0.15%	**$ -**		**$ 10.3432**
Trans Bay Cable	$ 120,454,400	$ 60,227,200	-	5.57%	**$ -**		**$ 10.3432**
Citizens Sunrise	$ 10,573,065	$ 5,286,533	-	0.49%	**$ -**		**$ 10.3432**
Total	**$ 2,164,416,245**	**$ 1,082,208,122**	**209,260,146**	**100.00%**		100.00%	

TAC net settlement invoicing example – TRR and 12CP peak demand TAC rate info

PTO Name	Peak Demand HV-TRR Amount [8] [Assumed 50% split]	Filed Annualized 12CP Demand (MW)[20] [9]	Percent of Total TRR [10] =[8] / sum of [8]	**HV Utility Specific 12CP Demand Rate ($/MW)** [11] = [8] / [9]	Percent of Total TRR (W/Load) [12] =[8] / sum of [8] w/Load	**12CP Demand TAC Rate ($/MW)** [13] = sum of [8] / sum of[9]
PG&E	$ 234,007,461	154,560	21.62%	**$ 1,514.0234**	23.35%	**$ 2,873.7801**
SCE	$ 515,239,368	170,436	47.61%	**$ 3,023.0665**	51.40%	**$ 2,873.7801**
SDG&E	$ 202,193,083	40,128	18.68%	**$ 5,038.7032**	20.17%	**$ 2,873.7801**
Anaheim	$ 14,891,464	4,668	1.38%	**$ 3,190.1165**	1.49%	**$ 2,873.7801**
Azusa	$ 1,053,599	504	0.10%	**$ 2,090.4732**	0.11%	**$ 2,873.7801**
Banning	$ 1,548,237	264	0.14%	**$ 5,864.5353**	0.15%	**$ 2,873.7801**
Pasadena	$ 730,113	2,088	0.07%	**$ 349.6709**	0.07%	**$ 2,873.7801**
Riverside	$ 7,519,979	356	0.69%	**$ 21,123.5379**	0.75%	**$ 2,873.7801**
Vernon	$ 17,771,921	2,184	1.64%	**$ 8,137.3265**	1.77%	**$ 2,873.7801**
Colton	$ 2,055,435	672	0.19%	**$ 3,058.6828**	0.21%	**$ 2,873.7801**
VEA	$ 5,342,739	720	0.49%	**$ 7,420.4708**	0.53%	**$ 2,873.7801**
DATC Path 15	$ 12,728,893	-	1.18%	**$ -**	-	**$ 2,873.7801**
Startrans IO	$ 1,612,100	-	0.15%	**$ -**	-	**$ 2,873.7801**
Trans Bay Cable	$ 60,227,200	-	5.57%	**$ -**	-	**$ 2,873.7801**
Citizens Sunrise	$ 5,286,533	-	0.49%	**$ -**	-	**$ 2,873.7801**
Total	**$ 1,082,208,122**	**376,580**	100.00%		100.00%	

TAC net settlement invoicing example – monthly UDC metered data inputs

PTO Name	Volumetric TAC Rate ($MWh) [1] = [7] TRR Information	Utility Specific Volumetric Rate ($MWh) [2] = [5] TRR Information	**Metered Gross Load (MWh)** [3]	12CP Demand TAC Rate ($MW) [4] = [13] TRR Information	Utility Specific 12cp Demand Rate ($MWh) [5] = [11] TRR Information	**Metered Peak Demand (MW)[21]** [6]
PG&E	$ 10.3432	$ 2.5575	**9,098,475**	$ 2,873.7801	$ 1,514.0234	**13,228**
SCE	$ 10.3432	$ 5.7903	**9,698,936**	$ 2,873.7801	$ 3,023.0665	**14,656**
SDG&E	$ 10.3432	$ 9.8789	**1,972,843**	$ 2,873.7801	$ 5,038.7032	**3,224**
Anaheim	$ 10.3432	$ 5.9385	**246,220**	$ 2,873.7801	$ 3,190.1165	**396**
Azusa	$ 10.3432	$ 4.0930	**27,786**	$ 2,873.7801	$ 2,090.4732	**39**
Banning	$ 10.3432	$ 10.7032	**17,886**	$ 2,873.7801	$ 5,864.5353	**24**
Pasadena	$ 10.3432	$ 0.6519	**118,556**	$ 2,873.7801	$ 349.6709	**171**
Riverside	$ 10.3432	$ 3.4480	**251,386**	$ 2,873.7801	$ 21,123.5379	**33**
Vernon	$ 10.3432	$ 15.0389	**104,931**	$ 2,873.7801	$ 8,137.3265	**185**
Colton	$ 10.3432	$ 5.5227	**39,120**	$ 2,873.7801	$ 3,058.6828	**58**
VEA	$ 10.3432	$ 9.8037	**42,718**	$ 2,873.7801	$ 7,420.4708	**62**
DATC Path 15	$ 10.3432	$ -		$ 2,873.7801	$ -	
Startrans IO	$ 10.3432	$ -		$ 2,873.7801	$ -	
Trans Bay Cable	$ 10.3432	$ -		$ 2,873.7801	$ -	
Citizens Sunrise	$ 10.3432	$ -		$ 2,873.7801	$ -	
Total			**21,618,857**			**32,076**

TAC net settlement invoicing example – allocation process for volumetric TAC rate monthly settlement

PTO Name	**Total Volumetric HV TAC Due From UDCs ($)** *[8]*	Proportion of total TRR (%) *[9]*	Amounts PTO Would Receive Under Volumetric Utility-Specific ($) *[10]*	Difference ($) *[11]*	Proportion of total TRR (w/ Load) (%) *[12]*	Allocation of Total Volumetric TAC Difference ($) *[13]*	**Total Volumetric HV TAC Due to PTOs ($)** *[14]*
	*= [1] * [3]*	*= [4] TRR Information*	*= [2] x [3]*	*= Sum of [8] - Sum of [10]*	*= [6] TRR information*	*= Sum of [11] x [12]*	*= [10] + [13]*
PG&E	**$ 94,107,200**	21.62%	$ 23,268,972	$ 70,838,228	23.35%	$ 24,108,199	**$ 47,377,171**
SCE	**$ 100,317,882**	47.61%	$ 56,159,586	$ 44,158,296	51.40%	$ 53,081,611	**$ 109,241,198**
SDG&E	**$ 20,405,481**	18.68%	$ 19,489,585	$ 915,896	20.17%	$ 20,830,580	**$ 40,320,165**
Anahiem	**$ 2,546,701**	1.38%	$ 1,462,175	$ 1,084,526	1.49%	$ 1,534,166	**$ 2,996,341**
Azusa	**$ 287,395**	0.10%	$ 113,727	$ 173,668	0.11%	$ 108,545	**$ 222,272**
Banning	**$ 185,000**	0.14%	$ 191,439	$ (6,439)	0.15%	$ 159,504	**$ 350,943**
Pasadena	**$ 1,226,243**	0.07%	$ 77,281	$ 1,148,962	0.07%	$ 75,219	**$ 152,500**
Riverside	**$ 2,600,136**	0.69%	$ 866,774	$ 1,733,362	0.75%	$ 774,732	**$ 1,641,506**
Vernon	**$ 1,085,320**	1.64%	$ 1,578,049	$ (492,729)	1.77%	$ 1,830,920	**$ 3,408,969**
Colton	**$ 404,622**	0.19%	$ 216,047	$ 188,576	0.21%	$ 211,757	**$ 427,804**
VEA	**$ 441,843**	0.49%	$ 418,798	$ 23,045	0.53%	$ 550,426	**$ 969,224**
DATC Path 15	**$ -**	1.18%	$ 2,630,067	$ (2,630,067)			**$ 2,630,067**
Startrans IO	**$ -**	0.15%	$ 333,095	$ (333,095)			**$ 333,095**
Trans Bay Cable	**$ -**	5.57%	$ 12,444,254	$ (12,444,254)			**$ 12,444,254**
Citizens Sunrise	**$ -**	0.49%	$ 1,092,313	$ (1,092,313)			**$ 1,092,313**
Total	**$ 223,607,823**	100%	**$ 120,342,163**	**$ 103,265,660**	100%	**$ 103,265,660**	**$ 223,607,823**

TAC net settlement invoicing example – allocation process for 12CP demand TAC rate monthly settlement

PTO Name	**Total 12CP Demand HV VAC Due From UDCs**	Proportion of total TRR	Amounts PTO Would Receive Under 12CP Demand Utility-Specific	Difference	Proportion of total TRR (w/ Load)	Allocation of Total 12CP Demand TAC Difference	**Total 12CP Demand HV TAC Due to PTOs**
	($) *[15]*	(%) *[16]*	($) *[17]*	($) *[18]*	(%) *[19]*	($) *[20]*	**($)** *[21]*
	= [4] x [6]	*= [10] TRR Information*	*= [5] x [6]*	*= Sum of [15] - Sum of [17]*	*= [12] TRR information*	*= Sum of [18] x [19]*	*= [17] + [20]*
PG&E	**$ 38,014,364**	21.62%	$ 20,027,502	$ 17,986,862	23.35%	$ 96,633	**$ 20,124,135**
SCE	**$ 42,118,122**	47.61%	$ 44,306,063	$ (2,187,941)	51.40%	$ 212,767	**$ 44,518,830**
SDG&E	**$ 9,265,067**	18.68%	$ 16,244,779	$ (6,979,712)	20.17%	$ 83,495	**$ 16,328,274**
Anaheim	**$ 1,138,017**	1.38%	$ 1,263,286	$ (125,269)	1.49%	$ 6,149	**$ 1,269,436**
Azusa	**$ 112,077**	0.10%	$ 81,528	$ 30,549	0.11%	$ 435	**$ 81,964**
Banning	**$ 68,971**	0.14%	$ 140,749	$ (71,778)	0.15%	$ 639	**$ 141,388**
Pasadena	**$ 491,416**	0.07%	$ 59,794	$ 431,623	0.07%	$ 301	**$ 60,095**
Riverside	**$ 94,835**	0.69%	$ 697,077	$ (602,242)	0.75%	$ 3,105	**$ 700,182**
Vernon	**$ 531,649**	1.64%	$ 1,505,405	$ (973,756)	1.77%	$ 7,339	**$ 1,512,744**
Colton	**$ 166,679**	0.19%	$ 177,404	$ (10,724)	0.21%	$ 849	**$ 178,252**
VEA	**$ 178,174**	0.49%	$ 460,069	$ (281,895)	0.53%	$ 2,206	**$ 462,275**
DATC Path 15	**$ -**	1.18%	$ 1,084,210	$ (1,084,210)		$ -	**$ 1,084,210**
Startrans IO	**$ -**	0.15%	$ 137,314	$ (137,314)		$ -	**$ 137,314**
Trans Bay Cable	**$ -**	5.57%	$ 5,129,979	$ (5,129,979)		$ -	**$ 5,129,979**
Citizens Sunrise	**$ -**	0.49%	$ 450,292	$ (450,292)		$ -	**$ 450,292**
Total	**$ 92,179,372**	100.00%	**$ 90,184,010**		100.00%	$ 413,912	**$ 92,179,372**

Updating HV-TAC rates for approved TRR changes

- ISO will continue to provide intra-year updates to HV-TAC rates when PTO's provide updates to approved HV-TRR amounts
  - When new assets are included or facilities are withdrawn from the HV-TRR rate base by PTOs that receive approval under FERC transmission rate proceedings
- ISO will update HV-TAC rates if PTO rate case forecasts are updated
- ISO will not update the annual HV-TRR bifurcation once established at start of annual period

Billing determinant data utilized for settlements under hybrid billing determinant approach

- Continue to utilize gross load settlement data to determine each UDC area 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 each UDC area 12CP monthly demand usage and associated HV-TAC 12CP demand charges

Alignment of treatment of Non-PTO entities under hybrid approach

- The ISO proposes to align approach for measuring use of the system by Non-PTO entities to align with proposed treatment for PTOs
  - Will only apply to those non-PTO entities currently billed for their use of the HV transmission system through the Wheeling Access Charge (WAC)
  - This change will not be applied to the WAC rates assessed to traditional exports and wheeling transactions
- Stakeholder feedback continues to be very supportive of 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

Proposal will result in three separate and distinct WAC rates:

1. Volumetric WAC rate ($/MWh) for traditional exports and wheeling transactions
   - This traditional volumetric WAC rate will be calculated the same as current practice, corresponding to full annual HV-TRR amount ($) and total sum of approved PTO gross load forecasts (MWh)
   - This rate will continue to be charged to all traditional exports and wheeling transactions

Proposal will result in three separate and distinct WAC rates (continued):

- Hybrid billing determinant volumetric WAC rate ($/MWh) for non-PTO entities.
  - This hybrid billing determinant volumetric WAC rate will be calculated corresponding with the annual volumetric HV-TRR amount ($) and the total sum of approved PTO gross load forecasts (MWh)
  - Equals annual system wide volumetric HV-TAC rate under hybrid proposal
  - This rate will be charged monthly to non-PTO entities currently taking ISO transmission service under the WAC charge

Proposal will result in three separate and distinct WAC rates (continued):

- Hybrid billing determinant 12CP demand rate ($/MW) for non-PTO entities.
  - Hybrid billing determinant 12CP demand WAC rate will be calculated corresponding to the annual peak demand HV-TRR amount ($) and gross load forecast the PTO’s FERC approved annualized 12CP demand forecast (MW)
  - Equals annual system wide 12CP demand HV-TAC rate under hybrid proposal
  - This rate will be charged monthly to non-PTO entities currently taking ISO transmission service under the WAC charge based on their monthly coincident peak demand
  - ISO will use average hourly demand corresponding to ISO system-wide monthly coincident peak for settlements purposes

Point of measurement issue

Transmission system is integral to the overall operation of the overall electric grid

- Provides benefits to customers of both transmission and distribution connected resources
  - Detailed description, including how DG can also provide benefits and reductions to future transmission costs has been discussed and provided in prior straw proposal
- Enables the safe and efficient service provided to all loads, even those located in close proximity to distributed resources
- ISO is committed to participation from distributed energy resources and believes they are an important and growing component of California generation mix
  - However, procurement and operation of local distributed energy resources is not viable independent of the transmission grid

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
  - ISO does not believe it is appropriate to reallocate these embedded costs
- 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

Existing transmission system costs are embedded costs and cannot be reduced

- Modifying the point of measurement will not improve efficiency or reduce these embedded transmission costs
- Changing the point of measurement simply shifts responsibility for the embedded costs of the existing system among the UDC areas
- Will not create cost reduction or efficiencies related to costs of existing facilities

Future reconsideration of point of measurement issue

- ISO is willing to revisit the point of measurement issue, for purposes of prospectively allocating the costs of future transmission facilities, if state policy makers and regulatory authorities, after careful consideration of the merits and implementation issues, support 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
- Not a firm commitment to make any future modifications:
  - The ISO will <u>reconsider</u> the issue in the future – if related changes are determined appropriate by state policy makers and regulatory authorities

Next steps

- Stakeholders are asked to submit written comments by July 18, 2018 to: initiativecomments@caiso.com
- Comment template will be available at the following link: http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx