TAC Structure Enhancements Draft Final Proposal Stakeholder Meeting

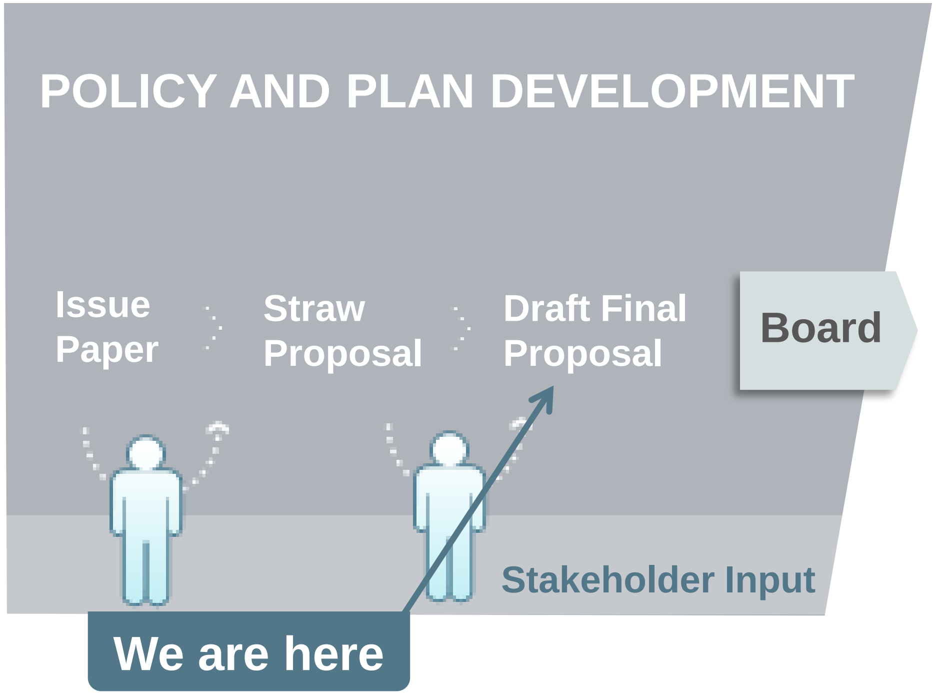
September 24, 2018

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 – 2:55 pm	Hybrid billing determinant proposal (continued)	Chris Devon
2:55 – 3:00 pm	Next steps and conclusion	James Bishara
3:00 pm	Adjourn	

Stakeholder Process



Initiative Schedule

Date	Milestone
Sept 17	Post draft final proposal
Sept 24	Hold stakeholder meeting
Oct 9	Stakeholder written comments due
Q1/Q2 TBD	Present final proposal to CAISO Board

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 draft final proposal

- Modified to use prior annual period historic peak demand data to derive 12CP demand rates instead of forecasted data
  - Stakeholders indicated concerns with both previously proposed alternatives for use of forecast data
  - ISO agrees with suggestions to utilize historic data
- Addition of proposed two year phase-in period for hybrid billing determinant rate structure proposal

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

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 will utilize historic data to set the HV-TRR split and resulting 12CP demand rates
  - Annualized system 12CP demand (MWs)
  - Described further in later slides
- ISO will utilize PTO specific rate case forecasts for determination of volumetric HV-TAC rates
- ISO will utilize PTO-specific HV-TAC rates for net settlement TAC invoicing (also described in later slides)

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 used
- Should reflect benefits being provided by users by aligning frequency of measurements with benefits associated with peak demand capacity and reliability functions 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
- Most stakeholders have indicated support for 12CP frequency
  - All monthly peak loads through year contribute to use of grid and benefits provided to users and should be reflected coincident peak billing determinant
  - Narrower definitions of peak load such as 4CP or 1CP would not accurately reflect peak related costs/benefits in other months of the year

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

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
- Proposed 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 of proposed annual system gross load factor calculation for HV-TRR bifurcation

Proposed LF calculation approach for HV-TRR bifurcation example with historic data

Year	ISO Annual Coincident Peak Load (MW)	Filed Annual HV-TRR ($)	Filed Annual Gross Load (MWh)	Volumetric TAC Rate ($/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 charge ($)	Volumetric HV-TRR portion (%)	TRR amount to be collected through peak demand charge ($)	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 historic settlements data from prior annual period of October 1 through September 30, for calculation of annual system gross load factor

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 billing determinant rates 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]*	Filed Annual Gross Load (MWh) *[3]*	HV Utility Specific Volumetric Rate ($/MWH) *[4]*	Volumetric TAC Rate ($/MWH) *[5]*	Volumetric TAC Amount ($) *[6]*
		[50% assumed TRR split]		*= [2] ÷ [3]*	*= total [2] ÷ total [3]*	*= [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
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
DATC Path 15	25,457,786	12,728,893	-	-	$ 5.1737	-
Startrans IO	3,224,199	1,612,100	-	-	$ 5.1737	-
Trans Bay Cable	120,454,400	60,227,200	-	-	$ 5.1737	-
Citizens Sunrise	10,573,065	5,286,533	-	-	$ 5.1737	-
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 ($) [7]	Annualized 12CP Demand (MW) [8]	HV Utility-Specific Peak Demand Rate ($/MW) [9]	Peak Demand TAC Rate ($/MW) [10]	Peak Demand TAC Amount ($) [11]
	[50% assumed TRR split]	*[from historic settlements data]*	*= [7] ÷ [8]*	*= total [7] ÷ total [8]*	*= [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
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
DATC Path 15	12,728,893	-	-	$ 2,845.3579	-
Startrans IO	1,612,100	-	-	$ 2,845.3579	-
Trans Bay Cable	60,227,200	-	-	$ 2,845.3579	-
Citizens Sunrise	5,286,533	-	-	$ 2,845.3579	-
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**

ISO agrees with stakeholder recommendations to utilize historic data to derive 12CP demand HV-TAC rates instead of forecasted data

- Previously proposed two other options:
  - CEC IPER demand forecast data & PTO FERC rate case forecast data
- Stakeholders expressed concerns related to burdens that would be imposed through use of forecast data
- Some PTOs' FERC rate case forecasts would need to be modified to include coincident peak load forecasts and ISO would need to develop iterative process for determining monthly coincident peak forecasts
  - Also would have caused issues related to the lag and frequency of some PTO's FERC rate cases

ISO will utilize historic peak demand data to derive 12CP demand HV-TAC rates instead of forecast data

- ISO will utilize historic settlements data (annualized 12CP demand MWs) from prior annual period for calculation of both PTO specific and system-wide 12CP demand HV-TAC rates
  - 12CP demand HV-TAC rates will be based on historic peak demand data from previous annual period of October 1 through September 30
  - For instance: 12CP demand HV-TAC rates for the 2021 annual period will utilize historic coincident peak demand figures from October 1, 2019 through September 30, 2020
- Historic data approach continues to align with need for PTO-specific demand rates for implementation of proposed hybrid billing determinant approach

Stakeholders requested analysis of historic peak demand data to support proposed time period utilized for determination of rates

- One year annual historic period is reasonable
  - Analysis provided shows low variance in the resulting annualized peak demand data & rates when comparing individual years and a number of longer time periods with rolling average annualized peak demand figures
- ISO believes analysis indicates proposed one year historic period is appropriate for use in setting 12CP demand rate component of hybrid HV-TAC structure
- One year historic period is consistent with intended rate design principles for the purposes of setting12CP demand HV-TAC rates

Comparison of historic peak demand data over different time periods (annualized demand in MWs)

Annualized 12CP demand 2014	Annualized 12CP demand 2015	Annualized 12CP demand 2016	Annualized 12CP demand 2017	Two-year rolling average annualized 12CP demand (2016 - 2017)	Three-year rolling average annualized 12CP demand (2015 - 2017)	Four-year rolling average annualized 12CP demand (2014 - 2017)
437,345	440,209	429,549	444,558	437,053.50	438,105.33	437,915.25

	Variance from: two-year rolling average (2016 - 2017)	Variance from: three-year rolling average (2015 - 2017)	Variance from: four-year rolling average (2014 - 2017)	Variance from: annualized 12CP demand 2017	Variance from: annualized 12CP demand 2016	Variance from: annualized 12CP demand 2015	Variance from: annualized 12CP demand 2014
Two-year rolling average historic (2016 - 2017)	-	-0.24%	-0.20%	-1.69%	1.75%	-0.72%	-0.07%
Three-year rolling average historic (2015 - 2017)	-0.24%	-	0.04%	-1.45%	1.99%	-0.48%	0.17%
Four-year rolling average historic (2014 - 2017)	0.20%	-0.04%	-	-1.49%	1.95%	-0.52%	0.13%

Comparison of historic time periods and resulting 12CP demand rates

	Annualized 12CP demand (MWs)	HV-TRR demand charge component (assuming Jan 2017 HV-TRR with 50% HV-TRR bifurcation; for static comparison purposes) ($)	Resulting 12CP Demand HV-TAC Rate ($/MW)	Variance in resulting 12CP demand rates versus 2017 only 12CP demand rate (%)
2014	437,345	$ 1,082,647,298	$ 2,475.4994	1.65%
2015	440,209	$ 1,082,647,298	$ 2,459.3938	0.99%
2016	429,549	$ 1,082,647,298	$ 2,520.4279	3.49%
2017	444,558	$ 1,082,647,298	$ 2,435.3342	-
Two-year rolling average (2016 - 2017)	437,053.50	$ 1,082,647,298	$ 2,477.1505	1.69%
Three-year rolling average (2015 - 2017)	438,105.33	$ 1,082,647,298	$ 2,471.2032	1.45%
Four-year rolling average (2014 - 2017)	437,915.25	$ 1,082,647,298	$ 2,472.2759	1.49%

ISO does not propose to apply weather normalization to historic demand data

- Some stakeholders suggest ISO should consider weather normalization of historic data
  - Stated need to align with CEC forecast data used in TPP and to avoid anomalous or overly volatile/varying resulting rates
- Potential complexity and resulting effects do not justify the inclusion of weather normalization
  - Historic annualized peak demand data is relatively stable year over year as shown by analysis and lack of volatility indicates weather normalization adjustments are not necessary
  - Additionally, the ISO does not believe weather normalization adjustments should be applied because of the potential complexity and low impacts associated with the issue

PTO-specific peak demand TAC rates

- ISO agrees with stakeholders on need to develop PTO-specific peak demand TAC rates similar to current PTO-specific volumetric TAC rates
- Needed to implement correct allocation of TAC costs associated TAC net settlement invoicing
  - Example for net settlements invoicing included in following slides

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 ($) [1]	Volumetric HV-TRR Amount [2]	Filed Annual Gross Load (MWh) [3]	Percent of Total TRR [4]	HV Utility Specific Rate ($/MWH) [5]	Percent of Total Volumetric TRR (W/Load) [6]	Volumetric TAC Rate ($/MWH) [7]
		[Assumed 50% split]		=[2] / sum of [2]	= [2] / [3]	=[2] / sum of [2] w/Load	= sum of [2] / sum of[3]
PG&E	$ 468,014,921	$ 234,007,461	91,500,000	21.61%	$ **2.5575**	23.34%	$ **5.1737**
SCE	$ 1,030,478,735	$ 515,239,368	88,983,449	47.59%	$ **5.7903**	51.38%	$ **5.1737**
SDG&E	$ 404,386,165	$ 202,193,083	20,467,098	18.68%	$ **9.8789**	20.16%	$ **5.1737**
Anaheim	$ 29,782,928	$ 14,891,464	2,507,620	1.38%	$ **5.9385**	1.48%	$ **5.1737**
Azusa	$ 3,096,475	$ 1,053,599	257,416	0.14%	$ **6.0145**	0.15%	$ **5.1737**
Banning	$ 1,460,226	$ 1,548,237	144,652	0.07%	$ **5.0474**	0.07%	$ **5.1737**
Pasadena	$ 15,039,959	$ 730,113	1,120,049	0.69%	$ **6.7140**	0.75%	$ **5.1737**
Riverside	$ 35,543,842	$ 7,519,979	2,180,985	1.64%	$ **8.1486**	1.77%	$ **5.1737**
Vernon	$ 2,985,548	$ 17,771,921	1,181,728	0.14%	$ **1.2632**	0.15%	$ **5.1737**
Colton	$ 4,110,870	$ 2,055,435	372,179	0.19%	$ **5.5227**	0.20%	$ **5.1737**
VEA	$ 10,685,478	$ 5,342,739	544,970	0.49%	$ **9.8037**	0.53%	$ **5.1737**
DATC Path 15	$ 25,457,786	$ 12,728,893	-	1.18%	-	-	$ **5.1737**
Startrans IO	$ 3,224,199	$ 1,612,100	-	0.15%	-	-	$ **5.1737**
Trans Bay Cable	$ 120,454,400	$ 60,227,200	-	5.56%	-	-	$ **5.1737**
Citizens Sunrise	$ 10,573,065	$ 5,286,533	-	0.49%	-	-	$ **5.1737**
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	Annualized 12CP Demand (MW)[21]	Percent of Total TRR	HV Utility Specific 12CP Demand Rate ($/MW)	Percent of Total Peak Demand TRR (W/Load)	12CP Demand TAC Rate ($/MW)
	[8] [Assumed 50% split]	[9]	[10] =[8] / sum of [8]	[11] = [8] / [9]	[12] =[8] / sum of [8] w/Load	[13] = sum of [8] / sum of[9]
PG&E	$ 234,007,461	154,560	21.62%	$ 1,514.0234	23.35%	$ 2,874.9464
SCE	$ 515,239,368	170,436	47.61%	$ 3,023.0665	51.40%	$ 2,874.9464
SDG&E	$ 202,193,083	40,128	18.68%	$ 5,038.7032	20.17%	$ 2,874.9464
Anaheim	$ 14,891,464	4,668	1.38%	$ 3,190.1165	1.49%	$ 2,874.9464
Azusa	$ 1,548,237	504	0.10%	$ 3,071.8995	0.11%	$ 2,874.9464
Banning	$ 730,113	264	0.14%	$ 2,765.5788	0.15%	$ 2,874.9464
Pasadena	$ 7,519,979	2,088	0.07%	$ 3,601.5227	0.07%	$ 2,874.9464
Riverside	$ 17,771,921	356	0.69%	$ 49,921.1264	0.75%	$ 2,874.9464
Vernon	$ 1,492,774	2,184	1.64%	$ 683.5046	1.77%	$ 2,874.9464
Colton	$ 2,055,435	672	0.19%	$ 3,058.6828	0.21%	$ 2,874.9464
VEA	$ 5,342,739	720	0.49%	$ 7,420.4708	0.53%	$ 2,874.9464
DATC Path 15	$ 12,728,893	-	1.18%	-	-	$ 2,874.9464
Startrans IO	$ 1,612,100	-	0.15%	-	-	$ 2,874.9464
Trans Bay Cable	$ 60,227,200	-	5.57%	-	-	$ 2,874.9464
Citizens Sunrise	$ 5,286,533	-	0.49%	-	-	$ 2,874.9464
Total	**$ 1,082,647,298**	**376,580**	100.00%		100.00%	

TAC net settlement invoicing example – monthly UDC metered data inputs

PTO Name	Volumetric TAC Rate ($MWh) *[1]*	Utility Specific Volumetric Rate ($MWh) *[2]*	**Metered Gross Load (MWh)** *[3]*	12CP Demand TAC Rate ($MW) *[4]*	Utility Specific 12CP Demand Rate ($MWh) *[5]*	**Metered Peak Demand [22] (MW)** *[6]*
	= [7 from TRR Information]	*= [5 from TRR Information]*		*= [13 from TRR Information]*	*= [11 from TRR Information]*	
PG&E	$ 5.1737	$ 2.5575	**9,098,475**	$ 2,874.9464	$ 1,514.0234	**13,228**
SCE	$ 5.1737	$ 5.7903	**9,698,936**	$ 2,874.9464	$ 3,023.0665	**14,656**
SDG&E	$ 5.1737	$ 9.8789	**1,972,843**	$ 2,874.9464	$ 5,038.7032	**3,224**
Anaheim	$ 5.1737	$ 5.9385	**246,220**	$ 2,874.9464	$ 3,190.1165	**396**
Azusa	$ 5.1737	$ 4.0930	**27,786**	$ 2,874.9464	$ 3,071.8995	**39**
Banning	$ 5.1737	$ 10.7032	**17,886**	$ 2,874.9464	$ 2,765.5788	**24**
Pasadena	$ 5.1737	$ 0.6519	**118,556**	$ 2,874.9464	$ 3,601.5227	**171**
Riverside	$ 5.1737	$ 3.4480	**251,386**	$ 2,874.9464	$ 49,921.1264	**33**
Vernon	$ 5.1737	$ 15.0389	**104,931**	$ 2,874.9464	$ 683.5046	**185**
Colton	$ 5.1737	$ 5.5227	**39,120**	$ 2,874.9464	$ 3,058.6828	**58**
VEA	$ 5.1737	$ 9.8037	**42,718**	$ 2,874.9464	$ 7,420.4708	**62**
DATC Path 15	$ 5.1737	-		$ 2,874.9464	-	-
Startrans IO	$ 5.1737	-		$ 2,874.9464	-	-
Trans Bay Cable	$ 5.1737	-		$ 2,874.9464	-	-
Citizens Sunrise	$ 5.1737	-		$ 2,874.9464	-	-
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 ($) [11]	Proportion of Total Volumetric TRR (w/ Load) (%) [12]	Allocation of Total Volumetric TAC Difference ($) [13]	Total Volumetric HV TAC Due to PTOs ($) [14]
	= [1] * [3]	= [4 from TRR Information]	= [2] x [3]	= Sum of [8] - Sum of [10]	= [6 from TRR information]	= Sum of [11] x [12]	= [10] + [13]
PG&E	$ **47,072,695**	21.61%	$ 23,268,972	$ 23,803,723	23.34%	$ (151,708)	$ **23,117,265**
SCE	$ **50,179,296**	47.59%	$ 56,159,586	$ (5,980,290)	51.38%	$ (334,031)	$ **55,825,555**
SDG&E	$ **10,206,881**	18.68%	$ 19,489,585	$ (9,282,704)	20.16%	$ (131,082)	$ **19,358,503**
Anaheim	$ **1,273,867**	1.38%	$ 1,462,175	$ (188,308)	1.48%	$ (9,654)	$ **1,452,521**
Azusa	$ **143,756**	0.14%	$ 167,120	$ (23,364)	0.15%	$ (1,004)	$ **166,116**
Banning	$ **92,537**	0.07%	$ 90,278	$ 2,259	0.07%	$ (473)	$ **89,805**
Pasadena	$ **613,370**	0.69%	$ 795,980	$ (182,609)	0.75%	$ (4,875)	$ **791,105**
Riverside	$ **1,300,596**	1.64%	$ 2,048,441	$ (747,846)	1.77%	$ (11,522)	$ **2,036,920**
Vernon	$ **542,880**	0.14%	$ 132,550	$ 410,330	0.15%	$ (968)	$ **131,582**
Colton	$ **202,393**	0.19%	$ 216,047	$ (13,653)	0.20%	$ (1,333)	$ **214,714**
VEA	$ **221,011**	0.49%	$ 418,798	$ (197,787)	0.53%	$ (3,464)	$ **415,335**
DATC Path 15	-	1.18%	$ 1,315,034	$ (1,315,034)	-	-	$ **1,315,034**
Startrans IO	-	0.15%	$ 166,547	$ (166,547)	-	-	$ **166,547**
Trans Bay Cable	-	5.56%	$ 6,222,127	$ (6,222,127)	-	-	$ **6,222,127**
Citizens Sunrise	-	0.49%	$ 546,157	$ (546,157)	-	-	$ **546,157**
Total	**$ 111,849,283**	100%	**$ 120,342,163**	**$ (650,113)**	100%	**$ (650,113)**	**$ 111,849,283**

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

PTO Name	Total 12CP Demand HV VAC Due From UDCs ($) [15]	Proportion of total TRR (%) [16]	Amounts PTO Would Receive Under 12CP Demand Utility-Specific ($) [17]	Difference ($) [18]	Proportion of total 12CP Demand TRR (w/ Load) (%) [19]	Allocation of Total 12CP Demand TAC Difference ($) [20]	Total 12CP Demand HV TAC Due to PTOs ($) [21]
	= [4] x [6]	*= [10] TRR Information*	*= [5] x [6]*	*= Sum of [15] - Sum of [17]*	*= [12] TRR information*	*= Sum of [18] x [19]*	*= [17] + [20]*
PG&E	**$ 38,029,790**	21.61%	$ 20,027,502	$ 18,002,289	23.34%	$ 84,007	**$ 20,111,509**
SCE	**$ 42,135,214**	47.59%	$ 44,306,063	$ (2,170,849)	51.38%	$ 184,968	**$ 44,491,031**
SDG&E	**$ 9,268,827**	18.68%	$ 16,244,779	$ (6,975,952)	20.16%	$ 72,586	**$ 16,317,365**
Anaheim	**$ 1,138,479**	1.38%	$ 1,263,286	$ (124,807)	1.48%	$ 5,346	**$ 1,268,632**
Azusa	**$ 112,123**	0.14%	$ 119,804	$ (7,681)	0.15%	$ 556	**$ 120,360**
Banning	**$ 68,999**	0.07%	$ 66,374	$ 2,625	0.07%	$ 262	**$ 66,636**
Pasadena	**$ 491,616**	0.69%	$ 615,860	$ (124,245)	0.75%	$ 2,700	**$ 618,560**
Riverside	**$ 94,873**	1.64%	$ 1,647,397	$ (1,552,524)	1.77%	$ 6,380	**$ 1,653,777**
Vernon	**$ 531,865**	0.14%	$ 126,448	$ 405,417	0.15%	$ 536	**$ 126,984**
Colton	**$ 166,747**	0.19%	$ 177,404	$ (10,657)	0.20%	$ 738	**$ 178,141**
VEA	**$ 178,247**	0.49%	$ 460,069	$ (281,823)	0.53%	$ 1,918	**$ 461,987**
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	-	5.56%	$ 5,129,979	$ (5,129,979)	-	-	**$ 5,129,979**
Citizens Sunrise	-	0.49%	$ 450,292	$ (450,292)	-	-	**$ 450,292**
Total	**$ 92,216,779**	100.00%	**$ 91,856,782**	$ 359,997	100.00%	**$ 359,997**	**$ 92,216,779**

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

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

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 has been supportive of this alignment in treatment of these entities

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

Hybrid billing determinant cost impact analysis

- ISO has provided analysis of the potential cost impacts to UDCs due to proposed hybrid billing determinant
  - Includes additional sensitivities requested by stakeholders
- 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

Load profiling applied to mask confidential PTO data

- 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
- Modeling uses load profiles of the larger PTO UDC areas applied to smaller UDC data
  - 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
  - ISO proposing phase-in period to address potential concerns about cost impact analysis accuracy and possible rate impacts

Proposed phase-in for hybrid billing determinants

- Previously, ISO did not believe any phase-in was necessary and noted impact analysis for proposed hybrid approach indicates relatively small impacts to most UDCs
  - Stakeholders raised concerns with accuracy of impact analysis for some PTO areas, ISO identified possible discrepancies is due to load profiling techniques applied in analysis to mask confidential load information
- ISO proposes a two-year phase in period in response to these concerns

ISO will phase-in the proposed modifications to the TAC billing determinant through annual bifurcation of HV-TRR components over two years

- For year one of implementing hybrid billing determinant proposal –
  - ISO will administratively bifurcate HV-TRR components so that **15%** of HV-TRR will be collected under 12CP peak demand HV-TAC rate and **85%** of HV-TRR will be collected under volumetric HV-TAC rate
- For year two of implementing hybrid billing determinant approach –
  - ISO will administratively bifurcate HV-TRR components so that **30%** of HV-TRR will be collected under the 12CP peak demand HV-TAC rate and **70%** of HV-TRR will be collected under volumetric HV-TAC rate
- Starting in year three – ISO will begin calculating HV-TRR bifurcation through proposed system load factor approach (discussed previously) and resulting bifurcation will be applied starting in year three of implementation

Next steps

- Stakeholders are asked to submit written comments by October 9, 2018 to: initiativecomments@caiso.com
- Comment template will be available at the following link: http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx