Review Transmission Access Charge Structure

Stakeholder Working Group Meeting

August 29, 2017

Agenda

Time	Topic	Presenter
10:00 – 10:10	Introduction	Kristina Osborne
10:10 – 10:45	Background to current TAC initiative	Neil Millar
10:45 – 11:30	Impacts of DG on transmission needs	Neil Millar
11:30 – 12:00	Example of Regional TAC settlement	Lorenzo Kristov
12:00 – 1:00	*LUNCH*	
1:00 – 1:30	Clean Coalition	Doug Karpa
1:30 – 1:50	California Public Utilities Commission	Bob Levin
1:50 – 2:10	California Large Energy Consumers Association	Barbara Barkovich
2:10 – 2:30	Department of Market Monitoring	Ryan Kurlinski
2:30 – 2:40	Pacific Gas & Electric	Eric Eisenman
2:40 – 3:00	Silicon Valley Power	Steve Hance
3:00 – 3:55	Discussion of analysis needs	Chris Devon
3:55 – 4:00	Next Steps	Kristina Osborne

Note: Individual presentations are posted on the initiative page on ISO's website.

Background to the current initiative (ISO)

ISO's TAC-related initiatives

- "TAC Options" (10/15 – 12/16)
  - Focused on transmission cost allocation over a potentially expanded balancing authority area (BAA)
  - Did not address topics of current initiative
- "Review TAC Wholesale Billing Determinant" (6-9/16)
  - Convened to consider proposal to bill TAC to internal load based on "transmission energy downflow" (TED) rather than Gross Load (end-use metered load)
  - Closed in favor of opening a more holistic examination of TAC structure in 2017
- "Review TAC Structure" – current initiative

Status of current initiative – Review TAC Structure

- The ISO posted a background white paper on April 12 that explains the current structure for recovering costs through the TAC
- ISO posted an issue paper on June 30 and held a stakeholder session on July 12
  - Discussed proposed scope and principles
  - Transmission cost recovery in other ISOs and RTOs
  - Considerations for treatment of load offset by distribution-connected resources
  - Stakeholders submitted written comments at end of July
- Led up to today's workshop!

Today's workshop focuses on:

- History of establishment of and arguments for ISO's original TAC structure
- Actual impact of DG to date on reducing transmission upgrade costs
- Potential methods for valuing DG benefits in reducing future transmission costs
- Example illustrating how HV TAC works today, and how change to ISO HV TAC would flow through to customers
- Presentations by stakeholders
- Discussion of types of analysis that would be helpful for this initiative

Considerations behind design of current HV TAC

- Design of current HV TAC included deeper thinking than aligning with energy market and general consensus
- Design anticipated congestion management as a major influence in day-to-day market operation and long-term planning to alleviate congestion
- As such, the HV TAC charge formed the base usage fee (analogous to a “tax”) to collect the revenue requirement on a fair basis, with congestion charges to send the appropriate variable “economic efficiency” signals for market operation and future investment decisions
- Existing transmission costs were recognized as largely fixed, with very little if any variable component

Considerations behind design of current HV TAC (2)

- As such, TOU rates or 12-coincident-peak demand-based rates were argued as muddling the variable congestion signals provided by the energy market
- Congestion patterns were the primary focus of the ISO in considering the effectiveness and implications of TOU rates, and significant congestion was occurring during off-peak hours and off-peak months
  - Moreover, congestion patterns can shift, so that a fixed TOU structure would lack the flexibility to stay aligned with changing patterns
- The ISO position was clear that the rate overall did not reflect marginal cost or avoided cost, on either a short- or long-term basis
- At <u>no</u> time did the ISO portray the current HV TAC as an economic efficiency signal tied to either marginal cost to serve new load or an avoided cost metric.

Changing circumstances warrant a review of the TAC structure and point to possible analyses that may be helpful to develop any appropriate change.

- Congestion currently plays a smaller role than anticipated in the siting of market-based resources
- Renewable generation is being developed under contract through RFO processes in response to state policy directives, and with policy-driven transmission addressed through the ISO transmission planning process
- Local reliability needs and transmission to address retirements (e.g. OTC, SONGS) are resulting in a combination of preferred and conventional resources
- Increasing proliferation of distributed energy resources of all types is changing load patterns and potentially changing transmission needs

Potential impacts of DG on reducing transmission costs and future needs

How could DG reduce needs for new reliability-driven transmission upgrades?

- Potential to reduce peak demands at the T-D interfaces – provided DG output aligns consistently and reliably with peaks – potentially reducing need for line and transformer upgrades
- Potential to help maintain distribution system voltages within prescribed ranges, thus deferring or eliminating the need for transmission-level voltage support upgrades
- Potential for some level of transient stability and frequency support from aggregated DG
- DG – as an alternate to lumpy transmission upgrades – can provide option of rapid deployment and ease of scalability as compared to transmission alternatives

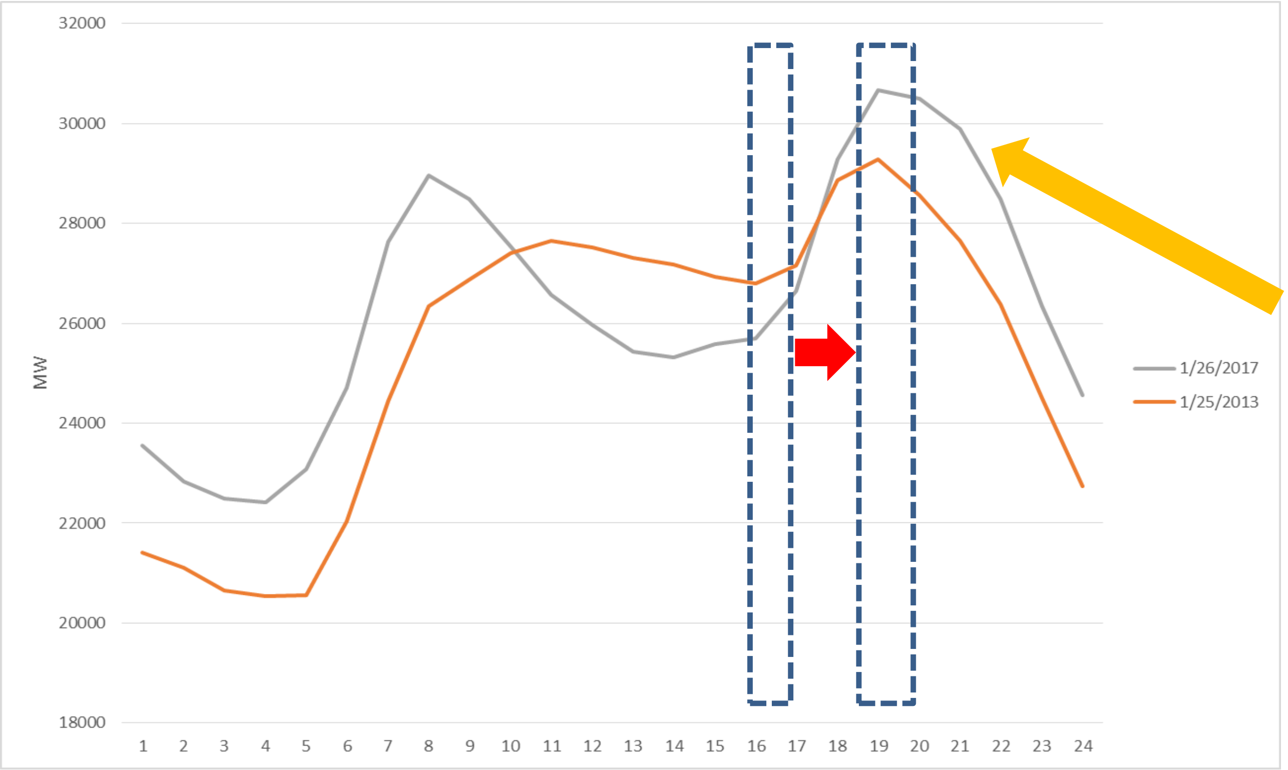
Current planning mechanisms capture these impacts and are continually being improved.

- Planning analysis already captures the impact of existing and forecasted behind the meter and grid-connected DG and energy efficiency
  - Considered in ISO approval or cancellation of transmission-level projects
  - Requires case-by-case and condition-specific analysis
- Reliability mitigations consider both transmission and non-transmission alternatives
- The ISO is among the first to use a composite load model (modeling DG separately rather than as a load modifier) to capture the impacts of DG on transient stability and frequency response for system level issues
- ISO is developing more thorough benchmarking of distribution system voltage control and reactive power consumption

Experience over recent years demonstrates some level of DG impact, helpful in some ways, detrimental in others – at least in transition

- Some level of DG aligned with peak loads has reduced peaks in some areas, and shifted peaks to later hours when the DG was no longer available – primarily solar PV
  - Benefit already fully achieved in some areas, unless and until more diverse DG types become available
- Voltage control on the distribution system has become more challenging due to increased volumes of dispersed and non-dispatchable resources
  - Impact is felt on transmission system – at least until enhanced communications and distribution voltage control are in place
  - What is the impact on distribution system costs?
- Unclear whether recent patterns of DER adoption and impacts will be sustainable and indicative of future impacts

Peak Shift Scenario: Solar DG both reduces the size of and time-shifts the peak demand, affecting need for transmission upgrades.



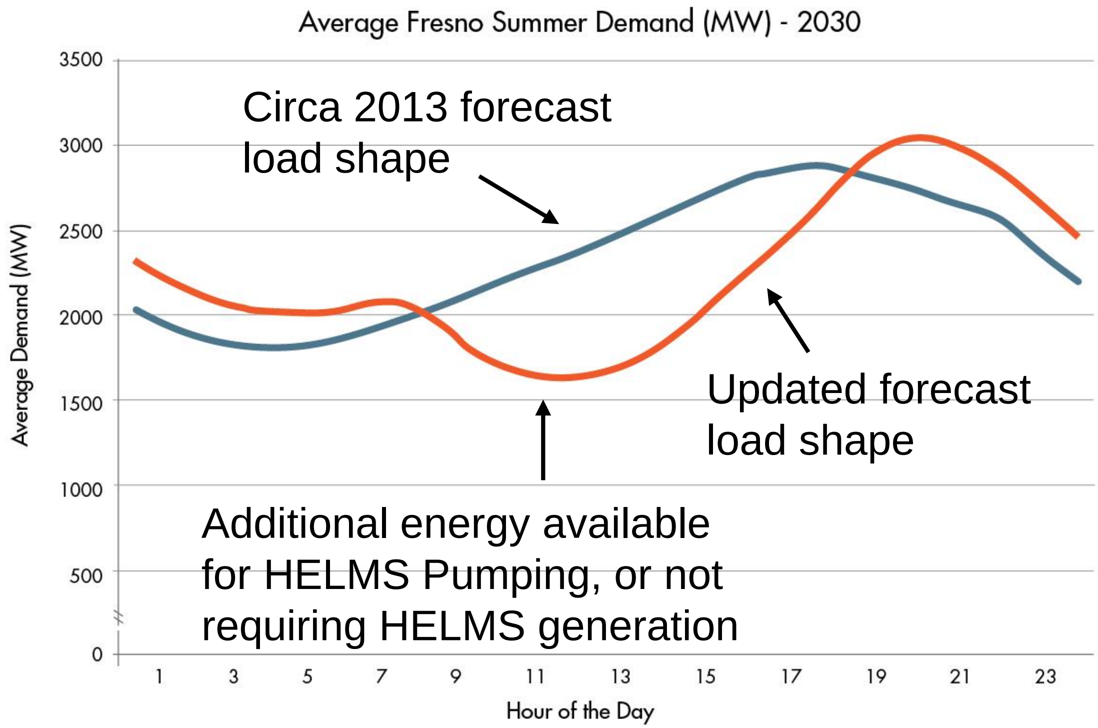
Resources that can clip the shifted peak may reduce need for future transmission upgrades. However, adding more solar PV alone will not reduce a post-sunset peak.

Circumstances behind recent PG&E transmission project cancellations – and further reviews underway

- 2015-16 transmission plan – 13 predominantly lower-voltage transmission projects were cancelled
- 2016-17 plan – 13 more cancelled, 16 projects receiving further review – and potential re-scoping
- Cancelled projects largely affected by a combination of events:
  - Declining load forecasts and increasing energy efficiency measures reduced needs – especially for many of the older projects
  - Behind the meter DG may have played some role in reduced peak loads – by reducing peak loads and possibly shifting peak to post-solar-production hours

Behind the meter solar generation exceeding original forecasts can reduce the need for a project.

- Gates-Gregg project initial need was to increase pumping capability for existing hydro storage in the area – Helms.
- The local reliability needs are in effect being met by a combination of new solar behind the meter and grid-connected DG paired with existing storage
- Use-limited resources such as solar DG can depend on other resources working together to provide an integrated solution, as in this example.



Are there any negative impacts of DG on existing transmission facilities or the need for upgrades?

- Greater requirement for active voltage management due to intermittent/variable resources?
- Wear and tear on electric delivery equipment due to reduced or variable flows?
  - In some instances the variability of DG could result in increased O&M costs for voltage regulation devices such as load tap-changing (LTC) transformers.
- High volume DG in a local area could trigger short circuit coordination issues on existing transmission (low voltage radial transmission lines in areas with high DG penetration such as Fresno).

Some additional observations

- Incremental benefits of DG may be estimable, but require careful consideration and analysis
- Are benefits from one type of resource, e.g. solar PV, sustainable during conditions of increased cloud cover and high load, such as monsoonal heat wave events?
- Many of the same questions – about the value of DG/DER for the transmission system – are under discussion in the Locational Net Benefits Analysis (LNBA) working group of the CPUC DRP proceeding.

Numerical example of Regional (HV) TAC settlement

Simplified numerical example to illustrate how ISO's Regional (HV) TAC settlement works

About this example:

1. Numbers are made up, for illustration purposes only
2. Assume 2 IOUs – both are PTOs and UDCs
3. Focus on high-voltage TRRs for existing facilities only
4. Two settlement periods, with the same gross load, DG production and TRRs for both periods

	T-D Interface 1		T-D Interface 2		T-D Interface 3		T-D Interface 4		Rest of System		
	IOU1	ESP1	IOU1	CCA1	IOU2	ESP2	IOU2	CCA2	IOU1	IOU2	ESP/CCA
Gross Load (MWh)	100	40	150	10	120	20	130	30	850	1150	0
DG Production (MWh)	30	15	0	10	10	0	0	20	100	0	0
Net Load at T-D Interface (TED)	70	25	150	0	110	20	130	10	750	1150	0

	IOU1	IOU2	Total
Total Gross Load (MWh)	1150	1450	2600
Total DG Production (MWh)	155	30	185
Total TED (MWh)	995	1420	2415

	IOU1	IOU2	Total
Regional or high-voltage TRR	$19,000	$20,000	$39,000
TAC rate based on Gross Load	$16.52	$13.79	$15.00
TAC rate based on TED	$19.10	$14.08	$16.15

ISO's TAC settlement adjusts for differences between each IOU's TRR and its share of the combined TRR

<u>Period 1:</u>

1. Each UDC collects in retail rates its affiliated PTO's TRR
2. ISO TAC settlement calculates each IOU's share of the combined HV TRR, and bills each UDC accordingly
3. Difference (1-2) adjusts retail rates in next period

<u>Period 2:</u>

- The adjustment from Period 1 is reflected in the amount of money the UDC will collect in retail rates in Period 2

PERIOD 1		
Results - Gross Load	**IOU1**	**IOU2**
UDC collects in retail rates	$19,000	$20,000
ISO charges UDC	$17,250	$21,750
UDC next period rate adjustment	$1,750	($1,750)

PERIOD 2		
Results - Gross Load	**IOU1**	**IOU2**
UDC collects in retail rates	$17,250	$21,750
ISO charges UDC	$17,250	$21,750
UDC next period rate adjustment	$0	$0

PERIOD 1		
Results - TED		
UDC collects in retail rates	$19,000	$20,000
ISO charges UDC	$16,068	$22,932
UDC next period rate adjustment	$2,932	($2,932)

PERIOD 2		
Results - TED		
UDC collects in retail rates	$16,068	$22,932
ISO charges UDC	$16,068	$22,932
UDC next period rate adjustment	$0	$0

Clean Coalition

Doug Karpa, Policy Director

California Public Utilities Commission (CPUC)

Bob Levin, Senior Regulatory Analyst

California Large Energy Consumers Association (CLECA)

Barbara Barkovich, Consultant

Department of Market Monitoring (DMM)

Ryan Kurlinski, Manager, Analysis and Mitigation

Pacific Gas & Electric (PG&E)

Eric Eisenman, Director, FERC and ISO Relations

Silicon Valley Power (SVP)

Steve Hance, Title

Analysis Needs

Chris Devon, Senior Infrastructure and Regulatory Policy Developer (ISO)

A decision to retain or modify the existing TAC structure should be based on careful, relevant analysis

- ISO wants to determine what types of analyses would be most useful, and how to prioritize the most useful ones
- These analytics will inform the ISO's positions on this initiative and help to develop the straw proposal
- Stakeholders are asked to provide ideas on the kinds of analytical questions the ISO should look into
- One general area that stakeholders are interested in is to estimate cost impacts of potential TAC change to various entities
- What other analysis would be helpful? What else can inform the process more holistically?

What would be useful to better understand the cost drivers of transmission and what affects these costs?

- Is it possible to analyze the main cost drivers for maintaining the transmission system to see how they may or may not by affected by DG or other resources?
- How can the ISO evaluate the cost drivers associated with maintaining the existing transmission system and how energy consumption or peak load could affect these cost drivers?

How can the ISO analyze alternative approaches?

- How can the ISO study and provide useful information on the impact of various potential options?
- What should the ISO analyze to inform stakeholders of the potential costs and benefits and any other impacts of alternative approaches?
  - What could help illustrate the impact of moving to a peak demand or a time of use based billing determinant?
  - What other analysis should be done to understand the impact of changing the point of measurement?
- How could the ISO try to consider PTO customer costs and benefits in examining potential cost shifts between PTO customers with various options?

How could the ISO examine the utilization of the transmission system at the T-D Interface?

- What is each UDC’s load at T-D interfaces?
- What is each UDC’s monthly peak at each T-D interface?
- We have only peak Gross Load (energy) – Would it be useful to have instantaneous monthly peak (power) for each UDC, and can we get it?
- Should we estimate cost shift impacts that would result from adopting the T-D interface point of measurement?
  - Such impact would have to be considered in conjunction with the potential TAC structure (volumetric, demand, TOU)
- What is the value load gets from Tx even when not getting kWh from the grid? How would we quantify this?

Down-stream impacts of TAC structure changes should also be considered as part of a holistic evaluation

- How can the ISO evaluate the down-stream impacts of potential changes?
- What analytics would inform the ISO and stakeholders of the potential impacts to PTOs, UDCs, LSEs, and related retail ratemaking?
- Should the ISO focus on this aspect yet, or wait until potential options are more well established?

Wrap Up

Next Steps

Milestone	Date
Stakeholder working group meeting	August 29, 2017
Written comments due on working group presentations and discussion	September 15, 2017
Publish straw proposal	October 31, 2017
Stakeholder meeting to discuss straw proposal	Nov (TBD)

Written stakeholder comments on August 29 working group presentations and discussion due COB Sept 15 to InitiativeComments@caiso.com. Please use comments template when submitting your comments.

View full stakeholder process schedule on page 5 of the issue paper http://www.caiso.com/Documents/IssuePaper-ReviewTransmissionAccessChargeStructure.pdf

Materials related to the Review TAC Structure initiative are available on the ISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx