COMMENTS OF THE STAFF OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION

ON TOPICS PRESENTED AT THE 2016-2017 TRANSMISSION PLANNING PROCESS NOVEMBER 16 2016 STAKEHOLDER MEETING

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November 30, 2016

Introduction

The Staff of the California Public Utilities Commission ("CPUC Staff") appreciates this opportunity to provide comments on matters discussed at the California Independent System Operator's (CAISO) 2016-17 Transmission Planning Process meeting on November 16, 2016. Our comments address updated documentation of the TEAM benefit/cost assessment framework in light of possible future applications; aspects of the Gas-Electric Coordination Study providing a longer term (10-year) look a LA Basin-San Diego summer reliability issues under continuation of reduced access to Aliso Canyon storage; and support for the CAISO's approach to not pursue transmission that might be valuable under certain long-term resource futures unless and until such futures are supported in resource planning.

1. Updated Documentation of the TEAM Framework Should Clarify Reasonable (Not Prescriptive) Expectations for Application and Applicability to Planning Issues and Decisions Beyond What Was Envisioned Under the Original TEAM Concept.

We are moving into an era of large, complex and interacting resource and demand-side[1] electric system changes extending from increased possibilities for distributed resources on one hand and western regional integration on the other. While the TEAM framework has been applied for recent studies,[2] the above developments suggest that the future could entail TEAM being applied to a more diverse range of situations. For example, proposed Transmission Access

[1] Some demand-side changes involve energy efficiency and demand response, time of use and/or cost-driven pricing, behind-the-meter resources and storage, and electrification of transportation and other sectors.

[2] Recent studies include economic evaluation of the Delaney-Colorado River and Harry Allen - Eldorado transmission projects, as well as EIM and SB 350 (regional ISO) benefit studies.

Charges ("TAC Options") for allocating certain high voltage transmission costs within a potential regional ISO rely partly on the TEAM framework, and so might evaluation of "interregional" transmission project proposals under western transmission providers' new planning provisions pursuant to FERC Order 1000.

Therefore, it is both appropriate and necessary that the TEAM framework documentation be updated in a clear manner that addresses planning needs and supports productive discussion regarding those needs. There has been substantial evolution in planning circumstances and decisions since the TEAM framework was first developed,[3] as well as evolution of modeling tools and accumulation of practical experience in applying the TEAM framework. These developments plus anticipated challenges going forward should be reflected in updated and expanded documentation of the TEAM framework.

We agree with statements at the November 16 meeting that the actual detailed application of the framework should be on a case-specific basis, not constrained within an overly prescriptive or narrow methodology. However, the updated framework documentation *should* provide insight into the application of TEAM over a range of situations and benefits likely to be encountered going forward, including new analytic tools and methods that may be applied. It is also essential that the CAISO establish reasonable bounds and expectations regarding what assessments *may and may not fall within the scope of TEAM*.

CPUC Staff recommendations regarding the CAISO's development of updated TEAM documentation cover the following areas:

a. Original five TEAM principles,

b. Kinds of situations and decisions for which the TEAM framework may be applied and applicable, and

c. Types of benefits quantified.

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[3] See the 2004 CAISO TEAM documentation at https://www.**caiso**.com/Documents/TransmissionEconomicAssessmentMethodology.pd

a. CPUC Staff support updating of the original TEAM principles taking into account a potentially expanded range of applications as well as new modeling tools.

The original five TEAM principles include the following.

i. Consideration (or at least potential consideration) of multiple benefit perspectives including consumers/ratepayers, generators, transmission owners, and society at large - - potentially over multiple geographical/electric system aggregations

ii. Full network representation (modeling), acknowledging that contract path approaches may be acceptable in some circumstances if adequately justified

iii. Market-based pricing

iv. Accounting for strategic behavior by generators

v. Modeling of uncertainty.

The CAISO's November 16 presentation indicates that the manner and extent to which the above principles are anticipated to be applied will be updated, and provides some helpful examples. CPUC Staff understand the TEAM framework to encompass development and utilization of production cost modeling studies, but potentially also to include use of additional analytic tools to cover the range of benefits being included in the framework. CPUC Staff recommendations for the CAISO's update of the TEAM framework include the following:

i. ***Benefit perspective*** The November 16 presentation indicates that applications of the TEAM framework to date have emphasized the CAISO ratepayer (CAISO footprint consumers) benefit perspective, whereas the original TEAM documentation anticipated a variety of perspectives including a WECC-wide perspective. Going forward the TEAM framework may be applied to transmission decisions affecting non-CAISO and non-California entities and stakeholders, both within and external to the transmission analysis/decision process. The updated documentation should illuminate (*not* narrowly prescribe) TEAM application in such expanded circumstances. The documentation should also clarify and update the extent and limitations of the "societal" perspective; the distinction between merchant versus LSE-owned/contracted generators; situations where there is reduced dependence on energy market revenues; situations where there is a mixture of organized market and bilateral trading practices; and situations where ability to identify resources as contracted to specific loads or load areas is significantly limited.

ii. ***Full network representation (modeling)*** The updated documentation should clarify (not prescribe) where less than full network modeling may be acceptable or appropriate such as if needed to make sensitivity or stochastic studies computationally manageable.

iii. ***Market-based pricing*** The updated documentation should clarify the meaning of "market-based pricing" when some modeled areas do not have organized markets (with LMP), and/or when there are large amounts of must-take, must-run, and/or potentially curtailed generation - - both with and without known contractual relationships between generators and loads.

iv. ***Accounting for strategic behavior by generators*** CPUC staff understand the CAISO's November 16 presentation as indicating that strategic behavior will not be modeled at least within the CAISO footprint. We request confirmation of this approach as well as clarification whether it would extend beyond the CAISO footprint.

v. ***Modeling of uncertainty*** The original TEAM design contemplated examination of uncertainty with or without explicit probability weighting and the November 16 presentation illustrates some typically considered uncertainties but also mentions "other sensitivities." Based on current planning challenges as well as recent studies (e.g., SB 350 studies), future planning challenges are likely to involve additional important uncertainties posing additional modeling challenges. This likelihood should be accounted for and clarified in the updated documentation of the TEAM framework (not fully prescribed). Examples include alternatives/sensitivities regarding resource additions and retirements (explicit portfolios and also more general resource uncertainties); hurdles or other inter-BA trading restrictions; carbon penalties/policies; RPS counting/credit practices; and other uncertainties that may be important going forward. Furthermore, the possibility of using "stochastic" models in the TEAM framework as indicated in the November 16 presentation should be more fully explained, especially regarding what variables could be treated stochastically and whether/how this may require acceptable sacrifices in detail elsewhere, such as using less than full network representation or modeling less than 8760 hours per year.

b. Updated documentation should clarify and illustrate the range of anticipated TEAM applicability to planning issues and decisions, especially if extending beyond the initial TEAM concept and application.

The updated TEAM framework documentation should provide meaningful insight (not prescribing full methodology) regarding extent and limits of TEAM applicability to types of situations and decisions anticipated going forward. Some example situations include:

i. Transmission benefiting or located within multiple areas (e.g., states or service territories) within a regional ISO such as envisioned under "TAC Options," and separately, "interregional" transmission located within or benefitting *multiple planning regions* including the CAISO plus one or more other regions.

ii. Single or multiple competing transmission options accessing renewable or preferred resources in-state; or out-of-state within a regional ISO; or outside of CA and CAISO - - as envisioned on page 27 of the November 16 presentation.

The CAISO should clarify when such situations, studies and decisions are within versus beyond the scope of TEAM.

iii. Transmission providing renewables integration benefits such as access to ancillary services or shared ramping capability, or increased ability to export overgeneration.

iv. Transmission providing system and/or local capacity benefits, when accounting for overall system + local + flexible capacity needs.

v. Other examples which CAISO believes to represent important foreseeable TEAM applications and/or which illustrate the expanded applicability of the TEAM framework beyond the original TEAM concept.

c. *The updated documentation should clarify application of the TEAM framework to calculate an expanded (relative to the initial TEAM concept) range of benefit categories, particularly benefit categories important for emerging planning challenges.*

This includes but is not limited to the following kinds of benefits.

i. ***Public policy-related benefits such as involving acquisition or integration of renewable or zero-carbon resources.*** Essentially this amounts to identifying and quantifying <u>*particular types of benefits*</u> under scenarios described under subtopic b. above. Key questions include: what benefits of this type can and should be incorporated into the TEAM framework, and at what point (and to what degree) do the needed benefit assessments and decisions have to be made *outside* of the TEAM framework?

ii. ***System and (separately) local capacity benefits.*** The original TEAM concept and documentation acknowledge only briefly the possibility of integrating capacity benefits into the overall TEAM framework for quantifying benefits. However, capacity benefits played an important role in two recent major transmission project approvals.[4] The updated documentation should clarify and establish reasonable bounds or rules of applicability for addressing capacity benefits within the TEAM framework. This should address quantification of both capacity *costs* (e.g., supply curves) and capacity *need* over time, and should also explicitly address both differences and interactions between analyses of *system* and *local* capacity. *Resource deliverability* and *capacity benefits* potentially address the same ultimate benefit. For purposes of TEAM applications, the distinction and interaction between these two benefit concepts should be clarified.

Additionally, as noted in the November 16 presentation, the general practice has been that capacity and deliverability issues are ultimately addressed via power flow studies. The updated TEAM documentation should clarify the circumstances under which TEAM's production simulation studies must be, or do *not* need to be supplemented with power flow studies. Where a combined

[4] These were the Delaney-Colorado River and Harry Allen - Eldorado transmission projects.

production simulation - power flow modeling approach would be used, how this would be done should be clarified (not prescribed).

iii. ***More generally, the original TEAM concept focused on energy market-related benefits based on loads, generator dispatch, transmission flows and locational marginal prices in production simulations, whereas emerging planning challenges appear to place increased emphasis on non-energy needs and services, must-run/must-commit and intermittent generation, and integration/overgeneration issues.***

The updated TEAM documentation should describe how the kinds or magnitudes of benefits needing to be calculated have changed and likely expanded under the above "emerging" circumstances. This should address if and where such evolving needs go beyond what can be addressed via the TEAM framework.

CPUC Staff look forward to the CAISO's updated draft TEAM documentation with opportunities for stakeholder review, comment and dialogue, which we believe that the CAISO will find helpful.

2. ***For the Gas-Electric Coordination Study (Aliso Canyon Storage Outage) the CAISO is Requested to Clarify Aspects of (a) How the Study Methodology from the April 2016 Aliso Canyon Risk Assessment Technical Report for Summer of 2016 was Extended to the Study for 2026[5], (b) How the "No BTM PV" Sensitivity Assessment was Constructed and (c) How These Kinds of Studies will be Applied for "Medium- and Long-Term Local Capacity Requirement Assessments"[6]***

CPUC Staff understands that broadly speaking the April 2016 Aliso Canyon Risk Assessment Technical Report projected gas supply shortfall over an 8-hour electric system peak scenario during a high stress summer day, relative to gas supply needed to fuel the minimum required local CAISO area (the SoCalGas-dependent portion) plus local LADWP area thermal generation under the most critical electric system contingency. This projected gas supply shortfall was then converted to electric supply shortfall assuming 103 MWh/MMcf. Regarding the long term extension of the above study to year 2026 as presented on November 16, we

[5] This refers to the assessment of summer of 2026 scenarios and reliability risks as presented at the November 16, 2016 Transmission Planning Process stakeholder meeting.

[6] Such application was indicated on page 83 of the presentation for the N 16, 2016 Transmission Planning Process stakeholder meeting.

understand that besides the appropriate long-term load forecast, it was assumed that planned transmission and resources infrastructure comes on line to help manage a potential gas (and thus local generation) shortfall.

Regarding how the assessment for summer of 2016 was extended to 2026, CPUC Staff request that the CAISO clarify the following.

i. Is there a basis for assuming that the minimum required local LADWP area generation over an 8-hour peak stress period remains unchanged from 2016 to 2026 even as the minimum required local *CAISO area* thermal generation (under the most critical electric system contingency) declines significantly presumably due to planned infrastructure additions? Should the LADWP assumptions be updated?

ii. The 103 MWh/MMcf gas-to-generation conversion used for the summer 2016 assessment, equivalent to roughly 9900 Btu/kWh, was carried forward unchanged for the 2026 assessment. Should a significantly different heat rate be assumed for local gas-fired generation ten years from now?

For constructing the no BTM PV sensitivity cases depicted on pages 79 and 80[7] of the November 16 presentation, the "Total ISO Balancing Area in SoCalGas system Gas Burn with minimum generation for the most critical transmission constraint" was increased by 875 MW and 483 MW under the two different critical electric system contingencies that were examined - - relative to the base case (with BTM PV) summarized on page 76. The CAISO is requested to clarify the following aspects of the methodology for constructing the no BTM PV cases, which could be relevant for future studies.

i. On Page 74 of the November 16 TPP presentation the CAISO states that the CEC 2026 forecast of SCE Peak Load Impact from distributed behind-the-meter photovoltaic generation (BTM PV) is 1,739 MW, and a table on page 75 indicates that "Total LA Basin peak load (1-in-10) without peak shifting is 18,580 MW. On Page 78, the total LA Basin load *without BTM PV*, for 6 PM, is shown as 19,775 MW. When compared to the previous figure this represents a peak increase of 1195 MW, or approximately 68% of the 1,739 MW peak load reduction impact of BTM PV, forecasted by the CEC. The CAISO should explain the methodology used to adjust LA Basin peak load under the peak shifting (no BTM PV) case.

[7] These particular pages were actually not numbered

What portion of CEC-forecasted BTM PV in the SCE area was assumed to be located in the LA Basin?

ii. For the Gas-Electric coordination study the load-increasing impact of removing BTM PV would have been spread over 8 hours, since the gas shortage effects were assumed to be spread (to accumulate) over the peak 8 hours. Thus, it appears that what matters is the impact of "no BTM PV" over 8 hours, not just during the peak hour. Some of these high stress summer day hours would presumably have significant sunlight and BTM PV generation, even when accounting for peak shifting leaving no (or low) BTM PV output in the later stress hours.

For the base case gas shortfall assessment (summarized on page 76) and for the corresponding no BTM PV assessment (summarized on pages 79 and 80) - - which 8 hours of the day were included in the gas supply shortfall assessment, and what were the assumed in-basin load and BTM PV output for each of those hours?

To further clarify the extension of the gas electric coordination studies to the 2026 long-term horizon, the CAISO should explain if and how assumed Diablo Canyon Power Plant (DCPP) retirement impacted study results, relative to having DCPP on line in the near-term studies. On Page 75 of the November 16 presentation, Path 26 flow is listed as 3,316 MW for the base case (with BTM PV), also noting that DCPP retirement affects Path 26 maximum flow. For the peak shifted/no BTM PV sensitivity case, Path 26 flow is stated as 3,823 MW on page 78. The CAISO should explicitly quantify how the DCPP retirement effect on Path 26 flow was incorporated into these assumptions and how it impacts results (local gas supply and thermal generation shortfall) for the 2026 base case summarized on page 76 and for the peak load shift/no BTM PV cases summarized on pages 79 and 80.

Finally, page 83 states the intent to conduct N-1-1 electric system contingency studies, beyond the N-1 studies already presented, apparently to inform "medium- and long-term local capacity requirement assessments." The CAISO should explain and justify studying such apparently extreme co-occurring contingencies (two gas storage outages + one gas pipeline outage + N-1 <u>*or*</u> N-1-1 electric system contingencies). The CAISO should also explain why studying *8-hour* coincidence of the above events is reasonable, and whether this is intended to *inform*, or to *require*, infrastructure investments. Additionally, the CAISO should explain how gas electric coordination studies examining 8-hours of co-occurring high loads plus co-occurring gas and electric system outages are or could be made compatible with and useful for local capacity requirements studies that have generally relied on snapshot peak load (not 8-hour) scenarios.

3. *Several Studies Described on November 16 Identify Where Transmission Investments May be Valuable Under Resource Futures that are Currently Only Speculative, and CPUC Staff Support the CAISO's Approach of Not Considering Such Investments for Detailed Study or Approval Until the Underlying Long-Term Resource Priorities are Clarified.*

The CAISO's studies of policy driven (for RPS resource deliverability) and economically driven (for congestion reduction) transmission discussed on November 16 identified the potential value of additional transmission capacity from the Imperial Valley into the CAISO area. It was noted that such transmission investment might be justified under a much increased need to import renewable energy (or capacity) from this area, beyond what is currently planned. Separately, enhancement of Helms pumping opportunities to help manage renewables-driven system overgeneration was apparently found to provide insufficient justification for the previously approved Gates-Gregg 230 kV transmission project, given currently projected levels of overgeneration. This project was also found not to be justified for reliability reasons, under updated load forecasts.

It is prudent to monitor situations such as those described above without pursuing the related transmission expansion possibilities, unless justified by longer term resource priorities established in the CPUC's Integrated Resource Plan (IRP) process.

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