Comments of the Staff of the California Public Utilities Commission

On the 2013-2014 Transmission Planning Process: Policy and Economic Study Results Plus Sub-$50M Projects For Approval

(Meeting Date: November 20 and 21, 2013)

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December 5, 2013

Introduction

The Staff of the California Public Utilities Commission ("CPUC Staff") appreciates this opportunity to provide comments on information presented and discussed at the California Independent System Operator's ("CAISO") November 20 and 21, 2013 Transmission Planning Process ("TPP") stakeholder meeting on policy and economic transmission studies plus reliability projects having estimated costs less than $50 million that are recommended for management approval.

CPUC Staff comments cover the following topics.

1. *The CAISO should clarify which transmission projects are considered appropriate for inclusion (without reconsideration) in the 2013-2014 Transmission Plan, and such projects should be demonstrated as necessary across the range of resource options being considered for the Los Angeles Basin and San Diego areas.*

2. *The CAISO should specifically identify the adjustments made to the CPUC/CEC-provided RPS portfolios.*

3. *The CAISO should explicitly identify which benefits the high distributed generation (DG) portfolio provides relative to the commercial interest portfolio (the TPP base case), in reducing the need for transmission investment.*

4. *For economic studies, transmission project benefits and benefit-cost ratios (BCR) should be reported not only for the "economic life" time horizon of 50 years, but also for a more understandable planning horizon of 20 years.*

5. *For economic studies in which capacity benefits play a substantial role, the basis for capacity benefits should be adequately explained and the implications of uncertainties regarding capacity benefits should be illuminated via sensitivity analysis.*

6. For each reliability project identified for inclusion in the transmission plan, the CAISO should explicitly identify if load shedding is allowed as an alternative (and if not, why not) and where load shedding is allowed should either identify the amount of avoided load shedding or else explain why the project can be identified as needed without quantifying avoided load shedding.

CPUC Staff comments on the above topics are included below.

1. The CAISO Should Clarify Which Transmission Projects are Considered Appropriate for Inclusion (Without Reconsideration) in the 2013-2014 Transmission Plan, and Such Projects Should be Demonstrated as Necessary Across the Range of Resource Options Being Considered for the Los Angeles Basin and San Diego Areas.

It is clear that major resource and reliability strategies for the Los Angeles Basin and San Diego areas are currently under consideration and could have substantial interaction with transmission planning matters addressed in the 2013-2014 TPP. This is acknowledged in the CAISO's presentations and discussion with stakeholders, on November 20-21, where it was stated that "reconsideration will be necessary depending on reliability mitigations that are ultimately selected"[1]

It would be helpful for stakeholders generally and for the CPUC's resource planning processes, if the CAISO could clarify which transmission projects identified in the November 20-21 meeting or elsewhere are considered ready for inclusion (without reconsideration) in the 2013-2014 Transmission Plan. No transmission infrastructure additions should be included in the 2013-2014 Transmission Plan unless demonstrated to be needed across the range of reliability solutions under consideration for the LA Basin and San Diego areas, particularly via the CPUC's Long Term Procurement Plan (LTPP, R.12-03-014) proceeding. However, clarification of the transmission needs and other issues associated with <u>alternative resource solutions</u> continues to be of great interest and value.

[1] As referenced on slide 10 of the November 20 presentation "Introduction and Overview – Policy-Driven and Economic Assessment."

2. *The CAISO Should Specifically Identify the Adjustments Made to the CPUC/CEC-Provided RPS Portfolios.*

CAISO staff mentioned at the November 20-21 meeting that small adjustments were made to the CPUC/CEC-provided RPS portfolios. To support coordinated planning, consistency of assumptions, and general efficiency of the CPUC's portfolio generation process going forward, the CAISO should explicitly identify these portfolio adjustments and their rationale. For example, it appears that the TPP cases contain about 250 more MW in the Riverside East area than are identified in the original transmittal letter from the CPUC and CEC.

3. *The CAISO Should Explicitly Identify Which Benefits the High Distributed Generation (DG) Portfolio Provides Relative to the Commercial Interest Portfolio (The TPP Base Case), In Reducing the Need for Transmission Investment.*

An important (certainly not the only) rationale for a high-DG RPS portfolio is to avoid the cost, delay, environmental impacts and potential controversy surrounding major transmission system additions to access concentrations of renewable resources remote from load centers. Thus, an important expected insight from studying multiple RPS portfolios in the TPP is clarification of the impact of a high DG portfolio in reducing the need for major transmission additions.

However, powerflow and stability studies for the RPS portfolios appear to not show reduced transmission needs for the high DG portfolio[2]. While deliverability studies for the base portfolio identified beneficial transmission investments in the SCE area (on the Lugo-Mohave line) and apparently also (not as clearly defined) in SDG&E area, the high-DG and environmentally constrained portfolios were not studied for deliverability implications.

[2] E.g., slides 9 and 11 of the "South Policy-Driven Powerflow and Stability Results" presentation from November 20 appear to indicate that the high DG portfolio would not avoid reliability transmission investments triggered by the TPP base (commercial interest) portfolio.

The CAISO should clarify if and why the high DG portfolio is apparently found to provide no benefits in terms of reduced transmission investment needs for reliability (powerflow and stability) purposes. Furthermore, delivery network upgrades have typically been a major driver of transmission needs for renewable generation, and yet the 2013-2014 TPP has not studied deliverability for the high DG portfolio and consequently cannot shed light on how that portfolio impacts delivery network upgrades. We understand that the unresolved status of major reliability solutions for the South Coast area make it problematic to clearly identify "policy" transmission needs, or the ability of a DG-intensive strategy to reduce those needs. However, before ultimately committing to major "policy"-related transmission investments going forward, it will be essential to have a clearer picture of how and where more emphasis on DG can help manage and limit those investments.

4. For Economic Studies, Transmission Project Benefits and Benefit-Cost Ratios (BCR) Should be Reported Not Only for the "Economic Life" Time Horizon of 50 Years, But Also for a More Understandable Planning Horizon of 20 Years.

Transmission investments clearly have long economic lives, so that long-term benefits should be considered. However, based both on past experience and very dynamic and uncertain conditions looking forward from today, the electricity planning future is very uncertain. It would be imprudent to commit to large and potentially environmentally challenging transmission investments without first being well informed regarding the extent to which such investments are likely to pay for themselves over a reasonably foreseeable planning horizon of 20 years, as opposed to paying for themselves based on benefits projected over a much more distant and uncertain future.

Therefore, while it is reasonable to compute transmission project benefits and BCR over an "economic life" planning horizon such as 50 years, *it is also reasonable and in fact essential to augment this information with benefits and BCR calculated over a shorter and more foreseeable planning horizon of 20 years*. Most of the discounted benefits should come from the first 20 years, and if a transmission project is not computed to "pay for itself" in 20 years, then at a minimum we need to be aware of this when weighing the project's risks and opportunities.

5. For Economic Studies in Which Capacity Benefits Play a Substantial Role, the Basis for Capacity Benefits Should Be Adequately Explained and the Implications of Uncertainties Regarding Capacity Benefits Should be Illuminated Via Sensitivity Analysis.

Calculated capacity benefits play a very important role in making the Delaney-Colorado River (DCR) project appear to be cost-effective, accounting for 44 percent of calculated overall benefits.[3] When ultimately computed, capacity benefits may also drive the Harry Allen-Eldorado project into "cost-effective" territory. While computed production benefits are underlain by extensive documented production simulation data input and methodology assumptions, and by augmenting base case analysis with 17 sensitivity cases for each of two time horizons,[4] the almost equally important capacity benefits are computed in a much simpler manner. The capacity benefits are based mainly on estimated differential new CT costs (CA vs. AZ) for 2025 and later, plus a higher annual capacity benefit for years 2020-2024 attributed to surplus capacity assumed to be available from Arizona.

Given the importance of the capacity benefit, the CAISO should more fully support and explain the way this benefit is computed, and should also provide meaningful sensitivity analysis. For example: "economic rent" for inframarginal (relative to California) capacity costs may be partly captured by AZ suppliers rather than fully by California consumers; marginal California capacity needs may be driven by local area (e.g., South Coast) needs including deliverability to that area, rather than system needs; and alternative LA Basin-San Diego reliability mitigations (e.g., transmission and resource-related measures) could impact the value and even MW magnitude of a DCR capacity benefit.

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[3] Slide 4 from the November 20 presentation "Economic Planning Studies – Part 1: Introduction).

[4] Sensitivity results are summarized on slide 41 of the November 20 presentation "Economic Planning Studies – part 4: Preliminary Results"

6. For Each Reliability Project Identified for Inclusion in the Transmission Plan, the CAISO Should Explicitly Identify if Load Shedding Is Allowed as an Alternative (and if Not, Why Not) and Where Load Shedding is Allowed Should Either Identify the Amount of Avoided Load Shedding or Else Explain Why the Project Can be Identified as Needed Without Quantifying Avoided Load Shedding.

The question of when avoided load shedding and associated benefit-cost ratios (BCR) based on value of service are applicable for justifying reliability transmission upgrades has come up in the past. Also, the 2013-2014 TPP reliability studies recently identified needed reliability upgrades (Estrella substation) due to circumstances where load shedding is apparently no longer allowable under revised NERC standards.

The California ISO Planning Standards of June 23, 2011 indicate that transmission upgrades not required by "standards 1, 2 and 3 above" [5] may be justified by BCR above 1.0, as well as stating that information required for BCR calculation shall "be documented in the ISO Transmission Plan." [6] In essence, conditions where the standards provide for use of BCR to justify transmission upgrades that are not otherwise categorically required - - tend to represent multiple contingencies (N-2, TPL-003, etc.) and non-radial situations, often involving relatively large magnitudes of both load dropping and mitigation investment. These also tend to be the situations where BCR and the amount of load dropping avoided by transmission investment are not reported in TPP reliability study results.

We recognize that load dropping and other consequences of contingencies in networked situations can be complex or difficult to enumerate. However, annually approved reliability upgrades on the CAISO-controlled grid run into the hundreds of millions of investment dollars, or more. There should be greater clarity and consistency (across all situations, locations and service areas) (1) in reporting whether or not load dropping is allowed (and if not, why not), and (2) where load dropping is allowed, in reporting either the magnitude of avoided load

[5] On page 13 of the June 23, 2011 California ISO Planning Standards, standards 1, 2 and 3 are described as requiring, respectively (1) avoidance of loss of more than 250 MW of load due to a single contingency, (2) serving substations 100 MW and above with at least two ("looped") lines closed during normal operation, and (3) back-ties (drop and pick-up schemes) available to radial loads being sized (capacity) to meet or exceed certain thresholds relative to the loads in question.

[6] Ibid., page 14.

dropping or the rationale for why the transmission investment is justified without quantifying avoided load dropping.

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