CALIFORNIA ISO
2012-2013 TRANSMISSION PLAN

COMMENTS OF THE STAFF OF THE

CALIFORNIA PUBLIC UTILITIES COMMISSION

ON THE DRAFT STUDY PLAN

(FEBRUARY 21 DOCUMENT AND FEBRUARY 28 MEETING)

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March 14, 2012

Introduction

The Staff of the California Public Utilities Commission ("CPUC Staff") appreciate this opportunity to provide comments on the California Independent System Operator's ("ISO") 2012-2013 Transmission Planning Process ("TPP") Draft Study Plan ("Study Plan") dated February 21, 2012 and discussed at the February 28 stakeholder meeting. We provide the following limited comments which mainly concern the need to provide greater transparency and disclosure in some areas, and especially the need to use the latest load forecast and to both include and take into account study cases that project continuing ("incremental") Demand Side Management (DSM) and Combined Heat and Power (CHP) measures over the 10-year planning horizon.

1. 2012-2013 TPP Studies Should Use the Latest Energy Commission Load Forecast and Should Include and Take Into Account Reasonably Expected Incremental (Uncommitted) DSM and supply- and demand-side CHP.

It is essential that planning assumptions be as up to date as possible, and for that reason the studies should be based on the current than the Energy Commission revised load forecast released on February 21, 2012, and if possible, the Energy Commission's final forecast expected to be released by the end of March. Additionally, assessment of transmission needs ten years out could be significantly influenced by which Energy Commission load forecast is used. CPUC resource planning via the Long Term Procurement Plan (LTPP) process assumes that DSM[1] and CHP[2] programs will continue and not simply terminate or "drop off a cliff" when their currently authorized funding ends. Therefore, the LTPP process "manages" CEC load forecasts to include such "incremental" CHP and DSM reasonably expected to occur. The selected values are modified downward from goals or potential study assumptions to account for uncertainty through stakeholder processes. For consistency with resource planning and to avoid a narrowly conservative picture of 10-years-out transmission needs, the ISO's 2012-2013 TPP studies should meaningfully assess scenarios that include the above incremental DSM and CHP, and should not identify major 10-year transmission needs without assessing the extent to which those needs would exist under load forecasts that include incremental DSM and CHP.

2. The Generation Assumptions Should be Consistent with State Policy and Reasonable Expectations

The assumptions on generation retirements only include generation units that have announced plans for retirement. A significant number of older plants are subject to the Water Resource Control Board's policy on cooling water intake structures. As such, these plants will require significant upgrades to operate past the policy's compliance dates. Many of the plant owners have indicated[3] they would repower units if they receive a long term contract and will retire the unit if they do not. Previous ISO analysis has indicated that not all the older steam generators will be needed. Assuming none of these plants retire biases the TPP analysis and provides no information on the trade-off

[1] Demand side management includes the impacts of future expected programs such as demand response and energy efficiency. While future year programs may not have specific programmatic designs or funding in place, savings are reasonably expected to occur in future years.

[2] Combined Heat and Power refers to both supply- and demand-side generation. Demand-side CHP reduces load on site without exporting extra energy off-site, while supply-side CHP would include exports from the host-site.

[3] The Water Resource Control Board required plant owners to file implementation plans for compliance with the policy.

between any needed transmission upgrades and new generation or repowers. Furthermore the retirement assumptions should be such that the generation is assumed retired consistent with current Water Resource Control Board policy compliance dates. It is important to note that to the extent these units are needed for proven reliability reasons, the Statewide Advisory Committee on Cooling Water Intake Structures is tasked with making annual recommendations to the Water Resource Control Board on any needed changes to the implementation schedule.

3. Assumptions Underlying Local Capacity Requirements (LCR) and Once Through Cooling (OTC)/AB 1318 Studies Need to Be Clearly Explained within the Study Plan (and Ultimately within the 2012-2013 Transmission Plan), and Divergence from Planning Assumptions Used by the CPUC and CEC Should Be Justified.

The draft 2011-2012 Plan referred to external planning materials when describing certain LCR and OTC[4] study assumptions. Combined with a more general need for greater clarity regarding assumptions for these studies, this made it difficult to assess exactly what inputs and assumptions were used.[5] This situation can complicate use and acceptance of the ISO's modeling results in other proceedings, and can impair ability to understand apparent discrepancies across different studies or projections. Therefore, CPUC Staff emphasize the need for clear documentation of LCR and OTC/AB1318[6]

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[4] OTC refers to plants subject to the State Water Resources Control Board, "Statewide Policy on the Use of Coastal and Estuarine Waters for Plant Cooling"; see http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/policy.shtml

[5] The LCR Tool had at least two different vintages publicly posted; see http://www.caiso.com/2734/2734e3d964ec0.html

[6] AB 1318 (Perez, Chapter 285, Statues of 2009) requires the Air Resources Board, in conjunction with the Energy Commission, CPUC, ISO, and the State Water Resources Control Board, to prepare a report for the Governor and Legislature that evaluates the electrical system reliability needs of the South Coast Air Basin; see http://www.arb.ca.gov/energy/esr-sc/esr-sc.htm

study assumptions, within the 2012-2013 TPP Study Plan, and ultimately within the 2012-2013 Transmission Plan itself.

4. There Should be Sufficient Description of Any Major Transmission Additions Brought into the Base Case from the Generator Interconnection Process (GIP).

For several years the ISO, CPUC, and other stakeholders have been pursuing the challenging goal of reducing the role of piecemeal transmission planning via the generator interconnection process and relying more strongly on holistic and transparent planning via the TPP. Recent steps in this direction include Cluster 1-4 deliverability study refinements and the TPP-GIP[7] integration initiative.

Thus, it is essential to adequately describe and analyze from a system-wide perspective any major GIP-driven transmission additions that are being imported directly into the 2012-2013 TPP base case. The ISO should explain which executed interconnection agreements result in transmission upgrades and their inclusion or exclusion from the base case and why this determination was made. Furthermore, there should be clear explanation of the correspondence between generation additions driving (or supported by) GIP-driven transmission additions and the study plan's established resource portfolios. The consequences for the Renewable Portfolio Standard (RPS) portfolios if particular GIP-driven upgrades were to be omitted should also be described.

The above information would support better understanding of the overall role of the proposed GIP-driven transmission projects. Additionally and importantly, it would inform resource planning and portfolio development.

At a minimum, the additional information that should be reported for any GIP-driven transmission facilities included in the base case includes the following.

- The physical/electrical/economic characteristics of such facilities, including voltage, transfer capability increase, endpoints, in-service date and cost.

[7] "TPP-GIP" means Transmission Planning Process-Generator Interconnection Procedures.

- The MW and locations of (1) the renewable (and other) generation having signed interconnection agreements for which the GIP-driven facilities are needed and (2) separately, the amount of *additional* generation (beyond that having signed interconnection agreements) that could be accommodated by such added transmission facilities.
- Whether the added GIP-driven facilities would be needed for reliability or deliverability purposes.
- The modeled 8760-hour utilization of the added facilities under the different RPS scenarios studied. Such utilization should also be reported for other major transmission additions.

5. Methodology, Assumptions and Ultimate Planning Role for RPS Resource-Related Reliability and Deliverability Studies Need to Be Adequately Explained and Justified

This is especially important in light of the anticipated increased importance of the TPP to plan *delivery* network upgrades under TPP-GIP integration reforms. The ISO should clarify the relative roles, in upcoming studies and 2012-2013 Plan development, of on-peak deliverability studies conducted for RPS portfolios versus 8760-hour simulations of potential resource curtailment (dump energy) for those same portfolios. Furthermore, the assumed output levels (relative to maximum capacity) for wind and solar generation should be more fully and quantitatively described than in the past, particularly for major resource areas and under scenarios (and in locations) where transmission additions are identified.

It appears that for the 2011-2012 Plan development, deliverability studies set wind and solar output levels somewhere between the 50% and 20% exceedance levels[8] over the Qualifying Capacity (QC) period[9]. This suggests that the amount of transmission capacity required for deliverability under such conditions would exceed what is needed to

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[8] A 20% exceedance level represents a level of output during the QC period wherein output is beyond that level 20% of the time.

[9] Qualifying Capacity is defined as the maximum dependable capacity of a resource. The QC determination period, i.e., the hours between 12 p.m. and 6 p.m. during May through September.

deliver the resources at their resource adequacy (Net Qualifying Capacity[10]) levels. This should be clarified and justified.

It is unclear, and needs to explained and taken into account when performing and interpreting studies, what should be the role of *reliability* studies conducted for RPS portfolios within the TPP. For example, are such results only informational, in that reliability network upgrades will be planned via reliability studies conducted for specific resources in the interconnection process? Similarly, the relationship between the ISO's standard TPP reliability studies for different parts of the grid (based on North American Electrical Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability criteria) versus reliability studies conducted specifically for RPS portfolios should be made clear.

For reliability and deliverability studies:

- Differences in assumed wind and solar output levels (deliverability vs. on-peak reliability studies) should be clarified,
- The assumed output of thermal generation at risk of retiring by 2022 should be clearly identified and the consequences of including versus excluding this generation in the reliability and deliverability studies should be clearly explained.

6. Key Economic Study Parameters Should be Sufficiently Documented, and Transmission Additions Identified Pursuant to Economic Study Requests Should be Eligible to Substitute for Other Transmission Additions Under Certain Circumstances.

Transmission costs can be high and can exceed estimates, especially in California and especially when encountering major siting issues. When conducting and reporting on economic congestion studies including the anticipated multifaceted Fresno/Central Valley study, as well as studies responding to study requests, the ISO should describe the source and rationale for transmission cost estimates. Assumptions and methods used to convert direct capital costs to total ratepayer costs, and to calculate various kinds of benefits

[10] Net Qualifying Capacity is QC further reduced to account for deliverability.

against which costs are compared, such as summarized in Section 5.4.4 of the 2011-2012 draft Plan, should be documented and justified. Finally, given the uncertainties in both future circumstances and in appropriate selection of economic parameters, economic assessment of large potential transmission projects should be augmented with sensitivity analysis regarding key assumptions and economic parameters.

When an analysis performed for a study request identifies an efficient alternative to previously identified transmission additions[11], the ISO should evaluate which alternative produces the best value for ISO ratepayers.

7. Major Identified "Reliability" Transmission Needs Based on N-2 (Category C) Contingencies Should be Adequately Justified

Transmission planning studies have sometimes identified costly or difficult to permit transmission additions based on N-2 contingencies. NERC, WECC and ISO reliability and planning standards do not require avoidance of load shedding under N-2 contingencies, but provide that transmission additions to address such contingencies may be considered taking into account the specific circumstances of the contingences, consequences and mitigation. If considering major transmission additions to address N-2 contingencies, the ISO should provide substantial, transparent analysis and information regarding the contingencies and their likelihood; the magnitude, duration and costs of load shedding; and the costs and effectiveness of alternative solutions.

8. Studies of Transmission Additions to Reduce LCR Subareas Should be Conducted

Due to conflicting OTC requirements and local air emissions requirements, there arises the necessity to perform additional analysis related to compliance that may not just be generation retirement or repowering. Transmission improvements specifically to reduce reliance on OTC plants as well as particular locations in the transmission topology

[11] This applies to previously identified transmission additions that have not yet been permitted.

(such as LCR subareas) are required in order to inform compliance alternatives for generating asset owners who have the choice of either retirement inside the current ISO transmission topology, repowering inside the current ISO topology, or undertaking another alternative such as refitting their water intake structures. Most importantly, transmission improvements for a future ISO transmission topology that reduce LCR requirements in sub-areas also needs to be examined, which the ISO has not addressed in a systematic manner. It is critical to be able to evaluate these tradeoffs in order to minimize ratepayer costs and make the most efficient decisions possible about future resource investment.

9. The Generation Assumptions Should be Consistent with State Policy and Reasonable Expectations

Due to conflicting OTC requirements and local air emissions requirements, there arises the necessity to perform additional analysis related to meeting reliability needs by creating options other than generation retirement or repowering. Transmission improvements specifically to reduce reliance on OTC plants as well as particular locations in the transmission topology (such as LCR subareas) are required in order to inform compliance alternatives for generating asset owners who have the choice of either retirement inside the current ISO transmission topology, repowering inside the current ISO topology, or undertaking another alternative such as refitting their water intake structures. Most importantly, transmission improvements for a future ISO transmission topology that reduce LCR requirements in sub-areas also needs to be examined, which the ISO has not addressed in a systematic manner. It is critical to be able to evaluate these tradeoffs in order to minimize ratepayer costs and make the most efficient decisions possible about future resource investment.

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