California Transmission Planning Group (CTPG)
Technical Study Team
Response to the August 5, 2011 Comments of the
Bay Area Municipal Transmission Group (BAMx)
on the CTPG's Phase 2 Study Plan

Comment:

Planned Transmission Projects
In its earlier comments, BAMx suggested to the CTPG that only those projects that have all of the following approvals, or are under construction, should be modeled in the Base Cases.

1. Balancing Area Authority Approval;
2. CPUC CPCN/PTC Approval, if applicable; and
3. Other resource agency approvals such as, Army Corps of Engineers and BLM permits, and environmental reviews under NEPA or CEQA, if applicable.

BAMx is disappointed that the CTPG proposes to model all the transmission projects approved by the California ISO in the Draft plan even though those projects lack regulatory approval.

CTPG Technical Study Team Response:

The CTPG Technical Study Team believes BAMx's approach is too restrictive and does not recognize that planned transmission upgrades can be determined to be needed long before final permits are obtained. Under BAMx's approach, CTPG would have to wait years before planned transmission upgrades could be included in CTPG's powerflow basecases. For example, 5½ years elapsed between the initial Sunrise Powerlink application at the CPUC for a Certificate of Public Convenience and Necessity (CPCN) in December 2005 and the final U.S. Forest Service Notice to Proceed in August 2011. The CTPG Technical Study Team believes it would have been unreasonable to exclude the Sunrise Powerlink from the CTPG's year 2020 powerflow basecases until August of 2011.

Comment:

Renewable Net Short Estimate
BAMx is pleased that the CTPG has decided to use the latest CEC Renewable Net Short (RNS) numbers. However, BAMx strongly disagrees with the CPTG's proposal to limit its analysis utilizing only the High range of the RNS. BAMx understands there are limitations to the number of scenarios that the CTPG can effectively study, but the impact of the uncertainty of the RNS level clearly should be considered when deciding on the scope of studies for this year. If the CTPG cannot study the impact of all three RNS levels in the 2011 process due to resource limitations, BAMx believes utilizing the Low range would be consistent with the desire of the CTPG to develop a "least regrets" analysis of needed transmission. Although use of the medium RNS range would not be consistent with the "least regrets" study approach, it would clearly be better than utilizing the High range. Utilizing the High range is clearly inappropriate because it

will unnecessarily overstate the need for transmission and therefore potentially will result in the inefficient use of costly new transmission resources.

CTPG Technical Study Team Response:

For its 2011 study work, the CTPG has selected assumptions likely to have the most impact on the existing transmission system. These assumptions include the CEC staff's May 2011 updated "High" forecast (as contrasted with BAMx's suggestion to use either the CEC staff's "Low" or "Mid" forecast). They also include the use of 25 percent of the CEC staff's time-of-system-peak incremental energy efficiency impacts and 25 percent of the CEC staff's time-of-system-peak incremental behind-the-load-meter solar PV impacts that correspond to the CEC staff's "High" forecast.[1]

BAMx's references to "least regrets" underscores the difficulty of translating the term into a meaningful process. Different stakeholders have different interpretations of what "least regrets" means and how it should be implemented. Should "least regrets" be interpreted in terms of minimizing the risk of building transmission that turns out to be under-utilized, or should it be interpreted in terms of building enough transmission to minimize the risk of impeding renewable resource development? Further it is unclear what level of future transmission utilization would satisfy a "least regrets" criteria, and what amount of new transmission would represent "least regrets" support for renewable resource development.

Comment:

<u>Existing Renewable Generation</u>
BAMx supports the CTPG's efforts in working closely with the CEC staff in modeling all the existing renewable generation that is expected to be online by the end of 2011. The CTPG has indicated that they could neither verify the 5.8 TWh of Out-of-State (OOS) renewable generation utilized within California nor the 4.6 TWh of in-State renewable generation that is expected to be in service by the end of 2011. BAMx supports the CTPG's decision to assume these resources and to adjust the net short accordingly. In Tables 5 and 7 of the Draft Plan, the CTPG has included the number and amount (capacity) of "Load Netted" units. BAMx thinks it would be easier to keep track of all the renewable generation shown if the CTPG would show the generation. However, BAMx agrees that the load netting should provide the same load flow results. Results for the dynamic studies may differ depending on how the load and generation are represented. At a minimum, the CTPG should describe and document the load netting process so Stakeholders utilizing the CTPG cases can fully understand the location and amounts of "Load Netted" units. Please also describe the "Load Netted´ process with examples in the next revision of the Draft Plan.

[1] For its updated "High" forecast, the CEC staff projects incremental energy efficiency programs will reduce California peak loads by 5789 MW in year 2020. The CEC staff projects incremental behind-the-load-meter solar PV will reduce California peak loads by 544 MW in year 2020. CTPG's technical studies will assume 25% of these impacts are actually realized during the 4:00 pm PST weekday hour in July, 2020 that is being simulated in the summer power flow cases.

CTPG Technical Study Team Response:

The CTPG Technical Study Team agrees with BAMx that there are distinct advantages to explicitly modeling as much generation as possible in the power flow cases as well as in dynamic simulation studies. The CTPG Technical Study Team anticipates on-going improvements in the identification of, and representation of, both in-state and out-of-state renewable resources. These improvements will reduce the need for "load netting." Generation which is physically located at the distribution level poses its own set modeling challenges since there are many such generators and since their detailed electrical characteristics are often not well-known and sometimes unavailable. In addition, the existing power flow models generally do not contain representations of the distribution system.

The CTPG will plan to add a description of the load netting process, possibly including an example, in the draft study report that is expected to be issued later this year.

Comment:

<u>2011 Proposed Scenarios</u>
BAMx believes that the key role of the CTPG is not only to identify the need for new transmission, but also to inform stakeholders about alternative methods of achieving the State's renewable goals. To achieve this objective, it is critical to assess the capability of the existing transmission infrastructure without having to rely on new transmission. This would be extremely important information for generation developers. This element is not incorporated in any of the nine (9) scenarios proposed by the CTPG. In this section of our comments, BAMx addresses how the CTPG could consider additional scenarios and make certain changes to the proposed scenarios to make them more useful and informative.

Although the information gained in the Out-of-State (OOS) stress scenarios proposed to be studied may provide useful information as to what transmission might help alleviate deficiencies driven by the OOS scenario assumptions, there are many new developments that make it less likely that any new major Out-of-State transmission is needed to serve California load prior to 2020. These new developments include, (i) several "approved" in-State projects, (ii) the likely reduction in RNS, (iii) the adoption of a State goal of 12,000 MW of distributed renewable generation, and (iv) the appearance of more than 70,000 MW of renewables in California ISO Cluster Studies. This leads to a conclusion that it is more important to inform Stakeholders of how much renewables can be imported into California using the existing system.

In our earlier comments, BAMx had recommended that the CTPG incorporate an additional scenario that assumes maximum utilization of existing transmission. Below, BAMx includes its response to some of the concerns/questions raised by the CTPG regarding this BAMx proposed scenario.

The BAMx scenario is envisioned to have no significant transmission additions. It would include only those renewable resources that can be connected to existing transmission and currently approved new transmission. The CTPG had indicated a concern that regarding this condition that only those renewable resources “that can be connected to existing transmission and currently approved new transmission” are eligible to be included would appear to exclude no renewable generator since any generator could be physically “connected” to the existing grid. BAMx recommends that the CTPG should consider any renewable generator that is in the generator interconnection queue (Clusters 1 through 4) that does not require any new transmission. A similar assumption should be made for non-ISO areas. BAMx is willing to further refine this concept for “no new transmission” and help the CTPG model it based on several specific criteria that could be applied to “filter” renewable generation such as, generation cost, State policy goal, *etc*.

BAMx’s proposed scenario involves an economic ranking that requires an estimate of the transmission costs that would be associated with each renewable resource. The CTPG was unclear how BAMx proposes to estimate these transmission costs in the absence of any technical studies that may identify reliability criteria violations for which new transmission infrastructure would provide mitigation. As a first step, the CTPG should utilize the E3/CPUC calculator or similar methodology to economically rank the generation resources based on combined G&T costs. Upon modeling the renewable generation selected by the calculator, the technical studies can confirm whether the existing and additional economic transmission assumed to be needed in this scenario is deemed sufficient. This could be an iterative process that ensures that the final set of renewable generation and associated transmission (new projects or reliability measures), if any, would minimize the overall cost while ensuring the network reliability.

The CTPG had expressed concern that BAMx had not proposed how to define the cut-off point in the economic ranking beyond which renewable resources would not be included. BAMx believes that the RNS level would dictate the amount of renewable resources modeled in this scenario.

BAMx recognizes that the BAMx proposed scenario is unique in assessing the capability of existing/approved transmission in meeting the State RPS target. The CTPG could request CPUC Staff assistance in developing this scenario. If such assistance is unavailable, BAMx is willing to work with the CTPG to develop additional details associated with this scenario.

CTPG Technical Study Team Response:

The CTPG appreciates the additional information provided by BAMx on their proposed “maximum utilization of existing transmission” scenario. BAMx explains that “the cut-off point in the economic ranking beyond which renewable resources would not be included” is actually the amount of renewables that fill the CTPG’s updated renewable net short. BAMx also indicates that there would be “an iterative process” between the CTPG’s technical analysis and the E3 calculator model to ensure the final set of renewable generation and associated transmission “would minimize the overall cost.”

All of the scenarios included in the CTPG’s Phase 2 study plan contain enough renewables to satisfy CTPG’s updated renewable net short. As the CTPG Technical Study Team understands BAMx’s proposal, renewable resources would be selected primarily on the basis of whether existing transmission is available. The availability of existing transmission is not, by itself, the sole criteria that regulatory entities and generation permitting authorities use to approve renewable projects. Accordingly, CTPG will not be performing BAMx's suggested "maximum utilization of existing transmission" scenario.

Comment:

CPUC Scenarios
BAMx suggests that in addition to the CPUC Public Policy scenario, *i.e*., *Cost-constrained* scenario, the CTPG should also study the CPUC *Environmentally-constrained* scenario. The latter is the only scenario that comes close to addressing the State's 12,000 MW Distributed Generation (DG) goal, which is a key part of Governor Brown's vision of the future and which all State regulatory agencies are working hard to achieve.[2] Selecting the *Environmentally-constrained* scenario as the Base Case is clearly the most appropriate from the standpoint of consistency with the State's energy goals because it is closest to correlating with the State's DG goal.

CTPG Technical Study Team Response:

The CTPG Technical Study Team recognizes that there is considerable interest in the Governor's 12,000 MW distributed generation goal. The CTPG Technical Study Team believes that a productive transmission assessment of this goal requires that policy makers work out the relevant details of the goal. Stakeholders will no doubt have a range of opinions as to how this goal should be implemented. The CTPG will consider including this scenario in its 2012 study plan.

Of note, the CTPG's version of the CPUC Public Policy scenario contains 2397 MW of new in-front-of-the-load-meter distribution-level renewable resources.[3] In addition, the CEC staff's May 2011 forecast update "does not revise the…self-generation assumptions" used in the CEC's adopted 2009 Integrated Energy Policy Report (IEPR) load forecast. The CEC's 2009 IEPR load forecast estimated that, between years 2009 and 2020, statewide peak demand would be reduced by 19 MW as result of added non-photovoltaic self-generation resources (behind-the-load-meter distribution-level resources) and by 548 MW as a result of added photovoltaic self-generation resources (behind-the-load-meter distribution-level resources).[4] Assuming an effective-to-installed capacity ratio of 80% for non-photovoltaic self generation and 50 percent for photovoltaic self generation, the CEC's adopted 2009 IEPR load forecast implies 24 MW (19 MW/.8) of new installed non-photovoltaic self generation resources by year 2020 and 1096 MW (548 MW/.5) of new installed photovoltaic self generation resources by year 2020. The CEC

[2] See California Clean Energy Future presentation, "Overview and Metric Review" IEPR Committee, Joint Agency Workshop dated July 6, 2011.
[3] This total is comprised of 25 MW of installed solar PV capacity in the LADWP distribution service area; 2029 MW of installed solar PV capacity in the PG&E, SCE and SDG&E distribution service areas; 44 MW of installed biomass capacity in the PG&E, SCE and SDG&E distribution service areas; 1 MW of installed biogas capacity in the PG&E, SCE and SDG&E distribution service areas; and 297 MW of installed wind capacity in the PG&E, SCE and SDG&E distribution service areas.
[4] From the CEC's adopted 2009 IEPR load forecast (December, 2009 *California Energy Demand 2010-2020, Adopted Forecast, Form 1.4 – Statewide).* "Non-PV Self Generation" at time of peak is 1916 MW in year 2009 and projected to be 1935 MW in year 2020 (1935 MW – 1916 MW = 9 MW). "PV Self Generation" at time of peak is 262 MW in year 2009 and projected to be 810 MW in year 2020 (810 MW – 262 MW = 548 MW).

staff's May 2011 forecast update therefore reflects approximately 3517 MW of new installed distribution-level generating resources (3517 MW = 2397 MW + 24 MW + 1096 MW), roughly 30 percent of the Governor's 12,000 MW goal.

Comment:

BAMx does not believe that the CTPG has modeled the CPUC *Cost-constrained* scenario accurately as far as the *Discounted Core* generation is concerned. The CPUC/E3 calculator provides first priority to the *Discounted Core* generation. However, it alters the *Discounted Core* to the extent it triggers additional significant transmission related costs that would overall make it economically inefficient. For instance, the Kramer and Pisgah CREZs have discounted core generation of 250MW (584GWh) and 500MW (1,169GWh), respectively. However, the CPUC *Cost-constrained* scenario restricts them to 62MW and 275MW, respectively, to avoid any new significant transmission network upgrades. The CTPG does not implement the CPUC approach in this regard. Instead it assumes the entire *Discounted Core* generation in these CREZs as given. BAMx encourages the CTPG to work with the CPUC staff in revising its modeling of the *Discounted Core* renewable generation in the CPUC Public Policy scenario accordingly and in adding an *Environmentally-constrained* or DG scenario as recommended above.

CTPG Technical Study Team Response:

The CPUC includes generation in its Discounted Core that it believes has a high likelihood of getting built. The CTPG Technical Study Team believes it is reasonable to include generation in the Discounted Core that has signed Purchase Power Agreements (PPAs), interconnection agreements in place and other measures of likely success including applicable regulatory and environmental permits. It is the CTPG Technical Study Team's opinion that it is inappropriate for generation that has some or all of these measures of success to be excluded from the Discounted Core on the basis of a spreadsheet modeling determination (the E3 calculator model) that the generation would "trigger[]…economically inefficient" transmission. The E3 calculator model includes highly generic assumptions concerning the costs of new transmission as well as the level of utilization of that transmission. The E3 calculator model contains no network modeling capabilities so any determinations within that model as to the use of any particular network upgrade are largely speculative.

Comment:

<u>Use of RETI Best CA CREZ Criterion</u>
The CTPG has decided to employ the RETI Best CREZ renewable project amounts, except in the case of the CPUC Public Policy scenario (See Table 16 of the Draft Plan). The RETI Best CREZ criterion relies on outdated cost and environmental scores, and has no consideration for utilizing existing and approved transmission in each CREZ. The CPUC has put significant effort into updating the cost, as well as environmental information, originally developed by RETI. CTPG should take advantage of those efforts. The use of RETI Best CREZ criterion ends up adding renewable generation projects that require new transmission. For instance, under the

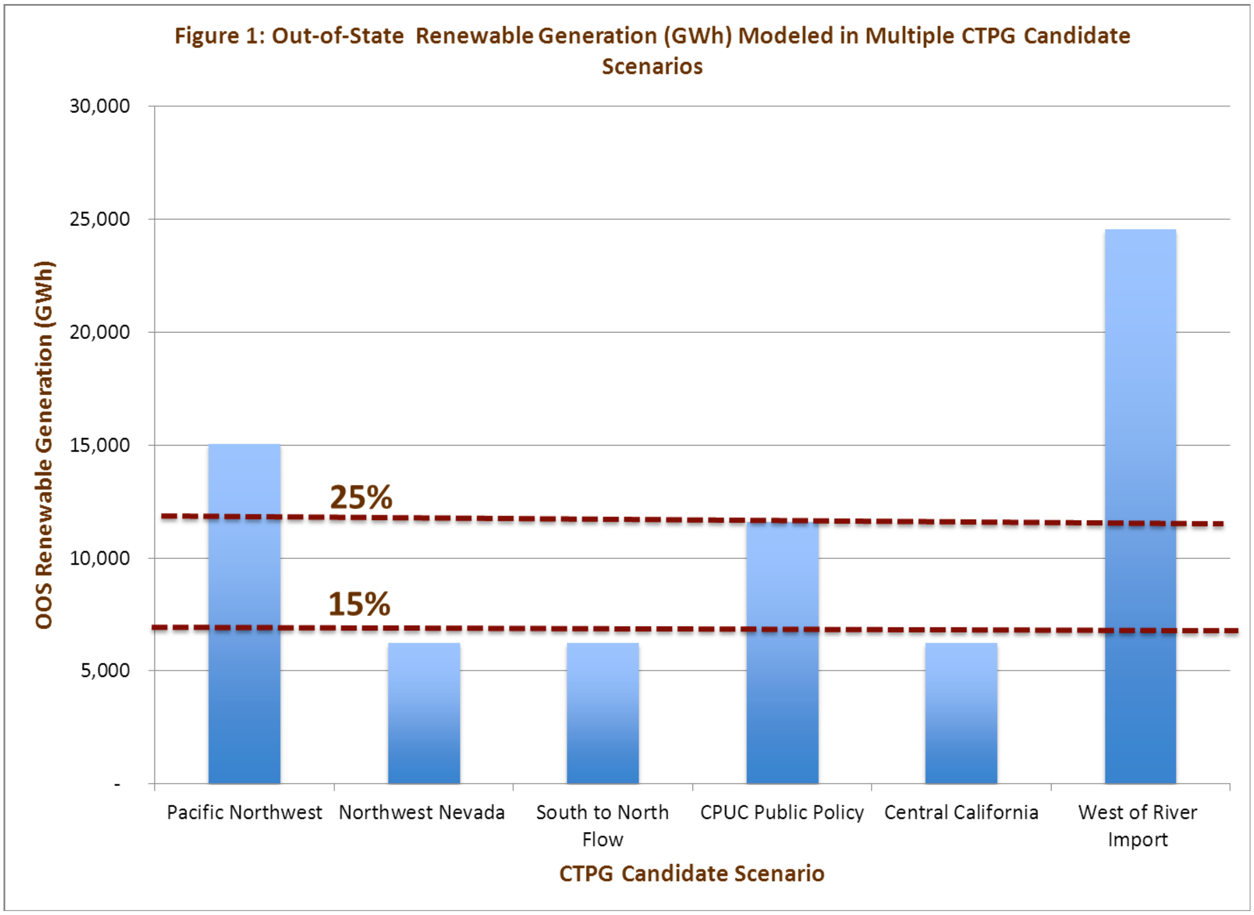
proposed CTPG approach, the Kramer CREZ had a relatively small amount (584 GWh as shown in Table 22: *Central California Scenario Renewable Dispatch*) of renewable generation in the *Discounted Core*. In order to fill the "net short", the CTPG has identified a significant amount (1,775 GWh) of additional renewable projects under the RETI Best CREZ criterion from Kramer rather than relying on additional potential resources within CREZs such as Westlands, San Diego South, Tehachapi or Palm Springs, which are already selected by CTPG under the *Discounted Core* criterion for the *Central California* scenario. Each of these CREZs has additional renewable resources under the generation interconnection queue that exceed the amounts identified in this scenario. Furthermore, the renewable projects from the Tehachapi CREZ were artificially restricted to 8,612 GWh, while the RETI Best CREZ approach indicated that Tehachapi CREZ was ranked higher than Kramer CREZ based on both the economic and environmental scores. BAMx strongly urges CTPG to incorporate renewable generation in CREZs that utilize existing/approved transmission infrastructure based on the California ISO generation interconnection queue data.

CTPG Technical Study Team Response:

The CTPG Technical Study Team appreciates BAMx's perspective that the POU-CPUC Discounted Core should be augmented with additional renewable resources on the basis of CREZs that have "existing/approved transmission infrastructure," rather than with additional renewable resources from the RETI Best CREZ. On the other hand, the RETI Best CREZ does provide an indication of where economic and environmentally feasible renewable resource development may occur. On balance, the CTPG Technical Study Team continues to believe the RETI Best CREZ provides a reasonable platform from which to augment the POU-CPUC Discounted Core.

Comment:

<u>Address the Restrictions on the Out-of-State (OOS) Resources</u>
Although claimed otherwise, it appears that the CTPG has not taken into account the restrictions on the amount of OOS resources that can be counted as part of the State's 33-percent RPS goal per the interconnection provisions of SBx1-2. The CPUC *Public Policy* scenario assumes that approximately 25 percent of the 2020 RPS target is met with OOS resources. However, as shown in Figure 1 below, the amount of OOS generation assumed in the CTPG Pacific Northwest and the CTPG West of River Import scenarios clearly exceeds such limit (25 percent dotted line). If the location of assumed OOS resources in the proposed Scenarios is not subject to the legislated restriction, the CTPG should explain why this RPS procurement restriction is not taken into consideration. Furthermore, the CTPG needs to consider that a subset of the OOS resources, say 10 percent, will be counted to be unbundled Renewable Energy Credits (RECs). This would mean that only 15 percent of the RPS net short needs to be physically delivered from OOS in the form of "bundled" RECs. Please document how the CTPG's rationale regarding how the CTPG Pacific Northwest and the CTPG West of River Import scenarios would comply with SBx1-2.



CTPG Technical Study Team Response:

The CTPG Technical Study Team believes its assumptions regarding the renewable resource development portfolios being studied in the CTPG's 2011 study work are consistent with the provisions of SBx1-2.

First, a plain reading of SBx1-2 suggests that so long as the output of an out-of-state renewable resource is scheduled into California, the output of the renewable resource can be counted toward a California Load Serving Entity's (LSE's) 33-percent RPS requirement. Section 399.16(b)(1)(A) of the Public Utilities Code states that "eligible renewable energy resource electricity products" include those that "are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source." Assuming the term "without substituting electricity from another source" is interpreted to mean that only the metered output of the renewable generator can be counted towards the RPS requirement, then it would appear that the ability to secure wheeling between the generator and a California balancing authority would allow the output of any out-of-state generator to be counted.[5]

[5] Assume that for a given hour, 100 MW is scheduled to a California balancing authority from an out-of-state generator (100 MWh) and that adjacent balancing authority scheduling the 100 MW to the California balancing authority actually delivers the 100 MWh. Assume further that during this hour, the metered output of the renewable generator is 80 MWh. The CTPG Technical Study Team believes that a reasonable interpretation of the "without

Second, Section 399.16(b)(1)(A) of the Public Utilities Code allows out-of-state renewable generation that has a "first point of connection with a California balancing authority" to be counted towards California LSEs' RPS requirements. There is a considerable amount of proposed out-of-state renewable generation that could meet this requirement. For example, proposed renewable generation in southern Nevada could connect to the CAISO balancing authority at Eldorado substation in southern Nevada, or to the LADWP balancing authority at McCullough, Marketplace or Mead also in southern Nevada. Proposed renewable generation in central Utah could connect to the LADWP balancing authority at Intermountain substation in Utah. Proposed renewable generation in western Arizona could interconnect with the California ISO balancing authority at Palo Verde or North Gila substations in Arizona.

Third, Section 399.16(b)(1)(B) of the Public Utilities Code provides that "eligible renewable energy resource electricity products" include those that have an "agreement to dynamically transfer electricity to a California balancing authority." Any out-of-state renewable resource could, in theory, have its output dynamically scheduled to a California balancing authority.

Finally, Section 399.16(b)(2) of the Public Utilities Code provides that "eligible renewable energy resources" include "Firmed and shaped…products providing incremental electricity and scheduled into a California balancing authority." The CTPG Technical Study Team is uncertain how the term "firmed and shaped" will be defined for purposes of SBx1-2, but one interpretation of these terms suggests contractual arrangements whereby the output of out-of-state renewable resources is "stored" in water reservoirs for some period of time (by reducing hydroelectric output that would otherwise take place) and then "released" on a controlled basis from the reservoirs at another period time (by increasing hydroelectric output that would otherwise take place) and scheduling this energy to a California balancing authority.

Taken together, these considerations indicate to the CTPG Technical Study Team that it is reasonable to assume that the out-of-state renewable resource portfolios being evaluated in CTPG's 2011 study work will not be in conflict with SBx1-2 as ultimately implemented.

substituting electricity from another source" term is that California load serving entities could only count 80 MWh towards their RPS requirements; the other 20 MWh being comprised of electricity substituted from another source.