Stakeholder Comments Template

Subject: Generation Interconnection Procedures Phase 2 ("GIP 2")

Submitted by	Company	Date Submitted
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This template was created to help stakeholders structure their written comments on topics detailed in the April 14, 2011 *Straw Proposal for Generation Interconnection Procedures 2 (GIP 2) Proposal* (at http://www.caiso.com/2b21/2b21a4fe115e0.html). We ask that you please submit your comments in MS Word to GIP2@caiso.com *no later than the close of business on May 5, 2011*.

Your comments on any these issues are welcome and will assist the ISO in the development of the draft final proposal. Your comments will be most useful if you provide the reasons and the business case for your preferred approaches to these topics.

Your input will be particularly valuable to the extent you can provide greater definition and clarity to each of the proposals as well as concerns you may have with implementation or effectiveness.

CPUC Staff Introductory Comments

California Public Utilities Commission Staff ("CPUC Staff") is providing limited comments on the Work Group 1 issue area, which focuses on improved integration of Generator Interconnection Procedures (GIP) into the broader Transmission Planning Process (TPP), including economic cost effectiveness tests for GIP-related transmission, and potentially modified interconnection customer (IC) cost responsibilities when GIP-related transmission is better integrated with the TPP. It is clear that the two specific Work Group 1 questions on this template do not cover the full range of relevant issues that have been discussed by stakeholders and presented in the CAISO's April 14 Straw Proposal. Therefore, CPUC staff comments on Work Group 1 issues are broken into two sections

corresponding to the two topics included in the template, but with the scope of each topic more broadly defined to better cover the range of issues.
While not addressed in present comments, other issue areas (assigned to other work groups) have been addressed by previous CPUC staff comments especially relating to potential opportunities and barriers for small generators. We expect to be further involved in these other issue areas in the future.

Finally, while present comments are limited to Work Group 1 topics, we recognize that all GIP-2 issue areas interact to some extent, and Work Group 1 issues especially interact with Work Group 5 issues regarding deliverability studies, which inherently affect the kinds and sequencing of studies, as well as Interconnection Customer ("IC") expectations and obligations, that would be sought or would occur under reformed GIP-TPP integration.

Comments on topics listed in GIP 2 Straw Proposal:

Work Group 1

1. Develop procedures and tariff provisions for cost assessment provisions. For providing constructive comments, CPUC staff expands this topic 1. to encompass the broader scope of GIP-TPP integration process issues laid out in the CAISO's April 14 Straw Proposal. (Certain IC-specific implications and issues are addressed under separate topic 2. below.)

Comments:

CPUC Staff emphasize the following priorities for improving GIP-TPP integration for efficient planning of RPS-driven transmission that is timely, cost-effective, and prepared for subsequent permitting.

A. Use of Portfolios is Not the Whole Story, but it is Essential

Efficient planning of RPS-driven transmission that is appropriately proactive but minimizes risks of inefficient investment or use of our environment must rely significantly on prospective resource "portfolios" to anticipate a range of futures that are likely and/or desirable. It has been claimed that this substitutes portfolios for interconnection studies or full commercial commitments, or that it amounts to picking winners. That is all true, to some extent, but is also desirable if we are to strike a balance between two "commercially-driven" extremes, neither of which is desirable:

1. We could let the "market" decide by planning enough RPS-related transmission only to meet the needs of those generators that express full commercial commitment by advancing to the point of signing interconnection agreements and contributing up-front funding. This piecemeal, slow, and inefficient process has already been rejected, several years ago.
2. Or, at the other extreme, we could plan enough transmission to serve all generators meeting a lower bar of commercial interest such as beginning Phase 1 interconnection studies or being short-listed for procurement. Then we could wait and see which of these generators ultimately win out "fair and square" in the market. However, such a process would be much too lengthy. Furthermore, it would result in too much "planned" transmission that by its pure magnitude would overwhelm efforts to rationally plan the most efficient and appropriately sized transmission solutions.

Thus, GIP-TPP integration <u>*does*</u> require a major role for reasonably constructed resource portfolios or scenarios that are consistent with market, technical and environmental information and with resource planning priorities. RPS-related transmission planning should be significantly driven by such portfolios, but it should also be applied in a way that minimizes risk of hindering development of either viable generation or obviously valuable and straightforward ("low hanging fruit) transmission expansions.

B. RPS-Related Transmission Must be More Fully Planned Based on the New "Policy" Criteria, and Some Approvals will be "Conditional"

Better GIP-TPP integration to plan RPS-related transmission that is cost effective and likely to be permitted requires full use of the new "policy" criteria for identifying and approving such transmission. *Transmission initially identified via the interconnection process should by default (not only in more limited circumstances) be planned and, if appropriate, approved in the TPP.* This requires fully applying established tariff criteria for identifying "policy"-driven transmission, including consistency with resource planning (especially the CPUC's LTPP, its assumptions and scenarios), use of environmental criteria, and explicit disclosure and consideration of transmission costs. This is not possible if heavily relying on the interconnection process for transmission planning. *Furthermore, it will be inevitable, and should be factored into GIP-TPP integration, that some RPS-related transmission when viewed from the broader proactive but prudent perspective will be identified as Category 2 or "conditional."* Otherwise, excessive amounts of transmission could be planned based on a range of futures and generator interconnections that could not possibly all occur at the same time.

C. An "Economic Test" within the TPP is Essential for All Substantial RPS-Driven Transmission.

Other than the most straightforward, small, or obviously appropriate transmission expansions (see below), all RPS-related transmission should be *economically assessed within the TPP*. This requires transparent disclosure and assessment of planning level costs for all such transmission expansions, and non-wires alternatives, within Phase 2 of the TPP as well is in the final Plan. This assessment should go beyond absolute costs for potential individual transmission additions to fully support (which is itself ambiguous) different RPS resource scenarios. There should also be assessment of the value of *incremental capacity deliverability (e.g., RA capacity) and energy deliverability (e.g., 8760 hour expected GWh delivery) provided by different incremental levels of transmission expansion and investment*. For example, it may *not* be cost-effective to provide full RA deliverability for all resources in a zone accessed by new transmission, and it may be most cost effective to provide expected delivery of only X%, but less than a full 100%, of the projected annual GWh output from a zone. This requires thought and creativity to develop a workable study methodology, and is strongly interwoven with deliverability issues being addressed in Work Group 5. From an efficient big picture planning perspective this is essential. We do recognize that the devil is in the details and that from an individual IC perspective this leaves important questions to be resolved, such as related to deliverability and what it realistically means.

C. Any "Big Picture" TPP Assessment of Cost-Effective Transmission to Access New Renewable Generation Must Realistically Consider DG and Out-of-State Renewables, and Well as Integration Studies and Needs.

These are examples of the more holistic perspective that must be brought to bear when using the TPP to plan RPS-driven transmission, which *cannot* be well addressed if not more fully integrating the GIP into the TPP.

D. GIP-TPP Sequencing Is Important, Including Treatment of Multiple IC "Vintages"

As pointed out by stakeholders, how to transition from where we are now to a future "end state" regarding better GIP-TPP integration will be critical and difficult. This partly involves thinking out the sequence and timelines under which TPP and GIP inform each other in terms of exchanging information and in terms of informing how generators choose to participate in the GIP. For example, designation of Category 1 and Category 2 "policy" transmission in the TPP could inform IC decisions regarding entering the queue, making post-Phase 1 deposits, and requesting deliverability. However, it must be anticipated that the set of ICs impacted by any particular Category 1 or 2 "policy" transmission designation in the TPP will often consist of *multiple* clusters or vintages of ICs, not just a single cluster. Therefore, in addressing GIP-TPP sequencing and coordination, it will be important to address how multiple vintages of ICs would participate.

E. Should GIP Phase 2 be Subsumed into the TPP?

Several parties suggest that GIP-TPP integration be taken to the point that GIP phase 2 is brought into the TPP where it can be addressed more holistically and transparently. One question raised has been whether "surplus" transmission should be initially planned (to accommodate above 33% RPS) to account for resource development failures and to promote resource competition. "Big picture" questions such as this would be best considered via the more holistic TPP and its Category 1 versus Category 2 designations, and not via the GIP. Such a holistic approach to assessing not only which transmission we may need, but also how much, is only addressed in the TPP, not the GIP. Thus the idea of subsuming GIP phase 2 into TPP should be seriously considered, paying careful attention to preserving two benefits of a separate "full GIP" track under some conditions, as follows:

1. There should be a separate track, allowing ICs to continue fully through the GIP up to interconnection if meeting appropriate criteria. Such criteria might address having transmission needs found to be sufficiently limited or to represent obvious or straightforward transmission expansions not significantly interacting with broader issues needing to be studied in the TPP. Such ICs would retain their regular GIP-driven cost responsibility for transmission expansions. This track should be available to smaller generators wherever possible.

2. If the remaining ICs are to complete GIP Phase 1 and then have their transmission be further planned in the TPP, then there should be substantial required "pay to play" commitments to weed out less viable projects. This is analogous to the role played by post-Phase 1 security and other requirements in the present GIP design, although the magnitude of commitments could be adjusted.

The mechanics and consequences of such deep integration of GIP phase 2 into the TPP should be assessed and vetted.

2. Clarify Interconnection Customer (IC) cost and credit requirements when GIP network upgrades are modified in the transmission planning process (per the new RTPP provisions) Consistent with the CAISO' straw proposal, CPUC Staff see this more broadly defined as: how to allocate transmission access (capacity and energy) and cost responsibility among individual ICs when their transmission is planned and potentially approved via the TPP.

Comments:

More fully integrating planning of generator interconnection-driven transmission into the TPP raises important questions regarding the rights and responsibilities of individual ICs. Some relevant questions, and CPUC Staff's initial views, include:

1. *Does TAC funding remove all IC financial responsibility? What about discouraging/weeding out nonviable generation?*

   CPUC Staff believes that there should be significant required IC commitments in order for an IC to progress beyond GIP Phase 1, even if that progression moves directly into the TPP. This is necessary to weed out less viable, premature or speculative projects, and to signal to ICs the transmission cost implications of their selected locations. Otherwise, a massive rush to get in line for "free" transmission could be expected. Should the commitments involve, for example, deposits, these could be reimbursed unless the transmission proceeds to development and the IC drops out for other than specified force majeure reasons.

2. *What about other signals for efficient generator location?*

   CPUC Staff believe that by more fully integrating transmission planning for renewable generation into the TPP, it will be more efficient and transparent to "signal" that certain locations are costly or even undesirable to access by transmission, since such resource locations are unlikely to be ranked favorably for inclusion in either resource scenarios or in the Transmission Plan (and eligibility for TAC funding) – especially when the TPP and resource planning processes are well coordinated with each other.

3. *What if an IC wants to go ahead even though its transmission needs are not included in the plan produced by the TPP?*

Such an IC could move ahead only if agreeing to upfront fund the transmission, and if the transmission is ultimately developed, would be reimbursed only to the extent there are reliability and economic benefits to the network.

4. *Do generators providing transmission self-funding obtain special rights regarding deliverability of capacity or energy?*

   A generator would be assigned the level of deliverability such as for RA purposes, supported by the transmission that the generator self-funded. Whether this entails any priority for energy delivery (scheduling and dispatch) should be further discussed, and may be inconsistent with the CAISO's current paradigm regarding transmission access and transmission rights.

5. *If the amount of transmission that is identified and included in the Plan via the TPP (for TAC funding,) cannot accommodate all ICs in a resource zone, how is the TAC-funded capacity allocated among the ICs?*

   The question deserves further analysis. Generally, pro-rata allocation among all ICs meeting certain threshold criteria appears preferable, such as based on falling within certain interconnection clusters and making certain deposits or other commitments, with PPAs perhaps also playing a role. ICs outside of this threshold would have to either wait for other ICs to drop out or else self-fund transmission. This is one reason why there should be sufficient commitments (pay to play) required from ICs seeking access to TAC-funded transmission, to weed out non-viable generators. The threshold for IC eligibility for such pro rata allocation should not be too severe, i.e., perhaps not limited to just one cluster window. Prorata allocation might trigger some trading of "rights" to TAC funded transmission, among the affected ICs, and this situation should be considered.

6. *If some of the generators qualifying for (TAC-funded transmission drop out, then (a) who pays for the resulting "surplus" transmission, and (b) if there are other generators waiting in line for that transmission, who gets it?*

   (a) Such "surplus" transmission is roughly analogous to such a "surplus" addressed by the CAISO's Location-Constrained Resource Interconnection policy, and should be addressed in a similar manner. That is, it should be rolled into the TAC until future generators show up to use it. However, in this case it still would *remain* rolled into the TAC when future generators show up, assuming that it is network transmission. This situation clearly requires some discipline in identifying "least regrets" transmission, including full sue of process and criteria already approved by FERC for planning "policy" transmission, and including use of appropriate resource scenarios and the "least regrets" principle.

   (b) Access to the TAC-funded transmission freed up by dropouts might first be prorata allocated among those generators in the initial IC tranche eligible for this transmission when it was first identified via the TPP. Additional eligibility requires further consideration by CAISO and stakeholders, and would presumably be based at least in part on generators' status in the interconnection process, including deposits.

7. *Is discretionary PTO upfront funding problematic?*

A major reason for more fully using the TPP to plan transmission for renewable generation is to identify those transmissions additions that are most cost-effective, least regrets, and otherwise desirable from a holistic perspective addressing the state's energy and environmental priorities – and to reward that transmission and its users with TAC (socialized) funding. This process could be weakened or short-circuited if *additional* transmission is identified by PTO's for TAC funding, outside of the transparent TPP. This should be discussed.