CPUC STAFF WORKSHOP REPORT

I.00-11-001
Transmission Costs Used in RPS Procurements
January 20-21, 2005

Summary of Recommendations

- Consider a **curtailability standard** on the order of 5-10% that would further RPS goals while minimizing transmission expenses and limiting IOU exposure to penalties for under-procurement.
- Coordinate **deliverability requirements** between the RPS and Resource Adequacy proceedings, allowing renewable resources to select the lowest standard for deliverability consistent with the Commission's resource adequacy goals.
- Consider a **new standard for transmission financing** that utilizes inter-agency collaboration to identify optimal grid investments in advancing renewable energy goals, while protecting ratepayer economic interests.

Introduction

On January 20 and 21, 2005, Commission staff led a party workshop to address outstanding issues related to the assessment of transmission costs in the Renewable Portfolio Standard (RPS) program.[1] As adopted in Commission decision D.04-06-013, (the TRCR Decision) present policy directs the IOUs to follow a multi-step process to estimate the transmission cost of connecting renewable resources, procured via competitive solicitations, to the grid. The process is known as the Transmission Ranking Cost Report (TRCR), and can be summarized as follows:

1) Prior to the RPS bid solicitation, the IOUs request information from potential bidders regarding their project technology, location, size and output profile.

2) The IOUs utilize a Commission-approved method of estimating the costs of upgrading the transmission system in order to bring the renewable generation to load. This method is undertaken for projects without the standard ISO System Integration Study and Facility Study (SIS/FS), which must ultimately be performed for each generator selected via the RPS bidding process, in order to establish a complete cost assessment.

3) The TRCR process results in transmission upgrade cost estimates for each cluster of potential RPS bidders. This cost assessment is provided in advance of bidding to each developer, providing that developer with important information regarding the viability of the project location, and the transmission costs that may be associated with the bid when it is evaluated by the RPS-obligated IOU.

The Transmission Ranking Cost Reports provide developers with valuable information regarding project viability and the costs that may be associated with it during bid ranking.

[1] Attachment 1 contains the attendee list for the workshop.

The present TRCR method was adopted in June 2004 for use in the first RPS solicitation. In recognition of the many lessons to be learned from this first attempt at up-front transmission cost approximations, the staff scheduled the workshops memorialized here to gather party input regarding areas of contention and opportunities for policy reform.

The intent of the workshop and of this report is to identify issues that can be addressed quickly, for application to the 2005 RPS solicitations, as well as those that will require a longer-term investigation – such as those that implicate the ongoing overall reforms to transmission planning and finance in California – for application to RPS solicitations in later years.

The workshop was organized around two themes in the TRCR process. While there was some overlap between the two, each theme was roughly the subject of one day of workshop effort:

1) The Commission, along with the California Energy Commission (CEC) and the California Power Authority, has adopted an Energy Action Plan containing a "loading order" of preferred energy resources[2]. That loading order places renewable generation first among resources that utilize the transmission system. In the context of this overarching state policy priority, what reforms to the TRCR process are necessary or appropriate to advance renewable energy goals?

2) In the TRCR decision, the Commission identified a number of specific transmission planning issues to be the subject of further party comment and deliberation. Bearing in mind that the 2004 RPS solicitations are ongoing, what lessons can be learned regarding these identified issues, and how should they be addressed in the future to advance the RPS planning effort and the state's resource goals more broadly?

The State Energy Action Plan places renewable resources first among resources that utilize the transmission system. How to balance this goal with transmission use by existing generation resources and evolving transmission policy was a key workshop issue.

The outline of this workshop report follows the agenda of the workshop, focusing first on the broad themes of the EAP Loading Order, renewable energy and transmission policy, followed by an issue-specific discussion of elements of the TRCR process. Since the workshops were off-the-record, specific party comments are paraphrased, and included solely in order to capture key themes and ideas raised during the two days of discussion.

The report concludes with a discussion of suggested near- and longer-term next steps.

[2] http://www.cpuc.ca.gov/PUBLISHED/REPORT/28715.htm

Day One: TRCRs and the RPS Program in the "Loading Order" Context

I. Issues Overview

Day One began with an overview of the RPS program and the TRCR process, summarized below:

1) **The RPS:** The RPS program is a procurement mandate imposed on California's load-serving entities (LSEs), requiring that they increase the amount of renewable generation sold to retail customers by at least 1% per year, with a goal of 20% by 2010. For purposes of transmission planning and the TRCR workshop, the RPS contains two important components:

    a. **Funding Mechanisms:** "Above-market" costs for renewable generation are to be funded via the Public Goods Charge (PGC). However, these PGC funds cannot be used to support transmission investments; hence, transmission costs (excluding gen-tie or direct assignment facilities, required to bring generation to the first point of grid interconnection) must be considered separately from the cost of generation.

    b. **Deliverability Standards:** Since the RPS standard measures the renewable generation content of *retail sales*, and LSEs face penalties for noncompliance with the mandate, some parties argue for a strict standard for deliverability. However, in light of the evolving standards for deliverability in other areas of Commission policy (such as the Resource Adequacy process), as well as the evolving standards at FERC and the CaISO, the compatibility of the RPS and more broadly applicable deliverability standards became a central issue in these workshops.

2) **The TRCR:** As noted above, the TRCR is designed to provide an approximation of transmission costs associated with a renewable generation bid. Party discussion during this period of the workshop fell into two categories:

    a. **The TRCR Concept**: Parties shared the understanding that the TRCR is not a substitute for the formal ISO SIS/FS, and acknowledged that all generation facilities will ultimately need to undergo such a study to determine the final costs of connecting to the grid. The IOUs expressed some support for the proposal that all RPS bidders must complete a SIS/FS study in advance of bidding, eliminating the need for the TRCRs completely. Other parties objected to this proposal on the grounds that many developers will not have the time or resources to

There was general agreement that deliverability standards are crucial regardless of where and how the grid upgrade assessment is made, and that these standards should be coordinated between the Commission, the ISO and FERC.

complete the ISO process in advance of the RPS solicitations. There was general agreement that deliverability standards are crucial regardless of where and how the grid upgrade assessment is made, and that these standards should be coordinated between the Commission, the ISO and FERC.

b. **The TRCR Process**: A recurring theme in the general discussion of the TRCRs was the "signaling" value of the IOU studies – i.e. the role of up-front identification of transmission expenses and constraints in helping developers to select optimal locations to site generation. This emerged as an important area for further policy development, in coordination with the ISO and the Energy Commission (see the discussion of the CEC's ongoing research in this area below).

3) **The Policy Context:** Parties returned at numerous points during the workshop to an important distinction in the present method of transmission planning in California: the difference between *total cost assessment* and *initial cost responsibility* for transmission upgrades.

a. **Cost Assessment**: The TRCRs (and ISO SIS/FS) establish the total cost, given a set of deliverability and reliability standards, of delivering an anticipated amount of generation to load.

b. **Cost Responsibility**: Once this total cost is established, it is presently the responsibility of the generator to fund the necessary upgrades, with reimbursement from ratepayers over the ensuing five years. Experience in California demonstrates that this is a burden that many renewable developers cannot bear, and the uncertainty of transmission finance under the present policy approach makes both planning and procurement difficult. Parties expressed an active interest in developing alternative methods of financing upgrades for renewable generation – such as pro-rating cost responsibility based on the share of each upgrade used by each generator, or encouraging the IOUs to move forward on transmission financing themselves[3]. While this issue was outside of the scope of the workshop, it represents an important area for further policy development – resolution of which may allow the Commission to take a more proactive role in planning for transmission of renewable energy.

While the issue was outside of the scope of this workshop, solving the problem of up-front financing for transmission may allow the Commission to engage in more effective long-range planning regarding which transmission facilities should be built to meet RPS goals.

[3] Several parties noted that, regardless of the ultimate method of assigning cost responsibility, the TRCR and SIS/FS methods should still be as accurate as possible, in order to allow the IOUs to pick those RPS bids that represent the best value to ratepayers.

4) **Early Lessons:** While the 2004 RPS solicitation negotiations are ongoing, two parties offered observations on early lessons learned from the TRCR process:

   a. **SDG&E**: The IOU noted that much of the information received in the initial request for data from developers in the TRCR process did not match with the bids ultimately received from those developers. As a result, the initial TRCR calculations did not present even a first approximation of the cost of connecting those resources as bid, meaning that the information provided to those bidders by the TRCR was of limited value.

   b. **CEERT**: CEERT argued strenuously that the deliverability standards used in the 2004 TRCRs are too strict, in relation to the state's goals for renewable generation, the emerging deliverability standards in other aspects of Commission policy (i.e. the RAR process), and the standards promulgated by the ISO and FERC (see the discussion of CEERT's presentation below).

II. The CEC's "Strategic Value Analysis" (SVA) Approach to Transmission Assessment

At the request of CPUC staff, the CEC's Public Interest Energy Research (PIER) group gave a presentation of early results from an in-depth research effort called the Strategic Value Analysis (SVA) (Attachment 2). The effort can be summarized as follows:

The CEC model incorporates a number of data sets representing transmission power flows, cost information, and GIS-based renewable resource location information at the bus level. In attempting to determine where the addition of renewable resources would be beneficial to the transmission system, the SVA initially screens out those buses additions would yield negative impacts. The model then incorporates multiple IOU procurement scenarios to define levelized costs for both generation and transmission at each bus. The model then identifies "hot spots" on the grid for the period 2005-2017, and assigns a Transmission Loading Relief Factor (TLR) corresponding to the addition of specific amounts of renewable generation at each identified bus.

The thrust of the effort is to identify to the most precise degree possible (down to the 64 kV level) the effects, both desirable and undesirable, of adding generation at specific points on the transmission system. In theory, according to the CEC, this analysis could result in a negative adder for RPS transmission costs – i.e., addition of specific generation at an identified spot could provide system benefits that outweigh the cost of installing any network upgrades.

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For purposes of RPS planning, this research may provide valuable additional information to renewable developers (and developers in general) regarding the best places to site their generation projects. While the SVA process does not at this time consider economic effects of generation addition (i.e. the increased availability of low-cost electricity to the system), and would thus not on its own be able to provide a full picture of the costs and benefits of a particular resource addition, it nonetheless may provide further valuable “signaling” information to bidders.

Parties discussed the interaction of the SVA results with two other ongoing efforts:

1) **The Energy Commission’s Renewable Resource Development Report (RRDR):** This report, produced as part of the Energy Commission’s Integrated Energy Policy Report (IEPR), identifies the geographic areas in California that offer the best prospects for economical renewable energy development. Combining the SVA results with this geographic information could thus help to correlate prime renewable resource areas with regions of the transmission system that would benefit from added generation. PIER staff indicated that this combination would be a part of the final SVA analysis, expected in Q2 2005.

The combination of the CEC’s SVA and Renewable Resource Development Report information could help the TRCR correlate prime renewable resource areas with regions of the transmission system that would benefit from added generation.

2) **The ISO’s Transmission Economic Assessment Methodology (TEAM)**: This effort, which is being evaluated in another phase of the present docket, provides modeling techniques to identify the economic benefits of adding specific transmission facilities to the grid. Parties briefly discussed the idea of integrating this work with the TRCR process, as a longer-range effort, to develop a better understanding of the economic benefits associated with each renewable bidder in a cost-benefit test.

Party discussion of these three analytical approaches to transmission planning in the TRCR context – the Energy Commission’s SVA and RRDR efforts, and the ISO TEAM concept – indicated that a focused combination of these processes may be a worthwhile undertaking for the Commission in pursuit of its renewable energy goals. Taken in combination with a transmission financing method that lessens the up-front financial burdens imposed on developers, these ideas may point

These research and modeling efforts at the CEC and ISO, in conjunction with a transmission financing method that lessens the up-front burden on developers, may point the way to the most cost-effective method of developing useful renewable energy for ratepayers.

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method of developing useful renewable energy for ratepayers.

A final point that emerged from this phase of the workshop, emphasizing general approaches to transmission assessment for renewable resources, identified an important ongoing task for the Commission to consider. Insofar as the RPS program does not require an ISO SIS/FS study to be completed prior to bidding, the TRCR – or something akin to it – will be required to estimate transmission costs and protect ratepayers from excessive expenditures.

Given this, the Commission should consider analyzing any discrepancies that may emerge between the up-front TRCR assessment of potential costs and the ultimate ISO estimation of costs via the SIS/FS process. Divergence between these two estimates may result in ratepayers ultimately bearing responsibility for renewable energy costs that exceed those anticipated in the RPS bid ranking process – particularly if the burden of up-front financing for transmission is shifted away from developers and towards IOU ratepayers.

III. CEERT PowerPoint Presentation--Flexible Deliverability Standards

CEERT argued that the modeling and deliverability assumptions embedded in the 2004 TRCRs are unreasonably strict and are inconsistent with other California and FERC requirements. In its presentation (Attachment 3), CEERT made the following key claims:

1) The IOU modeling inappropriately gives priority to all existing and previously proposed new generation, ahead of renewable resources – in violation of the EAP loading order.

2) The deliverability requirements in the TRCR, which trigger the assignment of costs for new transmission to renewable developers, assume a strict "no congestion" standard – akin, in CEERT's argument, to "planning a freeway system that never experiences traffic jams."

CEERT argued that deliverability standards should be flexible while remaining consistent with Commission Resource Adequacy and ISO policy requirements.

3) Given that 1) there will never be a transmission system that is entirely free of congestion, and 2) these standards are more strict than required by FERC or Commission Resource Adequacy policies, CEERT makes these recommendations for the TRCR process:
    a. Address certain major transmission constraints as a matter of statewide policy, rather than as a function of individual renewable generator additions.
    b. Create a deliverability standard for the RPS program that is consistent with the RAR process and ISO/FERC policy.

c. Allow for some amount of curtailability – in the range of 5-10% of contract capacity – in order to avoid costly transmission upgrades.

CEERT's assessment and proposed remedies were highly controversial and elicited extended discussion on each of the points above. Following is a point-by-point description of party arguments and suggested areas of further Commission effort.

A. Regarding Existing Requirements for Generation Prioritization under Commission/ISO/FERC Rules

Parties, in particular the IOUs, took issue with CEERT's suggestion that existing generation be given a lower priority on the transmission system than proposed new renewable generation. Parties noted that some existing generation and Reliability Must Run (RMR) facilities have fixed rights to utilize the grid. Further, these parties argue that any attempt at dispatch re-prioritization must consider flows associated with contractual must-take energy and hydroelectric generation throughout the West. In total, these pre-existing fixed rights to the transmission system may comprise as much as 25% of total ISO system transfer capability, according to party estimates.

Further, some parties contended that the very concept of a Commission-led loading order for transmission purposes may be trumped by FERC standards regarding prioritization in dispatch. PG&E raised a particular concern regarding the purpose of the RPS program in the context of displacing existing generation, arguing that any proposed changes to dispatch should emphasize the displacement of older, more polluting fossil facilities, rather than newer, cleaner plants.

To what extent is the Commission's EAP Loading Order, as applied to transmission policy, inconsistent with FERC regulations?

B. Compatibility with Existing and Emerging Standards for Deliverability

SCE in particular took issue with CEERT's claim that the current TRCR approach attempts to alleviate all congestion at all times, and asserted that the deliverability standards in the 2004 TRCRs are consistent with both FERC/ISO and CPUC standards.

This argument emerged as the central issue in the workshop. Following is a synopsis of issues and concerns expressed by parties regarding approaches to insuring compatibility across these various standards.

1) **Compatibility with FERC/ISO Deliverability**: In brief, there was no consensus among parties regarding the status of deliverability standards at the ISO. This uncertainty reflects the changing nature of FERC requirements, which are presently embodied in Order 2003b and establish a dual standard for interconnection service (the ISO has submitted a series of compliance filings to FERC to implement the order):

a. "Energy-Only" Interconnection Service: As described by parties, this FERC standard would allow generators to interconnect at a minimum cost in terms of transmission expansion, with no guarantee of the deliverability of the generator's output. In subsequent exchanges with staff, the ISO characterized the comparable standard in its January FERC compliance filing as establishing "Reliability Upgrades that would be the minimum investment (beyond the first point of interconnection) needed to interconnect safely and reliably to the ISO Controlled Grid."

b. “Network Resource” Interconnection Service: This FERC standard would mandate those additional transmission investments needed to deliver a generator’s output to load during peak periods of system operation. The ISO characterizes its compliance filing to FERC as an interim measure to comply with FERC’s Large Generator Interconnection Order, which assumes that deliverability standards will be imposed upon all systems to meet resource adequacy requirements. Assuming that such requirements will be implemented in California, the ISO could upgrade its generic interconnection service to offer both “Energy” and a "Network” interconnection" standard. This “Network” service prescribed in the FERC order would require that a new generator be deliverable to the "aggregate of load" in order to qualify as a capacity resource. The ISO’s recent compliance filing includes a deliverability assessment for new generators interconnecting to the ISO grid. This assessment identifies the facilities needed to ensure deliverability, in whole or in part, at the system peak. Construction of such facilities would be optional. Thus, the evolution of the ISO’s deliverability standards depends upon the Commission's ongoing Resource Adequacy Requirement process.

2) **Compatibility with Commission RAR Deliverability Standards**: According to ISO staff, establishment of these alternative deliverability standards is in response to FERC’s Large Generator Interconnection Order, which itself assumes that deliverability standards will be imposed upon all systems to meet resource adequacy requirements. Thus, the Commission’s ongoing Resource Adequacy Requirement (RAR) proceeding has important implications for RPS transmission planning – the terms and conditions adopted there will influence how the ISO implements flexible deliverability standards.

It is important to note, however, that a generator that elects to interconnect as an “energy-only” resource may not receive significant credit in the RAR analysis, and may not count towards the Commission’s reserve margin targets. Such a lower deliverability standard could also implicate the assessment of IOU performance against a Commission-established RPS target - i.e. how an energy-only resource would be evaluated in the RPS bidding process, given the uncertainty surrounding project output (see further discussion on this point in Section III, Day Two below). In both the RAR and RPS dockets, the Commission should balance potential interests in alleviating transmission costs for renewable generators with insuring that ratepayer funds are well spent in pursuit of resource adequacy targets.

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C. A Statewide Policy Approach to Major Transmission Constraints

CEERT advocated an approach to resolving major transmission constraints that would separate the process from the project-specific cost assessments of the TRCR. In the course of party discussion of this idea, two themes emerged:

1) **A Phased, Planning-Based Model (i.e. the Tehachapi approach)**: Parties referenced the ongoing work, in another phase of this docket, to plan for and build phased transmission upgrades to tap the wind resources in the Tehachapi region. CEERT and Vulcan argued that such an approach could be utilized for all major renewables-related transmission expansions in California. Transmission adders would be limited to each project's proportional share of the total upgrade cost, based on generator output. Up-front funding could be provided by either the IOU or by a consortium of developers.

   SDG&E raised the concern that some portion of transmission built under this approach might never be used, resulting in stranded costs to be borne by ratepayers. This concern is amplified by the fact that RPS procurement requires competitive solicitations: since developers in a region favored by a phased transmission expansion still might not win a bid, it is uncertain when, if ever, anticipated resources in a given area may be developed. Transmission costs to connect those potential resources could thus become "stranded".

   Vulcan suggested that this problem might be solved by establishing a Commission-endorsed "trigger point" stipulating the point at which, based on successful RPS bids in a given resource area, planned transmission upgrades should be constructed. While the issue of up-front financing was beyond the scope of the workshop, parties acknowledged that the ongoing work in the Tehachapi phase will be an important opportunity to develop the "trigger point" concept further.

2) **A Standard of Delivery to the ISO, with IOU Trades and Tradable Renewable Energy Certificates (TRECS)**: CEERT raised as another possibility the prospect of defining "deliverable" as receipt of power into the ISO control area. For example, a renewable generator in PG&E's territory would be required only to deliver in that region, and could satisfy the RPS requirements of another IOU via an inter-utility trade of energy or via a TREC transaction.

   This approach, which is under consideration in the RPS proceeding (R.04-04-026), could significantly decrease the transmission costs assessed via the TRCR process. However, parties noted that the RPS requirements stipulating that renewable energy be the

A deliverability standard that relies on the ISO may provide greater flexibility, but may not be consistent with IOU "best fit" requirements under the RPS legislation.

"best fit" to IOU needs might not be met by this type of deliverability standard. In effect, the "best fit" requirement would be passed to the ISO, which is not responsible for the resource planning function of the IOUs. While resolution of this issue is scheduled to take place in the RPS docket, party comments on the transmission implications of an ISO standard for delivery are clearly relevant to this proceeding.

D. Allowing for Appropriate Curtailability Standards for RPS-Eligible Generation

Closely associated with the debate surrounding deliverability standards is the treatment of curtailability in the TRCRs – i.e. the extent to which renewable generators can avoid costly transmission upgrades by committing to curtail some portion of their output during periods of congestion. D.04-06-013 directed the IOUs to use discretion on a case-by-case basis in evaluating the potential benefits of this approach, and suggested that future TRCRs might take a more structured approach to the question of curtailability.

CEERT argued that a TRCR standard that allows for curtailability of some marginal amount – i.e. 5-10% of committed project output – would serve ratepayer interests. SCE raised the concern that an unpredictable amount of renewable generation under contract could result in an IOU not reaching its RPS targets, with penalties possibly being imposed by the Commission. The IOU suggested that RPS contracts that allow for either curtailability or a weaker deliverability standard should not be of a take-or-pay nature.

A Commission standard that allows for modest curtailability – on the order of 5-10% of contract output, with appropriate exemptions from RPS penalties and without a take-or-pay component- may offer the most immediate benefits to ratepayers while questions of deliverability and up-front financing are resolved.

CEERT further suggested that a curtailability allowance of 5-10% could be coupled with a TREC system, allowing the IOUs to meet their RPS targets via a combination of direct energy purchases and tradable certificates. Parties agreed that this was an important issue for further consideration and coordination with the discussion regarding TRECs and RPS contract terms in R.04-04-026

<u>Day Two - Review of Specific Outstanding Issues Identified in D.04-06-013</u>

In response to the direction in the TRCR decision, day two of the workshop was devoted to discussion of specific TRCR-related issues, many of which were addressed in the general discussion of Day One. The following sections describe points that were not raised during the first day of the workshop.

- As a general question, the issue was raised as to whether bidders should be *required* to identify a project during the TRCR process in order to enter a bid.

I. Vulcan Presentation (Attachment 4): Vulcan Power opened Day Two with a brief presentation highlighting points in the TRCR process. The emphasis of the presentation was on the importance of a phased approach to transmission expansion, beginning with the identification of locations on the grid where new generation can be added without incurring any new transmission expense. Going forward, Vulcan recommends a two-step process: a conceptual transmission study identifying major expansions needed to optimize the grid, and a series of smaller, phased upgrades to accommodate marginal increases in new generation. Vulcan argued that the Commission's December 1, 2003 plan, "Electric Transmission Plan for Renewable Resources in California," supports investment in six major transmission upgrades that will provide benefits to ratepayers.

Vulcan recommends a two-step process: a conceptual transmission study identifying major expansions needed to optimize the grid, and a series of smaller, phased upgrades to accommodate marginal increases in new generation.

II. Deliverability
Most of the party deliberations regarding deliverability issues are captured in the previous section. Below are some further discrete points that may deserve further treatment in the TRCR process.

- **Vulcan**: Any relaxation of deliverability standards should be equitable to all renewable technologies and developers.
- **SCE**: Any favoring of renewables in the TRCR process may create an inconsistency between upfront cost assessment and the final determination of costs, via the ISO SIS/FS process. Further development of the TRCR should therefore be coordinated with the ongoing delivery standard reforms at the ISO, discussed above.
- **General party questions**:
  - How should rate recovery procedures account for delivery outside of an IOU's service territory?
  - How do congestion payments and contracts-for-differences work under an ISO-only deliverability standard?
  - How can Scheduling Coordinator-to-Scheduling Coordinator trades of intermittent resources, as proposed under a relaxed deliverability standard, work? Does the ISO Participating Intermittent Renewables Program/Amendment 42 accommodate this?
  - Why should development occur if deliverability is constrained? Is there a danger of turning a blind eye to existing deliverability problems by favoring renewables?
  - Should existing generators share the cost of transmission upgrades, in addition to new renewable projects? Can this be effectuated under CPUC jurisdiction?
  - Does an energy-only evaluation create a bias toward intermittent generation, or does the Least Cost/Best Fit analysis prevent this?

III. Curtailability
As with deliverability issues, the discussion recounted above captures the majority of the points raised regarding curtailability. Below is a list of further issues raised by parties.

- In addition to the problem of evaluating the likely output of a renewable bid that is eligible to curtail, parties were concerned that curtailability provisions may create uncertainty in the process of financing renewable development. Financiers may not be willing to invest if the output from, and hence the payments to, a generating plant are excessively variable.
    - **CEERT response:** Most of non-delivery risk is in the 95-100% of capacity range; risks at the margins of total power output should be manageable in both contract evaluation and project finance.
- **Vulcan**: Changes to deliverability and curtailability provisions should not lead to avoiding necessary grid investments.
- **PG&E**: The TRCR should continue to reflect real and total costs of full deliverability, in the interest of promoting maximum renewable development.
- **General party question:** Are there mechanisms such as Congestion Revenue Rights and Firm Transmission Rights that may be useful in allocating transmission access to EAP-preferred resources? Should the TRCRs be adjusted to reflect the possession of these rights?

Vulcan argued that any changes to deliverability and curtailability standards should not lead to avoiding necessary grid investments.

    - Given the short-term nature of these rights, parties generally did not support the notion that CRR/FTR may be useful in addressing the problems of assessing transmission needs for potential renewable bidders.

IV. Net Benefits
In this portion of the workshop, parties noted that the Commission, in D.04-06-013, chose not to adopt at that time a shorthand method of calculating the net costs and benefits associated with a given renewable generation addition. **TURN** in particular argued that such a method is needed, and that any increase in transfer capability should be counted as a credit in the TRCR. In an attempt to develop such a net benefits assessment, parties made the following observations:

- **The ISO TEAM method** of measuring net economic benefits may become available and suitable for this purpose; RPS information may be an appropriate first test of this method for the Commission to consider.
    - **SCE**: The ISO production simulation model reports are incomplete, and will require more cases to establish statistical relevance. They should also include all renewable technologies in the model.
- **The CEC Strategic Value Analysis** may also have a role here.
    - **SCE**: The CEC model only analyzed power flows. It may be a good tool for analyzing positive and negative impacts on the grid, but it is not a good economic analysis since it does not consider all economic factors.

- **SDG&E:** Why should there be a credit for unused capacity if the amount built is the minimum that can be added?
- **CEERT**: if we pursue a pro-rata cost allocation, the near-term need for a net benefits assessment is obviated.
  - **General Concern**: Even with pro-rating, an accurate picture of full costs and benefits is still necessary in protecting ratepayers.
- **CEERT**: IOUs should make carrying costs and ratemaking assumptions clear via the TRCR, and turn the total capital cost into a cents/kWh adder.
  - **SCE**: These calculations are only done when the bids are received.
- **CEERT**: IOUs may be double counting certain costs as a result of legal requirements prohibiting transmission and generation teams at the IOU from communicating with each other.

V. Sharing Gen-Tie Costs

D.04-06-013 identified the potential benefits of a TRCR method that allows for generators to share the cost of gen-tie facilities, or those facilities required to transmit power to the first point of interconnection with the grid. Under the present approach to this subject, IOUs ask bidders for their willingness to share these costs when the bid solicitations are issued. Parties made a number of points on this subject.

- Any reform to allow greater sharing of gen-tie costs should not also allow bidders unjustified opportunities to alter their bids. If gen-tie sharing is allowed, cost data should be provided before the bidding. Developers can negotiate sharing of the lines before submitting bids, and possibly loop in radial lines, which would provide even greater system benefits.
  - **Vulcan**: A mandatory bid conference and/or conceptual study before bidding would allow this sharing of costs without compromising the integrity of the bidding process.

- Only the IOUs can see the opportunity to construct a network facility from a number of multiple new gen-ties; IOUs should be encouraged to look for these opportunities.

Increased opportunities for bidders to share costs should not compromise the integrity of the bidding process.

VI. Dynamic Line Ratings

Dynamic Line Ratings (DLR) provide a means of assessing in "real time" the conditions of individual transmission lines, and, hence, potentially managing power flows in a more efficient manner. D.04-06-013 rejected the use of DLR in the 2004 TRCR process, but noted that the technology is evolving and may be of use in future RPS solicitations. The Valley Group made a presentation (Attachment 5) on behalf of CalWEA that began a dialog between parties on the subject, as summarized below.

- **CalWEA**: CEC PIER-funded DLR systems are in CA IOU territory now. The ability to utilize DLR adds potential marginal capacity (10-20%) on an operational basis.
- **PG&E**: The utility for planning, however, is lower – approaching zero.

  - o How can an IOU use DLR to assess any increased production over the life of a contract?
  - o How can DLR affect the bid formation, evaluation and ranking process?
  - o Relying on DLR can actually create operational problems – it may not be operationally possible to mitigate overload by backing down specific renewable generators, as congestion problems may be miles away from the generation whose output has been scheduled on the basis of a DLR assessment.
- Parties did not agree that DLR could be a functional short-term solution to any of the problems the TRCR is meant to address. Most felt that any benefits would be too small to meaningfully register in the TRCR process
  - o **CEERT**: Even a marginal benefit, in conjunction with the other marginal benefits discussed in the workshop, may be sufficient to improve the viability of California's potential stock of renewable generation.
  - o **SCE**: The TRCR is conceptually based and the figures are not exact. Moreover, even if marginal savings are added and there is some moderate positive impact, there may be new, contradictory costs too. The extra complexity is not worth the benefit.

VII. Coincident Generation

An analysis of coincident generation may reveal instances in which a transmission line can support the output of more intermittent renewable generation than the nameplate capacity of the generators would indicate. The analysis examines the production profile of intermittent resources to determine if wind in certain areas is likely to blow when other wind resources connected to the line are inactive. Parties observed that in-depth regional analysis is required for intermittent resource areas. The CEC-sponsored wind study collaborative may provide useful information for certain regions. Incorporating this information into future TRCRs may be possible via the CECs' SVA and RRDR studies, discussed above.

- **CEERT**: The CPUC should set some threshold at which a second look at potential bidders, employing coincident generation, is required in the TRCR.
- **SCE**: The short list assembly process is not as fixed as CEERT describes; these standards and approaches are loosely in place now

VIII. VAR Issues

Parties disagreed about the extent to which the present TRCR process appropriately treats VAR issues.

- **CEERT**: The principal concern is that VAR costs be applied on a project-specific basis, not as a generalized VAR tax for all bids.
  - o **General Question**: Can the TRCR capture this level of differentiation by project?
- **PG&E**: We must examine the VAR needs caused by a developer at both consumption as well as generation points.

IX. Transmission Acquisition at the Developer's Own Risk
This final subject elicited a short discussion among parties. The central question was whether bidders presently have the option of obtaining their own transmission. Parties generally agreed that bidders do have this option.

- **CEERT**: Bid packages should make this option clear to developers.
- **General Question**: What are the implications of this provision for getting power from outside of an IOU service territory? Can a developer avoid wheeling charges via this mechanism?
- **General Question**: How should the IOUs rank costs associated with transmission from outside the ISO? Is the present TRCR approach sufficient?

NEXT STEPS

Parties identified experiences in other states with renewable transmission issues. While the discussion at the workshop was brief, the Commission should consider examining the experiences of **Minnesota, Nevada, New Mexico, New York and Texas** to aid in its own efforts.

From the two days of discussion, staff has identified a series of near-, medium- and long-term steps the Commission should consider in advancing its goals for renewable energy and transmission planning.

I. **For the Near Term:** For the 2005 RPS solicitation, the Commission should consider implementing a **curtailability standard on the order of 5-10% of contract generation**. This approach may allow for substantial progress towards RPS goals without incurring large transmission costs to deliver a marginal increment of renewable generation to load. Contracts executed under this provision should likely not be structured with take-or-pay provisions applicable during any curtailment periods, and IOU penalties should likely not be imposed if annual RPS procurement targets are not reached as a direct consequence of these curtailability provisions. This effort should be coordinated with the standard contracts process in R.04-04-026.

II. **For the Near- to Medium Term:** Beginning immediately, the Commission should **coordinate deliverability standards between the RPS and RAR dockets**, in close collaboration with the ISO as it implements FERC orders. These standards should seek to balance the minimizing of transmission expenses to developers and ratepayers with maximum credit for renewable generation in the RAR framework. This effort should seek to insure that the TRCR standards are not more strict than those applied elsewhere in California energy planning.

III. **For the Near- to Long Term:** Beginning immediately, but recognizing that the process may take time, the Commission should **examine broadly applicable solutions to the problem of up-front transmission financing** by renewable developers. The state's energy agencies are developing a number of policy instruments and studies – such as the Commission's Electric Transmission Plan for Renewable Resources, the CEC's Strategic Value Analysis and Renewable Resource Development Report, and the ISO's TEAM method – that might be utilized in a coordinated fashion to identify the best transmission investments to support renewable energy. Once these investments are identified via this coordinated analysis, it may be possible to employ an up-front financing method that shifts the burden from developers while still protecting ratepayer interests.

CPUC STAFF WORKSHOP REPORT

ATTACHMENT 1

Attendee List
I.00-11-001: Transmission Costs Used in RPS Procurements
January 20-21, 2005

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- Attachment 2 – Strategic Location of Renewable Technology Based on Grid Reliability (PowerPoint Presentation)
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- Attachment 3 – Transmission Ranking Cost Reports (PowerPoint Presentation)
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- Attachment 4 – Geothermal Technology (PowerPoint Presentation)
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- Attachment 5 – Increasing Transmission Capability by Dynamic Rating of Lines and Transformers (PowerPoint Presentation)