ATTACHMENT B

Report on the Current Transmission Planning Process for Investor Owned Utilities

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Summary

This report attempts to provide a comprehensive analysis of the various factors that must be coordinated to achieve a consistent and sound plan for energy infrastructure in California with a focus on transmission. As a foundation, it describes and makes recommendations about the current transmission planning processes at the Independent System Operator (ISO) and the CPUC. A discussion of federal authority and how it impacts generation and transmission decision-making follows. Finally, since the Western transmission grid is interconnected, no discussion of California transmission would be complete without an understanding of regional initiatives.

In attempting to evaluate the state, federal, and regional components of transmission planning it has become obvious that transmission planning is extremely complicated, balkanized, and redundant in some circumstances in California. In evaluating how to conduct planning in a manner that best meets the energy infrastructure requirements and policy goals of California from both an economic and social perspective, this report makes the following recommendations:

1. The determination of "need" for a transmission project should only be assessed once to eliminate the redundancy that currently exists in the CPUC and ISO processes. To mitigate existing duplicative efforts, the Commission should move quickly to adopt an economic methodology for application in the CPCN process and, if required, in the interconnection process.

2. The Commission should consider revising GO 131-D, or develop a new general order, to implement changes to the existing process for determining need.

3. As part of the IOUs long-term procurement plans in R.01-10-024, the Commission should integrate local reliability considerations into the utilities overall procurement portfolio to reduce the need for expensive annual RMR contracts.

4. The CPUC should be more active in the ISO planning process.

5. The CPUC should drive a higher level of coordination between federal and state transmission related issues. There are two key areas where this sort of coordination is critical: 1) in the Commission's procurement proceeding; and 2) in the CPUC's transmission investigation.

Background

The Energy Action Plan recognizes that California needs to review its transmission planning oversight. It states:

> *The Public Utilities Commission will issue an Order Instituting Rulemaking to propose changes to its Certificate of Public Convenience and Necessity process, required under Public Utilities Code § 1001 et seq., in recognition of industry, marketplace, and legislative changes, like the creation of the CAISO and the directives of SB 1389. The Rulemaking will, among other things, propose to use the results of the Energy Commission's collaborative transmission assessment process to guide and fund IOU-sponsored transmission expansion or upgrade projects without having the PUC revisit questions of need for individual projects in certifying transmission improvements (EAP, page 7).*

The CPUC, the CEC, and ISO all have a statutory role in transmission planning. In some instances this results in inefficiencies and redundant review of transmission projects. This report has been developed entirely from the perspective of which entity is best able to do a particular job well and most efficiently. That is, like any other efficient and competent corporation or organization, duties and responsibilities should be assigned in a manner that allows for core competencies to be leveraged and expertise to govern. Assigning responsibility is this manner is more important now than ever given California's tight budgets and resource shortages.

Historically, the utilities internally evaluated options for new transmission by comparing generation versus transmission alternatives. Since AB 1890 and the onset of restructuring, the entire evaluation and the sequencing of necessary steps has changed making comprehensive analysis difficult. In the current environment, independent market participants often make decisions about new generation investment. The segregation of transmission and generation decision-making has served to create a fragmented and uncoordinated planning process that makes least cost analysis challenging. In addition, the complexity of issues and influences contributing to the decision-making of the unregulated market entities compounds the difficulties in planning. For example, transmission planners make certain assumptions when they assess the need for a particular project. One assumption is the location of particular generating units. An assumption that the utility and CAISO transmission planners made when assessing the transmission needs of Southern California, for example, was that additional generation in San Diego would be installed in summer 2003 (Otay Mesa). However, the Otay Mesa generating facility was not on-line as anticipated in the planning process because the generator was grappling with various financial and economic considerations.

When that plant was not on-line in summer 2003 to serve local demand on one side of a constrained transmission line, problems arose as congestion compounded existing bottlenecks[1]. This example underscores the challenges the State faces in coordinating the planning process and fostering an all-inclusive approach that balances options for meeting system need.

The current process for transmission planning from a statewide perspective is balkanized and in some instances redundant. This assessment of the transmission planning process originally set out to analyze ways that the CPUC's transmission assessment could be improved from a substance and process standpoint. However, in working through the current state of transmission planning in California as well as looking at generation and transmission trends recently, an evaluation that looks only through the lens of the CPUC process would be limited and out of step with the current state of affairs. Indeed, an evaluation that centered only on California and state jurisdiction would be limited and inadequate in light of the fact that California remains import dependent and much of the new generation coming on-line to serve California load is being sited outside the state.

This reality has large implications for successful planning coordination and for California consumers because generation siting out-of-state creates a demand for transmission accommodation within California. That is, since much of the new generation coming on-line originates outside California and therefore sidesteps the California planning and siting process, it still poses transmission requirements in-state so that the generation can reach customers. This circumstance highlights the difficulty in coordinating planning. It has also created a situation where transmission is "chasing" generation. The state has already been forced to recognize this planning disconnect as demonstrated in the problems surrounding the new generation on the Mexican border[2]. In truth, this is only the beginning since large quantities of new generation are coming on-line in Arizona and Nevada and are expected to compound the current bottlenecked transmission lines into California from the Southwest.

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[1] It should be noted that transmission congestion in this region is not solely due to delays in installing Otay Mesa. Rather, increased congestion is attributable to several factors including the new generation on the Mexican border, Duke placing a generating unit in the San Diego area in cold storage, and delays by the Commission in determining the need for the 230 kV Miguel to Mission upgrade.

[2] The CAISO filed Amendment 50 with FERC in May 2003 to address the problems associated with two new generation units on the Mexican border that came on-line in Summer 2003. Since insufficient transmission exists to accommodate the additional power coming from these plants (both having DWR contracts), under current CAISO congestion management rules, the ISO would be forced to pay the generators not to produce approximately 12 hours a day. The cost of this circumstance is approximately $50 million per year. FERC ruled on the CAISO's proposal to resolve these intra-zonal congestion problems on May 31, 2003. FERC approved additional mitigation to reduce the costs associated with backing down the generation, but denied further actions pending implementation of the CAISO's market re-design proposal, which is expected to resolve such problems through locational marginal pricing, rejection of infeasible schedules, and forward markets.

Ultimately, the pricing incentives that FERC authorizes through interconnection rules, the resolution of intra-zonal congestion management problems through the ISO's market redesign, and transmission ratemaking, bear strongly on the degree to which generation is located rationally and the implications for transmission. In short, a coordination of federal and state policy will be the deciding factor in whether the state can successfully analyze generation/transmission tradeoffs from a cost perspective, and implement a planning process that is rational, efficient, and cost effective.

While the focus of this report is the pricing incentives that have resulted in the generation and transmission landscape that we see today, there are non-price related reasons that California will be making transmission decisions on particular projects in the future. The premise of this report is generally that gas-fired generation can be located closer to load centers and therefore reduce the need for transmission. That is, a trade-off evaluation occurs that will result in a least cost, most efficient result. However, in some instances this is simply not the case. Renewable generation fuel resources are often constrained to specific sites (e.g. geothermal fields, high wind areas), and may require additional ancillary services. Therefore, a policy promoting renewables essentially takes the trade-off analysis off the table since a particular generation type, regardless of the transmission demand, will be chosen. In the case of wind, for example, much of the generation is not close to load centers and will require transmission to serve load. This situation creates a requirement for a different kind of analysis than what is required when one evaluates whether demand side options, transmission, or generation is the best and most cost effective way to meet need in a particular location. Inherently, state policy encouraging growth in the renewable power supply makes the determination that a particular generation type will meet a portion of need to serve the overarching objective of fuel diversity and environmental quality. In the case of renewables, this generation determination replaces the analysis described and encouraged in this report, which recommends an evaluation considering how best to serve need from a generation, transmission, and demand-side perspective.

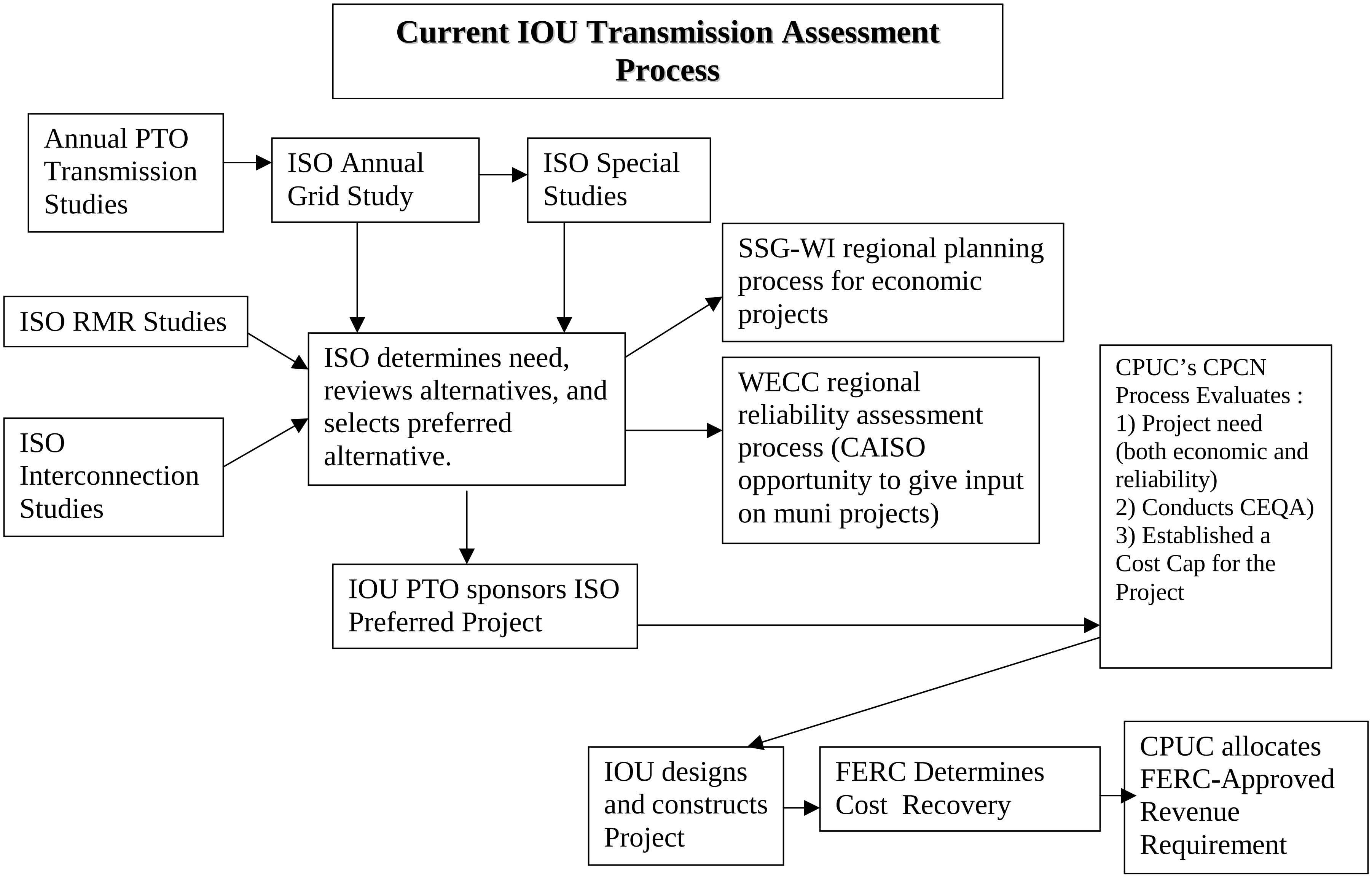
Balkanized Transmission Planning

Transmission planning in California is balkanized. Many states either have generation and transmission siting under the purview of one state agency (e.g. Arizona, Nevada) or do not have any state generation siting at all (e.g. Idaho, Pennsylvania, Alaska). In contrast, California has split generation and transmission siting authority between two state entities and among local governments. The California Energy Commission (CEC) oversees generation siting for thermal and nuclear units 50 MW or greater. For non-thermal units, such as renewable fuel sources, and units under 50 MW, local government jurisdictions conduct siting. Transmission projects sponsored by municipal utilities are reviewed and sited by the municipal board. Pursuant to PU Code section 1001 et seq., the Commission is responsible for assessing the need for new utility transmission infrastructure, both from a reliability and economic standpoint, and granting or denying a Certificate of Public Convenience and Necessity (CPCN).

In addition, AB 1890 gave the CAISO responsibility for determining the need for new transmission. While the CAISO transmission planning process determines the need of particular projects to maintain reliability and meet demand, it does not result in a CPCN. That is, once the utilities have undergone the CAISO transmission planning process and selected a particular project, the utilities then bring that project to the Commission for an additional need assessment, economic evaluation, and environmental assessment in order to obtain a CPCN.

Figure 1 describes the current transmission planning process:

Figure 1


Current IOU Transmission Assessment Process
Annual PTO Transmission Studies
ISO Annual Grid Study
ISO Special Studies
ISO RMR Studies
ISO Interconnection Studies
ISO determines need, reviews alternatives, and selects preferred alternative.
SSG-WI regional planning process for economic projects
WECC regional reliability assessment process (CAISO opportunity to give input on muni projects)
IOU PTO sponsors ISO Preferred Project
CPUC's CPCN Process Evaluates :
1) Project need (both economic and reliability)
2) Conducts CEQA)
3) Established a Cost Cap for the Project
IOU designs and constructs Project
FERC Determines Cost Recovery
CPUC allocates FERC-Approved Revenue Requirement

The recent adoption of SB 1389 potentially complicates the transmission assessment responsibilities in California. SB 1389 directs the CEC, in coordination with the CPUC and CAISO, to produce a bi-annual integrated energy policy report. The report should include “assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices (Public Resources Code section 25301 (a)). Section 25301(c) states that the integrated policy report should include an assessment of system reliability and the need for resource additions. Furthermore, SB 1389 explicitly states that the CEC’s report should evaluate the availability, reliability and efficiency of the electricity infrastructure and system including western regions and California electricity and transmission system capacity and use (section 25303 (3)).

While transmission assessment and siting is a state function, FERC’s jurisdiction over transmission ratemaking and interconnection standards has a strong impact on the financial incentives generators have when they propose a project in a particular location. For example, the current interconnection rules and transmission cost allocation do not provide financial disincentives to generators that site in remote locations away from load centers or want to interconnect in a location that necessitates extensive transmission upgrades. Under these circumstances a generator will site in the location most economically advantageous to it, usually near a water or fuel source. Often these locations are not near load centers and may not be the most economically advantageous locations for ratepayers. This situation is exemplified in the large amount of new generation located in Arizona, Colorado, and Nevada much of which is intended to serve California customers. The result is that generators are sheltered from the transmission costs that their particular projects impose and consumers are potentially disadvantaged by transmission costs in excess of those that would have been the case if generators were forced to internalize the real cost of siting decisions. In other words, consumers are potentially subsidizing generation siting decisions through excessive transmission costs.

This phenomenon has increased the pressure on the transmission systems, both due to the overall demand for transmission to accommodate new generation, and also because transmission systems were not designed for the market dynamics that have come with deregulation. Transmission systems were designed to transmit power over relatively short distances to load centers. With the onset of deregulation and regional wholesale markets, the use of the transmission system has drastically changed to accommodate a much larger overall volume of energy transactions that are occurring over greater distances[3].

[3] North American Electric Reliability Council. Reliability Assessment 2001-2010: The reliability of Bulk Electric Systems in North America. October 16, 2001.

Generation siting and transmission planning are not coupled as they were in the past. The lack of coordinated planning has been compounded by the lack of alignment between good planning and the financial incentives generators have when choosing where to locate. This situation has resulted in the problem of transmission chasing generation with the potential implication that consumers will be forced to pay for more transmission infrastructure or infrastructure at higher cost than otherwise would be the case if overall planning were better coordinated.

To most fully understand the interplay between the various processes that impact transmission planning, it is important to understand the CPUC and CAISO transmission assessment processes. To capture the sequencing more realistically, the CAISO process is described first since that is where the planning and project proposals begin. Once a determination on a particular IOU project has been made at the CAISO, the utility then proposes the project to the Commission.

The ISO Transmission Planning Process

The CAISO conducts transmission planning for the investor owner utilities (IOUs) and municipals that have joined the ISO as Participating Transmission Owners[4]. Currently, the Southern Cities[5] are the only non-IOU participants in the CAISO planning process. Federal entities, such as the Western Area Power Administration (WAPA), and municipalities do not go through the CAISO planning process, although some coordination occurs. Municipal entities have their own project approval and development process. The CAISO does analysis on the impacts of proposed municipal transmission projects and if concerns arise they are addressed through the Western Electricity Coordinating Council (WECC) reliability assessment processes. In short, while the CAISO controls approximately 80% of the current transmission system and plays a prominent role in the State's transmission planning, California does not and will not have 'one stop shopping' for transmission planning given the separate process that municipal and federal entities undergo.

There are essentially two types of transmission projects: 1) projects that are required to maintain system reliability; and 2) projects that are required for economic reasons (i.e. the cost savings to customers from building the project outweigh the project costs). The CAISO's transmission planning process has been primarily reliability focused, although the increase in transmission congestion, and

[4] Participating transmission owners (PTOs) are entities that turn over operational control of their transmission system to the CAISO. In addition, the PTOs have signed generator control agreements that give the CAISO the ability to dispatch generation.

[5] The cities of Riverside, Azusa, Banning, and Anaheim are referred to as the Southern Cities.

its associated costs, has complicated transmission assessment and blurred the demarcation between economic and reliability projects. The ISO has been more equipped, from an expertise perspective, to evaluate the reliability components of a project than the economic aspects. However, given experience in the transmission planning process in the past several years and its in-house expertise in evaluating market dynamics, it is developing the economic expertise necessary to foster a comprehensive approach toward transmission evaluation.

The CAISO's overall transmission planning process has multiple components: 1) the annual control area study that incorporates the individual yearly transmission plans submitted by the Participating Transmission Owners; 2) yearly reliability must-run studies; 3) focused studies for especially large and complicated projects; and 4) interconnection studies.

A focal point for CAISO's current transmission planning is the enormous amount of new generation that has been built in the Southwest, Colorado, and Nevada to serve California. This new generation will have large implications for the transmission requirements in California. (See Attachment A for the list of generation projects).

The CAISO Annual Control Area Grid Study

The CAISO's transmission planning process relies heavily on Participating Transmission owners (PTOs), which develop and submit annual transmission reports to the CAISO. The annual transmission plans have a rolling 10-year time-horizon.

Every year the three IOUs develop a transmission expansion report that looks out 10 years. The purpose is to assure that the system meets WECC/NERC reliability standards. The ISO reliability standards are more stringent than those of the WECC, which is essentially a floor for basic reliability requirements. After evaluating the three IOUs' yearly transmission reports, the ISO compiles a yearly control area grid study that has a 5-10 year outlook.

The CAISO's Focus Studies

In addition to yearly planning reports, the ISO has focus studies for major projects that are usually very difficult, expensive, and have large implications for reliability (e.g. Jefferson Martin, Valley Rainbow). A high level environmental review is conducted on project alternatives. Once a single project emerges from alternatives, a more in-depth environmental review is conducted by the utility. The time frame for project evaluation varies considerably between projects ranging from project evaluation that takes several months to more complicated projects that require years of development. The ISO Board approves projects that have an estimated cost greater than $20 million. ISO management approves projects that have estimated costs less than $20 million.

Once a project emerges from the focus study or yearly reports, the ISO asks the IOUs to seek a CPCN permit from the Commission. Before this point a lot of planning, consideration of alternatives, discussion with stakeholders, and other consideration has gone into the process. Historically, the CPUC has not been formally involved in the ISO planning and project development process[6]. By the time the project is before the CPUC for permitting, it has the ISO's support.

Interconnection Studies

When a new generator wishes to interconnect to the CAISO grid the Transmission Owner conducts the power flow analysis and makes a determination regarding the impacts to the transmission system that will occur with the proposed interconnection. Generally, system impact studies determine the required transmission upgrades that will be required to accommodate the new facility and estimates the transmission cost impacts. The CAISO then verifies the results and conducts an independent analysis of the transmission impacts and required upgrades to accommodate the new generator interconnection. As discussed in more detail in the section regarding federal issues, the FERC policies regarding the cost responsibility for transmission upgrades required to interconnect a new generator bear strongly on the incentives that generators have when determining where to locate. Pursuant to FERC's Order 2003, an interconnection cannot be denied.

Annual Reliability Must-Run Studies

Reliability Must-Run (RMR) units are generation units that the CAISO has determined have to run for *local* reliability reasons. They are predominantly in transmission-constrained areas such as the San Francisco peninsula where local generation near load balances the limitation on imports over constrained

[6] While the CPUC has not participated formally or actively in the ISO's or IOU's project development process, members of the Energy Division's CEQA team have attempted to work with utilities on specific project applications prior to filing formally with the Commission. While these efforts are taken to improve the application and thus ease review, these informal attempts to improve applications prior to filing have not been productive. These efforts are also undertaken once a particular project has already been selected. Therefore, while attempts to improve utility applications to ease review can and should be taken, they should be complimented by active and formal involvement early on in the ISO and IOU project development phases to maximize Commission input into project selection. To this end, the Energy Division's engineering team has recently starting taking a proactive approach to involvement in the ISO's Southwest Transmission Expansion Planning (STEP) process, which is looking at transmission alternatives to accommodate Southwest and Mexican generation.

transmission lines. The ISO conducts an annual evaluation to determine which units are required for local reliability. Once that determination has been made a one-year contract is executed that assures that the unit will be available when required for local reliability and sets out what that generator will be paid for its power. Since load pockets are predominantly an issue in Northern California, the vast majority of RMR contracts are for units in the PG&E service territory.

Fundamentally, annual RMR contracts complicate the coordination of infrastructure planning. While RMR contracts serve the valuable purpose of assuring local reliability, they also serve to further fragment the transmission planning and procurement processes. The annual RMR evaluation detracts from full cost assessment of transmission as well as complicates an assessment of generation/transmission investment trade-offs. Ideally, local reliability would be integrated into the comprehensive analysis of infrastructure need. That is, local reliability should be integrated into the evaluation of whether local generation, new transmission, or demand response best meets projected load.

Recommendation

1. As part of its evaluation of the IOUs' long-term procurement plans in R.01-10-024, the Commission should integrate local reliability considerations into the utilities overall procurement portfolio to reduce the need for expensive annual RMR contracts. This approach would facilitate a more comprehensive approach to resource planning as opposed to the fragmented assessment that is currently the case. Such an approach would increase the effectiveness of resource procurement, whether generation or transmission. It would also reduce costs to ratepayers[7]. The total cost of RMR contracts in 2003 was $360 million. There are several reasons that RMR contracts are expensive: 1) the generator is in an advantageous bargaining position since by their very nature RMR contracts are required for reliability; and 2) most of the generating units are very old and inefficient. The IOUs in their long-term procurement plans are in a position to foster a more comprehensive approach to meeting local and system needs through long range plans that incorporate generation, transmission, and demand-side trade-off analysis from a least cost perspective.

Addressing local reliability issues in the utilities' long-term plans would also provide a forum for the Commission to act in accordance with the CEC assessment of infrastructure and the environmental performance of generation in the context of IOU procurement. Pursuant to SB 1389, the CEC is charged with

[7] It should be noted that RMR units are currently considered essential for reliability and support of the transmission system. It is for this reason that RMR costs are considered transmission costs, not generation. If local reliability needs were evaluated and resolved through the utilities long-term plans, the costs of the solution could be considered a generation cost. This situation could represent a possible cost-shift.

assessing environmental performance of electric generation by looking to generation efficiency and air emissions control technologies and determine, statewide and regionally, the environmental consequences of generation additions displacing existing facilities (section 25303 (b)(1)).

Many RMR units are old, polluting, and inefficient plants. It was originally hoped that the merchant generators that purchased RMR units, such as Potrero and several in Pittsburg, would either upgrade or modernize the plants with cleaner burning, more efficient units. In many instances, that has not occurred. One of the predominant reasons is that financing for such investments is scarce or increasingly expensive as electric prices have fallen, and regulatory uncertainty persists. These circumstances have already resulted in some plant owners choosing to shut down units rather than invest in the environmental technologies that would allow the units to meet air quality standards. The CEC in its evaluation of environmental performance and infrastructure assessment will have to grapple with the question of local reliability and inefficient units. Incorporating this evaluation in the utilities long-term procurement plans makes sense since this approach should result in IOU actions that improve environmental performance, reduce RMR costs, and contribute to the statewide objectives identified by the CEC. It will allow for a comprehensive approach to meeting both system and local reliability needs. This forum will also foster collaboration between the CPUC, CAISO, and the CEC in addressing these complicated and overarching issues.

2. To ease the analysis and streamline the process once applications are filed at the Commission, the CPUC advisory and advocacy staff should be more active in the ISO planning process. This will provide a better understanding of what work has gone into a particular project prior to it being selected by the ISO, what alternatives were evaluated, and what criteria was used in the selection process. CPUC <u>formal</u> involvement and input in the earlier stages of project development and evaluation of alternatives would constitute a proactive means of decreasing the likelihood of delays and complications once the CPCN application comes before the CPUC. In addition, up front investment in the ISO project evaluation process will allow the CPUC to provide input into the assessment process and increase the chances that the selected project is the most desirable one.

CPUC Transmission Evaluation

Once the utilities have completed the ISO transmission planning process and selected a single project, they file an application with the Commission. Historically the utilities have initiated infrastructure expansion. However, more recently the Commission has become more proactive in transmission matters by calling upon the utilities to bring forward potential projects (see Attachment B for status of the Transmission Investigation, I.00-11-001). This more hands-on approach to initiating transmission evaluation was prompted by AB 970. Despite Commission actions to focus on transmission need, the decoupling of generation and transmission makes integrated planning challenging. It is important to highlight that, historically, the Commission has not been involved in the project selection process that occurs prior to the application filing at the Commission.

The Commission evaluates transmission projects from both a reliability and economic standpoint. The economic benefits of a project have been difficult to assess since an adequate model is lacking. Traditionally, the valuation of economic projects has been relatively simple in that the primary evaluation concentrated on whether access to cheaper generation justified the transmission cost increases. Since deregulation that evaluation has become much more complicated due to the dynamics of the market. For example, congestion costs and how they are treated under the market design, market power, and strategic bidding behavior are economic factors that must be assessed in the evaluation of an economic project. Given the inadequacy of traditional modeling to evaluate an economic transmission project in the current market, the Commission's decision regarding additional transmission to the Southwest directed the ISO and the utilities to develop a methodology to model the economic benefits of new transmission incorporating the market components that impact costs. The economic methodology is intended for universal application in transmission assessment recognizing the need for a more dynamic model that incorporates market factors.

While the Commission ordered the CAISO and the utilities to develop an economic methodology to evaluate transmission projects, it has yet to approve a methodology. Adopting an economic methodology will provide much needed clarity on project assessment going-forward, especially since many of the near-term projects are economic projects. The ISO filed an updated economic methodology developed jointly with London Economics, the consultant hired to develop this model, in February 2003. Path 15, Mission Miguel, and the need for new transmission to the Southwest have all been or are being evaluated based on economic benefit rather than whether the project is required for grid reliability[8].

[8] Since the London Economic model was not completed at that time, Path 15 and Mission Miguel were evaluated based on traditional economic analysis. The difficulty in modeling the economic benefits of additional transmission to the Southwest is what prompted the Commission to order the development of a more dynamic economic evaluation model. The London Economic model was not developed in time for use in the Commission's decision on Path 15. Nevertheless, the economic model, once completed, concluded that the investment in additional capacity on Path 15 was economic. In its evaluation of upgrades to path 26, the London Economic model concluded that additional investment in path 26 was not justified on economic grounds.

Recommendation

1. The determination of "need" for transmission should only be conducted once. The existing duplication in the ISO's and CPUC's transmission need determination should be eliminated. The Commission should adopt an economic methodology for universal application in transmission evaluation to eliminate the current redundancies in the CPUC's and ISO's need assessment.

   The Commission should adopt an evaluation methodology that the ISO and IOUs would use in project assessment to allow the Commission to defer to the ISO's determination of need, and avoid a separate evaluation, while at the same time meeting the statutory requirements of 1001. Revisiting the question of need for economic transmission projects would not be necessary to the extent that the Commission adopts an economic methodology for application to future projects.

   The ISO and utility should apply the Commission adopted economic methodology to projects before they are presented to the Commission for a CPCN. The determination of need will have been made using a Commission approved approach while allowing review of the application of the methodology rather than revisiting the determination of need in the CPCN evaluation. The advantages to this approach are that the Commission would be fulfilling its statutory responsibility under Section 1001 while at the same time creating a more streamlined process that eliminates the redundant evaluation of need that currently occurs. Eliminating duplicative need determinations by the ISO and Commission will result in reduced project evaluation costs, a more timely and efficient project evaluation, and resource efficiencies by all entities.

   A comprehensive resource evaluation should start in the Commission's procurement process where an evaluation of resource options is conducted before the IOU's transmission component of the resource mix can be approved. Upon a comprehensive determination of the required resources mix (e.g. generation, transmission, demand-side options), the IOUs will incorporate the transmission components into the ISO transmission planning process[9]. The ISO will then analyze the economics and reliability criteria of transmission projects utilizing an agreed upon economic and reliability assessment for IOU projects. That is, the IOUs in their long-term plans should balance the benefits of generation, transmission, energy efficiency, and demand response to meet system needs. That determination would be approved by the Commission in the procurement proceeding, and would then be reflected in the ISO's

[9] The process would be rolling in nature and the utilities would incorporate already approved projects or projects currently undergoing the ISO transmission planning process in their filings.

transmission planning process.

Therefore, the recommended approach would eliminate the existing redundancy in the transmission need assessment. It would accomplish this by having the ISO responsible for assessing whether a project is needed to meet reliability standards and economic criteria and the CPUC responsible for reviewing the application of the approved economic methodology, conducting CEQA, and implementing overall comprehensive planning through the IOUs long-term plans. An approach that eliminates redundancy and relies on the core competencies of the CAISO and the CPUC would result in cost savings and improved planning efficiency.

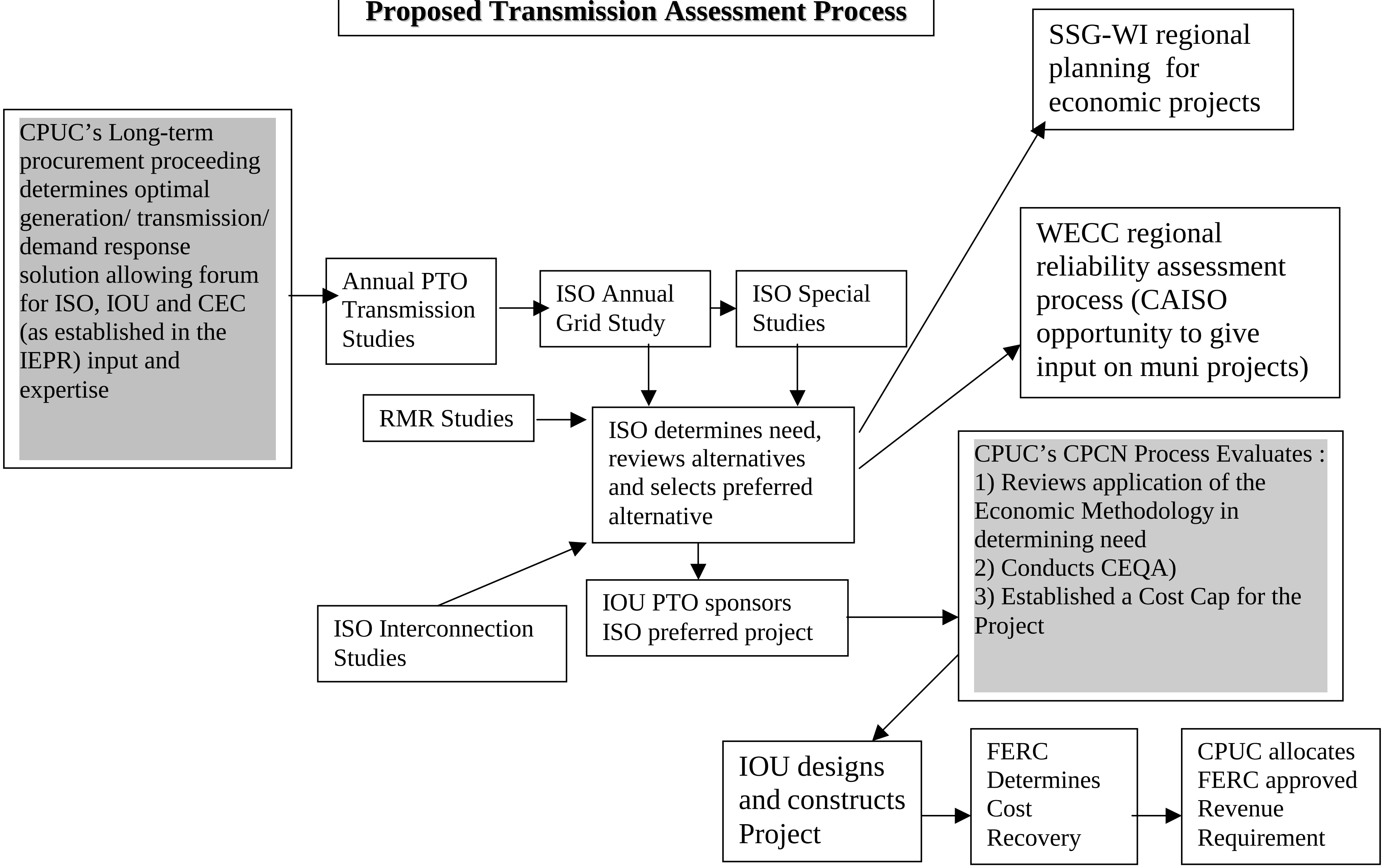
The assessment of the utilities long-term procurement plans at the CPUC is an ideal forum for the CEC to coordinate and collaborate with both the CPUC and the ISO in its role in producing the statewide and regional assessment for the Integrated Energy Policy Report. Having these entities together making hands-on decisions regarding infrastructure will reduce the likelihood of overlapping efforts and inconsistent policies while at the same time bringing together decision-makers in a way that fosters information sharing, reliance on specific expertise, and coordination.

2. One concrete step towards eliminating existing redundancies in the need determination would be for the Commission to revise GO 131-D, or develop a new general order to make changes to the existing process for determining need.

Figure 2 represents a proposed alternative transmission planning process:

Figure 2

Proposed Transmission Assessment Process



Federal Issues

Federal policy impacts transmission planning is three key ways: 1) through transmission pricing 2) wholesale market design; and 3) interconnection rules. The bottom line reason that FERC policies in these areas impact transmission is because they have cost implications for suppliers and thus provide the financial incentives for optimal generation siting. As mentioned, transmission planning in California is already being driven in large part by its reliance on imports and the large amount of new generation being built in neighboring states. FERC policies are also impacting transmission costs and siting decisions within California. Sub-optimal generation siting and by extension poor transmission planning, cannot be attributed to a single problem. Rather, the generation and transmission situation the state is facing today is a product of the interplay between several fundamental issues. The overriding factors influencing sub-optimal generation siting and potentially excessive transmission costs are interconnection rules and transmission cost allocation, transmission pricing, and a poor intra-zonal congestion management regime.

Interconnection

FERC's overarching policy has been to ease the ability of generators to interconnect to the transmission grid. Based on the premise that the interconnected nature of the transmission grid creates a benefit to all users, the FERC has long held that transmission service should be priced based on the cost of the grid as whole. That is, the FERC has favored "network" service based on average or incremental costs across the entire grid as opposed to direct assignment of costs to a particular entity. Therefore, a generator interconnecting to the grid would pay only the actual interconnection costs, but costs created throughout the system necessitated by the interconnection would be borne by all transmission customers in a "roll-in" fashion[10].

Recognizing that this approach is a poor fit with merchant generation, FERC has relaxed this policy in recent years. The policy change was due to many generators wanting to interconnect prior to having lined up load to purchase the output of the unit. The revised policy resulted in interconnection facilities (i.e. all facilities required to connect the generator to the network) being treated as direct assignment facilities and were directly assigned. The generator pays for the network upgrade that would not have been necessary 'but for' the interconnection. The transmission provider would then give a credit for the investment amount plus

10 In the California context, the rolled-in transmission costs are reflected in the ISO's grid wide Transmission Access Charge or TAC. FERC prohibits "*and*" pricing, which means that FERC does not allow the charging of a transmission customer for both a transmission service rate with the cost of the upgrades rolled in *and* the incremental cost of a network upgrade.

interest to the generator for the amount of the upgrade once transmission service begins[11]. FERC has continually reinforced its policy that a generator that pays for network upgrades beyond the first point of interconnection be paid back its investment within five years[12].

However, FERC's most recent ruling on July 24, 2003, continues its policy of requiring the five-year credit for network upgrades for non-independent transmission providers, but permits considerable interconnection pricing flexibility for independent transmission providers that have Locational Marginal Pricing.

FERC's earlier interconnection policies essentially allowed generators to be almost entirely insulated from the transmission costs resulting from their choice to interconnect in a particular location. FERC's decision that generators pay the cost of upgrades upfront has increased generator internalization of transmission costs when making siting decisions. However, FERC's direction that the transmission owners repay the generator's investment with interest within a five-year period has reduced the rational siting benefit. As PG&E argued in its comments on the Interconnection NOPR:

> *If the credit is based on transmission revenue, many projects will get their money back in 8 to 24 months. In any event, under the credit proposed in section 11.4.1 of the Interconnection Agreement, the Generator would get its money back in five years at the latest, with interest. This approach has the effect of insulating generators from cost responsibility for any network upgrades necessary to interconnect their projects, taking away the incentive to pick the least-cost location.*[13]

The ISO has raised similar issues arguing that such a fast pay-back for transmission upgrades mutes price incentives that lead to rational siting, which is not only the goal of sound transmission/generation planning, but most compatible and consistent with the pricing signals that will result from locational marginal pricing (LMP). In its July 24, 2003 Order FERC acknowledged the problems associated with the 5-year credit back stating:

> *While the Commission still finds these to be appropriate goals for an interconnection pricing policy, the commenters that object to the*

[11] See Tennessee Power Company (Tennessee). 90 FERC at 61,761, reh'g dismissed, 91 FERC at 61,271 (2000). In American Electric Power Service Corp., 97 FERC at 61,098 at 61,530-31 (2001), the FERC ruled that the generator credits should be made with interest.

[12] See FERC ANOPR on April 24, 2002 in RM02-1-000. Proposed interconnection agreement section 11.4.1. FERC adopted the Interconnection NOPR on July 24, 2003 . In addition, FERC has required a 5-year payback for individual Transmission Providers- see PG&E's *Los Madanos* and Edison's *Wildflower*)

[13] PG&E comments in R.M02-1-000. June 2002.

> *Commission's crediting policy make a number of valid points. Most importantly, as many point out, providing transmission service credits to an Interconnection Customer for the cost of Network Upgrades that would not be necessary but for the interconnection of the new Generating Facility mutes somewhat the Interconnection Customer's incentive to make an efficient siting decision that takes new transmission costs into account, and it provides the Interconnection Customer with what many view as an improper subsidy, particularly when the Interconnection Customer chooses to sell its output off-system*[14].

The interconnection cost allocation and pricing policy assigning generators the upfront costs is better than earlier policies, which provided little or no incentive to locate rationally. However, these policies still do not fully reflect the true costs associated with siting decisions. Put another way, a 5-year payback for network upgrades associated with interconnection discourages siting in the highest cost, least advantageous location, but does not deter mildly irrational, sub-optimal solutions.

As mentioned earlier, FERC's July 24, 2003 Order continues the policy of the 5-year payback but allows ISOs deference in this regard to tailor compensation for network upgrades to the market design. The premise is that in lieu of transmission cash credits, Congestion Revenue Rights (CRRs) could be allocated to generators that pay for transmission upgrades[15][16]. CRRs may entice generators to pay for transmission investment by providing a hedge against congestion costs. The hedge against congestion charges could provide the generator with a competitive advantage when marketing power to load since load would not be faced with a 'congestion mark-up' that might be associated with other supply options. Many contend this regime will provide better location pricing signals when siting generation. While this approach is new to California, it is used in the Eastern ISOs. However, in California where the value of CRRs is uncertain, especially in comparison to a cash credit, it is doubtful that compensating generators with CRRs alone would be sufficient to induce investment in network upgrades. Indeed, in the Eastern ISOs, CRRs are coupled with capacity incentives to induce transmission investment required by a generator interconnection. Under that construct, in addition to CRR allocation a generator that pays the costs of the network upgrade

[14] 104 FERC 61,103. RM.02-1-000, paragraph 695.

[15] The practice of compensating generators with property rights, currently called Firm Transmission Rights (FTRs), is similar to what the ISO currently does under its existing tariffs for inter-zonal deliverability upgrades funded by the generator. Under existing CAISO tariffs, deliverability upgrades are optional. Under the ISO proposed market re-design the distinction between inter-zonal and intra-zonal will be eliminated.

[16] FERC's policy of generator cash credits for transmission service when they make transmission investments is not particularly suitable in California where load pays transmission service, not generators.

qualifies as a capacity resource to meet Load Serving Entity's (LSE's) capacity requirements. As a qualified capacity resource the generators must pay the cost of transmission upgrades to ensure that the power is deliverable.

By January 20, 2004, the ISO and PTOs must submit compliance filings with FERC's Order 2003. In the long-term, a process where a generator pays the cost of network upgrades that are required to accommodate an interconnection and is compensated with CRRs in addition to qualifying as a capacity resource to fulfill utility capacity obligation, is a more desirable approach than the 5-year payback. The predominant reason is that the capacity resource/ CRR approach safeguards against excessive transmission costs by forcing generators to internalize the costs of serving their generation while at the same time providing incentives to invest in transmission upgrades. However, this is an evolutionary process that will likely require continuation of the crediting mechanism until the Commission has completed its development of a capacity policy in its procurement proceeding (R.01-10-024) and the ISO's market redesign is implemented. It should also be noted that a continuation of the 5-year credit may be required beyond establishment of a capacity resources/ CRR regime as it is likely that uncertainty about the value of CRRs will persist for a period once market re-design is implemented and lenders may be more inclined towards a cash credit. It is important to recognize that a construct whereby generators pay the costs of the network upgrades that would not be necessary but for the generator's interconnection is not inconsistent and should not substitute for regular investments in necessary transmission infrastructure by Transmission Owners.

Transmission Pricing

The fact that load (i.e. consumers) pays for transmission service in California, not generators, is one key cause of sub-optimal generation siting decisions and associated transmission costs.

California is one of the few states, and may be the only state, where load pays the entire transmission service charge. Since generators do not pay transmission charges, they are insulated from the transmission costs associated with a siting location. As businesses, the generators will choose their least cost option, which may be to locate near fuel and/or water sources. Such a siting choice is not necessarily the least cost, optimal outcome for consumers.

In other areas of the country, generators pay a portion of transmission service. In PJM[17], this is achieved by dividing up the network service transmission charge among load and suppliers. Alternatively, a generator could pay a point-to-point transmission charge with load paying a generic transmission charge. Under this

[17] PJM is the ISO for Pennsylvania, New Jersey, and Maryland.

construct, the transmission cost component tends to be rolled into the generators bilateral contract with load. Since transmission costs are directly internalized by generators and impact competitiveness, the result is more rational, least cost generation siting and transmission planning.

One of the reasons that California is witnessing a large amount of new generation locating in Arizona, Nevada, and Colorado, is because these locations are close to gas supplies. If generators assumed a portion of electric transmission charges, then generators would balance the costs of locating near a load center and paying lower transmission charges but incurring costs to transport gas to the units, or locating near a fuel source, mitigating gas transport charges, but incurring transmission costs[18]. As it stands under the current structure of load paying transmission service, the generators are choosing to locate near fuel sources, reducing gas transport charges. This situation could result in excessive transmission costs and infrastructure than otherwise would prevail if incentives were aligned in a manner that provide the appropriate price signals to locate generation in an overall least cost way.

Intra-zonal Congestion Management

Compounding the lack of appropriate incentives to locate generation in a least cost manner is the problem surrounding an inadequate intra-zonal congestion management system. Under the current market design, there exists three "zones" in the state. Following the premise that each megawatt is homogeneous and equally valuable in resolving system needs, generators are paid the market-clearing price no matter where in the state or zone the power is located. That is, a generator in Humboldt is paid the same price for its power as a generator in San Francisco. This is so even though the San Francisco power does not have to be transmitted as far to reach a load center and is thus "more valuable" in serving local and/or system needs. In short, current pricing has no mechanism to value location. In fact, due to the intra-zonal congestion management system, a generator has a financial disincentive to locate in a way that most economically benefits consumers.

Under the current market design, a generator is paid not to produce when the transmission system cannot accommodate the power. This is known as decrementing a unit and has lead to market manipulation in the form of the "dec game". Therefore, not only is the generator receiving the market-clearing price no matter where it locates, being sheltered from the interconnection costs no matter

[18] Analysis Group/ Economics. *Potential Adverse Consequences of Poor Transmission Pricing. Washington DC. October 23,2001*

what transmission infrastructure is required to accommodate the interconnection, but the generator is paid for not producing when the system cannot accommodate the power resulting from sub-optimal siting decisions. In its May 30, 2003 decision addressing the problems surrounding the new generation on the Mexican border and the transmission constraints that are estimated to cost consumers $4 million / month to resolve, the FERC recognized the perverse outcomes that are resulting from the pervasive problems in the current market design:

> *As long as the CAISO continues to accept infeasible schedules, it will continue to face the result of potentially having to pay generation not to produce in areas of over-generation. The Commission sees it as a perverse outcome that increased generator availability and entry would potentially raise costs for California consumers. In general, in a market-based context, one would expect increased generation availability to lower the overall cost of electricity rather than increase costs to consumers[19].*

The interplay between an inadequate congestion management regime, pricing that does not reflect locational value, and interconnection cost allocation that insulates generators from siting costs, has been a contributor to the generation and transmission landscape the state witnesses today. Currently, there are several proposals to rectify the perverse incentives that exist.

The ISO's market redesign proposal, once implemented, should resolve congestion management problems by optimizing the system prior to real-time and only accepting schedules that are feasible on the transmission system (i.e. a closer alignment of transmission engineering and pricing). The ISO's implementation of locational marginal pricing will essentially produce a value for location and the contribution of a particular generation unit in meeting system and local demand. In other words, LMP will devalue power located in remote locations away from load centers by incorporating transmission related costs into the price equation.

Recommendations

1) The general recommendation is that the CPUC should drive a higher level of coordination between federal and state transmission related issues. There are two key areas where this sort of coordination is critical: 1) in the Commission's procurement proceeding; and 2) in the CPUC's on-going transmission proceeding.

The Commission's procurement policy will provide the opportunity to remedy several of the problems that continue to result in poor generation siting and potentially excessive transmission costs. Currently generators are not responsible

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[19] See 103 FERC 61,265. Dated May 30, 2003.

for deliverability upgrades required by new generation facilities thus insulating them from transmission related costs. In addition, load pays for transmission costs in California. The Commission will directly impact the current incentives to invest in transmission infrastructure and provide economic incentive to site rationally by setting the policy framework in which the IOUs will procure resources. Requiring that contracted capacity be deliverable would impact the resources that will be able to meet that requirement and thus foster an incentive to invest in deliverability upgrades. Likewise, procurement contracts could split transmission related costs between load and generators thus serving to force the internalization of transmission related costs by generators. This internalization will filter into efficient siting decisions since the transmission related costs associated with those decisions would be incorporated into power contracts and impact competitiveness.

The Commission should move quickly to establish an economic methodology for application in new transmission projects. The reason the Commission ordered the ISO and IOUs to develop a more robust economic methodology was to more adequately capture market dynamics and apply such a methodology in the evaluation of economic transmission projects. While the availability of such a methodology for projects that require a CPCN will certainly be one of the benefits, the methodology will also be able to be applied at the interconnection stage to assess whether the benefits of a new generation facility outweigh the transmission related costs[20]. Such analysis is particularly important so long as the generators continue to receive a full repayment of upfront transmission costs within 5-years, thus muting the incentive to locate in a least cost location.

Regional Issues

California depends on power from neighboring regions to meet its needs cost effectively. While analysis of regional transmission issues has always been important due to the interconnectedness of the Western grid, it is becoming more so due to the large amount of new generation siting outside California. The focus on inter-state transmission lines is increasing accordingly. The Commission is already being faced with large inter-state transmission projects[21]. It is conceivable, and even likely, that this will increase the number of intra-state projects as well. Most new generation is coming on-line in Arizona and Nevada. Compared to the Southwest there is little new generation coming on-line in the North. The extent to

[20] The need to assess the economics of new generator interconnection is primarily a byproduct of the perverse economic incentives that exists under the current market design and 5-year credit for transmission investments. To the extent that LMP is implemented and transmission costs are reflected in the procurement process, the need for this assessment will be reduced or eliminated.

[21] The Commission concluded in D. 01-10-070 that new transmission to the Southwest was not likely to be needed for reliability purposes until 2008, which was the planning horizon used in the decision. Edison is expected to file its application, based on economic justifications, for Devers Palo Verde 2 in early 2004.

which PG&E, for example, starts contracting for cheap power from the Southwest, will have implications for large north-south transmission lines intra-state[22].

There are several undertakings on regional transmission planning. These are discussed below.

Western Governor's Association

In the aftermath of the Energy Crisis the WGA has spent considerable time on Western Transmission issues[23]. In 2002, Western Governors signed a Memorandum of Understanding with the Secretaries of Energy, Interior, and Agriculture and the heads of EPA and the Council on Environmental Quality to work cooperatively on energy development and conservation in the Western U.S. The focus of this MOU was inter-state transmission planning. The two key aspects include: 1) development of a region-wide planning process; and 2) development of a joint planning process that includes states, local governments, federal land management agencies, and tribal governments. The overall purpose of the MOU was to facilitate efficiency in the transmission planning process by coordinating among jurisdictional entities, eliminating duplicative review, creating an environmental review process that will facilitate document sharing, and streamlining review processes to make it structured and predicable. Western Governors signed a Protocol to implement the MOU that provides for cooperation on the review of any new applications to site transmission lines in the region (June 2002).

While the WGA continues to work on developing a joint review process, the Seams group has become the forum to address regional planning.

Seams Steering Group-Western Interconnection (referred to as Seams or SSG-WI)

The Seams working group is essentially designed to address issues that effect the three RTOs - CAISO, Westconnect in the Southwest, and RTO-west in the Northwest. CAISO is the only one of the three that has formalized its ISO/RTO status. This group is a forum to further the development of the West-wide inter-state transmission system. This working group was also formed in response to FERC encouraging transmission planning on a West-wide basis. In 2002 FERC said:

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[22] It should be noted, however, that the degree of access to regional power supplies is heavily impacted by ISO market rules and how attractive the California market is compared to other regions in the West.

[23] The Western Governor's have produced two major documents on Western transmission issues: "Conceptual Plans for Electricity Transmission in the West" (August 2001); and "Financing Electricity Transmission in the West" (February 2002). See http://www.westgov.org/wga/initiatives/energy/index.htm for a complete description of all WGA transmission planning activities.

> *Accordingly, while we have approved much of the conceptual framework for the creation of WestConnect and have encouraged WestConnect to continue working to develop appropriate solutions to the many outstanding issues that remain, it is still necessary to address any seams issues that may be created where different solutions are proposed by different RTOs in the Western Interconnection. In an October 25 Notice, the Commission emphasized the need for state participation to provide policy guidance to the seams resolution process and further requested that the Seams Steering Group of the Western Interconnection (SSG-WI) submit to the Commission by mid-January 2003:*
>
> *. . . a list of recommended market design elements appropriate for the western interconnect . . . which elements must be designed compatibly to avoid seams, and a plan and timeline for resolution of these issues that is coordinated with RTO development efforts. This plan would include specific tasks for each of the current SSG-WI working groups and any other working groups that may be necessary*[24].

Currently the SSG-WI Transmission Planning Working Group is evaluating uneconomic inter-state transmission congestion as well as coal, gas, and renewable generation scenarios. Based on this analysis, the seams group is performing studies for the 2008 and 2013 time frame. While the results of the studies indicate some promising combinations of transmission and generation under particular of hydro and gas conditions, they are intended for further development and analysis.

The Seams group considers reliability-driven transmission planning as the purview of the individual ISOs/RTOs. Therefore, the Seams group is primarily focused on economic transmission projects. Additionally, the CAISO intends to integrate the results of its sub-regional planning effort in the Southwest (see below) into the Seams transmission effort[25].

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[24] Arizona Public Service, Co., 101 FERC 61,350 (2002): See Notice Announcing Process for Western Interconnection Market Design and Postponing Technical Conference, 67 Fed. Reg. 67,157 (2002) (October 25 Notice).

[25] See ISO testimony dated June 23, 2003 in the CPUC's R.01-10-024.

Southwest Transmission Expansion Planning (STEP)

STEP is a forum to discuss possible solutions to particular transmission issues in Southern California and the Southwest. The meeting is conducted by the CAISO transmission planning team[26]. It is a regional meeting with transmission owners and authorities from Arizona and Mexico, Imperial irrigation district, WAPA, SDG&E, SCE, CAISO, Salt River Project, the CPUC's Energy Division, and others. The reason that a regional meeting is occurring in the Southwest is due to the large amount of generation coming on-line in the near future and transmission constraints that either exist or will exist once the generation begins to flow.

STEP is an informal gathering of interested entities that evaluate projects in the preliminary stages. The forum is very interactive and everyone is invited to comment on the proposals, submit alternatives, and ask questions regarding the data supporting proposals. For the most part, the time frame for projects under consideration is between 7-10 years. Due to the current need based on known generation coming on-line in the Southwest and Southern California a shorter-term outlook is emphasized.

CAISO plans to initiate a northwest sub-regional transmission planning effort similar to STEP.

Conclusion

The transmission planning process in California is balkanized and fragmented. The single biggest improvement in the current process will be to reduce the redundant assessment of need that occurs at the CAISO and the Commission. To eliminate a redundant review, the Commission should take a comprehensive look at all the options available to meet demand - generation, transmission, and demand-side options - in the context of the Commission's procurement proceeding. The Commission should also adopt an economic methodology for application in future transmission projects. The Commission would then be able to defer in the CPCN process to the CAISO assessment of need made when it approved the project rather than doing an additional assessment since the project would have been assessment using a Commission approved methodology. The economic methodology would also be able to be applied when the CAISO is evaluating new interconnection if it appears that the transmission related costs of a new project might outweigh the benefits.

[26] See http://www2.caiso.com/docs/2002/11/04/2002110417450022131.html for information on transmission proposals.

The Commission should also be formally involved in the CAISO planning process as an upfront effort to provide input and foster a better understanding regarding why a particular project was chosen and what criteria and assumptions were used in its selection. This upfront investment in the CAISO process should facilitate a smoother review process once the project is before the Commission.

Attachment A

There is an enormous amount of new generation that has been built in Arizona, Nevada, and Southern California that will serve California customers. The total megawatts from the projects listed below are 14,545[27]. Therefore, it is likely that additional transmission capacity will be required. When thinking about transmission capacity it is important to remember that 1 500kV line can transmit 1500-2000 MW. It seems likely that the existing 2 500 kV lines from the Southwest (Southwest Power Link and Devers Palo Verde) will not be sufficient to import Southwest power into Southern California. The generation projects below are on-line or very nearly on-line.

The new generation includes the following:

<u>Arizona</u>

Hassiampa Substation:

Hassiampa is South of Palo Verde, in Western Arizona. There is 6,600 MW of new generation at or near the substation. These projects include:

- Red Hawk- 1000 MW in-service
- Arlington Valley- 600 MW in-service
- Mesquite- 1250 MW in 2003
- Harquahala- 1170 MW in 2003

At the Gila Bend, near Hassiampa, the following new plant is likely to be in-service:

- Panda Power- 2080 MW in 2003

Near the Phoenix Metropolitan area, the following new plant is likely to be in-service:

- W. Phoenix 5- 500 MW in 2003

<u>Nevada</u>

[27] These generation additions are the basis of the assumptions in the ISO's STEP transmission planning process.

Las Vegas:
Approximately 3140 MW of new generation is likely to be in-serve near Las Vegas. These plants include:

- Las Vegas Cogen II (Black Hills) – 230 MW in-service since January 2003
- Apex (Mirant)- 550 MW in –service March 2003
- Bighorn- 570 MW in December 2003
- Silverhawk (Gen West)- 590 MW in April 2004
- Moapa (Duke)- 1200 MW (Currently suspended but 70% complete)

<u>Mexico</u>

Approximatley1660 MW of new generation is in-service in Mexico near the Imperial Valley sub-station:

- Ciclo Combinada Mexicali (Intergen)- 750 MW in-service July 2003 (590 MW connected to La Rosita and 160 MW connected to Imperial Valley 230 kV line)
- Central La Rosita (Intergen) – 310 MW in-service July 2003 (connected to Imperial Valley 230 kV line)
- Termoelectrica de Mexico (TDM, Sempra) – 600 MW. The generator is complete and able to be tested. However, given the large amount of congestion in that location, ISO operations has not permitted testing (connected to Imperial Valley 230 kV line).

A total of 1070 MW will be connected to the 230 kV system in Imperial Valley and 590 MW will be connected to the La Rosita substation in Mexico. 1160 MW of the power from these new units is intended to supply California customers.

<u>Southern California</u>

Several new units in California are likely to be in-service:
- Blyth # 1 – 520 MW in service in early 2003
- Pastoria Phase I (Calpine)- 750 MW suspended until 2004
- High Desert - 850 MW in-service 2003

Attachment B

Pursuant to AB 970, the Commission initiated a generic transmission investigation (I.00-11-001), which has considered transmission issues in 7 phases:

1) Phase 1 identified 32 transmission projects that were completed in 2001 (these were predominantly small scale upgrades). See D.01-03-077 dated March 27, 2001.

2) Transmission constraints to the Southwest. The decision concluded that new transmission to the Southwest was not required for reliability purposes within the planning horizon (i.e. not needed until 2008). It may be beneficial based on economic criteria. However, it was determined that a methodology to assess economic benefits of transmission projects needed to be developed. When rejecting the project, the Commission ordered development of a methodology to assess the economic benefits of transmission projects. See D.01-10-010 dated October 25, 2001.

3) Mission Miguel & Imperial Valley. Approved need on economic grounds. The economic analysis was based on traditional and more simplistic production cost analysis (i.e. the power cost savings justified transmission cost increases). That is, the economic analysis did not include market benefits and the more complicated economic factors surrounding the market dynamics such as strategic bidding and market power (See D. 03-02-069 dated February 27, 2003). The project is currently in the CEQA process. The Draft EIR is expected in early February 2004. A final decision is anticipated in early summer 2004.

4) Path 15 – proceeding completed. See D.03-05-083 dated May 29, 2003

5) Methodology to evaluate economic benefits of transmission projects. The ISO submitted a proposed methodology in February 2003 using a model it developed jointly with London Economics. However, this phase of the proceeding is not completed. The commission has yet to adopt a universal economic methodology for application in future transmission projects. In April 2003, an Administrative Law Judge ruling determined that the Commission should not move forward to adopt a generic methodology unless the Commission can evaluate its application to a specific project. The Commission deferred a determination on an economic methodology until the ISO had developed network model software and applied the methodology to an actual project. On December 15, 2003, the Assigned

Administrative Law Judge issued a ruling proposing a schedule whereby the Commission will assess and validate the economic methodology that the CAISO has developed pursuant to D.01-10-070[28]. A decision is anticipated in the fall on 2004

6) New transmission line and substation to interconnect Tehachapi wind resources. The proceeding is on going.

7) Statewide transmission plan for renewable generation development completed in December 2003.

[28] See. I. 00-11-001. Administrative Law Judge's Ruling Proposing a Phase 5 Schedule and Setting Further Prehearing Conference, dated December 15, 2003.

Attachment C

The Commission's Transmission Evaluation Process

Pursuant to GO 95, the utilities must apply to the Commission for a permit if a project is greater than 50 kV. California Environmental Quality Act (CEQA) assessment is conducted on any proposal greater that 50 kV.

General Order 131-D, adopted in 1994 by D.94-06-014, sets forth the Commission's current regulations pertaining to the construction of new transmission facilities. For projects over 200kV, a utility is required to obtain a CPCN. For facilities between 50kV and 200kV, a utility is required to obtain a "permit to construct." The "permit to construct" process "focuses solely on environmental concerns, unlike the CPCN process which considers the need for and economic cost of a proposed facility." D.94-06-014.

Prior to the adoption of G.O. 131-D the Commission had not required environmental review of power line facilities operating between 50 and 200 kV.

Pursuant to PU Code Section 1001, a project proposal greater than 200kV requires a Certificate of Public Convenience and Necessity (CPCN).
In relevant part, Section 1001 states:

> "no . . . gas . . . [or] electric corporation . . . shall begin the construction of a street railroad, or of a line, plant, or system, or of any extension thereof, without having first obtained from the commission a certificate that the present or future public convenience and necessity require or will require such construction."

A CPCN evaluation considers project need from reliability and economic perspective, environmental implications, and alternatives. Project alternatives are put forth in the environmental evaluation process.

GO 131-d gives the Commission 12-18 months to make a decision on the project (from the date the filing is deemed complete). When the utility requires a CPCN, it files a Proposed Environmental Assessment (PEA). This is the utility's own environmental assessment. The Commission rarely considers the PEA complete. This triggers the Commission's own environmental assessment

The PEA and the CPCN application are submitted simultaneously. The application triggers a CEQA evaluation by energy division. Contested environmental issues (following completion of the CEQA assessment) and the need for a CPCN are evaluated in evidentiary hearings. In evaluating a project under CEQA, one of two processes is followed. The first option is a negative declaration, which applies to more environmentally benign proposals. The second process is a full Environmental Impact Report (EIR), which involves a more extensive evaluation of the project's environmental impact. An EIR can take up to 1-2 years to complete.

(END OF ATTACHMENT B)